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A WGL Company

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August 5, 2024

VIA ELECTRONIC FILING

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 "G" Street, NW, 8th Floor
Washington, D.C. 20005

Re: Formal Case No. 1180
[Washington Gas's Application, Direct Testimony and Supporting Exhibits – PUBLIC]

Dear Ms. Westbrook-Sedgwick:

Transmitted for filing is Washington Gas Light Company's ("Company") Application for Authority to Increase Existing Rates and Charges for Gas Service in the District of Columbia, as well as the Direct Testimony and Supporting Exhibits of the following 15 Company witnesses (**public version**):

- James D. Steffes, Exhibit WG (A)
- Janet Burrows, Exhibit WG (B)
- Dylan W. D'Ascendis, Exhibit WG (C)
- Robert E. Tuoriniemi, Exhibit WG (D)
- Katina L. Banks, Exhibit WG (E)
- Tracey M. Smith, Exhibit WG (F)
- Ronald White, Exhibit WG (G)
- Kimberly Bell, Exhibit WG (H)
- Frederick J. Morrow, Exhibit WG (I)
- Ghislaine Quenum, Exhibit WG (J)
- Eric Block, Exhibit WG (K)
- Patrick Baryenbruch, Exhibit WG (L)
- Thomas Burgum, Exhibit WG (M)
- Paul H. Raab, Exhibit WG (N)
- Andrew Lawson, Exhibit WG (O)

Excel files associated with the testimony and exhibits are being provided via SharePoint.

Sincerely,

John C. Dodge
Associate General Counsel and
Director, Regulatory Matters

cc: Per Certificate of Service

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

FORMAL CASE NO. 1180

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY
FOR AUTHORITY TO INCREASE EXISTING RATES
AND CHARGES FOR GAS SERVICE

VOLUME 1 OF 3

PUBLIC

APPLICATION AND DIRECT TESTIMONY
WG (A) THROUGH WG (C)

(WITNESSES STEFFES, BURROWS AND D'ASCENDIS)

SUPPORTING EXHIBITS
WG (A)-1, WG (B)-1 THROUGH WG (B)-8 AND
WG (C)-1 THROUGH WG (C)-10

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DATED: AUGUST 5, 2024

APPLICATION

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	Formal Case No. 1180

APPLICATION OF WASHINGTON GAS LIGHT COMPANY

Pursuant to D.C. Code § 34-901 and 15 DCMR §§ 101, 104, 200-207 and 212, Washington Gas Light Company ("Washington Gas" or "Company") hereby requests authority to increase charges for gas service and to revise terms and conditions related to the provision of gas service in the District of Columbia ("Application"). The requested rates are designed to collect approximately $45.6 million in total annual revenues, which includes a transfer of $11.7 million from the PROJECT*pipes* surcharge to base rates; therefore, the incremental amount of the base rate increase is approximately $33.9 million. The $33.9 million of new revenues reflects an overall increase of approximately 11.9% over and above current rates.

I. APPLICANT

Washington Gas is a domestic corporation of the District of Columbia and the Commonwealth of Virginia and is qualified to conduct business in the State of Maryland. Washington Gas provides natural gas retail sales and delivery service in the District of Columbia and adjacent metropolitan regions of Maryland and Virginia. The Company's retail rates in the District of Columbia are subject to regulation by the Public Service Commission of the District of Columbia ("Commission").

II. SERVICE

All correspondence and communications concerning this Application should be sent to the following:

John C. Dodge
Associate General Counsel and
Director, Regulatory Matters
Washington Gas Light Company
1000 Maine Avenue, SW, Suite 700
Washington, DC 20024
jdodge@washgas.com

and

Cathy Thurston-Seignious
Supervisor, Administrative and
Associate General Counsel
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III. SUMMARY OF APPLICATION

Washington Gas is filing this request to increase base rates, because the Company is operating in the District of Columbia with insufficient cash flows from operating activities and an insufficient return on its investments to cover its financing costs. The current rate structure does not reflect Washington Gas's current cost of doing business in the District of Columbia, as explained in the supporting testimony included with this filing. Additionally, the under-earning was reflected in the two most recent Quarterly Earned Return filings for December 2023 and March 2024.[1] This Application,

[1] Filed under docket number WGRORETR2024-01-G-1 on February 29, 2024, and WGRORETR2024-01-G-3 on May 20, 2024, respectively.

as well as the supporting testimony and exhibits, reflect the Company's analysis that current rate levels are not sufficient to provide an appropriate return on investment and do not reflect the increased net investment and operating expenses incurred by the Company. Approval of the requested rate relief will allow Washington Gas an opportunity to earn a fair return on its investments and pursue its objectives and responsibilities, including maintaining a safe and reliable system and providing support in attaining the District of Columbia's climate goals.

The pre-filed testimony of Company Witness James Steffes, Exhibit WG (A), provides an overview of the Company's presentation, identifies the Company witnesses, and highlights the major issues in the case. The pre-filed testimony and exhibits of the other Washington Gas witnesses provide support for the need for a rate increase, as well as other proposals and recommendations.

Washington Gas's current base rates in the District of Columbia are inadequate due to a number of factors, including, but not limited to, (1) severe under-earning; (2) regulatory lag; (3) growth in the Company's rate base; (4) proposed new depreciation rates; (5) changes in tax requirements; (6) inflation; and (7) cost increases in Operation and Maintenance expenses. Given these factors, the current rate structure is not aligned with the Company's incurrence of costs. The rate relief requested in this Application is needed to provide the Company a sound financial position to continue the provision of safe and reliable service to its customers while contributing to a reduction in greenhouse gas emissions, consistent with the District of Columbia's climate goals.

The Company is requesting an opportunity to earn an overall rate of return of 7.874%, as supported by Company Witness Janet Burrows, Exhibit WG (B), including a return on common equity of 10.50%, as supported by Company Witness Dylan D'Ascendis, Exhibit WG (C). As demonstrated by Company Witnesses Robert Tuoriniemi, Exhibit WG (D), Katina Banks, Exhibit WG (E), Tracey Smith, Exhibit WG (F), Dr. Ronald White, Exhibit WG (G) and Kimberly Bell, Exhibit WG (H), to achieve the requested overall rate of return and collect revenues sufficient to meet the Company's cost of providing service to its District of Columbia customers, the Company requires a revenue increase of $45.6 million,[2] which is the amount of the increase in annual revenues requested in this Application.

The Company is also proposing new depreciation rates in this case, based on a 2024 Depreciation Rate Study prepared by Company Witness White, Exhibit WG (G), for the District of Columbia. Washington Gas is recommending primary account depreciation rates equivalent to a composite rate of 2.75%, reflecting an increase of 0.54% over the current rate.

Washington Gas is proposing a Weather Normalization Adjustment ("WNA"), which is a billing adjustment factor that creates a credit or charge to firm customers' distribution charges based on actual weather from October to May. The WNA eliminates the variability of weather from the calculation of revenues and offers more stability to customer bills. Company Witness Robert Tuoriniemi, Exhibit WG (D), discusses the WNA and how it can benefit customers by providing more stable and predictable bills, and the Company, by allowing Washington Gas an opportunity to earn its authorized rate of return, irrespective of weather. Company Witness Andrew Lawson, Exhibit WG (O), describes the Company's proposed mechanism for calculating the WNA factors.

[2] This includes a transfer of $11.7 million from the PROJECT*pipes* surcharge to base rates; therefore, the incremental amount of the base rate increase is approximately $33.9 million.

This Application is premised on ratemaking adjustments to a test year consisting of the 12 months ended March 31, 2024. The Company's selection of this test year is consistent with the Commission's policies and rules and, as adjusted by Washington Gas, is representative of the period during which new rates are expected to be in effect, *i.e.,* the "rate effective period" consisting of the 12-month period beginning August 1, 2025, and ending on July 31, 2026.

Appendix I, attached to this Application, addresses the Commission's filing requirements for rate changes, under Chapter 2 of the Commission's regulations.[3] It cross-references the contents of this filing with the filing requirements detailed in the Commission's regulations. Concurrent with the filing of this Application, Washington Gas is filing Supplemental Information pursuant to the Commission's rules governing base rate changes, as well as workpapers supporting the testimony and current affiliate agreements pursuant to the Company's merger obligations.

To reflect conditions more representative of the estimated rate effective period, which the Company projects will be the twelve months ended July 31, 2026, Washington Gas has proposed ratemaking adjustments for, *inter alia*: (1) normal weather; (2) income taxes; (3) wages, salaries and labor; (4) PROJECT*pipes* and other rate base growth; (5) inflation; and (6) general increases to operating expenses. The ratemaking adjustments, and the proposed rate of return, are needed to provide the Company with an opportunity to earn a reasonable return on its investments. Washington Gas continues to believe that limiting the adjustments by following precedent where the Commission has allowed only limited forward-looking adjustments to the test year does not fully reflect the costs and

[3] 15 DCMR § 200 *et seq.*

conditions expected in the rate effective period. However, consistent with the Commission's decision in Washington Gas's last base rate case, Formal Case No. 1169, the Company has proposed limited forward-looking adjustments in this case.

Company Witness Andrew Lawson, Exhibit WG (O), presents Washington Gas's rate design proposal, explains the mechanics of the WNA billing adjustment, and introduces other tariff changes.

The Company has complied with each of the Commission's filing requirements and directives; however, if the Commission's rules or orders are interpreted to require supplemental or different information, Washington Gas hereby respectfully requests a waiver of the filing requirements pursuant to 15 DCMR § 146.1. Alternatively, Washington Gas requests a reasonable opportunity to supplement this Application with the required responsive information.

IV. NEED FOR A RATE INCREASE

The Company's existing rates do not provide Washington Gas an opportunity to earn a reasonable rate of return in the District of Columbia. The supporting details and calculation of the level of the revenue deficiency are provided in the testimony and exhibits of Company Witnesses Robert Tuoriniemi, Exhibit WG (D), Katina Banks, Exhibit WG (E), and Tracey Smith, Exhibit WG (F). Washington Gas last sought a general rate increase in Formal Case No. 1169, which was filed on April 4, 2022.

V. SUMMARY OF PROPOSED TARIFF CHANGES

Proposed tariff changes are described and supported in the testimony and exhibits of Company Witness Lawson, Exhibit WG (O). To recover the revenue requirement identified in this proceeding, the Company is proposing a 25 percent increase in Customer

Charges for all customer classes. After deducting the increase in revenue from the proposed Customer Charges and the revenue increase associated with changes to General Service Provision charges, the balance of the requested revenue increase is proposed to be collected through the Distribution Charge or Peak Usage Charge. These proposals are designed to provide a modest movement of the existing balance of revenue responsibility by rate component towards higher fixed cost recovery and parity of return by customer class such that classes of customers earning below the system average rate of return will receive a larger share of the revenue increase and customer classes earning above the system average rate of return will receive a smaller share of the increase, as described in the testimony of Company Witness Lawson, Exhibit WG (O).

The proposed changes in base rates for customers' Customer and Distribution Charges are summarized below.

The first element of a firm customer's bill is the Customer Charge, and the proposed changes are as follows:

Type of Customer	Current Monthly Customer Charge	Proposed Monthly Customer Charge
RESIDENTIAL		
Heating/Cooling	**$16.55**	$20.70
Non-Heating/Non-Cooling:		
Individually Metered Apts.	**$12.00**	$15.00
Other	**$13.55**	$16.95
COMMERCIAL & INDUSTRIAL		
Heating/Cooling:		
Small	**$29.90**	$37.40
Large	**$70.05**	$87.55
Non-Heating/Non-Cooling	**$28.50**	$35.65
GROUP METERED APARTMENTS		

Heating/Cooling:		
Small	**$28.50**	$35.65
Large	**$70.05**	$87.60
Non-Heating/Non-Cooling	**$28.50**	$35.65

NATURAL GAS VEHICLE SERVICE AT CUSTOMER OPERATED REFUELING LOCATIONS AND NATURAL GAS VEHICLE DELIVERY SERVICE

All Customers	**$49.67**	$62.10

INTERRUPTIBLE

All Customers	**$121.00**	$151.25

COMBINED HEAT AND POWER/DISTRIBUTED GENERATION FACILITIES

All Customers	**$343.75**	$429.70

The second element of a firm customer's bill is the Distribution Charge per therm. The current and proposed basic charges are:

Type of Customer	Current Distribution Charge Per Therm	Proposed Distribution Charge Per Therm
RESIDENTIAL		
All gas used during the billing month		
Heating/Cooling	**$0.5638**	$0.7778
Non-Heating/Non-Cooling – Individually Metered Apartments	**$0.6610**	$0.8653
Other	**$0.6390**	$0.9246
COMMERCIAL & INDUSTRIAL		
All gas used during the billing month		
Heating/Cooling:		
Small	**$0.5821**	$0.8010
Large	**$0.4796**	$0.6063
Non-Heating/Non-Cooling	**$0.4811**	$0.6087
GROUP METERED APARTMENTS	**$0.4930**	$0.6252

Heating/Cooling		
Small		
Large	**$0.4863**	$0.6148
Non-Heating/Non-Cooling	**$0.4841**	$0.6124

NATURAL GAS VEHICLE SERVICE AT CUSTOMER OPERATED REFUELING LOCATIONS AND NATURAL GAS VEHICLE DELIVERY SERVICE

All therms	**$0.0745**	$0.1028

INTERRUPTIBLE

First 75,000 therms	**$0.2094**	$0.2887
Over 75,000 therms	**$0.1932**	$0.2663

COMBINED HEAT AND POWER/DISTRIBUTED GENERATION FACILITIES

All therms	**$0.1033**	$0.1430

The third element of a Commercial & Industrial and Group Metered Apartments firm customer's bill is the Peak Usage Charge. The current and proposed charges are:

	Present	Proposed
COMMERCIAL & INDUSTRIAL		
Rate per therm of peak month usage from prior year		
Annual Usage less than 3,075 therms	**$0.0519**	$0.0692
Annual Usage 3,075 therms or more	**$0.0421**	$0.0532
Non-Heating and Non-Cooling	**$0.0423**	$0.0534
GROUP METERED APARTMENTS		
Rate per therm of peak month usage from prior year		
Annual Usage less than 3,075 therms	**$0.0431**	$0.0544
Annual Usage 3,075 therms or more	**$0.0422**	$0.0533
Non-Heating and Non-Cooling	**$0.0423**	$0.0534
COMBINED HEAT AND POWER/DISTRIBUTED GENERATION FACILITIES		
Rate per therm of peak month usage from prior year	**$0.0904**	$0.1246

If granted in full, the average monthly effects of the proposed increase on the average customer bills will be:[4]

Type of Customer	Annual Therm Usage	Average Monthly Increase	Percent Increase
RESIDENTIAL			
Heating/Cooling	627	$15.33	17.6%
Non-Heating/Non-Cooling:			
Individually Metered Apts.	63	$4.07	20.8%
Other	477	$14.75	21.0%
COMMERCIAL & INDUSTRIAL			
Heating/Cooling:			
Small	1,180	$30.92	18.1%
Large	20,239	$249.16	10.9%
Non-Heating/Non-Cooling	4,345	$56.46	11.3%
GROUP METERED APARTMENTS			
Heating/Cooling:			
Small	1,664	$26.98	12.7%
Large	17,379	$220.62	11.1%
Non-Heating/Non-Cooling	4,518	$58.85	11.3%
INTERRUPTIBLE			
Interruptible	360,105	$2,409.94	20.0%

VI. PROCEDURAL SCHEDULE

Washington Gas respectfully requests that a decision on the merits of the Company's proposed rate increase and other proposals be rendered and new rates put into effect, by May 30, 2025. The length of time that passes before a final decision on the adequacy of current rates is an important issue for the Company and other stakeholders. The financial situation the Company is experiencing in the District merits

[4] Increases represented are before netting the transfer of $11.7 million from the PROJECT*pipes* surcharge into base rates.

adoption of a procedural schedule that concludes within a reasonable period of time. The Maryland Public Service Commission regularly processes cases in seven (7) months. The Virginia State Corporation Commission ("VA SCC") allows the Company to put rates into effect subject to a refund 150 days after the case's filing. More relevant to the instant case, the VA SCC allows rates subject to refund to go into effect 30 days after the case's filing for an expedited case, generally one that follows the precedents of the prior case. As discussed herein, the circumstances of this case warrant a timely resolution of the Company's request for rate relief.

Washington Gas requests that the Commission hold a pre-hearing conference by August 22, 2024, and adopt a procedural schedule by August 29, 2024, with a final decision rendered within nine (9) months of this filing[5] and new rates in effect by May 30, 2025. The Company requests that the Commission issue a fixed procedural schedule in this case, identifying timeframes and deadlines for discovery, as follows:

- Discovery served on Washington Gas commences with the filing of this Application, for the Office of the People's Counsel for the District of Columbia ("OPC").
- Discovery served on Washington Gas for intervenors granted party status commences on the date the party is granted that status.
- Washington Gas will make its Application and supporting testimony, including its informational filing, available online to the Commission and OPC within three (3) business days of this filing.

[5] GD 2023-02-M, Comments of Washington Gas Light Company at 16-17 (October 16, 2023).

- Washington Gas will require the execution of a protective agreement of non-disclosure by parties before granting access to Confidential or Attorney's Eyes-Only information.
- In discovery, parties may not request information presented in the Company's informational filing, unless the requesting party demonstrates that the utility's informational filing lacks the requested information.
- Deadlines should be established for issuing discovery on the Company's initial filing prior to the submission of direct testimony by the intervenors.
- Deadline for discovery on Intervenor testimony should be established.
- Deadline for issuing discovery on the Company's rebuttal testimony should be established.
- Washington Gas does not recommend any changes to the current objection and motion to compel practice.

With respect to discovery, once designated as a party, the party should be free to issue discovery on the utility's initial filing, on a rolling basis, up to the deadline for issuing discovery. Further rounds of discovery should be allowed on a limited basis but only pertaining directly to the intervenor's direct testimony or the Company's rebuttal testimony, as applicable. Reasonable allowances should be made for extensions of time, only for good cause shown.

Appendix II to this Application provides a Proposed Procedural Schedule, consistent with the Company's recommendations provided herein.

VII. CONCLUSION

The increase in rates proposed in this case is just, reasonable and non-discriminatory and is the minimum increase needed to recover the Company's revenue requirement. Accordingly, Washington Gas respectfully requests implementation of new rates, as provided in this Application, supporting testimony, and exhibits.

Respectfully submitted,

Karen M. Hardwick
Senior Vice President and General Counsel

____
JOHN C. DODGE
Associate General Counsel and
Director, Regulatory Matters

Attorneys for

WASHINGTON GAS LIGHT COMPANY
1000 Maine Avenue, SW, Suite 700
Washington, D.C. 20024

APPENDIX I

200 FILING REQUIREMENTS FOR RATE CHANGES

200.1 All rate change applications, other than tariff filings not affecting existing rates, shall include the following information:

(a) A statement of a historical test year and the basis for choosing this test year;

Exhibit WG (D)

(b) A statement of a proposed test year and the basis for choosing this test year;

Exhibit WG (D)

(c) A description of the nature and basis of the changes proposed;

Exhibits WG (A) – (O), as well as accompanying exhibits, supporting workpapers and supplemental information

(d) A listing of the tariff pages affected by the changes proposed;

Exhibit WG (O)-4

(e) A listing of the existing rates and proposed rates for each service for which changes are being proposed;

See Section V of this Application and Exhibit WG (O) and accompanying exhibits

(f) A full statement and description of any new or revised tariff rules and regulations;

Exhibit WG (O) and accompanying exhibits

(g) A statement listing the jurisdictional operating revenues of the utility for the historical test year and the proposed test year;

Exhibits WG (D) and WG (E) and accompanying exhibits

(h) A listing of the total number of jurisdictional customers or accounts served for the historical test year and the proposed test year;

Exhibit WG (O) and accompanying exhibits

(i) A calculation of the number of jurisdictional customers or accounts in each customer classification whose bills will be affected or a calculation of the average effect of the proposed change on jurisdictional customers in each customer classification based upon data for the historical test year and the proposed test year; and

Exhibit WG (O) and accompanying exhibits

(j) A calculation of the total proposed revenue change in dollars, by customer classification, projected on an annual basis.

Exhibit WG (O) and accompanying exhibits

200.2 Whenever, in a rate change application, a party proposes to change the ratemaking principles adopted in its most recent rate case, the party shall also file with its §200.1 filing a statement describing each proposed change in the ratemaking principles adopted by the Commission in the applicant's last general rate proceeding, showing the effect of each such change upon the applicant's request if no such changes were made.

Line	Description	Revenue Requirement	Supporting Exhibit
1	Weather Normalization Adjustment ("WNA")	None; this impacts the collection of the revenue requirement approved in this case.	WG (D) and WG (O)

200.3 Any rate change application that proposes to increase a utility's jurisdictional operating revenues by more than one percent (1%) when projected on an annual basis shall include, in addition to the statements required by §§200.1 and 200.2 and §§201 through 213, the following information:

(a) A statement showing the utility's calculation of the jurisdictional rate of return earned or to be earned in the historical test year and the proposed test year;

Exhibit WG (D) and accompanying exhibits

(b) The anticipated jurisdictional rate of return to be earned when proposed rate changes become effective;

Exhibit WG (D) and accompanying exhibits

(c) The jurisdictional rate base(s) used in the rate of return calculation supported, if available, by summaries of original cost or other factors used in its determination;

Exhibit WG (D) and accompanying exhibits

(d) A summary, on a functional basis, of the book value (actual or projected) of the utility's jurisdictional property at the close of the historical test year and the proposed test year;

Exhibits WG (D) and (F) and accompanying exhibits

(e) A statement showing the amount of depreciation reserve, at the close of the historical test year and the proposed test year, applicable to the property summarized in paragraph (d);

Exhibit WG (D) and accompanying exhibits

(f) A statement of jurisdictional operating income, setting forth the operating revenues and expenses by accounts, for the historical test year and the proposed test year;

Exhibit WG (D) and Exhibit WG (E) and accompanying exhibits

(g) A brief description of and basis for any major change affecting the utility's operating or financial condition during the proposed test year, known as of the date of transmittal of the application, and any major change during the rate effective period as follows:

(1) Known and measurable as of the date of transmittal of the application; or

(2) Known and which can be approximated with reasonable accuracy as of the date of transmittal of the application. For purposes of this section, "a major change" means one which materially alters the utility's operating or financial condition from that reflected in paragraphs (a) through (f); and

There are no major known changes that will materially alter the Company's operating or financial condition, other than that reflected in paragraphs (a) – (f).

(h) The most recent historic balance sheet available as of the date of filing.

Washington Gas Light Company
Condensed Balance Sheets (Unaudited)
Financial Statements

(In thousands)		March 31, 2024		December 31, 2023
ASSETS				
Property, Plant and Equipment				
At original cost	$	7,857,895	$	7,741,800
Accumulated depreciation and amortization		(1,980,110)		(1,948,570)
Net property, plant and equipment		5,877,785		5,793,230
Current Assets				
Cash and cash equivalents		11,246		16,742
Receivables (net of allowance of $20,060 and $19,461, respectively)		356,427		386,996
Gas costs and other regulatory assets		64,676		41,075
Inventory		71,406		136,417
Prepaid taxes		11,844		6,751
Other prepayments		23,059		25,119
Receivables from associated companies		10,537		8,278
Derivatives		14,497		5,696
Other		2,193		2,192
Total current assets		565,885		629,266
Deferred Charges and Other Assets				
Regulatory assets				
Gas costs		8,560		51,580
Pension and other post-retirement benefits		616		626
Excess deferred taxes and other		127,068		133,640
Prepaid pension and other post-retirement benefits		451,922		437,755
Operating lease right of use asset		31,664		32,595
Derivatives		39,694		27,054
Other		31,466		32,401
Total deferred charges and other assets		690,990		715,651
Total Assets	$	7,134,660	$	7,138,147
CAPITALIZATION AND LIABILITIES				
Capitalization				
Common shareholder's equity	$	2,486,842	$	2,357,771
Long-term debt		2,133,904		2,132,323
Total capitalization		4,620,746		4,490,094
Current Liabilities				
Current maturities of long-term debt		3,948		3,552
Notes payable		17,929		97,544
Accounts payable and other accrued liabilities		201,215		262,624
Customer deposits and advance payments		40,999		57,774
Gas costs and other regulatory liabilities		46,335		55,153
Accrued taxes		50,896		36,908
Payables to associated companies		22,768		14,101
Operating lease liability		6,486		6,439
Derivatives		6,438		11,271
Other		6,293		6,659
Total current liabilities		403,307		552,025
Deferred Credits				
Deferred income taxes		941,333		919,702
Accrued pensions and benefits		18,201		18,354
Asset retirement obligations		230,524		228,093
Regulatory liabilities				
Accrued asset removal costs		200,829		205,894
Pension and other post-retirement benefits		206,605		202,507
Excess deferred taxes and other		396,353		397,299
Operating lease liability		40,597		41,833
Derivatives		39,000		44,547
Other		37,165		37,799
Total deferred credits		2,110,607		2,096,028
Commitments and Contingencies (Note 10)				
Total Capitalization and Liabilities	$	7,134,660	$	7,138,147

The accompanying notes are an integral part of these statements.

200.4 The historical test year is the preferred proposed test year. However, the proposed test year may include forecasted data; Provided, that the proposed test year does not include more than six (6) months of forecasted data.

The Company is not using a proposed test year.

200.5 When a utility submits forecasted data as part of its proposed test year data, the utility's filing shall include, in addition to the information and data required by §§200.1 through 200.3 and §§201 through 213, as applicable, the following information:

(a) The basis for including forecasted data in the test year;

(b) Key assumptions which underlie the projected jurisdictional ratemaking data for the proposed test year, including but not limited to, the following:

(1) Operating Revenues;

(2) Construction Program;

(3) Operating Expenses:

(A) Fuel and interchange costs, if appropriate; and

(B) Operating and maintenance expenses (excluding those expenses under §200.5(a);

(c) Description of the procedures employed in the preparation of the projected data for the proposed test year; and

(d) Analyses of changes in jurisdictional rate base, jurisdictional expenses and jurisdictional operating income between the historical test year and the proposed test year.

The Company is not using a proposed test year.

200.6 Any request by a utility for relief from attrition shall be accompanied by the following:

(a) A demonstration of the existence and causes of attrition using the following tests:

(1) The rate of return on investment test: a comparison of the actual and authorized rates of return on total investment and return on equity for the historical test year and the nine (9) years preceding the historical test year;

(2) The operating ratios test: a comparison, for the historical test year and the nine (9) years preceding the historical test year, of the following:

(A) The actual revenues to expenses with the authorized revenues to expenses; and

(B) The actual revenues to actual expenses; and

(3) The revenues per net investment test: a comparison, for the historical test year and the nine (9) years preceding the historical test year, of the following: and

(A) The actual revenues to investment with the authorized revenues to investment; and

(B) The actual revenues to actual investment;

(b) Any other attrition tests offered by a utility to demonstrate the existence and causes of attrition; Provided, that the utility demonstrates that such tests are consistent with Commission orders and are relevant to the proceeding;

(c) Testimony and exhibits demonstrating the probability of the presence of attrition in the rate-effective period; and

(d) Testimony and exhibits showing any factors which would likely offset, at least in part, the presence of attrition during the rate-effective period.

Not applicable

200.7 In the attrition tests identified in §200.6, a utility shall, as applicable, do the following:

(a) Exclude fuel, gas, and interchange costs from its expenses;

(b) Exclude income derived from fuel, gas, and interchange costs from its revenues;

(c) Include income taxes as expenses; and

(d) Adjust its data for abnormal weather.

Not applicable

200.8 When a utility's historical test year and proposed test year are the same, the utility shall submit a single set of data.

The Company is not using a proposed test year.

200.9 If pro forma changes are included in a utility's proposed test year filing, data in that filing shall be provided for the proposed test year on an actual as well as a pro forma basis.

The Company is not using a proposed test year.

200.10 In cases governed by §200.3, the information specified in §§201 through 213 shall be supplied within twenty-one (21) days after the filing of the application, unless otherwise ordered by the Commission, but shall not be regarded as part of the evidentiary record unless admitted into evidence.

Information has been provided with this Application

200.11 Any request for waiver of the filing requirement in this section shall be submitted at the time of the filing of the application for a rate change. If the request for waiver is denied, the utility shall have twenty-one (21) days after the issuance of the denial by the Commission within which to supply the information.

Waiver requested in this Application, if applicable

200.12 One (1) copy of the required information shall be supplied to the Secretary of the Commission, the staff, the People's Counsel, and to each applicant for intervention that requests a copy.

Copies of this filing are being provided to these entities.

200.13 Staff and the Office of the People's Counsel may request additional copies prior to the end of the twenty-one (21) day period.

APPENDIX II

PROPOSED PROCEDURAL SCHEDULE

1.	Pre-Hearing Conference	August 22, 2024
2.	Order and Report on Pre-Hearing Conference Issued	August 29, 2024
3.	WGL Supplemental Testimony and Workpapers (if necessary)	September 13, 2024
4.	Deadline for Data Requests to WGL Regarding Application, Direct and Supplemental Testimony	September 20, 2024
5.	Settlement and Stipulation Conference	September 27, 2024
6.	Parties Report on Settlement and Stipulation Conference	October 1, 2024
7.	WGL Responses to Data Requests	October 4, 2024
8.	Deadline to Submit Follow-Up Data Requests	October 11, 2024
9.	Responses to Follow-Up Data Requests	October 18, 2024
10.	Direct Testimony and Exhibits of OPC and Intervenors	November 1, 2024
11.	Deadline for Data Requests Regarding OPC and Intervenors Testimony	November 15, 2024
12.	All Responses to Data Requests Regarding Intervenor Testimony	December 4, 2024
13.	Deadline for Follow-Up Data Requests on OPC and Intervenor Testimony	December 11, 2024
14.	Responses to Follow-Up Data Requests Regarding OPC and Intervenor Testimony	December 18, 2024
15.	Rebuttal Testimony and Exhibits by All Parties	January 8, 2025
16.	Deadline to Submit Data Requests Relative to Rebuttal Testimony	January 22, 2025
17.	Responses to Data Requests Relating to Rebuttal Testimony	February 5, 2025
18.	Deadline to Submit Follow-Up Data Requests on Rebuttal Testimony	February 12, 2025
19.	Responses to Follow-Up Data Requests on Rebuttal Testimony	February 19, 2025
20.	Hearings (If Applicable)	February 25-26, 2025
21.	Community Hearings (Location and Time TBD)	TBD
22.	Motions to Correct Transcript and Corrected Final List of Cross-Examination Exhibits	March 14, 2025
23.	All Post-Hearing Briefs (One Brief)	March 28, 2025
24.	Expected Decision	May 16, 2025
25.	Rates into Effect	May 30, 2025

WITNESS STEFFES
EXHIBIT WG (A)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF JAMES D. STEFFES
Exhibit WG (A)
(Page 1 of 1)

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Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF JAMES D. STEFFES

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is James D. Steffes and I am Senior Vice President for Washington Gas Light Company ("Washington Gas" or "Company"). I assumed my current position on January 15, 2021. In this capacity I lead our Government Affairs, Public Policy, Rates and Regulatory Affairs efforts. I also lead our Energy Acquisition team. My business address is 1000 Maine Avenue, SW, Washington, D.C. 20024.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. Prior to joining Washington Gas, I was the Executive Vice President for Direct Energy, which is a North American retail energy provider based in Houston, Texas. In that position I was responsible for communications, regulatory affairs, and governmental relations for a multi-state energy retailer. Previously, I held management positions in the energy industry, including the position of Senior Vice President, NRG Energy and President, Green Mountain Energy. I have worked in the energy industry since 1994.

I received a Bachelor of Science degree in Foreign Service from Georgetown University in Washington, D.C. and have a Master's in Public Policy from the Harvard Kennedy School in Cambridge, MA.

Q. HAVE YOU TESTIFIED PREVIOUSLY?

A. Yes. I have testified before the Virginia State Corporation Commission in the Company's 2022 base rate case (PUR-2022-00054). I have testified before the Maryland Public Service Commission (Case No. 9056 and Case No. 9704). I have also testified before the Illinois Commerce Commission (Case No. 05-0159).

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I will summarize the request for an annual base rate increase of $45.6 million, of which $11.7 million is related to the revenue requirement for capital spending associated with the Company's accelerated replacement program ("PROJECT*pipes*") currently being collected in a customer surcharge and being transferred into base rates in this proceeding. I support the overall justness and reasonableness of the Company's requested increase and provide an overview of the Company's testimony in this proceeding.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I sponsor Exhibit WG (A)-1, our 2023 Utilities Value Drivers Scorecard.

IV. DISCUSSION OF COMPANY

Q. PLEASE DESCRIBE WASHINGTON GAS.

A. Washington Gas has been providing service to customers since 1848 when it was founded through a Congressional charter, which remains in full force today. The Company celebrated its 175th anniversary on July 8, 2023. Washington Gas is a domestic corporation of the District of Columbia ("District") and the Commonwealth of Virginia and is qualified to conduct business in the State of Maryland. As of March 31, 2024, the Company provided natural gas service to more than 1.2 million customers system-wide, including 163,908 customers in the District.

V. DISCUSSION OF THE NEED FOR RATE RELIEF

Q. WHAT RELIEF DOES WASHINGTON GAS SEEK IN THIS CASE?

A. In this filing, Washington Gas requests an annual base rate increase of $45.6 million based on a test year consisting of the 12-month period from April 1, 2023, to March 31, 2024. The proposed base rate increase includes $11.7 million related to the revenue requirement for amounts currently being collected pursuant to the Company's District of Columbia accelerated replacement program through the PROJECT*pipes* surcharge that is being transferred to base rates.

Q. WHAT ARE THE PRIMARY FACTORS DRIVING INCREASED RATES?

A. Several key factors contribute to the request for an increase in base rates, including rate base growth since our prior rate case (including non-PROJECT*pipes* rate base growth), general cost increases in operation and maintenance expenses, new depreciation rates recognizing a new 2024 Depreciation Rate Study sponsored by Company Witness White, an increase in revenue requirement due to a tax normalization requirement from the Internal Revenue Service based on Private Letter Rulings (PLRs) related to tax sharing payments and Net Operating Loss Carryforwards, and an increase in our overall authorized rate of return based on actual test year average capital structure and an appropriate adjustment to the Company's authorized return on equity.

Q. PLEASE DESCRIBE THE COMPANY'S DIRECT CASE AND THE APPROACH IT IS TAKING THROUGH ITS APPLICATION AND SUPPORTIVE TESTIMONIES.

A. The Company's direct case presents the cost of service as of the rate effective period. Washington Gas is seeking a base rate increase due to its current higher level of cost of providing gas utility service in the District. Washington Gas last requested a general rate increase on April 4, 2022, in Formal Case No. 1169, based on a test period ending December 31, 2021. The final rates in that case were approved by the Public Service Commission of the District of Columbia's ("Commission") Order No. 21939, issued on December 22, 2023. The effective date of new rates was January 19, 2024, by Order No. 21942, issued on January 11, 2024.

Washington Gas has filed this request for an increase in base rates because the Company's most recently approved rates, which were implemented over twenty-one (21) months after the Company filed an application for rate relief, do not reflect the cost of doing business in the District and, therefore, do not provide Washington Gas a reasonable opportunity to recover its prudently incurred expenses and earn its authorized rate of return on investments made to provide service to the Company's customers in the District.

Again, to reiterate, our current base rates reflect average rate base and operating costs premised on a test year ending December 31, 2021. The Company seeks a timely process for the Commission to consider this specific rate matter to align our rates with the investments and spending required to provide safe and reliable service to the District's customers.

Q. WHEN DOES THE COMPANY PROPOSE THAT NEW RATES BE IMPLEMENTED?

A. Our application seeks new rates based on the material in this case to be implemented in May 2025.

Q. WHAT IS THE RATE EFFECTIVE PERIOD?

A. The rate effective period, *i.e.*, the initial one-year period in which the rates approved in this proceeding will be in effect, is the 12 months, August 1, 2025, through July 31, 2026.

Q. DOES THE DIFFERENCE BETWEEN WHEN WASHINGTON GAS SEEKS NEW RATES AND THE RATE EFFECTIVE PERIOD IMPACT THE REVENUE REQUIREMENT IN THIS CASE?

A. In the revenue requirement determination, the rate effective period, *i.e.*, the initial one-year period in which the rates approved in this proceeding will be in effect, is the 12 months beginning August 1, 2025, through July 31, 2026. The Company is proposing a procedural schedule that would allow it to place new rates into effect in May 2025. The difference between that date and the rate effective period used to develop the ratemaking adjustments in the cost of service has little or no impact on Washington Gas's revenue requirement recommendation.

Q. WHY IS THE PROPOSED PROCEDURAL SCHEDULE AND TIMELINE OFFERED BY THE COMPANY REASONABLE?

A. The Company is proposing a reasonable and appropriate timeline in litigating rate matters before the Commission. The Company is filing this rate case with a focus on a historical test year with limited non-precedential policy matters. In fact, Washington Gas is adopting many positions that this Commission ruled upon in its most recent rate decision in Formal Case No. 1169. For instance, Washington Gas is not seeking forward adjustments to betterment capital beyond the test year and is not seeking a return on Construction Work in Progress (CWIP). Furthermore, in this case, Washington Gas is not seeking a revenue decoupling mechanism or a surcharge related to cost recovery for climate-related activities. Given the approach Washington Gas is taking in this case and based on historical experience, achieving new rates by May 2025 is reasonable.

Q. DOES THIS TIMELINE COMPORT WITH THE COMPANY'S RECOMMENDATIONS RESPONDING TO THE COMMISSION NOTICE OF INQUIRY ("NOI") REGARDING FUTURE RATE CASES ISSUED ON JULY 27, 2023, IN DOCKET GD 2023-02-M?

A. Yes. The Company filed Initial and Reply Comments in response to the Commission's NOI. In Initial Comments and subsequent Reply Comments, the Company offered several recommendations that it believed are necessary to engender efficiency in the ratemaking process, thereby reducing litigation costs, which are paid for by customer. Foremost among the Company's recommendations is the need for the timely issuance of a procedural schedule for the adjudication of rate cases, with fixed milestones regarding the prehearing conference, discovery, public hearings, proceeding hearings, and briefing, as appropriate, as well as the issuance of a final decision and new rates implementation date.

Key to the Company's need for a reasonable timeline, the Company proposes that the Commission issue a procedural schedule within forty-five (45) days of the filing of this rate case application.

Q. WHAT INFORMATION IS THE COMPANY INCLUDING IN ITS FILING TO FACILITATE LITIGATION OF THIS CASE ALIGNED WITH ITS COMMENTS IN THE NOI MENTIONED ABOVE?

A. In its response to the Commission's NOI, the Company offered several recommendations related to the review of the Company's rate applications. To demonstrate its commitment to efficient case processing, the Company has included the following information with its Application or in Company Witness testimony (as seen in the following table):

INFORMATION	LOCATION
Annual Reports	See Compliance Filing 212.9
SEC Filings / 10-Q, 10-K	See Compliance Filing 212.9
Company Prospectus	See Compliance Filing 212.9
Annual Report to Shareholders	See Compliance Filing 212.9 and washingtongas.com
List of post-test year adjustments	See Witness (D) testimony
List of change in manner of recording accounting data	See Witness (D) testimony
Statement of any change in recording accounting data	See Witness (D) testimony

Q. WHAT HARM OCCURS IF THE COMMISSION DOES NOT AUTHORIZE THE COMPANY TO IMPLEMENT NEW RATES BY MAY 2025?

A. Washington Gas notes that the timeline experienced in Formal Case No.1169 was unprecedented and has resulted in inordinate regulatory lag. As Company Witness Tuoriniemi clearly demonstrates in his testimony, there are clear revenue deficiencies in the Company's net operating income. And while the Company's rates were adjusted in January 2024, that revenue increase does not remedy the severe under-earning the Company experiences today. The Company's March 2024 Quarterly Earned Return report showed the Company earned a return on equity of 1.03 percent on a distribution-only basis. As critical, cash flows from operating activities are still negligible. During the test year, on a per book basis, funds from operations and cash working capital provided only $118,340. This has a significant impact on our credit metrics, which Company Witness Burrows highlights in her testimony. The Company stresses the importance of the timely recovery of our investments and operating costs through an appropriate timeline for a Commission decision on rate relief in this rate case.

Q. IS THE COMPANY PROPOSING A CHANGE TO ITS CURRENT AUTHORIZED RETURN ON EQUITY?

A. Yes. Company Witness D'Ascendis explains why the Company is seeking a higher Return on Equity than currently authorized. The Company recognizes that the Commission issued an Order within the last 8 months establishing its current authorized Return on Equity. The Company also acknowledges that the Commission increased its authorized Return on Equity at that time. While the Commission did not adopt Company Witness D'Ascendis' recommendation fully, the direction of the change was aligned with his testimony in Formal Case No. 1169. As the testimony in this case makes clear, there is evidence that the return necessary for Washington Gas has increased from the period when testimony was presented in Formal Case No.1169. The Company, therefore, recommends that the Commission recognize this evidence as it determines the authorized Return on Equity for the Company in this rate case.

Q. PLEASE EXPLAIN THE COMPANY'S APPROACH TO PROJECT*pipes* COSTS IN THIS RATE CASE.

A. As mentioned above, the base rate increase of $45.6 million includes $11.7 million of revenue requirement for eligible PROJECT*pipes* infrastructure projects. These capital investments are initially recovered through a surcharge mechanism called the Accelerated Pipe Replacement Plan ("ARP") (also referred to as the PROJECT*pipes* surcharge) billed to customers monthly. These costs are transferred to base rates in a subsequent rate case proceeding when the surcharge is reset to reflect the movement of plant into rate base. As in Formal Case No. 1169, the Company adopts an average to end-of-period rate base adjustment to transfer PROJECT*pipes* expenditures, incurred as of March 31, 2024, to base rates.

VI. REASONABLENESS OF THE REQUESTED INCREASE IN RATES

Q. ARE THE RATES BEING PROPOSED BY WASHINGTON GAS JUST AND REASONABLE?

A. Yes. As detailed in the Direct Testimony of Company Witness Tuoriniemi, the Company has made significant investments in plant since the prior test year and the Company has experienced higher operating costs that are necessary to provide safe and reliable utility service to our customers. The rates proposed in this proceeding will enable Washington Gas to continue to provide value to customers, including supporting the Company's ability to provide safe and reliable service.

Q. PLEASE DISCUSS HOW WASHINGTON GAS PROVIDES VALUE TO CUSTOMERS.

A. The Company's value to customers results from our continued provision of safe, reliable natural gas distribution service at a reasonable cost. This service is delivered by and attributable to the hard work of our 1,506 employees, with more than two hundred employees either living or working in the District.[1] Our employees, with their on-going focus on safety and reliability, provide value to customers every day. In addition, our focus on delivering our Value Drivers, discussed more below, aligns our Company with the needs of our customers in the District.

Q. AS RELIABILITY AND SAFETY ARE COMPONENTS OF VALUE DELIVERED, PLEASE DISCUSS THE COMPANY'S PERFORMANCE IN 2023.

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[1] As of March 31, 2024.

A. I will highlight our focus on reliability and safety using three points - reliability performance, emergency call answer performance and system modernization.

Q. PLEASE DESCRIBE THE COMPANY'S RELIABILITY PERFORMANCE.

A. Washington Gas continues to place a strong focus on reliability for our customers. As Company Witness Morrow explains, for the twelve-months ending March 31, 2024, the Company had a reliability percentage of 99.69%.

Q. PLEASE DESCRIBE THE COMPANY'S PERFORMANCE ON EMERGENCY CALLS.

A. The second point relates to answering emergency calls. Customers who believe that an emergency exists, for instance if they believe they smell natural gas, can contact Washington Gas at any time, day or night, every single day of the year. The Company's target service level for emergency calls is 95% of calls answered within 30 seconds. During the test year, April 1, 2023, to March 31, 2024, on a system-wide basis, Washington Gas received 101,328 emergency calls. Over the course of the test year, our emergency call center representatives answered more than 99,000 of those calls within 30 seconds, a success rate of 99.02%.

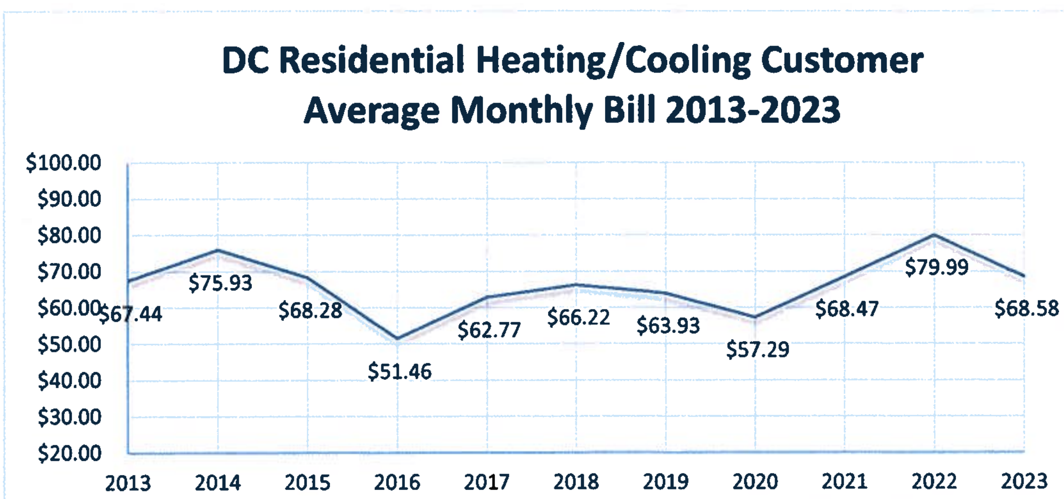
Q. WHAT DID THE COMPANY ACHIEVE ON SYSTEM MODERNIZATION?

A. We continue to work to modernize our system and replace older main and services, with significant focus through our accelerated replacement program. In 2023, across our District service territory, we installed 3.6 miles of new main pipe, retired 5.0 miles of aging main and remediated 1,968 service lines. Our focus on pipe replacement of aging infrastructure allows us to continue to deliver gas services safely and reliably for our customers.

Q. BEYOND SAFE AND RELIABLE SERVICE, THE COMPANY MENTIONED REASONABLE PRICING FOR CUSTOMERS. ARE WASHINGTON GAS' BILLS AFFORDABLE?

A. Washington Gas recognizes the need to maintain affordable bills for its customers. One way to see our focus on affordability is to look at Graph 1 below, in which Washington Gas' average monthly bill for residential heating/cooling customers during 2023 was slightly less than $69. This means that in 2023, our residential heating and cooling customers' costs were in line with 2015 levels. While significant inflation has occurred during this period, Washington Gas has worked hard to maintain overall bill affordability.

Graph 1: Average Residential Heating/Cooling Customer Monthly Bill



Q. WHAT IS THE RATE INCREASE FOR THE AVERAGE RESIDENTIAL HEATING/COOLING CUSTOMER FROM THIS PROPOSED RATE CHANGE?

A. The Company estimates its proposed rates will result in the average residential heating/cooling customer experiencing an increase to their total base rate bill of approximately $15.33 monthly as shown in Exhibit WG (O)-2, Schedule A. Because $11.7 million, or 26% of the Company's increase is related to the movement of PROJECT*pipes* costs into base rates, the approximate net increase to the average residential heating/cooling customer is approximately $11.40 per month. As the Commission is fully aware, based on the proposed procedural schedule, the earliest any proposed rate increase will impact customers will be in or after May 2025.

Q. WHAT ELSE IS WASHINGTON GAS DOING TO MAINTAIN AFFORDABLE ENERGY COSTS IN A PERIOD OF INCREASING INFLATION?

A. Washington Gas recently initiated an internal effort to organize our activities and operations that ensures our workforce is aligned with our customer needs, including remaining affordable. This has resulted in a reduction in the size of the workforce during April 2024 – exclusively in the Management layer – by over 70 positions. Although the changes impact employee costs after the end of the test year (*i.e.*, after March 2024), given that the total impact of these cost reducing activities are known and measurable, they have been included as an adjustment reflected in this case. Company Witness Smith details the savings that are applied to our proposed revenue requirement increase and Company Witness Tuoriniemi discusses the cost to implement these savings. Overall, this

April 2024 action allows us to meet our customer needs while lowering the revenue requirement in the District of Columbia by more than $1.2 million.

Q. WILL THESE CHANGES SUPPORT CUSTOMERS AND MEET YOUR OBLIGATIONS?

A. The Company constantly works toward enhancing operational efficiency and aligning operational tactics more closely with our customers' needs. Our adjustments include streamlining functions and decreasing headcount when necessary.

These changes will improve the Company's agility, reduce operational overlap, and help it better respond to the needs of our customers. One example of improving our agility and responding better to our customers' needs is the change wherein the Company has restructured Operations and Construction activities by appointing a senior leader responsible for these functions in the District of Columbia (the Company has also made this change in Maryland and Virginia). This should enhance the Company's ability to deliver safe, reliable, and affordable energy to the customers we serve in the District.

Q. DURING CERTAIN PRIOR PERIODS, THE COMMISSION FOUND THAT THE COMPANY'S CALL CENTER PERFORMANCE WAS INADEQUATE. HAS THE COMPANY EXPERIENCED SIMILAR CUSTOMER CARE ISSUES DURING THE TEST YEAR?

A. During the test year, the Company delivered solid customer service as demonstrated by the Service Level metrics shown in the table below. In no month during the test year did the Company's percentage of calls answered in 30 seconds fall below 83.65%.

MONTH	SERVICE LEVEL
April 2023	99.18%
May 2023	95.37%
June 2023	93.88%
July 2023	94.91%
August 2023	96.29%
September 2023	87.86%
October 2023	88.73%
November 2023	87.68%
December 2023	96.00%
January 2024	92.89%
February 2024	83.65%
March 2024	91.61%

Q. WHAT OTHER VALUE HAS THE COMPANY PROVIDED THAT THE COMMISSION SHOULD CONSIDER IN DETERMINING THE REASONABLENESS OF THIS RATE REQUEST?

A. One important focus for the Company has been on commitments to supplier diversity. As seen by the results, the Company has embraced our Supplier Diversity goals. One strategy has been cultivating direct relationships with diverse suppliers, referred to as Tier One Contractors. During 2023, 56% of diverse supplier spending was attributable to our direct relationships with Tier One Contractors.

The Company also established partnerships with various agencies and organizations that support supplier diversity in the District. These collaborations have helped to expand our network and identify qualified diverse suppliers. As an example of this work, Washington Gas highlighted a Certified Business Enterprise ("CBE") in February 2024 who has contributed to our business results and has also fostered economic growth within the community.[2]

The Company is progressing toward our goal of reaching a 35% diversity spend threshold by 2028. The Company disbursed $197 million in 2022, and $208 million in 2023, which is a diversity spend of 32.7% last year. Our commitment to advancing supplier diversity initiatives remains strong, and we will persist in exploring new opportunities to enhance our efforts.

Q. YOU MENTIONED YOUR "VALUE DRIVERS" ABOVE. PLEASE DESCRIBE THE COMPANY'S VALUE DRIVERS.

A. The 2023 Utilities Value Drivers are presented in Exhibit WG (A)-1. Our Value Drivers are developed annually to articulate how the Company will achieve operational excellence across the enterprise to support our customers. The 2023 Value Drivers fall into five focus areas:

- **Corporate Social Responsibility:** This value driver focuses on our environmental, social and governance ("ESG") initiatives. This encompasses safety and environmental, diversity and inclusion, corporate compliance, community investment and cyber/IT activities.
- **Operations:** This value driver focuses the Company on identifying and implementing a series of innovative process and technology initiatives to achieve key operational efficiencies driven through a high-performance

[2] "Washington Gas Celebrates Partnership with Fort Myer Construction." Washington Gas Press Release, February 15, 2024. Washington, DC.

culture. These efficiencies allow us to provide our customers with affordable service over time.

- **Customer Experience:** This value driver is about providing efficient, professional and cost-effective services to our customers, including helping our most vulnerable customers.
- **Regulatory & Public Policy:** This value driver concerns how the Company will ensure that it will work with its customers and policymakers to have a safe, reliable and affordable energy delivery system.
- **Emerging Ecosystem:** This value driver focuses the Company on developing action plans for near-term integrated strategies that are consistent with emerging public policy related to carbon reduction and support for customers.

Q. HOW DO THE COMPANY'S VALUE DRIVERS SUPPORT THE REASONABLENESS OF THE RATES PRESENTED?

A. Our business operations are developed consistent with the five areas found in the Value Drivers, and they are cascaded into Individual Value Drivers agreed to by the employee and their manager. The Value Drivers focus on the Company's commitment to achieving success across a broad range of metrics and align employees with achieving for our customers.

Q. DO THE VALUE DRIVERS AND THE SHORT-TERM INCENTIVES WORK TOGETHER TO SUPPORT CUSTOMERS?

A. Yes. Performance against Individual Value Drivers and overall Company delivery against Corporate Value Drivers support our customers by tying pay to performance for employees through our Short-Term Incentive mechanism when we deliver for our customers. As described more fully by Company Witness Burgum, the rates we are proposing in this case recognize the overarching structure of our compensation program and supporting our District customers.

Q. PLEASE DESCRIBE THE COMPANY'S SHORT-TERM INCENTIVE PROGRAM AND ITS BENEFITS TO CUSTOMERS.

A. Washington Gas' Short-Term Incentive ("STI") Plan is in place to incentivize employees to help the Company achieve its overarching strategic objective of delivering safe, reliable, affordable energy to our customers. Company Witness Burgum provides the details of the Company's compensation policy and STI Plan. Under the Company's STI Plan, all employees of the Company—including non-supervisory personnel, administrative personnel, and union employees—are eligible to receive incentive compensation commensurate with Company and individual performance outcomes outlined in the Company's Value Drivers. At the core of Washington Gas's STI Plan is a focus on safe, reliable and affordable service.

VII. SUPPORT FOR THE DISTRICT'S CLIMATE GOALS

Q. IS THE COMPANY MAKING ANY SPECIFIC PROPOSALS IN THIS APPLICATION RELATED TO ADDRESSING THE DISTRICT'S CLIMATE GOALS?

A. No. Given the Commission's directive in Formal Case No. 1169 to file such proposals in Formal Case No. 1167, the Company is not proposing any new programs for approval within this application addressing the District's climate goals.

Q. WHAT IS THE COMPANY DOING TO SUPPORT THE DISTRICT'S CLIMATE GOALS?

A. Washington Gas reaffirms our commitment to deliver energy safely, reliably, and affordably in an ever more sustainable way. As a manifestation of our commitment to provide service more sustainably, we have filed comments and program proposals in various energy efficiency and climate-related dockets before the Commission, including Formal Case No. 1160 and Formal Case No. 1167.

In Formal Case No. 1160, we filed an Application for Approval of Energy Efficiency ("EE") Programs on April 28, 2023, which is pending for Commission action. The Company's proposed EE Program Plan consists of eight unique programs and one initiative. The plan offers over 75 energy conservation measures or "offerings" to Washington Gas residential and commercial customers in the District, with a specific focus on low-income and moderate-income customers. The Company proposes to invest approximately $13.8 million in EE programs and Workforce Development initiatives that offer energy savings measures and resources to District of Columbia residents and businesses.[3] As the implementation of these programs depends on the approval of the Commission, the Company encourages the Commission to timely consider its EE proposals to support our customers and to assist the District and its residents in achieving their greenhouse gas reduction goals.

Q. IN ADDITION TO THE EE PROGRAM PROPOSAL, WHAT OTHER ACTIONS HAS THE COMPANY TAKEN TO SUPPORT THE DISTRICT'S CLIMATE GOALS?

[3] Formal Case No. 1160, Washington Gas Light Company's Application for Approval of Energy Efficiency Programs (April 28, 2023).

A. In Formal Case No. 1167, the Company filed its Climate Change Action program with the Commission on December 15, 2021, addressing the five-year period from 2021 – 2025. The Company's action plan proposes to support the District in achieving its climate goals and make solid progress toward achieving the District's 2045 vision. The Company's Climate Change Action Program, Part 1, identified thirteen (13) initiatives organized around four (4) program areas: End Use and Efficiency, Infrastructure and Operations, Sourcing and Supply, and Transportation. These program areas are aligned with the Company's Climate Business Plan and include Transportation as a new program area given the critical need for the decarbonization of the transportation sector within the District.[4]

The Company is filing four (4) programs in Formal Case No. 1167. We note that the programs provide the Commission with a portfolio of options that will enhance emissions data accuracy and transparency for the District's energy customers, streamline procedural processes, provide a robust fact-based framework for technical discussions and determinations, and that may help achieve emissions mitigation and reductions over time. Most significantly, the proposed programs align generally with the seven (7) principles outlined in the Commission's *Modernizing the Energy Delivery System for Increased Sustainability* ("MEDSIS") proceeding (Formal Case No. 1130), which promotes the development of a sustainable, well-planned, safe, reliable, secure, affordable, interactive, and equitable energy system as the District works towards its climate goals.

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[4] Formal Case No. 1167, Washington Gas Light Company's Climate Change Action Program, Part 1 (December 15, 2021).

The table below highlights the four (4) programs:

Program	Brief Description
Program I: Study Lower Carbon Technologies and Solutions	Support studies to assess the emissions reduction potential and feasibility in the District of the following technologies and solutions: • Networked geothermal • Sewage heat recovery • Carbon capture • Hybrid heating • In-District biomethane resources
Program II: Expedited Consideration for Biomethane Infrastructure	Adopt a procedural process framework that will allow Washington Gas to propose and develop infrastructure necessary to interconnect biomethane production to the distribution system.
Program III: Procure Carbon Neutral Credits	Allow Washington Gas to procure carbon credits to offset Scope 3 combustion emissions.
Program IV: Enhance Emissions Reporting Transparency and Accuracy	Require natural gas competitive service providers ("CSPs") and Washington Gas to report to the Commission the known emissions intensity of their supplies of certified gas and biomethane as well as the volume and type of carbon credits procured to offset customer emissions.

VIII. SUPPORT FOR MITIGATING CUSTOMER BILL VARIABILITY DUE TO WEATHER DEVIATIONS

Q. IS THE COMPANY SEEKING A REVENUE DECOUPLING MECHANISM IN THIS RATE CASE SIMILAR TO THE ONE SOUGHT IN FORMAL CASE NO. 1169?

A. No, it is not.

Q. IS THE COMPANY PROPOSING ANY OTHER ADJUSTMENTS TO MITIGATE THE RISK OF WEATHER?

A. Yes. Recognizing the Commission's statements in Formal Case No. 1169,[5] the Company is seeking in this rate case to implement a Weather Normalization Adjustment ("WNA") that provides an effective and efficient method of risk mitigation for both customers and the Company solely due to weather variations. The WNA assures that colder-than-normal weather or warmer-than-normal weather will neither penalize nor reward customers or the Company. In other words, the WNA merely ensures that deviations from the normal weather incorporated into rates will not cause Washington Gas to either over or under recover its cost of service. Because the weather is outside of the control of customers and the Company, it should not be a factor in determining the billing for distribution services and the recovery of the cost of providing services approved by the Commission.

Q. WHAT HAS THE COMPANY USED FOR NORMAL WEATHER IN THIS CASE?

A. Washington Gas has adopted a 30-year normal weather approach, as ordered by the Commission in Formal Case No. 1169. This is detailed in the testimony of Company Witness Raab. The recommended WNA is critical to achieve reasonable revenues under this 30-year normal weather approach. Importantly, the proposed WNA provides a proper price signal to customers

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[5] *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Natural Gas Service*, Formal Case No. 1169, Order No. 21939 at 109 (December 22, 2023).

reflecting the actual cost of distribution service. The WNA is required to provide a reasonable opportunity for the Company to earn revenues that eliminate weather variability and enable the Company to maintain financial integrity and attract capital. The Company is proposing that weather deviations from October until May be considered the "WNA Period". Outside of these months no adjustment will be made for weather-related revenue deviations. The WNA is reasonable because it also aligns all parties on the objective of establishing an appropriate normal weather to be reflected in rates.

Q. HOW IS THE COMPANY'S PROPOSED WNA CONSTRUCTED?

A. Importantly, the WNA proposed by the Company has several customer-friendly features that ensure that the WNA only adjusts for weather deviations, and not customer efficiency gains or economic impacts. When a WNA Period is warmer than normal (*i.e.*, there is a shortfall in the amount collected by the Company), the Company will accrue any shortfall due to weather deviations and carry that balance forward until the following WNA Period, where it will incorporate the balance into rates on a per therm basis. When a WNA Period is colder than normal (*i.e.*, there is an excess in the amount collected by the Company), the crediting of these weather-driven revenues to customers will occur within two months, providing customers with immediate bill relief. Finally, as proposed by the Company, if any WNA Period reflects a significant deviation from normal weather, the next WNA Period rate adjustment will be capped, ensuring that customers are not exposed to extreme rate volatility due to the WNA. Company Witnesses Tuoriniemi and Lawson describe more fully the Company's proposal and the WNA mechanism.

Q. PLEASE SUMMARIZE WHY THE PROPOSED WNA IS IN THE PUBLIC INTEREST AND SHOULD BE APPROVED.

A. The proposed WNA provides an effective and efficient method of risk mitigation due to weather for both customers and the Company. The WNA does not increase the authorized revenue for the Company; rather, it ensures that Washington Gas' experienced revenues better align with what the Commission approves in this proceeding. The symmetrical treatment for warmer-than-normal weather or colder-than-normal weather proposed by the Company treats all stakeholders fairly. The mechanism will also provide near-term relief to customers during a WNA Period where the weather has been colder-than-normal, while spreading the impact of warmer-than-normal weather over the subsequent WNA Period. The mechanism represents an improvement in ratemaking and fosters greater confidence that weather will not negatively impact nor reward customers or the Company.

IX. SUPPORT FOR TRANSPARENCY IN AFFILIATE COSTS

Q. IS THE COMPANY FILING AN AFFILIATE COST OF SERVICE STUDY ("ACOSS") WITH THIS RATE APPLICATION?

A. Yes, it is. These materials are in alignment with discussions with external parties, including the Apartment and Office Building Association of Metropolitan Washington. If the Commission imposes additional requirements for the ACOSS after the filing of this Application, the Company will file a revised ACOSS in subsequent testimony.

X. IDENTIFICATION OF WITNESSES

Q. PLEASE INTRODUCE THE COMPANY'S WITNESSES AND IDENTIFY THE ISSUES EACH ADDRESSES.

A. The Company supports its request for rate relief with this testimony, as well as the prepared direct testimonies of 14 additional witnesses:

- Company Witness Janet Burrows supports the proposed capital structure and cost of capital.
- Company Witness Dylan D'Ascendis proposes a reasonable rate of return on common equity.
- Company Witness Robert Tuoriniemi supports accounting and ratemaking adjustments, as well as adoption of a Weather Normalization Adjustment.
- Company Witness Katina Banks supports revenue adjustments.
- Company Witness Tracey Smith supports the Company Class Cost of Service Study, jurisdictional allocation, and labor adjustments.
- Company Witness Dr. Ronald White supports the Company's Depreciation Rate Study.
- Company Witness Kimberly Bell supports the impact of recent Internal Revenue Service Private Letter Rulings that necessitate a change in the treatment of federal income tax sharing payments.
- Company Witness Frederick Morrow supports certain investments that are proposed to be recovered in base rates, including PROJECT*pipes* costs transferred from the surcharge to base rates, and provides a

summary and description of the other capital plant proposed to be collected in base rates.

- Company Witness Ghislaine (Celine) Quenum supports the Affiliate Cost of Service Study and presents the Cost Allocation and Inter-Company Pricing Manual.
- Company Witness Eric Block supports inbound affiliate costs.
- Company Witness Patrick Baryenbruch presents the Affiliate Cost Study.
- Company Witness Thomas Burgum describes the Company's compensation framework and the value of our short-term incentive compensation approach.
- Company Witness Paul Raab sponsors the Company's Normal Weather Study underlying the proposed rates.
- Company Witness Andrew Lawson supports the Company's proposed rate design, WNA mechanism, changes to cost application for credit/debit card fees and other tariff changes.

XI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR PRINCIPAL CONCLUSIONS AND RECOMMENDATIONS.

A. Washington Gas' request for a base rate increase of $45.6 million is just and reasonable. Further, the Commission should authorize the Company to implement a Weather Normalization Adjustment to protect both customers and the Company from unpredictable weather and provide the Company with a fair opportunity to remove the impact of weather variability from distribution revenues. Finally, the Commission should authorize the Company to implement other tariff changes proposed by the Company in these proceedings.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

2023 Utilities Value Drivers Scorecard

Value Drivers	Priorities	Key Measures
Corporate Social Responsibility	Safety	TRIF & MVIR
	People	Talent & Culture Roadmap
Operations	Efficient Deployment of Capital	Capital Portfolio Execution
	Operational Excellence	Business Transformation
Customer Experience	Efficient Delivery of Service	Increase Utilization of Lower Cost Service Channels
	Meet Customer Expectations	Call Center Performance
Regulatory & Public Policy	Achieve Rates That Are Aligned with Customer Needs	Execute Rate Cases
		Execute APRP Extensions
Emerging Ecosystem	Lower-Carbon Gas Supply	RNG Procurement
	Business Development	New Markets

ATTESTATION

I, JAMES D. STEFFES, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

James D. Steffes
JAMES D. STEFFES

July 30, 2024
DATE

WITNESS BURROWS
EXHIBIT WG (B)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF JANET BURROWS
Exhibit WG (B)
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DIRECT TESTIMONY OF JANET BURROWS
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WASHINGTON GAS LIGHT COMPANY

District of Columbia

DIRECT TESTIMONY OF JANET BURROWS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Janet Burrows. I am Vice President and Treasurer of AltaGas Ltd. ("AltaGas"), the parent of Washington Gas Light Company ("Washington Gas" or "the Company"). My business address is 1700, 355 4 Avenue SW, Calgary, Alberta T2P 0J1.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have been employed by AltaGas since May 2019. I assumed my current role on August 1, 2023, following the election by AltaGas's Board of Directors. I am responsible for the administration and supervision of all treasury functions across AltaGas, its affiliates, and its subsidiaries.

Prior to joining AltaGas, I worked in various finance and accounting positions for 21 years.

I have a Bachelor of Commerce Degree from the University of Calgary. I have a Chartered Accountant Professional Designation (CPA) in Alberta, Canada.

Q. HAVE YOU PREVIOUSLY SUPPORTED TESTIMONY REGARDING UTILITY BASE RATE PROCEEDINGS?

A. This is my first testimony provided in support of a Washington Gas base rate proceeding.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I address the reasonableness of the Company's overall cost of capital, including the individual capital structure components apart from the return on common equity ("ROE"), which is presented by Company Witness D'Ascendis. Additionally, I describe the Company's financing strategy and plans. Finally, I address various commitments from Formal Case No. 1142, the Company's merger proceeding with AltaGas.

I recommend an overall rate of return of 7.874% for the Company. This return is based upon the following capital structure and cost rates (subject to rounding considerations), as detailed in Exhibit WG (B) - 1:

	Description	Capitalization ($000)	Ratio	Cost	Return
	A	B	C	D	E = C x D
	Debt				
1	Long-Term Debt	$ 1,915,107	42.881%	4.840%	2.075%
2	Short-Term Debt	$ 206,956	4.634%	6.202%	0.287%
3	Total Debt	$ 2,122,063	47.514%		2.363%
	Equity				
4	Common Equity	$ 2,344,085	52.486%	10.500%	5.511%
5	TOTAL	$ 4,466,148	100.000%		7.874%

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I sponsor the following eight (8) exhibits:

- Exhibit WG (B)-1 The Company's Recommended Capital Structure and Cost of Capital.
- Exhibit WG (B)-2 The Calculation of the 4 Quarter Average for Long-Term Debt and Equity.

- Exhibit WG (B)-3 Details of Short-Term Debt, including cost and average daily balance calculation.
- Exhibit WG (B)-4 Details of Long-Term Debt.
- Exhibit WG (B)-5 Comparison of Capital Structure to Selected Peer Companies.
- Exhibit WG (B)-6 Comparison of Debt Issuances Among Similarly Rated Companies.
- Exhibit WG (B)-7 Current and Historical Credit Ratings.
- Exhibit WG (B)-8 Current Credit Rating Agency Reports.

IV. THE COMPANY'S FINANCING STRATEGY

Q. PLEASE DISCUSS THE IMPORTANCE OF FINANCIAL PLANNING AND THE PRIMARY OBJECTIVES OF THE COMPANY'S FINANCING STRATEGY.

A. Financial planning prepares the Company to satisfy its short-term and long-term cash requirements on a timely basis so that it can meet its obligations to customers, creditors, employees, and shareholders. A sound financing strategy allows a company to fund its capital requirements at a reasonable cost and to remain flexible in accessing financial markets, even during periods of economic uncertainty or unexpected liquidity requirements.

Q. WHEN YOU REFERENCE FLEXIBILITY AS IT RELATES TO FINANCING OR FINANCING FLEXIBILITY, WHAT DO YOU MEAN AND WHY IS THAT IMPORTANT?

A. At its core, financing flexibility means the Company has the cash available to pay for its obligations on any day of the year and can handle most unforeseen events (also referred to as contingencies). Financing flexibility is also the freedom to choose the sources of cash and the timing of when those sources are accessed. Financing flexibility gives a company the ability to withstand adverse circumstances in financial markets and unexpected financing needs that may arise due to the inherent risk of unexpected cash requirements associated with a company's operations or factors affecting the industry in general. As examples, the 2020 COVID-19 Pandemic and the 2008 Financial Crisis were both substantial contractions in credit markets that the Company was able to weather without disruption to its ability to finance its utility obligations.

Q. WHAT FACTORS ARE CONSIDERED IN DEVELOPING A FINANCING PLAN?

A. The starting point in developing a company's financing plan is its capital requirements, consisting of capital expenditures, debt servicing and refinancing requirements, and working capital needs. These requirements are typically satisfied by operating cash flows (which includes the impact of actual income taxes paid), net of dividends paid to equity holders, with the balance being financed externally. Other factors affecting a company's financial planning include its credit ratings and the economic conditions potentially impacting its industry.

There are complex interrelationships among these factors that must be evaluated. For example, the return on equity, the level of equity in the capital structure, and total interest expense all affect interest coverage ratios, a key indicator of credit quality. A company's capital structure and its ability to service its capital structure are closely evaluated by credit rating agencies. As noted below, maintaining strong debt ratings is critical to ensure a reasonable cost of debt and helps maintain customer affordability.

Q. PLEASE EXPLAIN HOW THE COMPANY PREPARES ITS FINANCING PLAN.

A. We prepare an annual and multi-year financing plan. The annual financing plan is developed along with the annual budget for the Company. The purpose of the annual plan is to determine financing needs of the Company within the next year. This will determine how much of the utility's operations can be self-funded through operating cash flow and how much of the Company's capital plan and working capital requirements must be externally financed. After the amount of external financing is determined and based on the Company's targeted capital structure, we determine the amount to be funded through capital contributions (equity), and private placement notes (long-term debt). Each step in this process is performed at the utility level and does not involve any considerations of any Company affiliate.

The multi-year financing plan is prepared coincident with the preparation of the strategic plan which spans three years. The purpose of this multi-year plan is to determine the medium-term financing needs of the Company. It is prepared in a similar manner as I described above for the annual financing plan. This multi-year plan helps us determine when we file for additional financing authority before the commissions and how much financing authority we should seek.

Q. DOES WASHINGTON GAS BASE ITS FINANCING DECISIONS AND ANALYSIS ON THE NEEDS OF ITS PARENT?

A. No. As explained above, Washington Gas' capital structure is, and has been, set independently from its parent and is based solely on its need to fund the utility's operations at a reasonable cost and maintain efficient access to capital markets, as well as its regulatory commitment to maintain a common equity ratio between 48% to 55%. This will continue to be the case in the future, as required by Merger Commitments 32, 35, 36, and 37 in Formal Case No. 1142.

Q. PLEASE DESCRIBE THE MAJOR FINANCING EVENTS SINCE THE TEST YEAR IN FORMAL CASE NO. 1169.

A. After the 2021 test year in Formal Case No. 1169, the Company issued $200 million of long-term debt in 2022 and $200 million in 2023. The 2022, $200 million issuance occurred on December 29, 2022, and consisted of: $25,000,000 aggregate principal amount of its 5.25% Series 2022-A Notes due December 29, 2042 ("PP-2042"), and $175,000,000 aggregate principal amount of its 5.33% Series 2022-B Notes due December 29, 2052 ("PP-2052"). The 2023, $200 million issuance occurred on October 19, 2023, and consisted of: $150,000,000 aggregate principal amount of its 6.06% Series 2023-A Notes due October 14, 2033 ("PP-2033"), and $50,000,000 aggregate principal amount of its 6.43% Series 2023-B Notes due October 15, 2053 ("PP-2053").

Both issuances were priced at favorable spreads to US Treasuries based on the Company's A-/A ratings from S&P and Fitch respectively. Exhibit WG (B)-6 provides a comparison for each issuance to similar issuance that occurred around the same time. The exhibit demonstrates that the Company's spread was 5 basis points favorable (the average for the four issuances) to the average of similarly rated utilities issuing around that time. Thus, it also shows there is no negative impact on the Company's cost of debt for these two issuances related to the Company's association with AltaGas Ltd.

V. CREDIT RATINGS

Q. WHY ARE CREDIT RATINGS IMPORTANT TO A COMPANY THAT ISSUES DEBT SECURITIES?

A. Credit ratings are scoring systems applied by internationally recognized independent organizations (including credit rating agencies such as Moody's Investors Service ("Moody's"), Standard & Poor's Ratings Services ("S&P") and Fitch Ratings ("Fitch")) to assess an entity's ability to meet its financial obligations, including the ability to pay interest and principal when due. Each agency applies measures and ratios to entities within government or industry categories to give investors an indication of financial strength relative to peers and other issuers of debt securities. Buyers of debt securities consider an entity's credit rating when evaluating the risk of the investment. In general, the higher a security is rated, the less risky it is to investors, resulting in greater flexibility and possibly lower costs for issuers across a range of market conditions.

Q. WHAT ARE THE CREDIT RATING SCALES OF S&P AND FITCH AND WHAT DO THEY MEAN?

A. S&P maintains a letter rating scale from AAA to D (fully, AAA, AA, A, BBB, BB, B, CCC, CC, C, D) as its credit ratings. The cutoff for investment grade is BBB, below this credit rating starting at BB are considered speculative grade.[1] For the AA to CCC portion of the scale, S&P may modify the rating by a plus or minus sign to provide relative positions of entities within those ratings.[2] The

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[1] S&P Global Ratings. "Guide to Credit Rating Essentials." p. 9, https://www.spglobal.com/ratings/_division-assets/pdfs/guide_to_credit_rating_essentials_digital.pdf

[2] Ibid.

ratings are a measure of an entities' ability to meet its financial commitments and weather changes in economic conditions or circumstances. Fitch maintains a similar ratings scale with one additional level above D called RD – Restricted Default.[3]

Investment grade ratings mean there is a lower risk of an entity defaulting on its obligations. S&P has defined the terms of investment-grade and speculative-grade as follows:

> The term "investment-grade" historically referred to bonds and other debt securities that bank regulators and market participants viewed as suitable investments for financial institutions. Now the term is broadly used to describe issuers and issues with relatively high levels of creditworthiness and credit quality. In contrast, the term "non-investment-grade," or "speculative-grade," generally refers to debt securities where the issuer currently has the ability to repay but faces significant uncertainties, such as adverse business or financial circumstances that could affect credit risk.[4]

Q. WHAT ARE THE COMPANY'S LONG-TERM DEBT CREDIT RATINGS?

A. Washington Gas issues long-term debt primarily in the form of unsecured notes utilizing the private placement market. The current credit rating of the

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[3] Fitch Ratings. "Rating Definitions." https://www.fitchratings.com/products/rating-definitions

[4] S&P Global Ratings. "Guide to Credit Rating Essentials." p. 9, https://www.spglobal.com/ratings/_division-assets/pdfs/guide_to_credit_rating_essentials_digital.pdf

Company's senior unsecured long-term debt is A- by S&P, and A by Fitch.[5] On a relative basis, Fitch is one notch above.

Q. WHY IS AN "A" RATING VALUABLE AND ONE THE COMMISSION SHOULD SUPPORT THROUGH ITS ACTIONS?

A. An A rating indicates a "strong capacity to meet financial commitments, but somewhat susceptible to adverse economic conditions and changes in circumstances." Lower ratings mean the Company would be more susceptible to business cycles and other contingencies. The Company would be less able to weather tight credit markets, recessions, and other major economic events as well as circumstances specific to the jurisdictions in which the Company operates, the Company itself, or the utility industry. The financial flexibility described above is valuable and should be preserved and supported by the Commission. It enables the Company to provide utility service and meet its service obligations.

A rating one level above BBB is also valuable in that the Company does not skate close to the edge of a speculative rating. It provides a cushion for weathering adverse circumstances. The further down the ratings scale one goes, the less cushion there is until finally an entity hits default (a rating of D). And this cushion and our A rating has proven valuable to our commissions and our customers in times of financial market upheavals. In the most recent instance, the COVID-19 pandemic, the Company did not need to take out more costly forms of finance or incur more restrictive covenants for debt during that

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[5] The most recent credit reports issued by each rating agency is provided in Exhibit WG (B)-8. The Company's historical ratings are provided in Exhibit WG (B)-7.

period nor was there any interruption in our ability to effectively finance our on-going investments and support our cost of service.

Q. WHAT KEY CREDIT METRICS ARE IMPORTANT TO THE COMPANY'S CREDIT RATING AND WHAT INFORMATION ON THESE METRICS DOES THE COMPANY REPORT TO THE COMMISSION?

A. Pursuant to Merger Commitment 35 of Formal Case No. 1142, the Company reports quarterly on the Company's consolidated Funds from Operations ("FFO") / Debt, FFO / Interest, and Debt to Total Capitalization ratios. FFO is usually calculated as net operating income plus depreciation and amortization, deferred tax changes, and other noncash items outside of working capital. FFO is a cash flow measure like Earnings Before Interest, Tax, Depreciation and Amortization ("EBITDA") or Cash Flows from Operating Activities. The credit rating agencies can use any of these measures and adjust them for items like capital expenditures for a variety of ratio calculations.

FFO / Debt generally measures the ability of a company to pay off its debt using recurring cash flows from operations independent of working capital. For the March 31, 2024 period on a book basis, the Company's consolidated FFO / Debt ratio was reported as 17.7%. A FFO / Debt ratio of 17.7% would indicate it would take less than 5.6 years to service the Company's outstanding debt.

FFO / Interest Ratio is an interest coverage ratio that measures how well a company's cash flows can cover debt costs (interest expense). The larger the ratio is the less risk there is of a default. That can be viewed again as a cushion that insures the Company against default risk. As of our last report to the Commission and for the test year, FFO / Interest Ratio was 3.8.

The final metric is Debt-to-Total-Capitalization Ratio. The Commission has regular experience reviewing this metric as it is the capital structure of the Company, and the Commission adopts a capital structure in setting rates. For the credit rating agencies, this is a measure of how much leverage (debt) the Company uses. Greater leverage creates greater credit risk as the cost to service that debt will be larger even absent the impact this will have on the cost rate for debt. Equally, as fixed charges that must be paid every period, it reduces financial flexibility as it cannot be reduced or avoided. The measure as of March 31, 2024, was 46.4%. It is important to understand that is based on the balance of debt and total capitalization at March 31, 2024 using a GAAP basis, not an average, not including the regulatory assets and liabilities to arrive at a regulatory basis, nor does it have any adjustment to use daily averages of short-term debt.

Q. WHAT WOULD HAVE BEEN THE COMPANY'S FFO / DEBT RATIO ON A STANDALONE BASIS FOR ITS DISTRICT OF COLUMBIA OPERATIONS?

A. For the March 31, 2024, period, as shown in Company Witness Tuoriniemi's testimony, the standalone FFO / Debt ratio on a book basis for the Company's District of Columbia Operations was 10.2%, which is significantly lower than the consolidated FFO / Debt ratio. A FFO / Debt ratio of 10.2% would mean it would take almost 9.8 years to service debt from the Company's operations. This longer period needed to service debt repayments would therefore usually mean a higher credit risk and result in higher debt costs to ratepayers. Equally, these measures are below the downgrade threshold S&P sets for investment grade debt. Moving to a speculative credit rating would significantly increase the cost of debt for the Company and result in higher rates for customers.

Q. WHY IS THE COMPANY'S FFO / DEBT RATIO LOWER IN THIS CASE AND WHY IS THE RATIO LOWER ON A STAND-ALONE DC BASIS?

A. Warmer weather that reduces revenues in the District combined with higher operating costs, as described by Company Witness Tuoriniemi, are the primary drivers of the change in FFO / Debt. The Company's rates in the District are primarily collected volumetrically, and there is no current provision in the Company's tariff that adjusts for weather variations. In the last five years, weather was significantly warmer than the 30-year average that the Commission adopted in Formal Case No. 1169 driving the Company's revenues and cash flows lower and adversely affecting FFO.[6] This is an additional reason it is necessary for this Commission to adopt the Weather Normalization Adjustment mechanism proposed by Company Witnesses Tuoriniemi and Lawson. This will stabilize our FFO / Debt metric to some extent. We will still be exposed to the impact warm weather has on Asset Optimization margins.

Higher operating costs when rates do not increase timely to recover those costs also drive FFO lower. As Company Witness Steffes details, streamlining the procedural schedule for DC rate cases would reduce regulatory lag and improve the FFO / Debt metric.

Q. WHAT ARE THE COMPANY'S SHORT-TERM DEBT CREDIT RATINGS?

A. Washington Gas issues short-term debt primarily in the form of Commercial Paper ("CP"). The current credit rating of the Company's short-term debt is A2 by S&P, and F2 by Fitch. These ratings are all at the same equivalent tier.

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[6] Exhibit WG (D), the Direct Testimony of Robert E. Tuoriniemi.

Q. DOES THE MERGER OR ANY ONGOING AFFILIATION WITH ALTAGAS LTD. HAVE ANY ADVERSE IMPACT ON THE COST OF DEBT FOR RECENT ISSUANCES?

A. No, it does not. As I demonstrate above and discuss further below in our most recent debt issuances, the Company is issuing at similar spreads for our credit rating. As shown in Exhibit WG (B)-6, those spreads demonstrate there is no adverse impact. Equally, at this point in time, no one could predict what the Company's credit ratings and debt cost would have been had the merger not occurred. On a stand-alone basis, the Company would have operated the same large capital program as it committed to prior to the merger for accelerated replacements, and that would have reduced the Company's credit metrics and potentially impacted its ratings independent of any association with AltaGas Ltd. The inflows from financing activities were already increasing pre-merger because of the large capital spending program. Finally, S&P determines a stand-alone credit profile of A- which is no different than the Company's issuer credit rating. Thus, I have not made any adjustments to cost of recent borrowings.

I have not changed the prior adjustments made to the Company's September 13, 2019, and December 10, 2020, MTN issuances in the Company's two prior rate cases.

VI. CAPITAL STRUCTURE

Q. WHAT IS THE APPROPRIATE STARTING POINT IN DETERMINING THE COMPANY'S CAPITALIZATION?

A. The appropriate starting point is the capital structure expected in the rate effective period. Consistent with the historical precedent of this Commission in using a test year actual capital structure, the Company is recommending that capital structure adopted for ratemaking purposes be 52.486% equity and 47.514% debt. The structure is supported by the facts present during the test year. The Company's actual, average capital structure during that period was 52.486% equity. As shown in Exhibit WG (B)-5, the capital structure peer group mean and median equity ratio were 53.23% and 53.83% percent, respectively.

Q. HOW ARE THE ACTUAL INDIVIDUAL DEBT COMPONENT COSTS OF CAPITAL, THE ACTUAL CAPITAL STRUCTURE, AND ACTUAL RATE BASE DEVELOPED, AND WHAT FACTORS IMPACT THEM?

A. They are developed from the Company's financial statements, primarily the income statement and the balance sheet, which are prepared quarterly. At a high level, the income statement reflects the cost components of long-term debt and short-term debt (as interest expense). Our estimate of the cost of common equity, or ROE, is the subject of testimony from Company Witness D'Ascendis.

Q. PLEASE EXPLAIN EACH ADJUSTMENT MADE TO THE ACTUAL CAPITAL COMPONENT, BEGINNING WITH LONG-TERM DEBT.

A. As shown on line 1 of Exhibit WG (B)-4, the unadjusted face amount of long-term debt including current maturities was $2.026 billion as of March 31, 2024. The net result after reducing for unamortized premiums/discounts, issuance expenses, losses on refunds and hedging is a long-term debt amount of $2.015 billion shown on line 8 of Exhibit WG (B)-2. Using the same methodology, I obtained adjusted net long-term debt amounts at the June 30, 2023, September 30, 2023, and December 31, 2023 periods. As shown in Exhibit WG (B)-2 on line 8, I then averaged these amounts to arrive at $1.915

billion, which is my recommended long-term debt balance for ratemaking purposes.

Q. WHAT IS THE BASIS FOR THE AMOUNT OF SHORT-TERM DEBT IN THE CAPITAL STRUCTURE, AS RECOMMENDED IN THIS CASE?

A. The amount of short-term debt outstanding varies significantly by year, by month, and within a month as well. Consistent with past filings, I used average short-term debt to reflect the seasonal fluctuations that occur in this capital component and calculated the $207 million average daily balance for twelve months ended March 31, 2024, as shown on line 13 of Exhibit WG (B)-3, page 2.

Q. PLEASE EXPLAIN YOUR CALCULATION OF COMMON EQUITY IN EXHIBIT WG (B)-2.

A. I averaged the Company's common equity balance at the four quarters ending between June 30, 2023, and March 31, 2024. By averaging the Company's capital structure profile, I removed any bias to the capital structure associated with seasonality that occurs with an end of period measurement. The recommended equity balance, for this rate filing is $2.344 billion, as shown in line 9 of Exhibit WG (B)-2.

Q. IS THE COMPANY'S CAPITAL STRUCTURE REASONABLE?

A. Yes, the capital structure reasonably estimates the Company's actual cost of financing the safe and reliable distribution of natural gas to its customers, including those in the District of Columbia. This comports with the Commission's long-standing reliance on the actual capital structure for Washington Gas. This case deals with the setting of rates for Washington Gas customers in the District of Columbia. As such, reflecting the cost of financing those specific operations in the approved capital structure should be the goal of this case. It is also within the range set by the Commission in Formal Case No. 1142.

Q. WHAT MAIN FACTORS DROVE THE CHANGE IN THE COMPANY'S RECOMMENDED COMMON EQUITY RATIO FROM 54.19% IN FORMAL CASE NO. 1169 TO 52.49% IN THIS RATE PROCEEDING?

A. The main driver in the shift in our capital structure case-to-case was the issuance of $400 million of long-term debt: $200 million in 2022 and $200 million in 2023. Of the total $877 million increase in average test year capitalization, 54.72% of that increase was driven by additional debt financing versus 45.28% being driven by the growth in common equity. The higher contribution of debt has shifted the capital structure to greater leverage. This is in keeping with our target capital structure used for financial planning purposes that I described above. It is also consistent with the Commission's prior order that set a 52% equity and 48% debt capital structure in Formal Case No. 1169.

The necessity for external financing over this period is the same as explained above. The Company's internal cash generation is not sufficient to fully cover its capital program; thus, external financing was required and will continue to be required.

Q. HOW DOES THE COMPANY'S CAPITAL STRUCTURE COMPARE TO THAT OF ITS PEERS?

A. As shown in Exhibit WG (B)-5, the Company's equity component of its capital structure is very much in line with its peer group. In making this calculation, I started with Company Witness D'Ascendis's peer group used in his calculation of ROE. If a gas distribution company did not have its own balance sheet publicly available, I used its parent company's capital structure. This was the case for Atmos Energy Corporation and ONE Gas, Inc., with both having primarily utility operations. Company Witness D'Ascendis's peer group is limited to those gas utilities that issue public equity. However, many utilities like Washington Gas still issue debt and are rate independent of their parent. Equally, evaluating our capital structure versus peers with the same credit rating is a more relevant comparison to make as credit ratings are based upon leverage and cash flows. Thus, I expanded the group to pull in other gas utilities with A- ratings from S&P and had independent financial statements. The capital structure and credit metrics peer group includes the following added companies: NSTAR Gas Company, The Southern Connecticut Gas Company, Yankee Gas Services Company, DTE Gas Company, and Southern Company Gas. Consistent with how I calculated the Company's capital structure, I used a 4-quarter average capital structure for each of the peers.[7] The peer group's simple average common equity component is 53.23% and the median common equity component is 53.83%. Were the Company to have been included in the sample, the Company's common equity ratio of 52.486% would be ranked eighth highest out of twelve in the peer group comparison.

Comparing solely to the nine companies that also have A- credit ratings demonstrates the Company's leverage ratio is the second highest of this grouping. Equally, the Company's FFO-to-Debt measure is below the average and median of our A- peers. This demonstrates that our leverage cannot increase beyond 48% (or an equity ratio lower than 52%) without resulting in a

[7] The data and calculation of the four-quarter average calculation is provided in Exhibit WG (B)-5.

downgrade of our credit rating. Higher leverage would degrade our key credit metrics and put us further out of line with our peers.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND IN THIS PROCEEDING?

A. As shown in Exhibit WG (B)-1, I propose a capital structure consisting of 47.514% debt, and 52.486% common equity. This recommendation is supported by the facts and should be adopted by the Commission in determining rates set in this case.

VII. COST OF CAPITAL TO THE COMPANY

Q. WHAT WAS THE COST OF LONG-TERM DEBT AS OF MARCH 31, 2024?

A. The cost of long-term debt (including current maturities) was 4.840%, as shown in Exhibit WG (B)-1.

Q. WHAT ADJUSTMENTS WERE MADE TO REFLECT GAINS AND LOSSES ON REACQUIRED DEBT IN DETERMINING THE COST OF LONG-TERM DEBT?

A. Consistent with Commission practice, unamortized debt reacquisition gains and losses are reflected in the net amount outstanding, shown in Exhibit WG (B)-4.

Q. WHAT OTHER ADJUSTMENTS WERE MADE IN DETERMINING THE COST OF LONG-TERM DEBT?

A. Consistent with Commission practice, to calculate the cost of long-term debt, I also included the unamortized amounts of debt issuance expenses, issuance discounts and premiums, and hedge losses and gains.

Q. DID YOU MAKE ANY OTHER ADJUSTMENTS TO THE COST OF LONG-TERM DEBT?

A. Yes. I adopted the same adjustment the Company proposed for the cost of the $300 million MTNs issued in 2019 of seven (7) basis points as presented in its testimony for Formal Case No. 1162, and the four (4) basis points adjustment made to the $100 million Series L-2 MTNs issued on December 10, 2020. As noted above, no adjustments were made for recent issuances.

As I have used an average for the components of the capital structure, I adjusted the cost rate for long-term debt accordingly. Thus, when this rate is applied to the average balance of long-term debt, the resulting total debt service cost equates to the Company's current requirement of $92,687,012.

Q. HOW DID YOU DETERMINE THE PRO FORMA COST OF SHORT-TERM DEBT, AS SHOWN IN EXHIBIT WG (B)-3, PAGE 1 AND IN YOUR RECOMMENDED RATE MAKING CAPITAL STRUCTURE SHOWN IN EXHIBIT WG (B)-1?

A. The Company's financing strategy includes the prudent use of short-term debt to meet seasonal requirements and maintain financing flexibility. The Company has a commercial paper ("CP") program that is supported by back-up credit facilities in the form of bank revolving lines of credit.

The effective cost of issuing commercial paper includes the interest expense on short-term debt plus the origination and maintenance fees associated with the revolving credit agreements that are prerequisite to a viable commercial paper program. The gross amount of facility fee expenses was $1,055,045, as shown on Exhibit WG (B)-3, for the twelve-month period ended March 31, 2024.

As CP rates can vary between months, I utilized the average of the last three months as the starting point for my cost of short-term debt recommendation. As of March 31, 2024, this adjusted average cost of commercial paper debt during the most recent three (3) months was 5.693%. This interest rate, expressed on an effective yield basis and combined with the line of credit expenses, results in a pro forma total cost of short-term debt of 6.202%.

Q. WHAT IS THE BASIS FOR THE RETURN ON COMMON EQUITY CONTAINED IN EXHIBIT WG (B)-1?

A. I have adopted the 10.50% return on common equity recommended by Company Witness D'Ascendis, who has conducted a detailed analysis to determine the return on common equity required by investors.

VIII. REQUIRED RATE OF RETURN

Q. BASED ON THE INFORMATION YOU HAVE PRESENTED, WHAT IS THE FAIR RATE OF RETURN THAT SHOULD BE ALLOWED THE COMPANY?

A. The Company should be allowed a return of 7.874%, as shown in Exhibit WG (B)-1. This rate of return will allow the Company to continue providing service at a cost that is reasonable for the ratepayers and that will allow the Company to attract capital on reasonable terms.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

WASHINGTON GAS LIGHT COMPANY
Average Actual Capital Structure in the Test Year Ended March 31, 2024
($ in '000s)

	Description	Capitalization ($000) /a	Ratio	Cost	Return
	A	B	C	D	E = C x D
	Debt				
1	Long-Term Debt /b	$ 1,915,107	42.881%	4.840%	2.075%
2	Short-Term Debt /c	206,956	4.634%	6.202%	0.287%
3	Total Debt	$ 2,122,063	47.514%		2.363%
	Equity				
4	Common Equity /d	$ 2,344,085	52.486%	10.500%	5.511%
5	TOTAL	$ 4,466,148	100.000%		7.874%

/a From EXHIBIT WG (B)-2
/b From EXHIBIT WG (B)-4
/c From EXHIBIT WG (B)-3
/d Cost rate developed by Company Witness Dylan D'Ascendis, Exhibit WG (C)

WASHINGTON GAS LIGHT COMPANY
4 Quarter Average Capital Structure Calculation

Ln.	Description	Quarter Ended 6/30/2023	9/30/2023	12/31/2023	3/31/2024	Average
1	A	B	C	D	E	F
2	Short-Term Debt a/	$ 206,956,156	$ 206,956,156	$ 206,956,156	$ 206,956,156	$ 206,956,156
3	Face Amount Outstanding	$ 1,826,000,000	$ 1,826,000,000	$ 2,026,000,000	$ 2,026,000,000	
4	Unamortized Premium/Discount	$ 11,392,607	$ 11,287,264	$ 11,181,920	$ 11,076,576	
5	Unamortized Debt Issuance Cost	$ (12,022,410)	$ (11,878,754)	$ (13,119,763)	$ (12,976,145)	
6	Unamortized Hedge Loss	$ (8,962,627)	$ (8,828,656)	$ (8,694,685)	$ (8,560,713)	
7	Unamortized Gain/Loss on Reacquired Debt	$ (947,955)	$ (878,372)	$ (835,060)	$ (805,036)	
8	Total Long-Term Debt	$ 1,815,459,615	$ 1,815,701,482	$ 2,014,532,412	$ 2,014,734,681	$ 1,915,107,048
9	Common Equity	$ 2,259,048,238	$ 2,272,676,687	$ 2,357,771,287	$ 2,486,842,250	$ 2,344,084,615
10	Total Capitalization	$ 4,281,464,010	$ 4,295,334,325	$ 4,579,259,855	$ 4,708,533,088	$ 4,466,147,819
11	Capital Structure Weights					
12	Short-Term Debt	4.834%	4.818%	4.519%	4.395%	4.634%
13	Long-Term Debt	42.403%	42.271%	43.993%	42.789%	42.881%
14	Common Equity	52.763%	52.910%	51.488%	52.816%	52.486%

WASHINGTON GAS LIGHT COMPANY
Historical Year End Capital Structures

Ln.	Description	As of December, 31				
		2019	2020	2021	2022	2023
1	A	B	C	D	E	E
2	Short-Term Debt	$ 399,482,910	$ 284,952,896	$ 226,967,049	$ 316,442,057	$ 197,544,331
3	Face Amount Outstanding	$ 1,346,000,000	$ 1,446,000,000	$ 1,646,000,000	$ 1,846,000,000	$ 2,026,000,000
4	Unamortized Premium/Discount	$ (4,302,174)	$ 12,439,161	$ 12,020,963	$ 11,602,765	$ 11,181,920
5	Unamortized Debt Issuance Cost	$ (10,748,683)	$ (11,555,237)	$ (11,945,299)	$ (12,356,874)	$ (13,119,763)
6	Unamortized Hedge Loss	$ (10,838,355)	$ (10,302,470)	$ (9,766,456)	$ (9,230,570)	$ (8,694,685)
7	Unamortized Gain/Loss on Reacquired Debt	$ (1,922,115)	$ (1,643,784)	$ (1,365,452)	$ (1,087,121)	$ (835,060)
8	Total Long-Term Debt	$ 1,318,188,673	$ 1,434,937,672	$ 1,634,943,756	$ 1,834,928,200	$ 2,014,532,412
9	Common Equity	$ 1,578,592,010	$ 1,855,924,959	$ 2,022,274,223	$ 2,111,993,938	$ 2,357,771,287
10	Total Capitalization	$ 3,296,263,593	$ 3,575,815,526	$ 3,884,185,028	$ 4,263,364,195	$ 4,569,848,030
11	Capital Structure Weights					
12	Short-Term Debt	12.119%	7.969%	5.843%	7.422%	4.323%
13	Long-Term Debt	39.990%	40.129%	42.092%	43.039%	44.083%
14	Common Equity	47.890%	51.902%	52.064%	49.538%	51.594%

Note: Equity balances are seasonal, and year-end will represent low point in the Company's equity ratio and a high point for leverage.

WASHINGTON GAS LIGHT COMPANY
Short-Term Debt Cost
($ in '000s)

Ln.	Description	Amount Outstanding	Cost Rate	Debt Service Requirements
	A	B	C	D
1	Average Daily Balance	$ 206,956,156	5.693%	$ 11,781,296
2	Revolving Credit Agreement Expenses			$ 1,055,045
3	Total	$ 206,956,156	6.202%	$ 12,836,341

WASHINGTON GAS LIGHT COMPANY
Summary of Short-Term Debt
12 Months Ended 03/31/2024

			Commercial Paper			Bank Loans			Net Average Daily Balance		
Ln.	Month	Days	Average Daily Balance	Interest Rate	Interest Requirement	Average Daily Balance	Interest Rate	Interest Requirement	Average Daily Balance	Interest Requirement	Composite Interest Rate
	A	B	C	D	E	F	G	H	I	J	K
1	Apr-23	30	$ 172,109,016	5.523%	781,212	$ -	0%	$ -	$ 172,109,016	$ 781,212	
2	May-23	31	180,263,486	5.485%	839,793	-	0%	-	180,263,486	839,793	
3	Jun-23	30	208,932,734	5.558%	954,422	-	0%	-	208,932,734	954,422	
4	Jul-23	31	269,136,222	5.593%	1,278,554	-	0%	-	269,136,222	1,278,554	
5	Aug-23	31	261,071,538	5.697%	1,263,317	-	0%	-	261,071,538	1,263,317	
6	Sep-23	30	319,883,629	5.715%	1,502,446	-	0%	-	319,883,629	1,502,446	
7	Oct-23	31	268,132,635	5.701%	1,298,239	-	0%	-	268,132,635	1,298,239	
8	Nov-23	30	193,679,270	5.705%	908,232	-	0%	-	193,679,270	908,232	
9	Dec-23	31	231,417,983	5.744%	1,129,016	-	0%	-	231,417,983	1,129,016	
10	Jan-24	31	164,783,733	5.746%	804,178	-	0%	-	164,783,733	804,178	
11	Feb-24	29	112,460,137	5.663%	506,039	-	0%	-	112,460,137	506,039	
12	Mar-24	31	97,661,171	5.668%	470,173	-	0%	-	97,661,171	470,173	
13	Annualized	366	$ 206,956,156		$ 11,735,620	$ -		$ -	$ 206,956,156	$ 11,735,620	5.671%
14	Cost Rate Using Most recent 3 mon			5.693%							5.693%

		Commercial Paper			Bank Loans			Net Ending Balance		
		Ending Balance	Interest Rate	Interest	Ending Balance	Interest Rate	Interest	Ending Balance	Interest Rate	Interest
15	As of 03/31/2024	$ 117,726,849	5.666%	$ 18,277	$ -	$ -	-	$ 117,726,849	5.666%	$ 18,277

16	Type Of Instrumen	Commercial Paper	Non-committed lines
17	Holder:	Issued through US Bank	Various (see Exhibit WG(B)-3, page 3)
18	Maturity:	Not applicable	Variable
19	Term:	Not applicable	Variable

Washington Gas Light Company
Summary of Revolving Credit Facility
12 Months Ended March 31, 2024

Term of Deal (years): Starts on June 27, 2023 and terminates on July 17, 2026
Amount Drawn during 12 Months Ended March 31, 2024: $0.00

Ln.	Bank	Lending Commitment /a	Arrangement b/	Annual Admin Fees	One-Time Up-Front Fees c/	Facility Fee	Total
	A	B	C	D	E	F	G
1	6/27/2023 to 7/17/2026						
2	Wells Fargo Bank , National Association	$ 71,000,000	$ 180,100	$ 15,000	$ 179,267	$ 46,888	$ 421,255
3	TD Bank, N.A.	71,000,000	99,500			$ 46,888	146,388
4	The Bank of Nova Scotia	71,000,000	110,000			$ 46,888	156,888
5	Bank of America, N.A.	47,400,000	47,400			$ 31,303	78,703
6	Canadian Imperial Bank of Commerce	47,400,000	26,400			$ 31,303	57,703
7	Mizuho Bank, Ltd.	47,400,000	47,400			$ 31,303	78,703
8	Royal Bank of Canada	47,400,000	26,400			$ 31,303	57,703
9	US Bank, National Association	47,400,000	26,400			$ 31,303	57,703
10	Total	$ 450,000,000	$ 563,600	$ 15,000	$ 179,267	$ 297,178	$ 1,055,045

Notes:
a/ Revolving credit facility and terms are based on letter of agreement with each of the banks, there are not any compensating balance requirements.
b/ Arrangement fees and Upfront fees were paid on June 27, 2023
c/ Paid to the Agent, Wells Fargo Bank, who allocates the up-front fees amongst the lenders according to their lending commitments in the revolving credit facility executed on June 27, 2023

Washington Gas Light Company
Long-Term Debt Cost
March 31, 2024

Ln.	Description	Amount Outstanding / Balance	Cost Rate	Debt Service Requirements
1	Long-Term Debt (MTNs and Private Placements)	$ 2,026,000,000	4.532%	$ 91,808,600
2	Unamortized Premium/Discount	11,076,576		(421,374)
3	Unamortized Debt Issuance Cost	(12,946,803)		691,842
4	Unamortized Hedge Loss	(8,560,713)		535,886
5	Unamortized Gain/(Loss) on Reacquired Debt	(713,376)		72,058
6	Total Debt at March 31, 2024	$ 2,014,855,685	4.600%	$ 92,687,012
7	Average Total Debt Cost Calculation	$ 1,915,107,048	4.840%	$ 92,687,012

Washington Gas Light Company
Long-term Notes Outstanding As Of Mar 31, 2024

LT Debt Notes As of Mar 31, 2024

Ln.	Trade Number A	BU B	Coupon C	Merger Condition No. 38 Adjustment D	Adjusted Coupon E	Face Amount Face Amount	Amount Outstanding (Inc. CM) G	Settlement Date H	Retired As Of I	Nominal Maturity Date J	Maturity Measurement Date K	Maturity (years) L	Term M	Assume Option Exercise? N	Put Option Date O	Call Option Date P
1	C-9	01	6.820%		6.820%	10,000,000	10,000,000	10/09/1996		9-Oct-26	9-Oct-26	2.53	30.00	N	9-Oct-06	None
2	C-10	01	6.820%		6.820%	5,000,000	5,000,000	10/09/1996		9-Oct-26	9-Oct-26	2.53	30.00	N	9-Oct-06	None
3	C-11	01	6.820%		6.820%	5,000,000	5,000,000	10/09/1996		9-Oct-26	9-Oct-26	2.53	30.00	N	9-Oct-06	None
4	C-12	01	6.820%		6.820%	5,000,000	5,000,000	10/09/1996		9-Oct-26	9-Oct-26	2.53	30.00	N	9-Oct-06	None
5	C-13	01	6.630%		6.630%	10,000,000	10,000,000	10/23/1996		23-Oct-26	23-Oct-26	2.56	30.00	N	23-Oct-03	None
6	C-14	01	6.630%		6.630%	6,000,000	6,000,000	10/23/1996		23-Oct-26	23-Oct-26	2.56	30.00	N	23-Oct-03	None
7	C-15	01	6.630%		6.630%	6,000,000	6,000,000	10/23/1996		23-Oct-26	23-Oct-26	2.56	30.00	N	23-Oct-03	None
8	C-16	01	6.620%		6.620%	6,000,000	6,000,000	10/23/1996		23-Oct-26	23-Oct-26	2.56	30.00	N	23-Oct-03	None
9	D-1	01	6.570%		6.570%	6,000,000	6,000,000	02/21/1997		22-Feb-27	22-Feb-27	2.89	30.00	N	22-Feb-07	None
10	D-2	01	6.570%		6.570%	8,000,000	8,000,000	02/21/1997		22-Feb-27	22-Feb-27	2.89	30.00	N	22-Feb-07	None
11	D-3	01	6.570%		6.570%	10,000,000	10,000,000	02/21/1997		22-Feb-27	22-Feb-27	2.89	30.00	N	22-Feb-07	None
12	D-4	01	6.570%		6.570%	6,000,000	6,000,000	02/21/1997		22-Feb-27	22-Feb-27	2.89	30.00	N	22-Feb-07	None
13	D-5	01	6.400%		6.400%	3,000,000	3,000,000	07/22/1997		22-Jul-27	22-Jul-27	3.31	30.00	N	22-Jul-04	None
14	D-6	01	6.400%		6.400%	3,000,000	3,000,000	07/22/1997		22-Jul-27	22-Jul-27	3.31	30.00	N	22-Jul-04	None
15	D-7	01	6.460%		6.460%	6,000,000	6,000,000	07/23/1997		23-Jul-27	23-Jul-27	3.31	30.00	N	23-Jul-04	None
16	D-8	01	6.490%		6.490%	15,000,000	15,000,000	09/25/1997		27-Sep-27	27-Sep-27	3.49	30.01	N	27-Sep-07	None
17	D-9	01	6.490%		6.490%	7,500,000	7,500,000	09/25/1997		27-Sep-27	27-Sep-27	3.49	30.01	N	27-Sep-07	None
18	D-10	01	6.490%		6.490%	7,500,000	7,500,000	09/25/1997		27-Sep-27	27-Sep-27	3.49	30.01	N	27-Sep-07	None
19	D-11	01	6.570%		6.570%	10,000,000	10,000,000	01/12/1998		12-Jan-28	12-Jan-28	3.78	30.00	N	None	None
20	D-12	01	6.720%		6.720%	12,000,000	12,000,000	02/10/1998		15-Feb-28	15-Feb-28	3.88	30.01	N	None	None
21	D-13	01	6.850%		6.850%	4,000,000	4,000,000	03/09/1998		9-Mar-28	9-Mar-28	3.94	30.00	N	None	None
22	D-14	01	6.810%		6.810%	26,000,000	26,000,000	03/13/1998		13-Mar-28	13-Mar-28	3.95	30.00	N	None	None
23	E-6	01	7.500%		7.500%	8,500,000	8,500,000	04/03/2000		1-Apr-30	1-Apr-30	6.00	29.99	N	1-Apr-10	None
24	G-3	01	5.440%		5.440%	40,500,000	40,500,000	08/11/2005		11-Aug-25	11-Aug-25	1.36	20.00	N	None	None
25	G-4	01	5.700%		5.700%	19,000,000	19,000,000	01/18/2006		18-Jan-36	18-Jan-36	11.80	30.00	N	None	None
26	G-5	01	5.700%		5.700%	6,000,000	6,000,000	01/18/2006		18-Jan-36	18-Jan-36	11.80	30.00	N	None	None
27	G-7	01	5.781%		5.781%	25,000,000	25,000,000	03/22/2006		15-Mar-36	15-Mar-36	11.96	29.98	N	None	None
28	I-1	01	5.211%		5.211%	75,000,000	75,000,000	12/03/2010		3-Dec-40	3-Dec-40	16.68	30.00	N	None	None
29	J-1	01	5.000%		5.000%	75,000,000	75,000,000	12/05/2013		15-Dec-43	15-Dec-43	19.71	30.03	N	None	15-Jun-43
30	J-2	01	4.224%		4.224%	100,000,000	100,000,000	09/12/2014		15-Sep-44	15-Sep-44	20.46	30.01	N	None	15-Mar-44
31	PP-2044	01	4.240%		4.240%	50,000,000	50,000,000	12/15/2014		15-Dec-44	15-Dec-44	20.71	30.00	N	None	15-Jun-44
32	K-1	01	3.796%		3.796%	250,000,000	250,000,000	09/16/2016		15-Sep-46	15-Sep-46	22.46	30.00	N	None	15-Mar-46
33	K-1 Reopening	01	3.796%		3.796%	200,000,000	200,000,000	09/18/2017		15-Sep-46	15-Sep-46	22.46	28.99	N	None	15-Mar-46
34	L-1	01	3.650%	-0.070%	3.580%	300,000,000	300,000,000	09/13/2019		15-Sep-49	15-Sep-49	25.46	30.01	N	None	15-Mar-49
35	L-1 Reopening	01	3.650%	-0.040%	3.610%	100,000,000	100,000,000	12/10/2020		15-Sep-49	15-Sep-49	25.46	28.76	N	None	15-Mar-49
36	PP-2051	01	2.980%		2.980%	200,000,000	200,000,000	12/15/2021		15-Dec-51	15-Dec-51	27.71	30.00	N	None	None
37	PP-2042	01	5.250%		5.250%	25,000,000	25,000,000	12/29/2022		29-Dec-42	29-Dec-42	18.75	20.00	N	None	None
38	PP-2052	01	5.330%		5.330%	175,000,000	175,000,000	12/29/2022		29-Dec-52	29-Dec-52	28.75	30.00	N	None	None
39	PP-2033	01	6.060%		6.060%	150,000,000	150,000,000	10/19/2023		14-Oct-33	14-Oct-33	9.54	9.99	N	None	None
40	PP-2052	01	6.430%		6.430%	50,000,000	50,000,000	10/19/2023		15-Oct-53	15-Oct-53	29.54	29.99	N	None	None
41	Totals /a		4.544%		4.532%	2,026,000,000	2,026,000,000					20.39				

Notes: /a - The total for Unamortized Debt Issuance costs and Unamortized Reacquired Debt differs from the March 31, 2024 general ledger amounts shown in Exhibit WG(B)-2 by $29,343 and $91,661 respectively. The differences are attributable to passed amortization adjustments that were immaterial and will be booked in subsequent accounting periods. For calculation of the cost rate, the adjusted balances are used along with the correct annual amortization. The four quarter average uses the actual general ledger balances for these financial statement lines. The difference in the schedules and resulting calculations is immaterial.

Washington Ga
Long-term Not‹

LT Debt Notes

Ln.	Trade Number	Interest Payment Dates	Unamortized Premium/Discount	Amortization Expense (Annualized)	Amortization Method	Original Debt Issuance Costs	Unamortized Debt Issuance Cost	Amortization Expense (Annualized)	Amortization Method	Unamortized Hedge Loss	Amortization Expense (Annualized)	Amortization Method
	A	Q	R	S	T	U	V	W	X	Y	Z	AA
1	C-9	3/15 and 9/15			Straight-Line	$ (80,434)	$ (6,703)	$ 2,681	Straight-Line			Straight-Line
2	C-10	3/15 and 9/15			Straight-Line	$ (40,216)	$ (3,351)	$ 1,341	Straight-Line			Straight-Line
3	C-11	3/15 and 9/15			Straight-Line	$ (40,216)	$ (3,351)	$ 1,341	Straight-Line			Straight-Line
4	C-12	3/15 and 9/15			Straight-Line	$ (40,216)	$ (3,351)	$ 1,341	Straight-Line			Straight-Line
5	C-13	3/15 and 9/15			Straight-Line	$ (77,934)	$ (6,494)	$ 2,598	Straight-Line			Straight-Line
6	C-14	3/15 and 9/15			Straight-Line	$ (46,760)	$ (3,897)	$ 1,559	Straight-Line			Straight-Line
7	C-15	3/15 and 9/15			Straight-Line	$ (46,760)	$ (3,897)	$ 1,559	Straight-Line			Straight-Line
8	C-16	3/15 and 9/15			Straight-Line	$ (46,760)	$ (3,897)	$ 1,559	Straight-Line			Straight-Line
9	D-1	3/15 and 9/15			Straight-Line	$ (46,170)	$ (4,364)	$ 1,539	Straight-Line			Straight-Line
10	D-2	3/15 and 9/15			Straight-Line	$ (61,617)	$ (5,819)	$ 2,054	Straight-Line			Straight-Line
11	D-3	3/15 and 9/15			Straight-Line	$ (77,040)	$ (7,273)	$ 2,568	Straight-Line			Straight-Line
12	D-4	3/15 and 9/15			Straight-Line	$ (46,219)	$ (4,364)	$ 1,541	Straight-Line			Straight-Line
13	D-5	3/15 and 9/15			Straight-Line	$ (24,772)	$ (2,553)	$ 826	Straight-Line			Straight-Line
14	D-6	3/15 and 9/15			Straight-Line	$ (24,772)	$ (2,553)	$ 826	Straight-Line			Straight-Line
15	D-7	3/15 and 9/15			Straight-Line	$ (44,719)	$ (5,106)	$ 1,491	Straight-Line			Straight-Line
16	D-8	3/15 and 9/15			Straight-Line	$ (115,560)	$ (13,803)	$ 3,852	Straight-Line			Straight-Line
17	D-9	3/15 and 9/15			Straight-Line	$ (57,780)	$ (6,902)	$ 1,926	Straight-Line			Straight-Line
18	D-10	3/15 and 9/15			Straight-Line	$ (57,780)	$ (6,902)	$ 1,926	Straight-Line			Straight-Line
19	D-11	3/15 and 9/15			Straight-Line	$ (89,540)	$ (11,193)	$ 2,985	Straight-Line			Straight-Line
20	D-12	3/15 and 9/15			Straight-Line	$ (189,655)	$ (24,234)	$ 6,322	Straight-Line			Straight-Line
21	D-13	3/15 and 9/15			Straight-Line	$ (40,090)	$ (5,234)	$ 1,336	Straight-Line			Straight-Line
22	D-14	3/15 and 9/15			Straight-Line	$ (575,647)	$ (75,154)	$ 19,188	Straight-Line			Straight-Line
23	E-6	3/15 and 9/15			Straight-Line	$ (60,318)	$ (12,064)	$ 2,011	Straight-Line			Straight-Line
24	G-3	3/15 and 9/15			Straight-Line	$ (315,666)	$ (21,045)	$ 15,783	Straight-Line	$ (77,443)	$ 106,350	Straight-Line
25	G-4	3/15 and 9/15			Straight-Line	$ (148,090)	$ (58,414)	$ 4,936	Straight-Line	$ 34,073	$ (2,849)	Straight-Line
26	G-5	3/15 and 9/15			Straight-Line	$ (46,765)	$ (18,445)	$ 1,559	Straight-Line	$ 10,760	$ (900)	Straight-Line
27	G-7	3/15 and 9/15			Straight-Line	$ (194,855)	$ (77,941)	$ 6,495	Straight-Line	$ 44,833	$ (3,749)	Straight-Line
28	I-1	3/15 and 9/15			Straight-Line	$ (820,716)	$ (456,145)	$ 27,360	Straight-Line	$ (3,908,423)	$ 234,396	Straight-Line
29	J-1	3/15 and 9/15	$ (63,953)	$ 3,251	Straight-Line	$ (908,889)	$ (596,193)	$ 30,315	Straight-Line	$ 344,904	$ (17,525)	Straight-Line
30	J-2	3/15 and 9/15			Straight-Line	$ (1,093,432)	$ (747,589)	$ 38,013	Straight-Line	$ 459,872	$ (23,367)	Straight-Line
31	PP-2044	6/15 and 12/15			Straight-Line	$ (440,684)	$ (304,075)	$ 14,654	Straight-Line	$ -		Straight-Line
32	K-1	3/15 and 9/15			Straight-Line	$ (2,619,083)	$ (1,960,857)	$ 87,311	Straight-Line	$ (5,469,288)	$ 243,530	Straight-Line
33	K-1 Reopening	3/15 and 9/15	$ (2,279,908)	$ 101,517	Straight-Line	$ (1,998,218)	$ (1,547,471)	$ 68,904	Straight-Line			Straight-Line
34	L-1	3/15 and 9/15	$ (1,284,296)	$ 51,458	Straight-Line	$ (3,216,498)	$ (2,733,499)	$ 107,196	Straight-Line			Straight-Line
35	L-1 Reopening	3/15 and 9/15	$ 14,704,733	$ (577,600)	Straight-Line	$ (1,405,540)	$ (1,244,616)	$ 48,888	Straight-Line			Straight-Line
36	PP-2051	6/15 and 12/15			Straight-Line	$ (793,733)	$ (733,101)	$ 26,458	Straight-Line			Straight-Line
37	PP-2042	6/15 and 12/15			Straight-Line	$ (113,768)	$ (106,636)	$ 5,688	Straight-Line			Straight-Line
38	PP-2052	6/15 and 12/15			Straight-Line	$ (796,375)	$ (763,036)	$ 26,544	Straight-Line			Straight-Line
39	PP-2033	4/15 and 10/15			Straight-Line	$ (1,056,320)	$ (1,009,151)	$ 105,636	Straight-Line			Straight-Line
40	PP-2052	4/15 and 10/15			Straight-Line	$ (352,107)	$ (346,133)	$ 11,736	Straight-Line			Straight-Line
41	Totals /a		$ 11,076,576	$ (421,374)		$ (18,251,715)	$ (12,946,803)	$ 691,842		$ (8,560,713)	$ 535,886	

Notes: /a - The t
differences are ‹
correct annual a

Washington Ga
Long-term Not

LT Debt Notes

Ln.	Trade Number	Unamortized Gain/(Loss) on Reacquired Debt	Amortization Expense (Annualized)	Amortization Method
	A	AB	AC	AD
1	C-9			Straight-Line
2	C-10			Straight-Line
3	C-11			Straight-Line
4	C-12			Straight-Line
5	C-13			Straight-Line
6	C-14			Straight-Line
7	C-15			Straight-Line
8	C-16			Straight-Line
9	D-1	$ (53,923)	$ 5,687	Straight-Line
10	D-2	$ (71,897)	$ 7,583	Straight-Line
11	D-3	$ (89,871)	$ 9,478	Straight-Line
12	D-4	$ (53,923)	$ 5,687	Straight-Line
13	D-5			Straight-Line
14	D-6			Straight-Line
15	D-7			Straight-Line
16	D-8			Straight-Line
17	D-9			Straight-Line
18	D-10			Straight-Line
19	D-11			Straight-Line
20	D-12	$ (38,630)	$ 9,862	Straight-Line
21	D-13			Straight-Line
22	D-14			Straight-Line
23	E-6			Straight-Line
24	G-3			Straight-Line
25	G-4			Straight-Line
26	G-5			Straight-Line
27	G-7	$ (405,131)	$ 33,761	Straight-Line
28	I-1			Straight-Line
29	J-1			Straight-Line
30	J-2			Straight-Line
31	PP-2044			Straight-Line
32	K-1			Straight-Line
33	K-1 Reopening			Straight-Line
34	L-1			Straight-Line
35	L-1 Reopening			Straight-Line
36	PP-2051			Straight-Line
37	PP-2042			Straight-Line
38	PP-2052			Straight-Line
39	PP-2033			Straight-Line
40	PP-2052			Straight-Line
41	Totals /a	$ (713,376)	$ 72,058	

Notes: /a - The t
differences are a
correct annual a

Washington Gas Light Company
Gains or (Losses) on Reacquired Debt
March 31, 2024

Ln.	Reacquired Debt	Amount Outstanding	Amount Paid for Reacquired Debt a/	Dat Debt Was Reacquired	(Losses) Realized on Reacquired Debt	Amortized Over Life of New Issue
	A	B	C	D	E	F
1	First Mortgage Bonds					
2	8-5/8% Series	$27,500,000	$28,921,750	04/01/97	($1,421,750)	Series D
3	8-5/8% Series	7,500,000	7,810,543	05/01/97	($310,543)	Series D
4	8-3/4% Series	4,000,000	4,175,000	03/01/98	($175,000)	Series D
5	8-3/4% Series	5,000,000	5,227,500	03/01/98	($227,500)	Series D
6	8-3/4% Series	2,000,000	2,090,600	03/01/98	($90,600)	Series D
7	Subtotal First Mortgage Bonds	$46,000,000	$48,225,393		($2,225,393)	
8	Medium-Term Notes					
9	Series E, Trades 11 & 12	$25,000,000	$25,958,158	03/17/06	($958,158)	Series G-7
10	Subtotal Medium Term Notes	$25,000,000	25,958,158		($958,158)	
11	TOTAL	$71,000,000	$74,183,551		($3,183,551)	

a/ Includes unamortized debt expense and unamortized discount associated with the reacquired debt at the time of debt reacquisition.

WASHINGTON GAS LIGHT COMPANY
PEER COMPARISON - CREDIT METRICS AND CAPITAL STRUCTURE
($ in '000s)

Ln.	Company	Debt a/	Equity a/	=B+C Total Avg Capital Structure	=C/D Adjusted Equity Percentage	Credit Ratings (S&P / Fitch / Moody's)	Debt at March 31, 2024 (GAAP Basis)	FFO	Interest	FFO-to-Debt	FFO-to-Interest	Debt-to-Total Capitalization
	A	B	C	D = B + C	E = C / D	F	G	H	I	J = H / G	K = H / I	L = B / D
1	Atmos Energy Corporation (NYSE:ATO)[1]	7,212,382	11,091,073	18,303,455	60.60%	(A- / - / A1)	7,535,708	399,010	170,468	5.3%	2.3	39.40%
2	New Jersey Natural Gas Company[1,2]	1,537,412	1,861,041	3,398,453	54.76%	(- / A- / A1)	1,523,841	NA	58,608	NA	NA	45.24%
3	Northwest Natural Gas Company	1,455,596	1,231,845	2,687,441	45.84%	(A+ / - / Baa1)	1,475,086	210,107	62,061	14.2%	3.4	54.16%
4	ONE Gas, Inc.	3,021,975	2,724,359	5,746,334	47.41%	(A- / - / A3)	3,127,958	471,854	116,581	15.1%	4.0	52.59%
5	NSTAR Gas Company	879,951	1,389,147	2,269,098	61.22%	(A- / A- / -)	894,058	152,239	29,940	17.0%	5.1	38.78%
6	The Southern Connecticut Gas Company[2]	354,694	609,905	964,599	63.23%	(A- / A- / A3)	387,333	43,996	19,481	11.4%	2.3	36.77%
7	Yankee Gas Services Company	1,007,488	1,416,000	2,423,488	58.43%	(A- / - / A2)	1,043,561	108,955	37,749	10.4%	2.9	41.57%
8	DTE Gas Company[2]	2,480,750	2,786,250	5,267,000	52.90%	(A- / BBB+ / A3)	2,536,000	137,000	105,000	5.4%	1.3	47.10%
9	Southern Company Gas	8,090,750	10,862,000	18,952,750	57.31%	(A- / BBB+ / A3)	8,197,000	1,422,998	318,000	17.4%	4.5	42.69%
10	Spire Missouri Inc.[1]	2,310,175	1,900,375	4,210,550	45.13%	(A- / - / Baa2)	2,230,100	67,659	106,400	3.0%	0.6	54.87%
11	Spire Alabama Inc.[1]	865,875	938,125	1,804,000	52.00%	(A- / - / Baa2)	812,400	47,517	35,200	5.8%	1.3	48.00%
12	NiSource Inc.	13,253,250	8,817,975	22,071,225	39.95%	(BBB+ / BBB / Baa2)	12,970,900	1,813,044	533,900	14.0%	3.4	60.05%
	*Part of Company Witness Dylan D'Ascendis's list. For Spire, Inc. the gas utility subsidiaries that have independent financial statements and credits ratings were used.											
13	Average (All Companies)				53.23%					10.82%	2.8	46.77%
14	Median (All Companies)				53.83%					11.36%	2.9	46.17%
15	Average (A- rated companies)				55.36%					10.09%	2.7	44.64%
16	Median (A- rated companies)				57.31%					10.44%	2.3	42.69%
17	Washington Gas	2,122,063	2,344,085	4,466,148	52.49%	(A- / A / -)	2,155,781	381,843	99,406	17.7%	3.8	47.51%

Source: S&P Global website
[1] *Companies with 09/30/24 year-end*
[2] *Financials were sourced from S&P Capital IQ as these entities do not have independently published financial statements*
a/ For peer Debt and Equity amounts the average total Debt outstanding and Equity for the four quarters ended 03/31/2024 was utilized
Washington Gas Debt and Equity amounts represent proposed capital structure amounts in this filing.

Washington Gas Light Company
Peer Comparison - Supporting Schedule
($ in '000s)

Ln.	Company Name		TOTAL REVENUE	NET INCOME BEFORE TAXES	NET INCOME	NET INCOME GROWTH
	A		B	C	D	E
1	NSTAR Gas Company	4057115	759,066	147,498	110,026	41.85
2	The Southern Connecticut Gas Company	4063060	387,627	34,337	28,431	(44.76)
3	Yankee Gas Services Company	4064141	644,651	97,098	78,668	9.67
4	DTE Gas Company	4057126	1,736,000	366,000	278,000	45.10
5	ONE Gas, Inc. (NYSE:OGS)	4427129	2,098,167	268,042	227,928	2.62
6	Atmos Energy Corporation (NYSE:ATO)	4057157	4,056,069	1,168,701	999,646	26.98
7	Southern Company Gas	4057108	4,533,000	962,000	716,000	38.77
8	Northwest Natural Gas Company	10344596	1,126,885	131,678	96,755	(8.42)
9	New Jersey Natural Gas Company	4061755	1,010,680	164,482	134,592	(3.58)
10	Spire Missouri Inc.	4060957	1,738,300	130,800	120,300	29.44
11	Spire Alabama Inc.	4004296	602,000	103,200	78,600	(30.51)
12	NiSource Inc. (NYSE:NI)	4057051	5,245,700	866,600	736,900	5.95

Four-Quarter Average Capital Structure

Ln.	Company Name	TOTAL DEBT a/ 2024 TTM Average	TOTAL EQUITY a/ 2024 TTM Average	TOTAL DEBT FQ12024	TOTAL DEBT FQ42023
13	NSTAR Gas Company	879,951	1,389,147	894,058	925,090
14	The Southern Connecticut Gas Company[2]	354,694	609,905	387,333	378,826
15	Yankee Gas Services Company	1,007,488	1,416,000	1,043,561	1,111,755
16	DTE Gas Company[2]	2,480,750	2,786,250	2,536,000	2,613,000
17	ONE Gas, Inc. (NYSE:OGS)	3,021,975	2,724,359	3,127,958	3,069,615
18	Atmos Energy Corporation (NYSE:ATO)[1]	7,212,382	11,091,073	7,535,708	7,540,756
19	Southern Company Gas	8,090,750	10,862,000	8,197,000	8,299,000
20	Northwest Natural Gas Company	1,455,596	1,231,845	1,475,086	1,460,397
21	New Jersey Natural Gas Company[1,2]	1,537,412	1,861,041	1,523,841	1,649,383
22	Spire Missouri Inc.[1]	2,310,175	1,900,375	2,230,100	2,419,100
23	Spire Alabama Inc.[1]	865,875	938,125	812,400	901,800
24	NiSource Inc. (NYSE:NI)	13,253,250	8,817,975	12,970,900	14,162,000

Source Data: S&P Capital IQ

[1] Companies with 09/30/24 year-end

[2] Financials were sourced from S&P Capital IQ as these entities do not have independently published financial statements

a/ For peer Debt and Equity amounts the average total Debt outstanding and Equity for the four quarters ended 03/31/2024 was utilized

Washington Gas Light Company
Peer Comparison - Supporting Schedule
($ in '000s)

Company Name	TOTAL DEBT	TOTAL EQUITY	INTEREST	ROACE	EBITDA
A	F	G	H	I	J
NSTAR Gas Company	879,951	1,389,147	29,940	7.64	240,101
The Southern Connecticut Gas Company	354,694	609,905	19,481	4.47	96,640
Yankee Gas Services Company	1,007,488	1,416,000	37,749	5.58	193,365
DTE Gas Company	2,480,750	2,786,250	105,000	9.94	651,250
ONE Gas, Inc. (NYSE:OGS)	3,021,975	2,724,359	116,581	8.35	655,442
Atmos Energy Corporation (NYSE:ATO)	7,212,382	11,091,073	170,468	9.01	1,923,925
Southern Company Gas	8,090,750	10,862,000	318,000	6.58	1,702,000
Northwest Natural Gas Company	1,455,596	1,231,845	62,061	7.75	313,595
New Jersey Natural Gas Company	1,537,412	1,861,041	58,608	7.05	313,171
Spire Missouri Inc.	2,310,175	1,900,375	106,400	6.16	381,100
Spire Alabama Inc.	865,875	938,125	35,200	8.33	211,800
NiSource Inc. (NYSE:NI)	13,253,250	8,817,975	533,900	9.57	2,181,400

Four-Quarter Average Capital Structure

	TOTAL DEBT	TOTAL DEBT	TOTAL EQUITY	TOTAL EQUITY	TOTAL EQUITY
	FQ32023	FQ22023	FQ12024	FQ42023	FQ32023
NSTAR Gas Company	929,099	771,557	1,549,629	1,416,321	1,281,856
The Southern Connecticut Gas Company[2]	335,651	316,965	615,392	600,563	612,307
Yankee Gas Services Company	1,029,582	845,054	1,491,614	1,375,900	1,358,301
DTE Gas Company[2]	2,483,000	2,291,000	3,043,000	2,721,000	2,664,000
ONE Gas, Inc. (NYSE:OGS)	2,989,976	2,900,351	2,829,985	2,765,877	2,646,747
Atmos Energy Corporation (NYSE:ATO)[1]	7,122,906	6,650,158	11,618,639	11,273,209	10,870,064
Southern Company Gas	8,172,000	7,695,000	11,074,000	10,803,000	10,833,000
Northwest Natural Gas Company	1,483,252	1,403,647	1,282,362	1,232,620	1,202,103
New Jersey Natural Gas Company[1,2]	1,524,330	1,452,092	1,973,375	1,866,280	1,814,836
Spire Missouri Inc.[1]	2,328,300	2,263,200	2,007,100	1,901,900	1,844,800
Spire Alabama Inc.[1]	895,400	853,900	966,900	924,100	928,000
NiSource Inc. (NYSE:NI)	13,258,000	12,622,100	9,794,900	10,136,300	7,769,300

Source Data: S&P Capital IQ

[1] Companies with 09/30/24 year-end

[2] Financials were sourced from S&P Capital IQ
a/ For peer Debt and Equity amounts the avera
was utilized

Washington Gas Light Company
Peer Comparison - Supporting Schedule
($ in '000s)

Company Name	INVENTORIES	PP&E	GEOGRAPHY	INDUSTRY CLASS.	S&P RATING	FFO/DEBT ADJ.
A	K	L	M	N	O	P
NSTAR Gas Company	22,453	2,407,497	United States	Gas Utilities	A-	23.17
The Southern Connecticut Gas Company	47,676	1,053,172	United States	Gas Utilities	A-	15.14
Yankee Gas Services Company	37,378	2,461,976	United States	Gas Utilities	A-	14.43
DTE Gas Company	94,500	5,953,250	United States	Gas Utilities	A-	10.77
ONE Gas, Inc. (NYSE:OGS)	238,052	6,059,118	United States	Gas Utilities	A-	17.59
Atmos Energy Corporation (NYSE:ATO)	214,060	19,995,584	United States anc	Gas Utilities	A-	22.08
Southern Company Gas	334,500	16,306,250	United States	Gas Utilities	A-	18.46
Northwest Natural Gas Company	91,897	3,257,498	United States	Gas Utilities	A+	14.52
New Jersey Natural Gas Company	152,067	3,359,630	United States anc	Gas Utilities	NR	NA
Spire Missouri Inc.	151,825	3,987,400	United States anc	Gas Utilities	A-	11.92
Spire Alabama Inc.	64,225	1,593,025	United States anc	Gas Utilities	A-	16.41
NiSource Inc. (NYSE:NI)	457,750	22,035,275	United States anc	Multi-Utilities	BBB+	13.71

Four-Quarter Average Capital Structure

	TOTAL EQUITY
	FQ22023
NSTAR Gas Company	1,308,780
The Southern Connecticut Gas Company[2]	611,358
Yankee Gas Services Company	1,438,186
DTE Gas Company[2]	2,717,000
ONE Gas, Inc. (NYSE:OGS)	2,654,826
Atmos Energy Corporation (NYSE:ATO)[1]	10,602,381
Southern Company Gas	10,738,000
Northwest Natural Gas Company	1,210,296
New Jersey Natural Gas Company[1,2]	1,789,673
Spire Missouri Inc.[1]	1,847,700
Spire Alabama Inc.[1]	933,500
NiSource Inc. (NYSE:NI)	7,571,400

Source Data: S&P Capital IQ

[1] Companies with 09/30/24 year-end

[2] Financials were sourced from S&P Capital IQ

a/ For peer Debt and Equity amounts the avera was utilized

Washington Gas Light Company
Peer Comparison - Supporting Schedule
($ in '000s)

Company Name	FFO ADJ.	FFO/INTEREST	EQUITY ADJ
A	Q	R	S
NSTAR Gas Company	152.24	7.01	1,380.09
The Southern Connecticut Gas Company	44.00	5.14	608.08
Yankee Gas Services Company	108.96	5.54	1,429.37
DTE Gas Company	137.00	4.19	2,690.50
ONE Gas, Inc. (NYSE:OGS)	471.85	10.57	2,724.36
Atmos Energy Corporation (NYSE:ATO)	399.01	6.22	11,091.07
Southern Company Gas	1,423.00	5.22	10,862.00
Northwest Natural Gas Company	210.11	3.82	1,231.85
New Jersey Natural Gas Company	NA	NA	NA
Spire Missouri Inc.	67.66	3.21	1,900.38
Spire Alabama Inc.	47.52	6.75	938.13
NiSource Inc. (NYSE:NI)	1,813.04	4.71	8,635.69

Four-Quarter Average Capital Structure

NSTAR Gas Company
The Southern Connecticut Gas Company[2]
Yankee Gas Services Company
DTE Gas Company[2]
ONE Gas, Inc. (NYSE:OGS)
Atmos Energy Corporation (NYSE:ATO)[1]
Southern Company Gas
Northwest Natural Gas Company
New Jersey Natural Gas Company[1,2]
Spire Missouri Inc.[1]
Spire Alabama Inc.[1]
NiSource Inc. (NYSE:NI)

Source Data: S&P Capital IQ

[1] *Companies with 09/30/24 year-end*

[2] *Financials were sourced from S&P Capital IQ*

a/ For peer Debt and Equity amounts the avera
was utilized

Washington Gas Light Company
October 19, 2023 Debt Issuance
Comparison of Debt Prices of Similar Maturities

10 -Year Comparables	Date	Type	Public/ Private Issuance	Ratings (S&P / Fitch / Moody's)	Size ($ Million)	Tenor (Years)	Unadjusted Spread (Bps)	Normalized Spread (for Type, and Secondary Index-Eligible vs New) a/
Washington Gas Light Company	**Oct-23**	**Unsecured**	**Private**	**A- / A / -**	**150**	**10.0**	**135**	**135**
New Jersey Natural Gas	Sep-23	Unsecured	Private	- / A- / A1	50	10.0	125	125
DTE Gas	Sep-23	Secured	Private	A- / BBB+ / A3	145	12.0	145	155
Southern Indiana Gas & Electric	Sep-23	Secured	Private	BBB / - / -	185	10.0	140	150
Madison Gas & Electric	Aug-23	Unsecured	Private	AA- / - / A1	40	11.0	130	130
Yankee Gas Services	Aug-23	Secured	Private	A- / - / A2	170	7.0	135	145
Portland General Electric	Aug-23	Secured	Private	A / - / A1	150	10.0	145	155
Alabama Power Co	Oct-23	Unsecured	Public	A- / A+ / -	450	8.9	111	136
Atmos Energy Corp	Oct-23	Unsecured	Public	A- / - / A1	400	10.1	120	145
Virginia Electric and Power Corp	Oct-23	Unsecured	Public	BBB+ / A / A3	400	9.8	129	154
Average (excluding Washington Gas Light)							**131**	**144**
Difference to Comparable Normalized Average								**(9)**

30 -Year Comparables	Date	Type	Public/ Private Issuance	Ratings (S&P / Fitch / Moody's)	Size ($ Million)	Tenor (Years)	Unadjusted Spread (Bps)	Normalized Spread (for Type, and Secondary Index-Eligible vs New) a/
Washington Gas Light Company	**Oct-23**	**Unsecured**	**Private**	**A- / A / -**	**50**	**30.0**	**155**	**155**
New Jersey Natural Gas	Sep-23	Unsecured	Private	- / A- / A1	50	30.0	145	145
Madison Gas & Electric	Sep-23	Unsecured	Private	AA- / - / A1	30	30.0	150	150
Georgia Transmission Corp	Aug-23	Secured	Private	AA- / A+ / A2	150	30.0	155	165
Southwestern Public Service	Aug-23	Secured	Private	A- / A- / A3	100	30.0	180	190
Portland General Electric	Aug-23	Secured	Private	A / - / A1	100	30.0	170	180
Dominion Energy South Carolina	Oct-23	Secured	Private	A / - / A2	500	30.0	140	175
Atmos Energy Corp	Oct-23	Unsecured	Public	A- / - / A1	500	30.1	134	159
Virginia Electric & Power	Oct-23	Unsecured	Public	BBB+ / A / A3	600	29.8	147	172
Wisconsin Power & Light	Oct-23	Unsecured	Public	A / - / Baa1	350	26.5	137	162
Baltimore Gas & Electric	Oct-23	Unsecured	Public	A / A / A3	700	29.6	130	155
Average (excluding Washington Gas Light)							**149**	**165**
Difference to Comparable Normalized Average								**(10)**

a/ Secured debt estimated to be about 10 bps less than Unsecured, Index-Eligible Secondary about 25 bps less than new issuance Private Placements

Washington Gas Light Company
December 29, 2022 Debt Issuance
Comparison of Debt Prices of Similar Maturities

20 -Year Comparables

	Date	Type	Public/ Private Issuance	Ratings (S&P / Fitch / Moody's)	Size ($ Million)	Tenor (Years)	Unadjusted Spread (Bps)	Normalized Spread (for Type, and Secondary Index-Eligible vs New) a/
Washington Gas Light Company	**Dec-22**	**Unsecured**	**Private**	**A- / A / -**	**25**	**20.0**	**150**	**150**
Idaho Power Company	Dec-22	Secured	Private	A- / - / A2	170	20.0	135	145
Caribbean Utilities Co Ltd	Nov-22	Unsecured	Private	NAIC-1/A	80	20.0	200	200
Lone Star Transmission LLC	Nov-22	Secured	Private	NAIC-1/A	60	20.0	140	150
Veolia Water	Oct-22	Unsecured	Private	NAIC-1/A	200	20.0	140	140
Average (excluding Washington Gas Light)							**154**	**159**
Difference to Comparable Normalized Average								**(9)**

30 -Year Comparables

	Date	Type	Public/ Private Issuance	Ratings (S&P / Fitch / Moody's)	Size ($ Million)	Tenor (Years)	Unadjusted Spread (Bps)	Normalized Spread (for Type, and Secondary Index-Eligible vs New) a/
Washington Gas Light Company	**Dec-22**	**Unsecured**	**Private**	**A- / A / -**	**175**	**30.0**	**180**	**180**
York Water Co	Mar-23	Unsecured	Private	A- / - / -	40	30.0	170	170
Delmarva Power & Light	Mar-23	Secured	Private	A / A / -	65	30.0	165	175
Atlantic City Electric	Mar-23	Secured	Private	A / A / A2	75	30.0	165	175
Idaho Power Company	Dec-22	Secured	Private	A- / - / A2	62	30.0	170	180
American Transmission Co	Oct-22	Unsecured	Private	A+ / - / A2	50	30.0	185	185
Veolia Water	Oct-22	Unsecured	Private	NAIC-1/A	135	30.0	175	175
East Ohio Gas Co	Oct-22	Unsecured	Private	BBB / A- / A2	250	30.0	215	215
New Jersey Natural Gas	Oct-22	Secured	Private	- / A- / A1	125	30.0	160	170
Commonwealth Edison	Dec-22	Secured	Public	A / A / A1	450	29.2	114	149
Centerpoint Energy Houston	Dec-22	Secured	Public	A / A / A2	300	29.8	118	153
Alabama Power Co	Dec-22	Unsecured	Public	A- / A+ / -	700	29.2	128	153
Virginia Electric & Power	Dec-22	Unsecured	Public	BBB+ / A / A3	600	29.4	148	173
Baltimore Gas & Electric	Dec-22	Unsecured	Public	A / A / A3	500	29.4	124	149
Average (excluding Washington Gas Light)							**157**	**171**
Difference to Comparable Normalized Average								**9**

a/ Secured debt estimated to be about 10 bps less than Unsecured, Index-Eligible Secondary about 25 bps less than new issuance Private Placements

WASHINGTON GAS LIGHT COMPANY

Medium Term Notes and Short-Term Debt Credit Ratings

		As of December 31,					As of March 31, 2024
		2019	2020	2021	2022	2023	2024
	A	B	C	D	E	F	G
	Senior Unsecured LT Debt						
1	Moody's	A2	A3	A3	n/a	n/a	n/a
2	Standard & Poor's	A-	A-	A-	A-	A-	A-
3	Fitch	A	A	A	A	A	A
	Senior Unsecured ST Debt						
4	Moody's						
5	Standard & Poor's	A-2	A-2	A-2	A-2	A-2	A-2
6	Fitch	F2	F2	F2	F2	F2	F2

S&P Global
Ratings

RatingsDirect®

Washington Gas Light Co.

July 17, 2024

Primary contact

Redacted

Secondary contacts

Redacted

In December 2023, Washington Gas Light Co. received decisions in two rate case proceedings in the District of Columbia (DC) and Maryland. The District of Columbia Public Service Commission approved a $24.6 million rate increase based on a return on equity (ROE) of 9.65% (up from 9.25%) and an equity layer of 52%. The Maryland Public Service Commission approved a rate increase of $12.6 million based on a ROE of 9.5% (down from 9.7%). We view the Washington rate case outcome as largely in line with our base-case expectation, though partially offset by the length of time it took to reach a decision. We view the Maryland decision as below our base case. As such, we continue to monitor the regulatory jurisdictions.

S&P Global Ratings expects WGLC to effectively manage its regulatory risk, which supports our view of its business risk profile. The company has a large customer base of about 1.2 million customers across three regulatory jurisdictions and benefits from numerous regulatory mechanisms, such as riders for aged pipe replacement, weather normalization, gas purchase cost adjustments, and bad debt recovery. Furthermore, while its robust capital spending plan to replace aged pipe infrastructure entails some operating risk, it also provides lower-risk rate base growth.

Our negative outlook reflects our outlook on parent AltaGas Ltd. The negative outlook on AltaGas reflects its increasing exposure to higher risk, nonregulated midstream businesses, and construction risk during the Ridley Island Energy Export Facility (REEF) terminal's build out.

We forecast credit measures will remain within our expected range for the significant financial risk profile category. We expect WGLC's funds from operations (FFO) to debt to average 16%-19% over our forecast period, incorporating the recent rate-case outcomes, capital spending averaging about $530 million, continued use of existing regulatory mechanisms, and negative discretionary cash flow. We assess the company's financial measures using our medial volatility financial benchmark table, reflecting the company's lower-risk regulated gas distribution utility operations and effective management of regulatory risk.

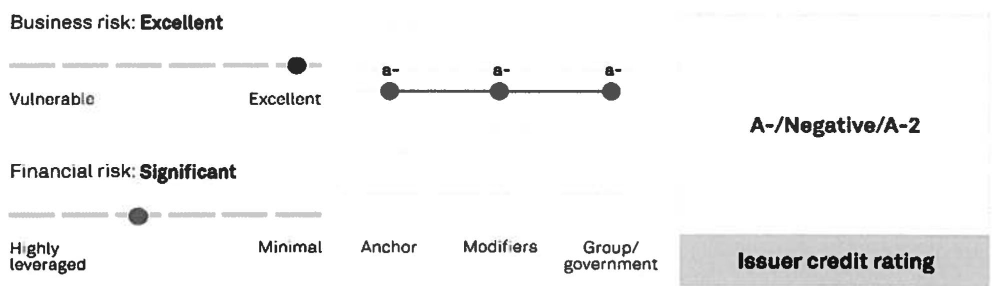
We continue to view WGLC as an insulated core subsidiary of AltaGas. Insulating measures between WGLC and AltaGas allow us to rate WGLC three notches higher than its parent, reflecting the cumulative value of the structural and regulatory protections that insulate WGLC from AltaGas as well as the strength of WGLC's stand-alone credit profile.

Key insulating measures include:

- WGLC's status as a separate entity, with financial performance and funding that are highly independent from AltaGas;

- Strong economic basis for AltaGas to preserve WGLC's credit strength because it generates about 40% of the group's EBITDA;
- Lack of cross default provisions between WGLC and AltaGas or any of its subsidiaries;
- An independent board of directors;
- Requirements by regulators for WGLC to maintain investment-grade ratings;
- Dividend restrictions if WGLC's credit rating falls below investment grade or if the dividend reduces WGLC's equity ratio below 48%; and
- Merger commitments that allow the regulators to order AltaGas to divest WGLC if AltaGas' financial state deteriorates.

Ratings Score Snapshot



Recent Research

- AltaGas Ltd. Outlook Revised To Negative On Additional Midstream Investments; Ratings Affirmed, June 7, 2024
- Tear Sheet: Washington Gas Light Co., January 23, 2024

Company Description

WGLC, a fully owned subsidiary of WGL Holdings Inc., is a fully regulated utility that provides natural gas service to more than 1.2 million customers in the Washington, D.C.; Maryland; and Virginia. WGL Holdings Inc. is owned by AltaGas Ltd.

Outlook

The negative outlook on WGLC reflects our outlook on AltaGas.

Downside scenario

We could lower the rating on WGLC within the next 12-24 months if we downgrade AltaGas, or WGLC's stand-alone financial measures deteriorate, including FFO to debt of consistently below 15%.

Upside scenario

We could affirm the rating and revise the outlook to stable on WGLC within the outlook period if we affirm our rating on AltaGas.

Financial Summary

Washington Gas Light Co.--Financial Summary

Period ending	Sep-30-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	$	$	$	$	$	$
Revenues	1,248	1,331	1,234	1,449	1,747	1,566
EBITDA	368	334	371	392	439	539
Funds from operations (FFO)	309	254	308	313	360	442
Interest expense	76	75	76	76	89	109
Cash interest paid	62	64	66	68	80	97
Operating cash flow (OCF)	123	203	227	318	339	455
Capital expenditure	393	433	390	474	531	516
Free operating cash flow (FOCF)	(270)	(230)	(163)	(156)	(191)	(60)
Discretionary cash flow (DCF)	(358)	(359)	(263)	(256)	(291)	(160)
Cash and short-term investments	0	17	0	0	0	17
Gross available cash	0	17	0	0	0	17
Debt	1,498	1,852	1,900	1,979	2,183	2,355
Common equity	1,457	1,572	1,856	2,022	2,112	2,358
Adjusted ratios						
EBITDA margin (%)	29.5	25.1	30.0	27.0	25.1	34.4
Return on capital (%)	6.9	5.5	6.0	5.9	6.4	7.9
EBITDA interest coverage (x)	4.8	4.4	4.9	5.1	4.9	4.9
FFO cash interest coverage (x)	6.0	5.0	5.7	5.6	5.5	5.5
Debt/EBITDA (x)	4.1	5.6	5.1	5.1	5.0	4.4
FFO/debt (%)	20.6	13.7	16.2	15.8	16.5	18.8
OCF/debt (%)	8.2	11.0	11.9	16.1	15.5	19.3
FOCF/debt (%)	(18.0)	(12.4)	(8.6)	(7.9)	(8.8)	(2.6)
DCF/debt (%)	(23.9)	(19.4)	(13.8)	(12.9)	(13.3)	(6.8)

Peer Comparison

Washington Gas Light Co.--Peer Comparisons

	Washington Gas Light Co.	Piedmont Natural Gas Co. Inc.	ONE Gas Inc.
Foreign currency issuer credit rating	A-/Negative/A-2	BBB+/Stable/A-2	A-/Stable/A-2

Washington Gas Light Co.--Peer Comparisons

Local currency issuer credit rating	A-/Negative/A-2	BBB+/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual
Period ending	2023-12-31	2023-12-31	2023-12-31
Mil.	$	$	$
Revenue	1,566	1,628	2,327
EBITDA	539	804	633
Funds from operations (FFO)	442	606	539
Interest	109	174	105
Cash interest paid	97	170	73
Operating cash flow (OCF)	455	756	911
Capital expenditure	516	1,028	661
Free operating cash flow (FOCF)	(60)	(272)	250
Discretionary cash flow (DCF)	(160)	(272)	103
Cash and short-term investments	17	0	19
Gross available cash	17	0	19
Debt	2,355	4,137	2,647
Equity	2,358	4,052	2,766
EBITDA margin (%)	34.4	49.4	27.2
Return on capital (%)	7.9	7.8	6.9
EBITDA interest coverage (x)	4.9	4.6	6.0
FFO cash interest coverage (x)	5.5	4.6	8.4
Debt/EBITDA (x)	4.4	5.1	4.2
FFO/debt (%)	18.8	14.6	20.4
OCF/debt (%)	19.3	18.3	34.4
FOCF/debt (%)	(2.6)	(6.6)	9.4
DCF/debt (%)	(6.8)	(6.6)	3.9

Rating Component Scores	
Foreign currency issuer credit rating	**A-/Negative/A-2**
Local currency issuer credit rating	**A-/Negative/A-2**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**a-**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a-**
Group Credit Profile	**bbb-**
Entity Status within Group	**Core, Insulated (No Impact on SACP)**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

FitchRatings

RATING ACTION COMMENTARY

Fitch Revises AltaGas and Subs Outlook to Negative; Affirms IDRs

Tue 02 Jul, 2024 - 5:06 PM ET

Fitch Ratings - New York - 02 Jul 2024: Fitch Ratings has revised the Rating Outlook for the Long-Term Issuer Default Rating (IDR) to Negative from Stable for AltaGas Ltd. (AltaGas), wholly owned subsidiary WGL Holdings, Inc. (WGLH) and Washington Gas Light Company (WGL). Fitch has also affirmed AltaGas' and WGL's Long-Term IDRs and Short-Term IDRs at 'BBB'/'F3' and 'A-'/'F2', respectively. Fitch has additionally affirmed WGLH's Long-Term IDR at 'BBB'.

The Negative Outlook reflects Fitch's expectation that FFO leverage will remain higher for longer reaching 5.7x by YE 2025, inclusive of expected asset sales. AltaGas' FFO leverage averaged 7.4x over the last four years. Elevated midstream capex along with delayed monetization of Mountain Valley Pipeline (MVP) have weakened the credit profile. Opportunistic expansion of its midstream business including development of Pipestone II and Ridley Island Energy Export Facility (REEF) will require capex of over CAD1.5 billion from 2024-2026, funded with debt and internal cash flows. Continued expansion in the more volatile midstream segment is a concern from a business risk perspective.

Fitch could lower AltaGas' ratings if FY 2024 FFO leverage exceeds 6x or FY 2025 leverage exceeds 5.5x. Fitch could revise the Outlook to Stable is able to reduce FFO-leverage is sustainably below 5.5x by in 2025 and beyond.

WGL's and WGLH's Outlooks have been revised to Negative reflecting Fitch's parent subsidiary rating linkage (PSL) criteria.

KEY RATING DRIVERS

AltaGas and WGLH

High Leverage: AltaGas' FFO-leverage has averaged 7.4x over the last four years and stood at 7.1x in 2023, considerably higher than expected. Elevated midstream capex, including the Pipestone acquisition and subsequent development of Phase II, and the weaker than expected rate case in Maryland continue to pressure leverage. Fitch expects development of projects to continue, including CAD675 million in capital requirement for AltaGas' portion of REEF. Partially funded with debt, this spend will offset expected improvement in leverage from cost optimization, utility customer growth averaging 1%, efficient utility capital allocation and debt reduction from asset sales.

In 2023, AltaGas sold utility and related operations in Alaska, with the resulting proceeds of CAD1.1 billion applied toward debt reduction. The monetization of AltaGas' share of MVP, which Fitch expects will be completed in 2025, will also be used to lower debt. Fitch expects deleveraging from these transactions will result in improvement in FFO leverage to 5.7x in 2025, higher than Fitch's downgrade threshold of 5.5x. Absent other concrete measures to lower leverage, Fitch would lower the ratings.

Weak Business Mix: Fitch views the high proportion of midstream contribution to be a weakness as it has greater volatility than utility earnings. More stable utility operations will contribute approximately 55%-60% of cash flow over the long term. The remainder will largely come from partially contracted midstream operations and smaller power generation operations, averaging between 43% and 46% over the next three years. Fitch calculates largely debt-funded midstream capex offsets the funding from the monetization of MVP. Non-utility operations sustained over 45% may lead to a ratings downgrade.

Volatility from Midstream Segment: Approximately 80% of midstream EBITDA is derived from investment-grade counterparties, lending stability to cash flow. Contractual structure has improved, with tolling levels increasing to approximately 56% of capacity starting second quarter of 2024. Approximately 95% of global export volumes for the remainder of 2024 are either tolled or financially hedged. With shorter transportation times, AltaGas is competitively positioned to service growing NGL (natural gas liquid) demand in Asia.

However, year-to-year cash flow is exposed to pricing differentials between the U.S. and Asia. Failure to lock in this differential in 3Q22 squeezed butane margins, adversely affecting midstream EBITDA. Management modified its hedging strategy by locking in a higher percentage of firmly committed and merchant volumes and managing the propane-butane product mix, which improved margin realization. Hedges for the year are executed largely starting in the first quarter, and price differentials can be volatile depending upon global market factors. For example, average hedged price for export volumes are USD17.88/bbl for 2024, compared to USD12.17/bbl in 2023, a 47% difference in one-year.

Future inefficient hedging or increased exposure to market risk may result in negative rating action.

Additional Regulatory Risks: AltaGas' diversified group of relatively low-risk U.S. gas-distribution utilities serve approximately 1.6 million customers in parts of Maryland, Virginia, the District of Columbia (DC) and Michigan under generally credit supportive economic regulation. Fitch believes the regulatory compacts in Maryland and Virginia remain balanced, although election changes in Maryland have introduced a measure of uncertainty. Earned ROEs remain well below allowed ROEs due to regulatory lag and lack of weather decoupling in DC and Michigan. A significant unexpected deterioration in rate regulation could result in future credit rating downgrades.

PSL - AltaGas and WGLH: WGLH's Outlook was revised to Negative due to its PSL with AltaGas. Fitch analyzed parent-subsidiary rating linkage between AltaGas and intermediate holding company subsidiary WGLH by utilizing the strong subsidiary path laid out in Fitch's "Parent and Subsidiary Linkage Rating Criteria". Legal ring-fencing and access and control are each evaluated as open, resulting in consolidated ratings for AltaGas and WGLH. WGLH, unlike AltaGas's utility subsidiaries, is not subject to rate regulation. Its strategy and treasury functions are centrally managed by AltaGas.

PSL - WGLH and WGL: WGL's Outlook was revised to Negative due to its parent-subsidiary linkage (PSL) with WGLH. There is a parent subsidiary linkage between WGLH and WGL. Fitch determines AltaGas' Standalone Credit Profile (SCP) based upon consolidated metrics. Fitch considers WGL to have stronger SCP than WGLH. As a result, the linkage between WGLH and WGL is assessed following the weak parent/strong subsidiary path. Emphasis is placed on the subsidiary's status as a regulated entity.

Legal ring-fencing is porous, given the general protections afforded by economic regulation, and access and control are also porous. AltaGas centrally manages the treasury function for all of its utility subsidiaries and is the sole source of equity; however, WGL issues its own long-term debt. Due to the aforementioned assessment, Fitch will limit the difference between AltaGas and any of its higher-rated regulated subsidiaries to two notches.

WGL

Rate Regulation: WGL derives approximately 80% of its earnings from its Maryland and Virginia jurisdictional service territories. The remaining 20% is from its DC service territory. Fitch believes rate regulation in Maryland and Virginia is generally credit supportive although WGL's recent base rate outcome in Maryland was weak. The adoption of regulatory mechanisms for system betterment and timely recover other costs, providing WGL with a reasonable opportunity to earn its authorized ROE.

Regulation in DC is more challenging, in Fitch's view, compared with Maryland and Virginia. There is no weather normalization in DC, nor does WGL hedge to offset for variations in weather. DC does not have statutory time limit on rate case proceedings, test years are historical by the time decisions are rendered and historically, ROEs have been below national averages, although in the latest rate case they were in-line with the national average for natural gas local distribution companies.

Maryland adopted multiyear rate plans in utility base rate filings, including forward-looking test years. In Fitch's view, these developments underscore an improving regulatory environment in Maryland in recent years. The approval of WGL's 2019 base rate case settlement was indicative of a balanced regulatory environment. However, changes in the governor's office and their impact on the Public Service Commission of Maryland (MPSC) in 2023 has, in Fitch's view, injected a measure of uncertainty regarding the direction of the regulatory compact in Maryland and its potential impact on energy policy and utilities in the state.

Fitch believes concerns regarding the regulatory compact in Maryland are manageable within WGL's current rating category in the near to intermediate term. While not currently anticipated, any meaningful deterioration in jurisdictional price regulation could trigger credit rating downgrades.

Pipe-Replacement Programs: Cost-recovery mechanisms are in place for pipe-replacement programs in Virginia, Maryland and DC. Infrastructure replacement capex designed to enhance system safety and reliability is relatively uncontroversial and a key driver of WGL's utility capex program. Fitch believes these mechanisms to be constructive mitigating regulatory lag and enhancing pipeline system safety and resilience.

DC Rate Case: In April 2022, WGL filed a base rate case with the DC Public Service Commission (DCPSC) requesting rates designed to increase annual revenues USD53 million, which includes a transfer of USD5.3 million previously approved for natural gas system improvements. The rate increase incorporates a 10.4% authorized ROE and a 53.69% equity component of regulatory capital. The DCPSC approved a base rate increase of USD24.7 million in December 2023, reflecting a 9.65% ROE and a 52% equity component of regulatory capital. The decision includes a transfer of $4.7 million from the PROJETpipes surcharge resulting in a net increase of $19.9 million.

Virginia Rate Case: In August 2023, a settlement was filed in WGL's pending distribution base rate case in Virginia, authorizing a USD73 million rate increase based on a 9.65% ROE with an equity component of 52.527%. Prior to the settlement, WGL sought a USD86.6 million rate increase based upon a 10.75% ROE. Fitch believes the settlement, is a constructive development and includes approvals for some of WGL's low carbon efforts amongst other initiatives.

Maryland Rate Case: WGL filed a base rate application in Maryland in May 2023 requesting an incremental USD49.4 million increase in rates based on a 10.75% authorized ROE and an equity component of 52.599%. In December 2023, MPSC issued a final order authorizing gas distribution base rate increase of, which was amended in the 1Q24 to approximately $13 million at a 9.50% ROE (52.60% return on capital), which Fitch considers restrictive.

Stable Financial Profile: Fitch expects WGL's FFO-leverage metrics will average approximately 4.2x over the forecast, improving from 4.7x in 2023 as the rate cases are settled to 4.0x in 2026. Financial metrics remain well below our 4.5x downgrade threshold for the ratings given the diversity of jurisdictions and timely recovery from the pipe-replacement program.

AltaGas is weakly positioned at its 'BBB' rating. With EBITDA of approximately CAD1.3 billion at YE 2023, it is smaller than Emera Incorporated (Emera; BBB/Negative), but larger than Algonquin Power & Utilities Corp. (APUC; BBB/Stable). Emera and APUC had operating EBITDA of approximately CAD2.9 billion and CAD1.0 billion, respectively, at YE 2023. Fitch estimates AltaGas' FFO leverage will average 5.8x during the next three years, comparable with APUC's approximately 7.1x and better than Emera's 7.9x over the same period.

Canadian utility holding company APUC benefits from regulatory diversification but owns utilities that operate in somewhat less constructive regulatory environments, in Fitch's view, with APUC's largest utility operating in Missouri. Fitch expects utility operations to account for approximately 75% of consolidated APUC EBITDA. Emera de-emphasized unregulated investments to focus on utility operations in the U.S., Canada and the Caribbean in recent years.

Fitch believes regulation in Emera's two largest jurisdictions, Florida and Nova Scotia, are balanced. Emera derives roughly 95% of its earnings from regulated operations. AltaGas generates only 55%-60% of its cash flow from regulated utility operations with the remaining coming from partially contracted midstream operations that can be volatile.

Like Emera and APUC, AltaGas's operations include significant low-risk utility operations. AltaGas, through WGL, provides gas utility services to affluent populations in parts of Virginia, Maryland and DC, with prospective customer growth estimated at 1% per year. AltaGas also provides gas distribution service to parts of Michigan. Collectively, AltaGas's U.S. utilities experienced customer growth of 1%, and approximately 70% of their customers are residential. Emera and APUC, unlike AltaGas, have meaningful electric utility operations.

KEY ASSUMPTIONS

--Continuation of reasonable economic regulation across AltaGas' jurisdictional service territory;

--One percent annual customer growth at AltaGas' U.S. gas utility segment on average;

--Additional rate case filings as per management's schedule;

--Normalized annual sales at WGL in 2024-2026;

--Monetization of MVP in line with management's assumptions and the entire proceeds used towards debt reduction;

--Midstream export volumes increasing 5%-10% over the next three years, while increasing the proportion of export volumes from the facility to take-or-pay contracts from merchants;

--Capex averages CAD1.3 billion per annum during 2024-2026;

--Any additional midstream capex executed in a credit-friendly manner.

AltaGas and WGLH

Factors that Could, Individually or Collectively, Lead to Stabilization of the Outlook

--FFO leverage below 6.0x by 2024 and clear line of sight to leverage below 5.5x by 2025; and

--A financial policy that is consistent with maintaining FFO leverage below 5.5x on a sustained basis post 2025.

Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade

--A rating upgrade is unlikely given AltaGas' FFO leverage and business mix profile. However, an upgrade may result from more credit-supportive regulatory trends at AltaGas' U.S. utility business compared with Fitch's rating case;

--Stronger than expected performance at AltaGas' midstream businesses;

--Sustained FFO leverage of 4.5x or better on a consistent basis.

Factors that Could, Individually or Collectively, Lead to Negative Rating Action/Downgrade

--FFO leverage above 6.0x in 2024, and above 5.5x in 2025 and thereafter;

--Significant deterioration across AltaGas' jurisdictional service territory;

--Additional debt-financed midstream capex resulting in higher leverage;

--Failure to raise adequate and timely financing from asset sales or other sources to maintain leverage within Fitch's downgrade thresholds;

--Regulated businesses contributing less than 55% of cashflows on a sustained basis.

Additional Sensitivities for WGLH

Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade

--An upgrade at AltaGas would result in an upgrade at WGLH.

Factors that Could, Individually or Collectively, Lead to Negative Rating Action/Downgrade

--A downgrade of AltaGas would result in a downgrade at WGLH.

WGL

Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade:

--Continued balanced economic regulation across its jurisdictional service territory;

--Better than expected rate case outcomes;

--Sustained FFO Leverage of 3.5x or better.

Factors that Could, Individually or Collectively, Lead to Stabilization of the Outlook

--A revision of AltaGas' Outlook to Stable, given Fitch's maximum allowed two-notch differential between the Long-Term IDRs of the entities.

Factors that Could, Individually or Collectively, Lead to Negative Rating Action/Downgrade:

--A downgrade to AltaGas' Long-Term IDR, given Fitch's maximum allowed two-notch differential between the Long-Term IDRs of the entities;

--Significant deterioration in WGL's currently balanced jurisdictional service territory;

--Sustained FFO Leverage of worse than 4.5x;

--Unexpected catastrophic events that could result in prolonged outages and/or large third-party liabilities.

BEST/WORST CASE RATING SCENARIO

International scale credit ratings of Non-Financial Corporate issuers have a best-case rating upgrade scenario (defined as the 99th percentile of rating transitions, measured in a positive direction) of three notches over a three-year rating horizon; and a worst-case rating downgrade scenario (defined as the 99th percentile of rating transitions, measured in a negative direction) of four notches over three years. The complete span of best- and worst-case scenario credit ratings for all rating categories ranges from 'AAA' to 'D'. Best- and worst-case scenario credit ratings are based on historical performance. For more information about the methodology used to determine sector-specific best- and worst-case scenario credit ratings, visit https://www.fitchratings.com/site/re/10111579.

LIQUIDITY AND DEBT STRUCTURE

Adequate Liquidity: Fitch believes liquidity is adequate at AltaGas and WGL. AltaGas has a revolving credit facility with total borrowing capacity of CAD2.3 billion revolving credit facility which had an availability of 2.26 billion at March 31, 2024. The company had cash and cash equivalents of CAD101 million on its balance sheet as of March 31, 2024. Remaining maturities in 2024 include senior notes totaling CAD550 million.

CAD800 million is due in 2025. WGL's USD450 million credit facility had approximately USD337 million available as of March 31, 2024.

The revolving credit facility expires July 17, 2026. Fitch expects WGL to be cash flow negative in 2024-2026 due to the utility's large capex program, with external funding provided through a balanced mix of equity and debt. Maturities are manageable, with USD294 million maturing over the next five years.

ISSUER PROFILE

AltaGas is a Canada-based energy infrastructure company with operations in the U.S. and Canada with CAD24 billion of total assets. The company has two primary business segments: Utilities and Midstream.

REFERENCES FOR SUBSTANTIALLY MATERIAL SOURCE CITED AS KEY DRIVER OF RATING

The principal sources of information used in the analysis are described in the Applicable Criteria.

Click here to access Fitch's latest quarterly Global Corporates Macro and Sector Forecasts data file which aggregates key data points used in our credit analysis. Fitch's macroeconomic forecasts, commodity price assumptions, default rate forecasts, sector key performance indicators and sector-level forecasts are among the data items included.

ESG CONSIDERATIONS

The highest level of ESG credit relevance is a score of '3', unless otherwise disclosed in this section. A score of '3' means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. Fitch's ESG Relevance Scores are not inputs in the rating process; they are an observation on the relevance and materiality of ESG factors in the rating decision. For more information on Fitch's ESG Relevance Scores, visit https://www.fitchratings.com/topics/esg/products#esg-relevance-scores.

RATING ACTIONS

ENTITY / DEBT	RATING			PRIOR
AltaGas Ltd.	LT IDR	BBB Rating Outlook Negative	Affirmed	BBB Rating Outlook Stable
	ST IDR	F3	Affirmed	F3
senior unsecured	LT	BBB	Affirmed	BBB
preferred	LT	BB+	Affirmed	BB+
subordinated	LT	BB+	Affirmed	BB+
WGL Holdings, Inc.	LT IDR	BBB Rating Outlook Negative	Affirmed	BBB Rating Outlook Stable
	ST IDR	F3	Affirmed	F3
senior unsecured	LT	BBB	Affirmed	BBB
senior unsecured	ST	F3	Affirmed	F3
Washington Gas Light Company	LT IDR	A- Rating Outlook Negative	Affirmed	A- Rating Outlook Stable

VIEW ADDITIONAL RATING DETAILS

FITCH RATINGS ANALYSTS

ENTITY / DEBT	RATING			PRIOR
	ST IDR	F2	Affirmed	F2
senior unsecured	LT	A	Affirmed	A
senior unsecured	ST	F2	Affirmed	F2

VIEW ADDITIONAL RATING DETAILS

FITCH RATINGS ANALYSTS

Redacted

MEDIA CONTACTS

Redacted

Redacted

Redacted

MEDIA CONTACTS

Redacted

Additional information is available on www.fitchratings.com

PARTICIPATION STATUS

The rated entity (and/or its agents) or, in the case of structured finance, one or more of the transaction parties participated in the rating process except that the following issuer(s), if any, did not participate in the rating process, or provide additional information, beyond the issuer's available public disclosure.

APPLICABLE CRITERIA

Corporate Hybrids Treatment and Notching Criteria (pub. 12 Nov 2020)

Parent and Subsidiary Linkage Rating Criteria (pub. 16 Jun 2023)

Corporates Recovery Ratings and Instrument Ratings Criteria (pub. 13 Oct 2023) (including rating assumption sensitivity)

Corporate Rating Criteria (pub. 03 Nov 2023) (including rating assumption sensitivity)

Sector Navigators – Addendum to the Corporate Rating Criteria (pub. 21 Jun 2024)

APPLICABLE MODELS

Numbers in parentheses accompanying applicable model(s) contain hyperlinks to criteria providing description of model(s).

Corporate Monitoring & Forecasting Model (COMFORT Model), v8.1.0 (1)

ADDITIONAL DISCLOSURES

Dodd-Frank Rating Information Disclosure Form

Solicitation Status

Endorsement Policy

ENDORSEMENT STATUS

AltaGas Ltd.	EU Endorsed, UK Endorsed
Washington Gas Light Company	EU Endorsed, UK Endorsed
WGL Holdings, Inc.	EU Endorsed, UK Endorsed

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The complete span of best- and worst-case scenario credit ratings for all rating categories ranges from 'AAA' to 'D'. Fitch also provides information on best-case rating upgrade scenarios and worst-case rating downgrade scenarios (defined as the 99th percentile of rating transitions, measured in each direction) for international credit ratings, based on historical performance. A simple average across asset classes presents best-case upgrades of 4 notches and worst-case downgrades of 8 notches at the 99th percentile. For more details on sector-specific best- and worst-case scenario credit ratings, please see Best- and Worst-Case Measures under the Rating Performance page on Fitch's website.

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ATTESTATION

I, JANET BURROWS, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Janet Burrows

JANET BURROWS

07/26/2024

DATE

WITNESS D'ASCENDIS
EXHIBIT WG (C)

EXHIBIT WG (C)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

<u>DIRECT TESTIMONY OF DYLAN W. D'ASCENDIS</u>
EXHIBIT WG (C)
(Page 1 of 2)

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DIRECT TESTIMONY OF DYLAN W. D'ASCENDIS
EXHIBIT WG (C)
(Page 2 of 2)

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Exhibits

WASHINGTON GAS LIGHT COMPANY

District of Columbia

DIRECT TESTIMONY OF DYLAN W. D'ASCENDIS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, NJ 08054.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by ScottMadden, Inc. as Partner.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of Washington Gas Light Company ("Washington Gas" or "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT BUSINESS EXPERIENCE.

A. I have offered expert testimony on behalf of investor-owned utilities before more than 35 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the National Energy Regulator in Canada, the Alberta Utility Commission, one American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured monthly. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are shown in Exhibit WG (C)-1.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding Washington Gas' return on common equity ("ROE") for its natural gas distribution operations.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR RECOMMENDATION?

A. Yes. I have prepared Exhibit WG (C)-1 through Exhibit WG (C)-10.

Q. WHAT IS YOUR RECOMMENDED COMMON EQUITY COST RATE?

A. I recommend that the Commission authorize Washington Gas the opportunity to earn a ROE of 10.50% on its jurisdictional rate base, based on its ratemaking capital structure. The Company's ratemaking capital structure consists of 42.88% long-term debt, at an embedded debt cost rate of 4.84%, 4.63% short-term debt, at a cost rate of 6.20%, and 52.49% common equity at my recommended ROE of 10.50%. The ratemaking capital structure and cost of long-term debt is sponsored by Company Witness Janet Burrows. The overall rate of return is summarized on page 1 of Exhibit WG (C)-2 and in Table 1 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	42.88%	4.84%	2.08%
Short-Term Debt	4.63%	6.20%	0.29%
Common Equity	52.49%	10.50%	5.51%
Total	100.00%		7.88%

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ROE.

A. My recommended ROE of 10.50% is summarized on page 2 of Exhibit WG (C)-2. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to Washington Gas. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the Company

1 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).

2 *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1923) (*Bluefield*).

and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from the application of several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of a Utility Proxy Group whose selection criteria will be discussed below. Although I have not included the results in determining the recommended ROE, I have also applied these same models to a Non-Price Regulated Proxy Group, which I demonstrate is similar in total risk to the Utility Proxy Group. The results of the models based on the Non-Price Regulated Proxy Group serve as a check on the reasonableness of my other analytical models. The results derived from each are as follows:

Table 2: Summary of Common Equity Cost Rate

	Prospective Interest Rate	**Current Interest Rates**
Discounted Cash Flow Model (DCF)	9.99%	9.99%
Risk Premium Model (RPM)	10.82%	10.82%
Capital Asset Pricing Model (CAPM)	11.57%	11.63%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.01%	12.02%
Indicated Range of Common Equity Cost Rates Before Adjustments	9.99% - 11.63%	
Business Risk Adjustment	0.00%	
Indicated Range of Common Equity Cost Rates After Adjustment	9.99% - 11.63%	
Recommended Cost of Common Equity	10.50%	

The indicated range of common equity cost rates applicable to the Utility Proxy Group is between 9.99% and 11.63% before any Company-specific adjustments.

To reflect Washington Gas' specific risks, I reviewed the Company's risks as compared to the Utility Proxy Group, specifically, its smaller size and its regulatory risk to determine whether a Company-specific risk adjustment was appropriate. That review revealed an indicated upward adjustment of 0.19% to the indicated range of ROEs, but I chose to not apply a relative risk adjustment at this time. I also have not included flotation costs, as Washington Gas's parent, AltaGas, has not issued equity since the acquisition of the Company. From the 9.99% and 11.63% range of ROEs attributable to both the Utility Proxy Group and Washington Gas, I recommend the Commission adopt an ROE of 10.50% for ratemaking purposes.

II. GENERAL PRINCIPLES

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATE OF 10.50%?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, *i.e.,* the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[3]

In summary, the U.S. Supreme Court has found a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Commission's decision in this proceeding, therefore, should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure their financial

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[3] *Hope*, 320 U.S. 591 (1944), at 603.

integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, *i.e.,* for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of the source of the funding, public funding or corporate funding.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other, similarly situated companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective as measured by their combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (*i.e.,* business risk) and financing (*i.e.,* financial risk) of the Company's District of Columbia utility operations on a stand-alone basis.

Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (*i.e.*, rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS GUARANTEED?

A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the rate-setting process should provide the utility a reasonable opportunity to recover its return of, and return on, its prudently incurred investments, but it does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (*e.g.*, management performance, operating and maintenance expenses, etc.), there are several factors beyond a utility's control that affect its ability to earn its authorized return. Those may include factors such as weather, the economy, and the prevalence and magnitude of regulatory lag.

A. Business Risk

Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks <u>generally</u> faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, emerging technologies, the vagaries of weather, and the like, all of which have a direct bearing on earnings.

Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. When determining an appropriate return on common equity, the relevant issue is where investors see the subject company in relation to other similarly situated utility companies (*i.e.,* the Utility Proxy Group). To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (*i.e.,* failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (*I.E.*, INVESTMENT RISK)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (*i.e.*, total risk) faced by bond investors.[4] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

III. PROXY GROUP SELECTION

Q. ARE YOU FAMILIAR WITH WASHINGTON GAS' OPERATIONS?

A. Yes. Washington Gas provides natural gas distribution services to approximately 165,000 customers in Washington, D.C.[5] Washington Gas has a long-term issuer rating of A- from S&P.[6]

Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE UTILITY PROXY GROUP.

A. The companies selected for the Utility Proxy Group met the following criteria:

(i) They were included in the Natural Gas Utility Group of *Value Line's Standard Edition* (May 24, 2024) (*Value Line*);

(ii) They have 60% or greater of fiscal year 2023 total operating income derived from, or 60% or greater of fiscal year 2023 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition

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4 Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, *e.g.*, an S&P rating can be an A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, *e.g.*, a Moody's rating can be A1, A2 and A3.

5 AltaGas Ltd., SEC form 40-F.

6 Source: S&P Global Market Intelligence. Note: Washington Gas' Moody's rating was withdrawn on May 3, 2023.

activity (*i.e.*, one publicly traded utility merging with or acquiring another) or any other major development;

(iv) They have not cut or omitted their common dividends during the five years ended 2023 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services (Bloomberg) adjusted Beta coefficients (beta);

(vi) They have positive *Value Line* five-year dividends per share growth rate projections; and

(vii) They have *Value Line*, Zacks, S&P Capital IQ, or Yahoo! Finance consensus five-year earnings per share growth rate projections.

The following six companies met these criteria:

Table 3: Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire Inc.	SR

Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN ESTIMATING THE ROE FOR THE COMPANY?

A. Because the Company is not publicly traded and does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.[7]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses that necessarily must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group indicated results.

IV. <u>COMMON EQUITY COST RATES</u>

Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE MARKET-BASED?

A. Yes. As discussed previously, regulated public utilities, like the Company, must compete for equity in capital markets along with all other companies with commensurate risk, including non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those

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[7] The development of the Non-Price Regulated Proxy Group is explained in more detail in Section IV.

companies. If an individual investor is choosing to invest their capital among companies with comparable risk, they will choose the company providing a higher return over a company providing a lower return.

Q. ARE YOUR COST OF COMMON EQUITY MODELS MARKET-BASED?

A. Yes. The DCF model is market-based in that market prices are used in developing the dividend yield component of the model. Regarding the RPM, the total market risk premium approach uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk, and the Predictive Risk Premium Model (PRPM) uses monthly market returns in addition to expectations of the risk-free rate. In addition, betas (β), which reflect the market/systematic risk component of equity risk premium, are derived from regression analyses of market prices. The CAPM is market based for many of the same reasons that the RPM is market based (i.e., the use of expected bond yields and betas). Selection criteria for the non-price regulated companies are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE COMPANY'S ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I applied to the Utility Proxy Group described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on multiple models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the specific models on which I rely focus on different aspects of return requirements and provide different insights into investors' views of risk and return.

The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (i.e., the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the ROE. Just as the use of market data for the Proxy Groups adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

Q. HAS THE COMMISSION INDICATED IT MAY CONSIDER MULTIPLE METHODS IN ESTIMATING THE COST OF EQUITY?

A. Yes, it has. In Order No. 18712 the Commission noted that its "preference for the DCF model does not preclude consideration of other methods like the CAPM and RPM for calculating cost of equity in some instances."[8]

A. Discounted Cash Flow Model

Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield

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8 *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*, Formal Case No. 1137, Order No. 18712 (March 3, 2017), at P 59.

on market price plus a growth rate equals the capitalization rate; *i.e.*, the total common equity return rate expected by investors.

$$K_e = (D_0\,(1+g))/P + g$$

where:

K_e = the required Return on Common Equity;

D_0 = the annualized Dividend Per Share;

P = the current stock price; and

g = the growth rate.

Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?

A. I used the single-stage constant growth DCF model in my analyses.

Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE CONSTANT GROWTH DCF MODEL.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of May 31, 2024, divided by the average closing market price for the 60 trading days ended May 31, 2024.[9]

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.

A. Because dividends are paid periodically (*e.g.,* quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy

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9 *See,* Column 1, page 1 of Exhibit WG (C)-3

Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Exhibit WG (C)-3 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO THE UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF MODEL.

A. Investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, S&P Capital IQ, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of earnings per share growth in my DCF analysis.

Over the long run, there can be no growth in dividends per share without growth in earnings per share. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using projected earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.

A. As shown on page 1 of Exhibit WG (C)-3, for the Utility Proxy Group, the mean result of applying the single-stage DCF model is 10.02%, the median result is 9.95%, and the average of the two is 9.99%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF. This approach takes into consideration all proxy company results while mitigating high and low side outliers of those results.

B. The Risk Premium Model

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively), and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, (2) an equity risk premium based on the S&P Utilities Index, and (3) an equity risk premium based on authorized ROEs for natural gas distribution utilities.

Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD APPLICABLE TO THE UTILITY PROXY GROUP.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. Because I am unaware of any publication that provides forecasted public utility bond yields, I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the third calendar quarter of 2025, and *Blue Chip's* long-term projections for 2026 to 2030, and 2031 to 2035. As shown on line 1, page 1 of Exhibit WG (C)-4, the average expected yield on Moody's Aaa-rated corporate bonds is 5.14%.

Because that 5.14% estimate represents a corporate bond yield and not a utility specific bond yields, I adjusted the expected Aaa-rated corporate bond yields to an equivalent A2-rated public utility bond yield. That resulted in an upward adjustment of 0.51%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[10] Adding that recent 0.51% spread to the expected Aaa-rated corporate bond yield of 5.14% results in an expected A2-rated public utility bond yield of 5.65%.

I then reviewed the average credit rating for the Utility Proxy Group from Moody's to determine if an adjustment to the estimated A2-rated public utility bond was necessary. Since the Utility Proxy Group's average Moody's long-term issue rating is A2, no other adjustment is needed to make the A2 prospective bond yield applicable to the A2-rated public utility bond. The results are a 5.65% expected bond yield applicable to the Utility Proxy Group.

Table 4: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[11]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip*)	5.14%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.51%
Prospective Bond Yield Applicable to the Utility Proxy Group	5.65%

Q. DID YOU INCLUDE CURRENT INTEREST RATES IN YOUR ANALYSES?

A. Yes. Even though I do not agree with using current interest rates in a rate of return analysis, I recognize that the Commission has stated its preference for the use of current, and not projected, interest rates.[12] As such, in addition to my normal practice of relying on projected interest rates, I have also presented my

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10 As shown on line 2 and explained in note 2, page 1 of Exhibit WG (C)-4.

11 As shown on line 3 and explained in note 2 on page 1 of Exhibit WG (C)-4.

12 *See*, Formal Case No. 1137, *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*, Order No. 18712, March 3, 2017, at 27.

ROE analyses based on current interest rates. The current yield, as of May 31, 2024, on A2-rated public utility bonds is 5.69%.

Q. PLEASE SUMMARIZE THE UTILITY BOND YIELDS APPLICABLE TO YOUR PROXY GROUPS.

A. The current and prospective utility bond yields I apply in my analyses are shown in Table 5 below and in page 1 of Exhibit WG (C)-4.

Table 5: Summary of the Proxy Group's Utility Bond Yields[13]

Prospective Bond Yields Applicable to the Proxy Group	5.65%
Current Bond Yields Applicable to the Proxy Group	5.69%

To develop the indicated ROE using the total market approach RPM, the current and prospective bond yields are then added to the average of the different equity risk premiums described below.

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) the beta. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 8, on page 6 of Exhibit WG (C)-4. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, a *Value Line*-based equity risk

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13 As shown on page 1 of Exhibit WG (C)-4.

premium, and a combined *Value Line,* Bloomberg, and S&P Capital IQ-based equity risk premium. Each of these is described below.

Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?

A. To derive an historical market equity risk premium, I used the most recent holding period returns for the large company common stocks less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2023.[14] Using holding period returns over a very long time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, *i.e.*, a company expected to operate in perpetuity.

The long-term arithmetic mean monthly total return rate on large company common stocks was 11.91% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 5.95% from 1928 to 2023.[15] As shown on line 1 of page 6 of Exhibit WG (C)-4, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.96%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in Kroll's Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2023 ("SBBI - 2023").[16] The use of the arithmetic mean return rates and yields is appropriate

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14 Source: SBBI-2023 Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2022; Bloomberg Professional.

15 As explained in note 1, page 9 of Exhibit WG (C)-4.

16 SBBI – 2023, at 193-194.

because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.

A. To derive the regression-based market equity risk premium of 6.92% (based on projected interest rates) and 6.73% (based on current interest rates), shown on line 2, page 6 of Exhibit WG (C)-4, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. The relationship between interest rates and the market equity risk premium was modeled using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares (OLS) regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta\,(R_{Aaa/Aa})$$

where:

RP = the market equity risk premium;

α = the regression intercept coefficient;

β = the regression slope coefficient; and

$R_{Aaa/Aa}$ = the Moody's Aaa/Aa rated corporate bond yield.

Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK PREMIUM.

A. The PRPM, published in the *Journal of Regulatory Economics,*[17] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility (ARCH)".[18] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (i.e., the variance of historical equity risk premiums).

The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate bonds during the period from January 1928 through May 2024.[19] Using

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17 Autoregressive conditional heteroscedasticity. See "A New Approach for Estimating the Equity Risk Premium for Public Utilities", Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. *The Journal of Regulatory Economics* (December 2011), 40:261-278.

18 www.nobelprize.org.

19 Data from January 1928 to December 2022 is from SBBI - 2023. Data from January 2023 to May 2024 is from Bloomberg.

a generalized form of ARCH, known as GARCH, the projected equity risk premium is determined using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series and a GARCH coefficient. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[20] produces the predicted annual equity risk premium. The resulting PRPM predicted a market equity risk premium of 8.46%.[21]

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* DATA FOR YOUR RPM ANALYSIS.

A. As noted previously, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in notes 5 and 6 on page 6 of Exhibit WG (C)-4. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended May 31, 2024, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line* (Standard Edition).[22]

The average median expected price appreciation is 46%, which translates to a 9.92% annual appreciation, and when added to the average of *Value Line's* median expected dividend yields of 2.13%, equates to a forecasted annual total return rate on the market of 12.05%. The forecasted Moody's Aaa-rated

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20 Annualized Return = (1 + Monthly Return) ^12 - 1.
21 Shown on line 3, page 6 of Exhibit WG (C)-4.
22 As explained in detail in note 1, page 2 of Exhibit WG (C)-5.

corporate bond yield of 5.14% and the average Aaa and Aa corporate bond yield for the three months ended May 2024 of 5.29% are deducted from the total market return of 12.05%, resulting in equity risk premiums of 6.91% and 6.76%, respectively, as shown on page 6, line 4 of Exhibit WG (C)-4.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON THE S&P 500 COMPANIES.

A. Using data from *Value Line*, Bloomberg, and S&P Capital IQ, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 15.19%. Subtracting the respective yield on Aaa-rated and Aaa/Aa-rated corporate bonds of 5.14% and 5.29%, respectively, results in equity risk premiums of 10.05% and 9.90%, respectively.

Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK PREMIUM FOR USE IN YOUR RPM ANALYSIS?

A. I gave equal weight to the five equity risk premiums, based on prospective and current interest rates, in arriving at equity risk premiums of 7.66% and 7.56%, respectively.

Table 6: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[23]

	Prospective Interest Rates	Current Interest Rates
Historical Spread Between Total Returns of Large Stocks and Aaa and Aa-Rated Corporate Bond Yields (1928 – 2023)	5.96%	5.96%
Regression Analysis on Historical Data	6.92%	6.73%
PRPM Analysis on Historical Data	8.46%	8.46%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Aaa Corporate Bond Yields	6.91%	6.76%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less Aaa Corporate Bond Yields	10.05%	9.90%
Average	7.66%	7.56%

After calculating the average market equity risk premiums of 7.66% and 7.56%, I adjusted it by the beta to account for the risk of the Utility Proxy Group. As discussed below, the beta is a meaningful measure of prospective relative risk to the market as a whole and is a logical means by which to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Exhibit WG (C)-5, the average of the mean and median beta for the Utility Proxy Group is 0.81. Multiplying the 0.81 average beta by the market equity risk premiums of 7.66% and 7.56% result in beta-adjusted equity risk premiums for the Utility Proxy Group of 6.20% and 6.12% respectively.

Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A2-RATED PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding

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23 As shown on page 6 of Exhibit WG (C)-4.

period returns, and one equity risk premiums based on the expected returns of the S&P Utilities Index, using data from *Value Line,* Bloomberg, and S&P Capital IQ. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium, between the S&P Utility Index total returns of 10.45% and monthly A-rated public utility bond yields of 6.43% from 1928 to 2023, to arrive at an equity risk premium of 4.02%.[24] I then used the same historical data to derive equity risk premiums of 4.81% (based on projected interest rates) and 4.77% (based on current interest rates) based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to May 2024 to arrive at a PRPM-derived equity risk premium of 4.39% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 10.46% using data from *Value Line,* Bloomberg, and S&P Capital IQ and subtracted the prospective A2-rated public utility bond yield (5.65%[25]), which results in an equity risk premium of 4.81%. Subtracting the current A2-rated public utility bond yield of 5.69%[26] results in an equity risk premium of 4.77%. As with the market equity risk premiums, I averaged each risk premium to arrive at my utility-specific equity risk premiums of 4.51% (using prospective bond yields) and 4.49% (using current bond yields).

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24 As shown on line 1, page 9 of Exhibit WG (C)-4.
25 Derived on line 3, page 1 of Exhibit WG (C)-4.
26 Derived on line 4, page 1 of Exhibit WG (C)-4.

Table 7: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[27]

	Prospective Interest Rates	Current Interest Rates
Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2023)	4.02%	4.02%
Regression Analysis on Historical Data	4.81%	4.77%
PRPM Analysis on Historical Data	4.39%	4.39%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P Utilities Index less A2 Public Utility Bond Yields	4.81%	4.77%
Average	4.51%	4.49%

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM BASED ON AUTHORIZED ROES FOR NATURAL GAS DISTRIBUTION UTILITIES?

A. The equity risk premiums of 4.79% and 4.77% shown on line 3 of page 5 of Exhibit WG (C)-4 are the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds. That analysis is shown on page 10 of Exhibit WG (C)-4 and contains the graphical results of a regression analysis of 834 rate cases for natural gas distribution utilities which were fully litigated during the period from January 1, 1980 through May 31, 2024. It shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result

27 As shown on page 9 of Exhibit WG (C)-4.

consistent with financial literature on the subject.[28] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds. Given the prospective A2-rated public utility bond yield of 5.65%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.79%, which is shown on line 3, page 5 of Exhibit WG (C)-4. Additionally, given the current A2-rated public utility bond yield of 5.69%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.77%, which is also shown on line 3, page 5 of Exhibit WG (C)-4.

Q. WHAT IS YOUR CONCLUSION OF AN EQUITY RISK PREMIUM FOR USE IN YOUR TOTAL MARKET APPROACH RPM ANALYSIS?

A. The equity risk premium I applied to the Utility Proxy Group is 5.17% (based on projected interest rates) and 5.13% (based on current interest rates, which are the averages of the beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums.[29]

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[28] See, e.g., Robert S. Harris and Felicia C. Marston, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts", Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity", Financial Management, Spring 1985, at 33-45.

[29] As shown on page 5 of Exhibit WG (C)-4.

Table 8: Summary of the Calculation of the Equity Risk Premium[30]

	Prospective Interest Rates	Current Interest Rates
Beta-Derived Equity Risk Premium	6.20%	6.12%
S&P Utility Index-Derived Equity Risk Premium	4.51%	4.49%
Authorized Return Risk Premium	4.79%	4.77%
Average	5.17%	5.13%

Q. WHAT IS THE INDICATED RPM COMMON EQUITY COST RATE BASED FOR THE UTILITY PROXY GROUP?

A. As shown on line 7, page 1 of Exhibit WG (C)-4, and shown on Table 9, below, I calculated common equity cost rates of 10.82% based on both prospective and current interest rates for the Utility Proxy Group based on the RPM.

Table 9: Summary of the Risk Premium Model[31]

	Prospective Interest Rates	Current Interest Rates
Moody's Utility Bond Applicable to the Respective Proxy Group	5.65%	5.69%
Equity Risk Premium	5.17%	5.13%
Indicated Cost of Common Equity	10.82%	10.82%

C. The Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta (β). A beta less than 1.0 indicates

30 As shown on page 5 of Exhibit WG (C)-4.
31 As shown on page 1 of Exhibit WG (C)-4.

lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta (R_m - R_f)$$

Where:
R_s = Return rate on the common stock;
R_f = Risk-free rate of return;
R_m = Return rate on the market as a whole; and
β = Adjusted beta (volatility of the security relative to the market as a whole)

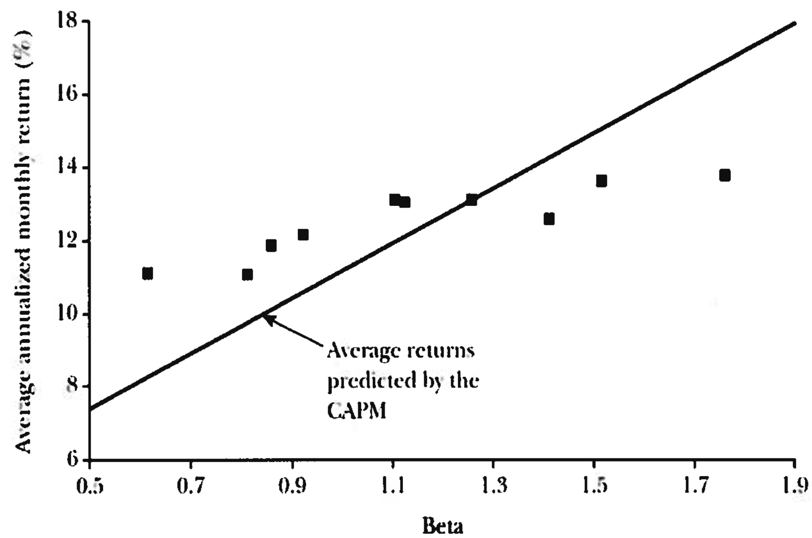
Numerous tests of the CAPM have measured the extent to which security returns and beta are related as predicted by the CAPM, confirming its validity. The empirical CAPM (ECAPM) reflects the reality that while the results of these tests support the notion that the beta is related to security returns, the empirical

Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[32]

The ECAPM reflects this empirical reality. Fama & French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[33]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

32 Roger A. Morin, Modern Regulatory Finance (Public Utility Reports, Inc., 2021), at page 223 ("Morin").

33 Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004 at 33 (Fama & French).

> With few exceptions, the empirical studies agree that ... low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[34]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = RF + x\,(RM - RF) + (1-x)\ \beta(RM - RF)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = RF + 0.25(RM - RF) + 0.75\ \beta(RM - RF)$$ [35]

Fama & French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'... The regressions consistently find that the intercept is greater than the average risk-free rate... and the coefficient on beta is less than the average excess market return... This is true in the early tests... as well as in more recent cross-section regressions tests, like Fama and French (1992).[36]

Finally, Fama & French further note:

> Confirming earlier evidence, the relation between beta and average return `for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[37]

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34 Morin, at 207.
35 Morin, at 221.
36 Fama & French, at 32.
37 Fama & French, at 33.

Clearly, the justification from Morin and Fama & French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

Q. WHAT BETAS DID YOU USE IN YOUR CAPM ANALYSIS?

A. With respect to beta, I considered two methods of calculation: (1) the average of the betas of the respective proxy group companies as reported by Bloomberg, and (2) the average of the betas of the respective proxy group companies as reported by *Value Line*. While both of those services adjust their calculated (raw) betas to reflect the tendency of beta to regress to the market mean of 1.00, *Value Line* calculates beta over a five-year period, while Bloomberg's calculation is based on two years of data.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in column 5 on page 1 of Exhibit WG (C)-5, the risk-free rates adopted for both applications of the CAPM are 4.41% and 4.55%. The risk-free rate of 4.41% is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the third calendar quarter of 2025, and long-term projections for the years 2026 to 2030 and 2031 to 2035. The risk-free rate of 4.55% is the three-month average as of May 2024.

Q. WHY IS THE YIELD ON LONG-TERM TREASURY BONDS APPROPRIATE FOR USE AS THE RISK-FREE RATE?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (*i.e.,* cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSES.

A. The basis of the market risk premium is explained in detail in note 1 on Exhibit WG (C)-5. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, one *Value Line* data-based market risk premium, and one Bloomberg, *Value Line*, and S&P Capital IQ data-based market risk premium.

The long-term income return on U.S. Government securities of 4.99% was deducted from the monthly historical total market return of 12.16%, which results in an historical market equity risk premium of 7.17%.[38] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities. That regression analysis yielded a market equity risk premium of 7.93% (using projected interest rates) and 7.79% (using current interest rates). The PRPM market equity risk premium is 9.44% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through May 2024.

The *Value Line*-derived forecasted total market equity risk premium is

[38] Sources: SBBI - 2023, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21); Bloomberg Professional.

derived by deducting risk-free rates of 4.41% and 4.55%, discussed above, from the *Value Line* projected total annual market return of 12.05%, resulting in total market equity risk premiums of 7.64% and 7.50%.

The S&P 500 projected market equity risk premium using *Value Line,* Bloomberg, and S&P Capital IQ data is derived by subtracting the projected risk-free rates of 4.41% and 4.55% from the projected total return of the S&P 500 of 15.19%. The resulting market equity risk premiums are 10.78% and 10.64%, respectively.

These five measures, when averaged, result in average total market equity risk premiums of 8.59% (using projected interest rates) and 8.51% (using current interest rates).

Table 10: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[39]

	Prospective Interest Rates	Current Interest Rates
Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2023)	7.17%	7.17%
Regression Analysis on Historical Data	7.93%	7.79%
PRPM Analysis on Historical Data	9.44%	9.44%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	7.64%	7.50%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less 30-Year Treasury Bond Yields	10.78%	10.64%
Average	8.59%	8.51%

39 As shown on page 2 of Exhibit WG (C)-5.

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE UTILITY PROXY GROUP?

A. The results of my application of the CAPM and ECAPM are shown on page 1 of Exhibit WG (C)-5, and in Table 11 below.

Table 11: Summary of the Capital Asset Pricing Model[40]

	Prospective Interest Rates	Current Interest Rates
Mean	11.55%	11.62%
Median	11.58%	11.64%
Average of Mean and Median	11.57%	11.63%

Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rates using the CAPM/ECAPM range from 11.57% to 11.63%.

D. Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies based on the DCF, RPM, and CAPM

Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-PRICE REGULATED COMPANIES?

A. Although I am not an attorney, my interpretation of the *Hope* and *Bluefield* cases is that the Supreme Court of the United States did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Utility Proxy Group being used to estimate the

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40 As shown on page 1 of Exhibit WG (C)-5.

cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the betas and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (*i.e.*, five years). These selection criteria resulted in a proxy group of 52 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, *i.e.*, not utilities;

(iii) Their unadjusted betas must lie within plus or minus two standard deviations of the average unadjusted beta of the Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Betas measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas <u>and</u> similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH SHOWS THE DATA FROM WHICH YOU SELECTED THE 52 DOMESTIC, NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. Yes, the basis of my selection and both proxy groups' regression statistics are shown in Exhibit WG (C)-6.

Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, RPM, AND CAPM FOR THE NON-PRICE REGULATED PROXY GROUP?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums.

As shown on page 1 of Exhibit WG (C)-7, the results of the common equity models applied to the Non-Price Regulated Proxy Groups – which group is comparable in total risk to the Proxy Groups – are as follows:

Table 12: Summary of Model Results Applied to the Non-Price Regulated Proxy Groups[41]

	Prospective Interest Rates	Current Interest Rates
Discounted Cash Flow Model	11.08%	11.08%
Risk Premium Model	12.53%	12.33%
Capital Asset Pricing Model	12.11%	12.17%
Mean	11.91%	11.86%
Median	12.11%	12.17%
Average of Mean and Median	12.01%	12.02%

V. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENT

Q. WHAT IS THE INDICATED RANGE OF COMMON EQUITY COST RATES BEFORE ADJUSTMENT?

A. Based on the results of the application of multiple cost of common equity models to the Utility Proxy Group, the indicated range of common equity cost rates are between 9.99% and 11.63% before Company-specific adjustments. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

As will be discussed below, Washington Gas has greater risk than the Utility Proxy Group. Because of this, the indicated range of model results based

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41 As shown on page 1 of Exhibit WG (C)-7.

on the Utility Proxy Group must be adjusted to reflect Washington Gas' greater relative risk.

VI. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

A. Business Risk Adjustment

Q. WHAT COMPANY-SPECIFIC BUSINESS RISKS DID YOU CONSIDER FOR YOUR RELATIVE RISK ANALYSIS?

A. As detailed below, I have considered Washington Gas' size and its regulatory environment relative to the companies in the Utility Proxy Group.

1. Size Comparison

Q. DOES A COMPANY'S SMALLER SIZE RELATIVE TO THE UTILITY PROXY GROUP COMPANIES INCREASE ITS BUSINESS RISK?

A. Yes. A smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for a company because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Returns," Kroll states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original).[42]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama & French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 38, they note:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[43]

Based on this evidence, Fama & French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[44] Eugene Brigham, a well-known authority, states:

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42 Kroll: Cost of Capital Navigator: U.S. Cost of Capital Module, "Size as a Predictor of Equity Returns," at 1

43 Fama & French, at 25-43.

44 Richard A. Brealey and Steward C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms**. (emphasis added).[45]

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of Washington Gas, including its smaller relative size, which is justified and supported above by evidence in the financial literature.

2. Regulatory Risk

Q. IS THE REGULATORY ENVIRONMENT IN WHICH A UTILITY OPERATES AN IMPORTANT CONSIDERATION IN DETERMINING AN APPROPRIATE ROE?

A. The regulatory environment is one of the most important issues considered by both debt and equity investors in assessing the risks and prospects of utility companies. Moody's finds the regulatory environment to be so important that 50.00% of the factors that weigh in the Company's ratings determination are determined by the nature of regulation, and noted:

> For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The

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45 Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

> regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.[46]

Similarly, S&P has noted that:

> The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most.[47]

Q. ARE YOU AWARE OF SERVICES THAT RATE REGULATORY ENVIRONMENTS?

A. Yes, I am. Regulatory Research Associates (RRA) provides an assessment of the degree to which regulatory jurisdictions are constructive, or not. As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint, Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid range rating; and, 3, a

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46 Moody's Investor Service, Rating Methodology, *Regulated Electric and Gas Utilities*, June 23, 2017.

47 Standard & Poor's, *Utilities: Assessing U.S. Utility Regulatory Environments*, November 15, 2011.

> weaker (less constructive) rating. We endeavor to maintain an approximately equal number of ratings above the average and below the average.[48]

Q. HAS RRA COMMENTED SPECIFICALLY ON THE REGULATORY ENVIRONMENT IN DC?

A. Yes, it has. Specifically, RRA notes:

> The regulatory environment in the District is relatively restrictive from an investor viewpoint. Authorized ROEs have generally been somewhat below industry averages when established. In addition, the PSC's continued reliance on rate case test years that are largely historical by the time decisions are rendered and average rate base valuations, coupled with the rejection of timely non-rate case recovery mechanisms to reflect new investment negatively impacts the utilities' ability to earn the authorized return.[49]

Q. DID YOU CONDUCT AN ANALYSIS TO COMPARE WASHINGTON GAS' REGULATORY RISK TO THE UTILITY PROXY GROUP?

A. Yes, I did. I examined the RRA Ranking of each regulatory jurisdiction the Utility Proxy Companies operate in and calculated an average RRA Regulatory ranking for each Utility Proxy Company.

Q. WHAT DID THAT ANALYSIS REVEAL?

A. As shown on page 1 of Exhibit WG (C)-9, the RRA regulatory ranking study showed that the average regulatory risk ranking of the Utility Proxy Group was Average/2 compared to the District of Columbia ranking of Below Average/2, which is the second lowest rating of RRA's rating scale. This shows that Washington Gas is riskier than the Utility Proxy Group based on regulatory risk factors. Given the restrictive nature of Washington Gas' regulatory environment,

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48 Source: RRA.

49 Regulatory Research Associates, accessed June 7, 2024.

as demonstrated in the comparison of the Utility Proxy Group's average RRA regulatory ranking to that of the Company, Washington Gas' increased relative risk should be considered when determining the ROE for the Company in this proceeding.

Q. HAVE YOU ALSO REVIEWED THE REGULATORY MECHANISMS IN PLACE AT THE COMPANY AND THE UTILITY PROXY GROUP AS IT RELATES TO THE COMPANY'S REGULATORY RISK COMPARED TO THE UTILITY PROXY GROUP?

A. Yes, I have. It is important to remember that the cost of capital is a comparative exercise, so if a mechanism is common throughout the companies on which one bases their analyses, the comparative risk is zero, because any impact of the perceived reduced risk (if any) of the mechanism(s) by investors would be reflected in the market data of the proxy group. However, as shown on Exhibit WG (C)-10, every single one of the proxy companies is allowed to use forward test years (or historical test years adjusted for known and measurable changes) in at least one of their jurisdictions. In addition, every proxy company has some form of partial decoupling, such as fixed variable rate design and weather normalization mechanisms.

As such, if there is any perceived risk reduction (and associated reduction to the investor required return) with the employment of either of these rate constructs, the strict use of a historical test year by Washington Gas and its lack of a weather normalization adjustment is indicative of an increased level of risk for investors as compared to the Utility Proxy Group. As discussed in Company Witness James Steffes' direct testimony, Washington Gas is pursuing a weather normalization mechanism in this proceeding.

Q. IS THERE A WAY TO QUANTIFY A RELATIVE RISK ADJUSTMENT DUE TO WASHINGTON GAS' GREATER BUSINESS RISK WHEN COMPARED TO THE UTILITY PROXY GROUP?

A. Yes. As a proxy for the business risk adjustment, I used the Kroll size study. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2023 period. As shown on Exhibit WG (C)-8, the median size premium for the Utility Proxy Group with a market capitalization of $3.862 billion falls in the 5th decile, while the Company's estimated market capitalization of $569 million places it in the 8th decile. The size premium spread between the 5th decile and the 8th decile is 0.19%. Even though an 0.19% premium to the indicated ROE applicable to the Utility Proxy Group, I did not apply a business risk adjustment to the Utility Proxy Group's indicated common equity cost rate at this time.

B. Flotation Cost Adjustment

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (*e.g.*, underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED COMMON EQUITY COST RATE?

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit recovery of these costs....
>
> The simple fact of the matter is that common equity capital is not free....[Flotation costs] must be recovered through a rate of return adjustment.[50]

Q. SHOULD FLOTATION COSTS BE RECOGNIZED ONLY IF THERE WAS AN ISSUANCE DURING THE TEST YEAR OR THERE IS AN IMMINENT POST-TEST YEAR ISSUANCE OF ADDITIONAL COMMON STOCK?

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues

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50 Morin, at 329.

common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, \$0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at \$1.00 with 5% in flotation costs, it will net \$0.95 in investment. Assuming the investor in that stock requires a 10% return on his or her invested \$1.00 (*i.e.*, a return of \$0.10), the company needs to earn approximately 10.5% on its invested \$0.95 to receive a \$0.10 return.

Q. DO THE COMMON EQUITY COST RATE MODELS YOU HAVE USED ALREADY REFLECT INVESTORS' ANTICIPATION OF FLOTATION COSTS?

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[51] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[52] Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

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[51] Eugene F. Brigham and Phillip R. Daves, <u>Intermediate Financial Management</u>, 9th Edition, Thomson/Southwestern, at p. 342

[52] Morin, at pp. 337-339

Q. DID YOU CALCULATE A FLOTATION COST ALLOWANCE FOR WASHINGTON GAS IN THIS PROCEEDING?

A. No, I did not. Because AltaGas, Washington Gas' parent company, has not issued equity that was used to finance Washington Gas's operation since its acquisition, I have not calculated flotation costs as of May 31, 2024. However, should AltaGas issue equity during the course of this proceeding, I reserve the right to include flotation costs in future analyses.

VII. CONCLUSIONS AND RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDED ROE FOR WASHINGTON GAS?

A. Given the indicated ROE range applicable to the Utility Proxy Group and Washington Gas of 9.99% to 11.63%, I conclude that an appropriate ROE for the Company is 10.50%.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.50% FAIR AND REASONABLE TO WASHINGTON GAS AND ITS CUSTOMERS?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Washington Gas Light Company
Table of Contents
Supporting Exhibits Accompanying the Direct Testimony
of Dylan W. D'Ascendis, CRRA, CVA

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MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and is a leading expert witness with respect to cost of capital, capital structure, and valuation. He has served as a consultant for investor-owned and municipal utilities and authorities for 15 years. Dylan has testified as an expert witness on over 150 occasions regarding rate of return, cost of service, rate design, and valuation before more than 40 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Expert Witness Testimony
- Rates and Regulation
- Return on Equity
- Valuation
- Utility Regulations
- Rate Case Planning, Management, and Support
- Utility Benchmarking

Recent Articles and Speeches

- "Decoupling, Risk Impacts, and the Cost of Capital." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal. March 2020
- "Decoupling Impact and Public Utility Conservation Investment." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal. 130 (2019), 311-319
- "Establishing Alternative Proxy Groups." Presentation before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum. April 4, 2019. New Orleans, LA
- "Past Is Prologue: Future Test Year." Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit. May 2, 2017. Savannah, GA
- "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley. The Electricity Journal. May 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks." Presentation before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum. April 17-18, 2013. Indianapolis, IN

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the city
- Co-authored a valuation report on behalf of a large investor-owned utility in response to a new state regulation which allowed the appraised value of acquired assets into rate base

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Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Alaska Power Company	08/23	Alaska Power Company	Docket No. TA 909-2 / U-23-054	Capital Structure
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/23	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	Proceeding ID. 27084	Determination of Cost-of-Capital Parameters
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
Foothills Water & Sewer, LLC	10/23	Foothills Water & Sewer, LLC	Docket No. WS-21182A-23-0292	Rate of Return and Fair Value Rate Base
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Summit Utilities Arkansas, Inc.	01/24	Summit Utilities Arkansas, Inc.	Docket No. 23-079-U	Rate of Return
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
California Public Utilities Commission				
San Gabriel Valley Water Company	05/23	San Gabriel Valley Water Company	Docket No. A23-05-001	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Commission of the Canada Energy Regulator				
Trans-Northern Pipelines Inc.	11/22	Trans-Northern Pipelines Inc.	Docket No. C-22197	Cost of Capital
Delaware Public Service Commission				
Artesian Water Company, Inc.	04/23	Artesian Water Company, Inc.	Docket No. 23-0601	Rate of Return
Delmarva Power & Light Co.	12/22	Delmarva Power & Light Co.	Docket No. 22-0897 (Electric)	Return on Equity
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity

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Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/24	Tampa Electric Company	Docket No. 20240025-EI	Return on Equity
Peoples Gas System, Inc.	04/23	Peoples Gas System, Inc.	Docket No. 20230023-GU	Rate of Return
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System, Inc.	09/20	Peoples Gas System, Inc.	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Aqua Illinois, Inc.	01/24	Aqua Illinois, Inc.	Docket No. 24-0044	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0082 (Electric)	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0067 (Gas)	Return on Equity
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company	02/23	Bluegrass Water Utility Operating Company	2022-00432	Return on Equity
Atmos Energy Corporation	07/22	Atmos Energy Corporation	2022-00222	PRP Rider Rate
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return

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Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy Corporation	04/20	Atmos Energy Corporation	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unitil	05/23	Northern Utilities, Inc. d/b/a Unitil	Docket No. 2023-00051	Return on Equity
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	05/23	Washington Gas Light Company	Case No. 9704	Rate of Return
FirstEnergy Service Company	03/23	Potomac Edison Company	Case No. 9695	Rate of Return
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy Corporation	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	9/23	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 23-80	Rate of Return
Unitil Corporation	9/23	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 23-81	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	D.P.U. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy Corporation	03/19	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Atmos Energy Corporation	07/18	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Confluence Rivers Utility Operating Company, Inc.	01/23	Confluence Rivers Utility Operating Company, Inc.	Case No. WR-2023-0006/SR-2023-0007	Rate of Return
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/23	Southwest Gas Corporation	Docket No. 23-09012	Return on Equity
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity

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Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
New Hampshire Public Utilities Commission				
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
New Jersey Natural Gas Company	01/24	New Jersey Natural Gas Company	Docket No. GR24010071	Rate of Return
Middlesex Water Company	05/23	Middlesex Water Company	Docket No. WR23050292	Rate of Return
FirstEnergy Service Company	03/23	Jersey Central Power & Light Co.	Docket No. ER23030144	Rate of Return
Atlantic City Electric Company	02/23	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy Service Company	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
New Mexico Gas Company	09/23	New Mexico Gas Company	Case No. 23-00255-UT	Return on Equity
Southwestern Public Service Co.	11/22	Southwestern Public Service Co.	Case No. 22-00286-UT	Return on Equity
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	11/22	Aqua Ohio, Inc.	Case No. 22-1094-WW-AIR	Rate of Return
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Columbia Water Company	05/23	Columbia Water Company	Docket No. R-2023-3040258	Rate of Return
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return

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Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
FirstEnergy	04/22	Pennsylvania Electric Company	Docket No. R-2024-3047068	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Co.	02/23	Southwestern Public Service Co.	Docket No. 54634	Return on Equity
CSWR – Texas Utility Operating Company, LLC	02/23	CSWR – Texas Utility Operating Company, LLC	Docket No. 54565	Rate of Return
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Texas Railroad Commission				
Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	Docket No. OS-23-00013758	Return on Equity
Virginia State Corporation Commission				
Aqua Virginia, Inc.	07/23	Aqua Virginia, Inc.	PUR-2023-00073	Rate of Return
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity

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Resume and Testimony Listing of:
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Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
FirstEnergy Service Company	05/23	Monongahela Power Company and The Potomac Edison Company	Case No. 23-0460-E-42T	Return on Equity
FirstEnergy Service Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
FirstEnergy Service Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

Washington Gas Light Company
Recommended Capital Structure and Cost Rates for Ratemaking Purposes

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	42.88%	4.84%	(1)	2.08%
Short-Term Debt	4.63%	6.20%	(1)	0.29%
Common Equity	52.49%	10.50%	(2)	5.51%
Total	100.00%			7.88%

Notes:

(1) Company-provided
(2) From page 2 of this Exhibit.

Washington Gas Light Company
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Six Natural Gas Distribution Companies using Prospective Interest Rates	Proxy Group of Six Natural Gas Distribution Companies using Current Interest Rates
1.	Discounted Cash Flow Model (DCF) (1)	9.99%	9.99%
2.	Risk Premium Model (RPM) (2)	10.82%	10.82%
3.	Capital Asset Pricing Model (CAPM) (3)	11.57%	11.63%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	12.01%	12.02%
5.	Indicated Common Equity Cost Rate before Adjustment for Company-specific Risk	9.99% - 11.63%	
6.	Business Risk Adjustment (5)	0.00%	
7.	Flotation Cost Adjustment (6)	0.00%	
8.	Recommended Range of Common Equity Cost Rates after Adjustment for Company-Specific Risk	9.99% - 11.63%	
9.	Recommended Common Equity Cost Rate	10.50%	

Notes:
(1) From page 1 of Exhibit WG (C)-3
(2) From page 1 of Exhibit WG (C)-4
(3) From page 1 of Exhibit WG (C)-5
(4) From page 1 of Exhibit WG (C)-7
(5) As discussed in Mr. D'Ascendis' Direct Testimony, a business risk adjustment is not applicable in this proceeding.
(6) As discussed in Mr. D'Ascendis' Direct Testimony, a flotation cost adjustment is not applicable in this proceeding.

Washington Gas Light Company
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Six Natural Gas Distribution Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.76 %	7.00 %	7.00 %	7.40 %	NA	7.13 %	2.86 %	9.99 %
New Jersey Resources Corporation	3.91	5.00	NA	6.00	5.87	5.62	4.02	9.64
NiSource Inc.	3.82	9.50	6.00	7.40	7.00	7.48	3.96	11.44
Northwest Natural Holding Company	5.23	6.50	NA	2.80	4.40	4.57	5.35	9.92
ONE Gas, Inc.	4.18	3.50	5.00	5.00	3.00	4.13	4.27	8.40
Spire Inc.	4.98	4.50	5.00	6.36	6.50	5.59	5.12	10.71
							Average	10.02 %
							Median	9.95 %
							Average of Mean and Median	9.99 %

NA= Not Available

Notes:

(1) Indicated dividend at 05/31/2024 divided by the average closing price of the last 60 trading days ending 05/31/2024 for each company.
(2) From pages 2 through 7 of this Exhibit.
(3) Average of columns 2 through 5 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 6) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.76% x (1+(1/2 x 7.13%)) = 2.86%.
(5) Column 6 + Column 7.

Source of Information:

Value Line Investment Survey
www.zacks.com Downloaded on 05/31/2024
www.yahoo.com Downloaded on 05/31/2024
S&P Capital IQ

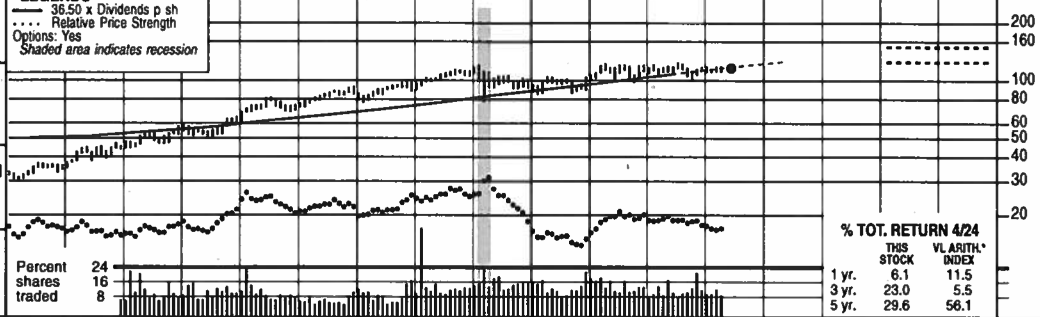
ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 116.33 | P/E RATIO 16.8 (Trailing: 17.4 / Median: 20.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 4 Lowered 2/16/24
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Lowered 3/22/24
BETA .85 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0	125.3	121.5
Low:	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	97.7	101.0	110.5

LEGENDS
— 36.50 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range
Low-High: $102-$148 | Midpoint (% to Mid): $125 (5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+30%)	10%
Low	125	(+5%)	5%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	314	322	358
to Sell	281	280	295
Hld's(000)	136508	137279	137294

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.1	11.5
3 yr.	23.0	5.5
5 yr.	29.6	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	*27.10*	*28.50*	Revenues per sh A	*37.15*
4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	*10.95*	*11.75*	"Cash Flow" per sh	*13.65*
2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	*6.75*	*7.20*	Earnings per sh AB	*8.35*
1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	*3.22*	*3.46*	Div'ds Decl'd per sh C■	*4.25*
5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	*20.00*	*20.25*	Cap'l Spending per sh	*20.00*
22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	*75.30*	*78.60*	Book Value per sh	*83.50*
90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	*155.00*	*158.00*	Common Shs Outst'g D	*175.00*
13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*16.5*
.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08	*estimates*		Relative P/E Ratio	*.90*
4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%			Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $7535.7 mill. Due in 5 Yrs $915.0 mill.
LT Debt $7526.1 mill. LT Interest $135.0 mill.
(LT interest earned: 8.3x; total interest coverage: 8.3x)
Leases, Uncapitalized Annual rentals $41.3 mill.

Pfd Stock None

Pension Assets-9/23 $502.4 mill.
Oblig. $431.6 mill.
Common Stock 150,877,056 shs.
as of 5/3/24

MARKET CAP: $17.6 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	*4200*	*4500*	Revenues ($mill) A	*6500*
289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	*1025*	*1115*	Net Profit ($mill)	*1475*
39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	*15.5%*	*16.0%*	Income Tax Rate	*25.0%*
5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	*24.4%*	*24.8%*	Net Profit Margin	*22.7%*
44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	*19450*	*20700*	Total Capital ($mill)	*24350*
6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	19607	*21900*	*23000*	Net Plant ($mill)	*27000*
6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	*9.0%*	*9.0%*	Return on Shr. Equity	*10.0%*
9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	*9.0%*	*9.0%*	Return on Com Equity	*10.0%*
4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
50%	51%	50%	50%	48%	48%	49%	49%	49%	49%	*49%*	*49%*	All Div'ds to Net Prof	*50%*

CURRENT POSITION ($MILL.)

	2022	2023	3/31/24
Cash Assets	51.6	15.4	262.5
Other	2996.1	870.4	1169.9
Current Assets	3047.7	885.8	1432.4
Accts Payable	496.0	336.1	367.9
Debt Due	2386.4	253.4	9.6
Other	720.2	763.1	677.7
Current Liab.	3602.6	1352.6	1055.2
Fix. Chg. Cov.	1238%	1059%	1070%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-4.0%	-.5%	*5.0%*
"Cash Flow"	6.5%	7.0%	*6.5%*
Earnings	9.5%	9.0%	*7.0%*
Dividends	7.0%	8.5%	*7.5%*
Book Value	9.5%	12.0%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	1647.2	*786.5*	*607.8*	*4200*
2025	*1250*	*1725*	*865*	*660*	*4500*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	2.08	2.85	*1.00*	*.82*	*6.75*
2025	*2.26*	*2.94*	*1.10*	*.90*	*7.20*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	.805	.805			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2023: 66.5%, residential; 28.0%, commercial; 3.8%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/23 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy has performed nicely, from an earnings standpoint, thus far in fiscal 2024 (ends September 30th). Through the first half, per-share profits of $4.93 were 12.3% higher than the $4.39 amount registered for the same period last year. This was brought about partially by positive rate-case outcomes. Lower bad-debt expense also helped. Furthermore, results were favorably impacted by legislation to reduce property-tax expenses in Texas. But a rise in both depreciation expense and interest charges provided somewhat of an offset. Nevertheless, for the entire year, it appears that the bottom line will increase around 10%, to $6.75 per share, relative to fiscal 2023's $6.10 tally. Concerning fiscal 2025, share net may grow another 7% or so, to $7.20, as operating margins expand further.

There has been action on the rate-filing front. During the first six months, Atmos managed to complete some regulatory proceedings leading to a $138.4 million boost in annual operating income. What's more, there were ratemaking initiatives in progress at the conclusion of March seeking $96.4 million of annual operating income. Of course, there are no guarantees that the company will receive everything it desires.

The capital spending target for fiscal 2024 was raised from $2.9 billion to $3.1 billion. The revised estimate marks a 10.5% increase from fiscal 2023's $2.8 billion figure. Like last year, a substantial amount of the resources is being used to enhance the safety and reliability of Atmos' natural gas distribution and transmission systems. Leadership adds that it projects total capital expenditures from fiscal 2024 through fiscal 2028 to be roughly $17 billion. A meaningful portion of the investments will continue to be deployed to where they are currently. Assuming that finances remain healthy, the company ought to have minimal difficulty accomplishing these objectives.

These top-quality shares have strengthened some in price over the past six months. That's due partly, we think, to the energy firm's solid earnings of late. However, long-term total return potential looks unspectacular. The equity is untimely, as well.

Frederick L. Harris, III *May 24, 2024*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early Aug.
(C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

NEW JERSEY RES. NYSE-NJR

RECENT PRICE **44.12** | P/E RATIO **14.9** (Trailing: 17.3; Median: 17.0) | RELATIVE P/E RATIO **0.82** | DIV'D YLD **3.9%** | VALUE LINE

TIMELINESS 4 Raised 3/29/24
SAFETY 2 Lowered 4/17/20
TECHNICAL 5 Lowered 5/3/24
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$37-$60	$49 (10%)

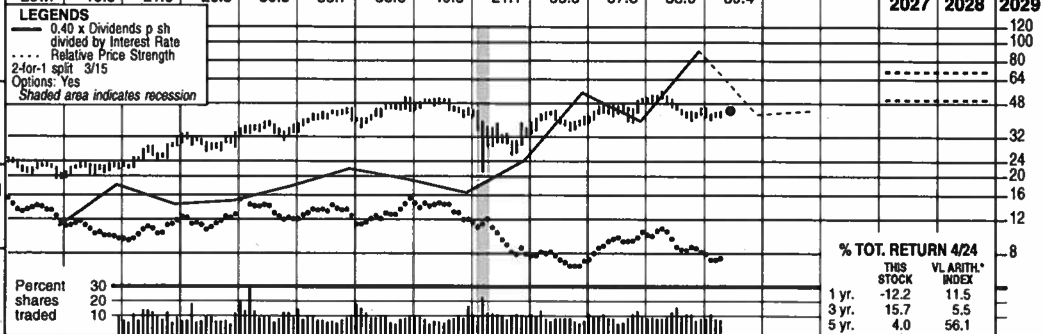
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+60%)	15%
Low	50	(+15%)	7%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	157	153	161
to Sell	156	163	143
Hld's(000)	71570	69494	70304

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	51.4	55.8	45.8
Low:	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8	38.9	39.4



% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.2	11.5
3 yr.	15.7	5.5
5 yr.	4.0	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.38	20.12	21.50	22.00	Revenues per sh A	25.00
1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.86	4.22	4.55	4.60	"Cash Flow" per sh	5.25
1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.70	2.95	3.00	Earnings per sh B	3.50
.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	1.68	1.76	Div'ds Decl'd per sh C■	1.95
.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	6.50	5.13	4.40	5.50	Cap'l Spending per sh	6.25
8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	19.00	20.40	22.30	23.65	Book Value per sh D	27.00
84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	95.64	97.57	100.00	100.00	Common Shs Outst'g E	100.00
12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.7	Bold figures are		Avg Ann'l P/E Ratio	17.0
.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	.98	1.02	Value Line		Relative P/E Ratio	.95
3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%	estimates		Avg Ann'l Div'd Yield	4.0%

CAPITAL STRUCTURE as of 3/31/24
Total Debt $3070.8 mill. Due in 5 Yrs $580 mill.
LT Debt $2726.2 mill. LT Interest $125 mill.
Incl. $9.3 mill. capitalized leases.
(Interest coverage: 4.85x)
Pension Assets-9/23 $405.0 mill. Oblig. $493.7 mill.

Pfd Stock None

Common Stock 98,822,278 shs. as of 5/3/24

MARKET CAP: $4.4 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	2150	2200	Revenues ($mill) A	2500
176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	261.8	295	300	Net Profit ($mill)	350
30.2%	26.3%	15.5%	17.2%	--	--	NMF	10.3%	21.4%	15.8%	21.5%	22.0%	Income Tax Rate	22.0%
4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.3%	13.7%	13.6%	Net Profit Margin	14.0%
38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	57.5%	57.0%	Long-Term Debt Ratio	55.0%
61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	42.5%	43.0%	Common Equity Ratio	45.0%
1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	5250	5500	Total Capital ($mill)	6000
1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	5150	5250	Net Plant ($mill)	5550
12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	5.6%	5.5%	5.5%	5.5%	Return on Total Cap'l	6.0%
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	13.0%	12.5%	Return on Shr. Equity	13.0%
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	13.0%	12.5%	Return on Com Equity	13.0%
11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.6%	5.5%	5.0%	Retained to Com Eq	5.5%
40%	50%	60%	59%	40%	59%	60%	56%	53%	58%	57%	59%	All Div'ds to Net Prof	56%

CURRENT POSITION ($MILL.)

	2022	2023	3/31/24
Cash Assets	1.1	1.0	5.0
Other	755.0	531.1	548.7
Current Assets	756.1	532.1	553.7
Accts Payable	156.6	151.8	127.2
Debt Due	499.1	368.3	344.6
Other	448.5	286.5	317.3
Current Liab.	1104.2	806.6	789.1
Fix. Chg. Cov.	545%	520%	480%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-3.0%	-6.0%	2.5%
"Cash Flow"	7.0%	4.5%	5.0%
Earnings	5.0%	2.5%	5.0%
Dividends	6.5%	6.5%	5.0%
Book Value	7.5%	7.0%	4.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	657.9	450	574.9	2150
2025	680	575	460	485	2200

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	d.04	.50	2.50
2023	1.14	1.16	.10	.30	2.70
2024	.74	1.41	.05	.75	2.95
2025	.75	1.45	.05	.75	3.00

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42	.42			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 576,000 cust. at 9/30/23. Fiscal 2023 volume: 128 bill. cu. ft. (23% interruptible, 50% residential, commercial & firm transportation, 27% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2023 dep. rate: 2.8%. Has 1,350 empls. Off./dir. own less than 1% of common; BlackRock, 15.9%; Vanguard, 11.4% (12/23 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources delivered a strong fiscal 2024 second-quarter performance. (Fiscal year ends September 30th.) Despite a lower-than-expected revenue figure due to falling natural gas prices, the company's cost structure allowed earnings to remain unfettered. Indeed, net financial earnings exceeded our projections, landing at $1.41 per share, well above the prior year's tally. This brings the total for the first six months of fiscal 2024 to $2.15, just shy of the $2.30 in the year before, which was boosted by a unique winter storm. The performance was bolstered by significant capital investments of more than $850 million since the last rate case in 2021. Too, the company's SAVEGREEN program, a large energy efficiency filing, helped in catering to New Jersey's increasingly sustainability-focused regulatory climate. Despite some broader headwinds, the company continues to manage its operating costs well.

We have raised our earnings outlook for the next two years. The energy services segment is poised to contribute to our increased expectations due to the earlier mentioned SAVEGREEN program within the context of a particularly strong residential construction market and efficiency incentives in its operating region. On a similar note, Clean Energy Ventures is experiencing rapid deployment with 34 megawatts under construction and a solar pipeline of over 870 megawatts of investment opportunities. Most importantly for sustainable earnings performances henceforth is a new rate case progressing through regulatory channels that should amplify earnings performance substantially in fiscal 2026, if passed.

New Jersey's regional strength provides a solid base for sustainable growth. With a favorable regulatory backdrop characterized by a commitment to the transition to sustainable energy systems, infrastructure investment opportunities are wide, which will help to grow the company's earnings base for the foreseeable future.

The stock remains favorable for low risk and steady income characteristics. The issue has returned about 6% over the past three months but still offers decent value from its income component.

Earl B. Humes *May 24, 2024*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early August.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2023: $585 million, $6.00/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	60

NISOURCE INC. NYSE-NI

RECENT PRICE 28.80 | P/E RATIO 16.9 (Trailing: 17.1 Median: 21.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Raised 3/22/24
SAFETY 2 Raised 2/23/24
TECHNICAL 4 Raised 5/24/24
BETA .95 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6	29.0	29.2
Low:	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	23.8	22.9	24.8

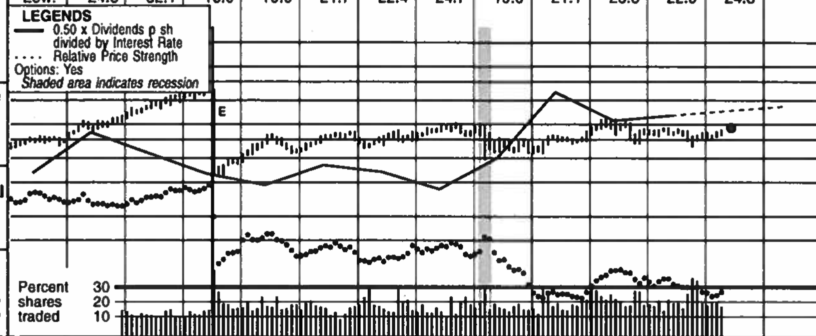
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$25-$40 $33 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+75%)	17%
Low	35	(+20%)	8%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	249	278	313
to Sell	256	234	253
Hld's(000)	393166	394475	413866



Target Price Range
2027 | 2028 | 2029

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.7	11.5
3 yr.	19.1	5.5
5 yr.	18.3	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.23	12.33	*13.80*	*14.55*	Revenues per sh	*16.10*
3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.47	3.64	*3.80*	*4.80*	"Cash Flow" per sh	*4.40*
1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	1.60	*1.70*	*1.85*	Earnings per sh A	*2.20*
.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	*1.06*	*1.12*	Div'ds Decl'd per sh B ■	*1.20*
3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	6.32	5.93	*7.00*	*6.50*	Cap'l Spending per sh	*6.75*
17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	13.14	22.71	*23.20*	*22.15*	Book Value per sh C	*20.40*
274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	411.10	446.38	*450.00*	*450.00*	Common Shs Outst'g D	*450.00*
12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	NMF	19.3	21.3	18.7	18.0	19.6	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	NMF	1.04	1.13	.96	.99	11.8	.97	*Value Line*		Relative P/E Ratio	*1.05*
5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $12970.9 mill. Due in 5 Yrs $4175 mill.
LT Debt $11724.6 mill. LT Interest $450 mill.
(Interest cov. earned: 4.5x) (54% of Cap'l)

Leases, Uncapitalized Annual rentals $9.6 mill.
Pension Assets-12/22 $1.4 bill. Oblig. $1.4 bill.

Pfd Stock $486 mill. Pfd Div'd $42.8 mill.

Common Stock 448,305,338 shs.
as of 4/30/24
MARKET CAP: $12.9 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	5505.4	*6200*	*6550*	Revenues ($mill)	*7250*
530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	716.3	*765*	*835*	Net Profit ($mill)	*990*
36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	17.2%	17.8%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
--	--	--	--	--	--	--	2.0%	2.3%	3.5%	*3.0%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	52.2%	*52.5%*	*52.5%*	Long-Term Debt Ratio	*55.0%*
43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	31.6%	45.5%	*40.0%*	*40.0%*	Common Equity Ratio	*37.5%*
14331	9792.0	10129	11832	12856	13843	14972	16131	17099	21192	*22000*	*21000*	Total Capital ($mill)	*24450*
16017	12112	13068	14360	15543	16912	16620	17882	19843	22275	*24500*	*25750*	Net Plant ($mill)	*28000*
5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	3.4%	*3.5%*	*4.0%*	Return on Total Cap'l	*4.0%*
8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	7.1%	*7.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	12.0%	7.4%	*8.5%*	*10.0%*	Return on Com Equity	*11.0%*
3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.0%	2.8%	*3.5%*	*4.0%*	Retained to Com Eq	*5.0%*
61%	NMF	63%	NMF	60%	64%	67%	64%	64%	63%	*62%*	*61%*	All Div'ds to Net Prof	*55%*

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	40.8	2245.4	102.2
Other	2543.5	2254.0	1958.0
Current Assets	2584.3	4499.4	2060.2
Accts Payable	899.5	749.4	612.5
Debt Due	1791.9	3072.4	1246.3
Other	1969.1	1443.3	1266.2
Current Liab.	4660.5	5265.1	3125.0
Fix. Chg. Cov.	255%	225%	425%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-5.0%	-3.5%	*5.5%*
"Cash Flow"	.5%	6.5%	*5.5%*
Earnings	1.5%	15.0%	*9.5%*
Dividends	-.5%	3.5%	*4.5%*
Book Value	-3.0%	.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	1183.2	1089.5	1704.6	5850.6
2023	1966.0	1090.0	1027.4	1422.0	5505.4
2024	1706.3	*1400*	*1200*	*1893.7*	*6200*
2025	*1805*	*1480*	*1270*	*1995*	*6550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.77	.13	.11	.39	1.37
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	.53	1.60
2024	.85	*.15*	*.13*	*.57*	*1.70*
2025	*.90*	*.20*	*.15*	*.60*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265	.265			

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 488,833 electric in Indiana, 3,200,000 gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2024: electrical, 32%; gas, 67%; other, less than 1%. Generating capacity, coal, 69.4%; purchased & other, 30.6%. 2022 reported depreciation rates: 3.5% electric, 2.4% gas. Has 7,364 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource had a strong earnings performance in the first quarter of 2024. The company continued its streak of consecutive quarterly growth by posting earnings of $0.85 per share, a 10% increase from the previous year. While this matched our target, the metric shows an outperformance considering the significant expansion of the number of diluted shares outstanding in the quarter, which we did not anticipate. The shares were likely issued in response to a large portion of debt that came due in the quarter, reflecting the utility's challenge of financing in the current high interest-rate environment. Still, investment is critical for the company's growth. Fortunately, the utility enjoys a strong regulatory environment across its geographies in Indiana, Ohio, Pennsylvania and Virginia, which together contributed to a rate-base of $18.8 billion at the end of 2023.

Our near-term earnings targets remain unchanged at the current juncture. Year-end earnings per share of $1.70 is likely, due to our anticipation of rate-base growth of roughly 8%-10%. The company has plans for significant capital expansion, including $16.4 billion aimed at enhancing system reliability and the transition to more sustainable energy sources. NiSource's track record for efficient capital allocation has led to consistent regulatory execution and affordable energy for its customers, supporting a low operating-risk profile. Too, tailwinds from sustainable investments, such as solar projects and infrastructure hardening, are likely to synergize with trends within the mid-west, such as the reshoring of manufacturing and the increasing development of data centers within its operating footprint. Economic conditions permitting, we anticipate steady earnings growth through to late decade.

Our stock projections reflect NiSource's strong prospects. Despite a strong return of more than 12% over the past three months, these good quality shares still reflect appealing value to the risk-sensitive accounts. The stock's high marks for Price Stability (95) pair well with it's above-average dividend yield of 3.8% to create a strong offering to income-style conservative investors.

Earl B. Humes *May 24, 2024*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due early August. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '23: $1485.9 million, $3.33/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	60

N.W. NATURAL NYSE-NWN

RECENT PRICE 38.48 | P/E RATIO 15.4 (Trailing: 16.9 Median: 24.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 5.1% | VALUE LINE

TIMELINESS 3 Raised 3/22/24
SAFETY 2 Raised 2/23/24
TECHNICAL 4 Raised 5/17/24
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High $33-$54 | Midpoint (% to Mid) $44 (15%)

2027-29 PROJECTIONS

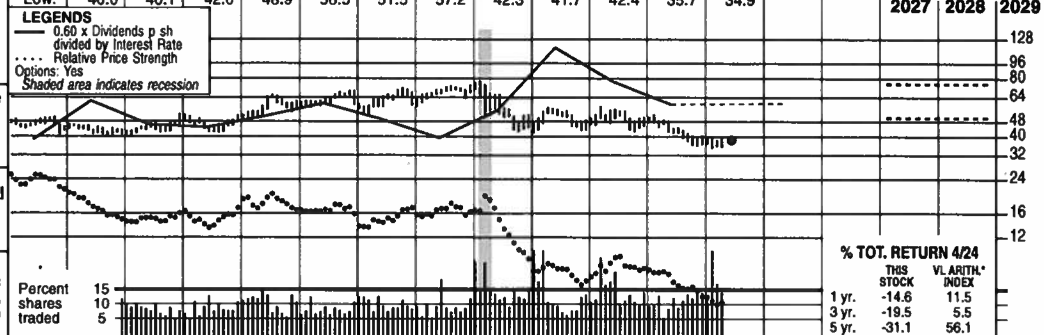
	Price	Gain	Ann'l Total Return
High	75	(+95%)	22%
Low	50	(+30%)	11%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	122	115	123
to Sell	123	110	90
Hld's(000)	26926	27474	28414

High:	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6	52.4	40.3
Low:	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	42.4	35.7	34.9

Target Price Range 2027 2028 2029



% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.6	11.5
3 yr.	-19.5	5.5
5 yr.	-31.1	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	31.82	**29.50**	**29.25**	Revenues per sh	**31.25**
5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	5.83	**5.85**	**6.65**	"Cash Flow" per sh	**7.20**
2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	2.59	**2.50**	**3.00**	Earnings per sh A	**3.20**
1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	**1.95**	**1.96**	Div'ds Decl'd per sh B ■	**1.98**
3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	8.70	**9.25**	**9.50**	Cap'l Spending per sh	**10.00**
23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.08	34.12	**36.55**	**36.60**	Book Value per sh D	**36.10**
26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	37.63	**39.00**	**41.00**	Common Shs Outst'g C	**45.00**
18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	--	26.6	30.9	25.0	19.5	19.6	16.6	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**20.0**
1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	--	1.44	1.65	1.28	1.06	1.13	.96	*estimates*		Relative P/E Ratio	**1.10**
3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%			Avg Ann'l Div'd Yield	**3.3%**

CAPITAL STRUCTURE as of 3/31/24
Total Debt $1670.3 mill. Due in 5 Yrs $1415 mill.
LT Debt $1574.7 mill. LT Interest $80 mill.

(Total interest coverage: 5.0x)

Pension Assets-12/23 $283.0 mill. Oblig. $425.5 mill.

Pfd Stock None

Common Stock 38,028,137 shares as of 4/26/24

MARKET CAP $1.5 billion (Small Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	1197.5	**1150**	**1200**	Revenues ($mill)	**1400**
58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	93.9	**97.5**	**125**	Net Profit ($mill)	**145**
41.5%	40.0%	40.9%	--	26.4%	16.2%	23.1%	25.8%	25.2%	25.7%	**25.0%**	**25.0%**	Income Tax Rate	**25.0%**
7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	7.8%	**8.5%**	**10.3%**	Net Profit Margin	**10.2%**
44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	52.6%	**50.0%**	**50.0%**	Long-Term Debt Ratio	**50.0%**
55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	47.4%	**50.0%**	**50.0%**	Common Equity Ratio	**50.0%**
1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	2709.2	**2850**	**3000**	Total Capital ($mill)	**3250**
2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	3358.0	**3500**	**3675**	Net Plant ($mill)	**3900**
5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	3.6%	3.5%	**3.5%**	**4.0%**	Return on Total Cap'l	**4.5%**
7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	**7.0%**	**8.0%**	Return on Shr. Equity	**9.0%**
7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	**7.0%**	**8.0%**	Return on Com Equity	**9.0%**
1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.1%	1.7%	**1.5%**	**3.0%**	Retained to Com Eq	**3.5%**
85%	92%	87%	NMF	76%	82%	79%	71%	79%	75%	**78%**	**65%**	All Div'ds to Net Prof	**62%**

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	29.3	32.9	72.4
Other	714.9	568.5	465.3
Current Assets	744.2	601.4	537.7
Accts Payable	180.7	145.4	107.9
Debt Due	348.9	240.7	95.6
Other	369.1	310.8	264.8
Current Liab.	898.7	696.9	468.3
Fix. Chg. Cov.	320%	240%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-2.5%	--	4.5%
"Cash Flow"	1.0%	2.5%	5.0%
Earnings	-1.0%	2.5%	6.5%
Dividends	1.5%	.5%	.5%
Book Value	1.0%	.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	355.7	1197.5
2024	433.5	*220*	*130*	*366.5*	*1150*
2025	*450*	*230*	*135*	*385*	*1200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	1.21	2.59
2024	1.69	*.05*	*d.65*	*1.41*	*2.50*
2025	*2.10*	*.05*	*d.60*	*1.45*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488	.488			

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 795,000 customers, in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 38%; commercial, 23%; industrial, gas transportation, 39%. Employs 1,380. BlackRock Inc. owns 17.6% of shares; Vanguard, 12.4%; Off./Dir., .84% (4/24 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Holdings continues to face challenging earnings comparisons. The northwestern natural gas utility saw its earnings decrease year-over-year for the fourth consecutive quarter in the March period to start 2024. Earnings per share in the company's cyclical-peak season amounted to $1.69, well below our target for a flat performance versus the year-prior's $2.01 result. The downturn in performance was primarily due to regulatory lag effects on its capital investments and rising cost pressures resulting in higher pension, depreciation, and interest expenses. Despite this, strengths such as a 1.7% growth in its customer base, low regional unemployment, and a peak-day delivery record of 8 million thermal units, paint an backdrop of strong demand. However, we expect that cost-of-living concerns across its operating footprint have led regulators to scrutinize the company's filings and tighten up on the rate-base regulatory approval process, hampering results of late.

We've cut our near-term earnings target to reflect the likelihood of continued regulatory challenges. While underlying operations should continue to grow steadily based on demographic trends, profitability leading into the cyclical-low season is likely to underwhelm. Instead, the company is refocusing its efforts on infrastructure hardening, including a planned $82 million investment that is slated for the current year as part of its rate case filings. We expect a relief in the final stanza of the year with rate adjustments likely to be resolved by November.

The long-term outlook here is more nuanced. Northwest is positioned in a strong geographic market that is undergoing a heavy investment cycle into clean-energy and energy-efficiency initiatives that ought to provide ample tailwinds to late decade. However, we also note some potential risks as both wildfires and seismic events have the potential to cause impairment to the company's infrastructure.

These good quality shares offer solid return potential and an above average dividend. The stock is a strong pick for conservative accounts, due to its Price Stability (85) and Financial Strength (A).

Earl B. Humes *May 24, 2024*

(A) Diluted earnings per share. Excludes nonrecurring items: '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early August.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.

(D) Includes intangibles. In 2023: $163 million, $4.33/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	15

ONE GAS, INC. NYSE-OGS

RECENT PRICE 63.81 | P/E RATIO 16.0 (Trailing: 15.8; Median: 21.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 12/8/23
SAFETY 2 New 6/2/17
TECHNICAL 3 Raised 5/24/24
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High: $42-$77 | Midpoint (% to Mid): $60 (-5%)

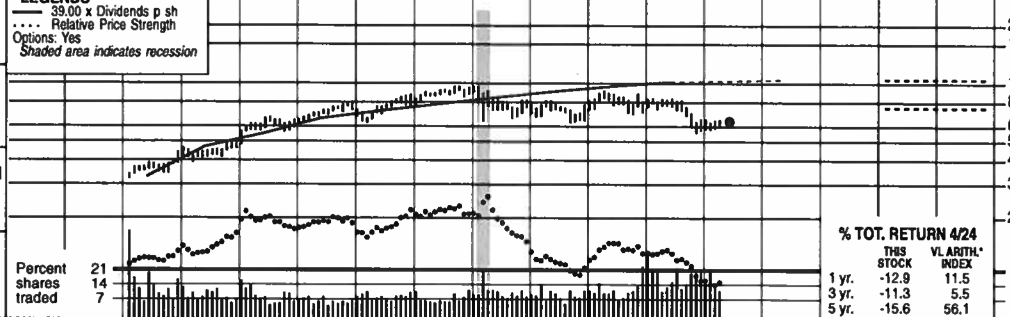
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+65%)	16%
Low	75	(+20%)	8%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	158	148	159
to Sell	133	153	160
Hld's(000)	53044	51074	52932

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3	84.3	66.5
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	68.9	55.5	57.7



The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
	34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	41.95	39.30	42.50	Revenues per sh	70.15
	4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	9.04	9.65	10.70	"Cash Flow" per sh	13.95
	2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	4.14	4.00	4.20	Earnings per sh A	5.00
	.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	2.64	2.68	Div'ds Decl'd per sh B■	2.85
	5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	11.79	11.95	12.15	Cap'l Spending per sh	12.60
	34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	48.91	50.15	53.55	Book Value per sh	60.20
	52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	56.55	56.50	56.50	Common Shs Outst'g C	57.00
	17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	18.0	Bold figures are		Avg Ann'l P/E Ratio	18.0
	.94	1.00	1.19	1.18	1.25	1.35	1.11	1.02	1.16	1.01	Value Line		Relative P/E Ratio	1.00
	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%	estimates		Avg Ann'l Div'd Yield	3.2%
	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	2372.0	2220	2400	Revenues ($mill)	4000
	109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	231.2	225	235	Net Profit ($mill)	285
	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	14.9%	15.5%	16.0%	Income Tax Rate	20.0%
	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	9.7%	10.1%	9.8%	Net Profit Margin	7.1%
	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	43.8%	45.0%	45.0%	Long-Term Debt Ratio	51.0%
	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	56.2%	55.0%	55.0%	Common Equity Ratio	49.0%
	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	4926.3	5150	5500	Total Capital ($mill)	7000
	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	6135.2	6425	6800	Net Plant ($mill)	8000
	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	5.9%	5.5%	5.5%	Return on Total Cap'l	5.5%
	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	8.0%	8.0%	Return on Shr. Equity	8.5%
	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	8.0%	8.0%	Return on Com Equity	8.5%
	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	3.2%	3.0%	3.0%	Retained to Com Eq	3.5%
	40%	53%	52%	55%	56%	56%	58%	60%	60%	62%	66%	64%	All Div'ds to Net Prof	57%

CAPITAL STRUCTURE as of 3/31/24
Total Debt $3128.0 mill. Due in 5 Yrs $890.0 mill.
LT Debt $2146.4 mill. LT Interest $120.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x)
Leases, Uncapitalized Annual rentals $6.7 mill.
Pfd Stock None
Pension Assets-12/23 $977.0 mill. Oblig. $962.1 mill.
Common Stock 56,569,396 shs. as of 4/29/24
MARKET CAP: $3.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	9.7	18.8	11.5
Other	1207.9	746.4	652.2
Current Assets	1217.6	765.2	663.7
Accts Payable	360.5	278.1	196.6
Debt Due	572.7	888.9	981.6
Other	256.2	310.2	225.3
Current Liab.	1189.4	1477.2	1403.5
Fix. Chg. Cov.	540%	390%	420%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	--	7.0%	9.5%
"Cash Flow"	--	7.0%	9.0%
Earnings	--	6.0%	3.5%
Dividends	--	8.5%	2.5%
Book Value	--	4.5%	4.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	606.0	2372.0
2024	758.3	410	350	701.7	2220
2025	800	430	410	760	2400

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.79	.56	.38	1.12	3.85
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	1.27	4.14
2024	1.75	.56	.43	1.26	4.00
2025	1.85	.60	.48	1.27	4.20

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66	.66			

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 160 Bcf of natural gas supply in 2023, compared to 165 Bcf in 2022. Total volumes delivered by customer (fiscal 2023): transportation, 59.3%; residential, 29.7%; commercial & industrial, 10.6%; other, .4%. ONE Gas has around 3,900 employees. BlackRock owns 14.5% of common stock; The Vanguard Group, 11.6%; American Century Investment, 7.5%; officers and directors, 1.5% (4/24 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas, Inc. began 2024 in low gear. First-quarter earnings per share slipped about 5%, to $1.75, relative to last year's $1.84 figure. That was traced partly to higher employee-related costs, given planned investments in the company's workforce and ongoing in-sourcing efforts. Also, sales volumes decreased and interest expense rose. But new rates did provide somewhat of an offset. Still, right now, it appears that the bottom line will recede around 3% for the whole year, to $4.00 per share, versus the $4.14 tally generated in 2023. But turning to 2025, a 5% recovery, to $4.20 a share, seems plausible. That's based, to a certain degree, on our assumption that the business environment is generally favorable.

Prospects out to the end of the decade appear promising. ONE Gas remains the top natural gas distributor, as measured by number of customers, in both Oklahoma and Kansas, and holds the number-three position in Texas. (Services are provided to more than two million residential, commercial, and transportation clients at present.) Furthermore, we believe those markets have decent growth potential and are located in one of the most active drilling areas in the United States. Also, supported by the solid balance sheet, the company ought to continue to meet its working capital requirements, capital expenditures, and other obligations with little difficulty.

There are risk factors to bear in mind, however. ONE Gas' lack of geographic diversification leaves it somewhat more susceptible to regional economic downturns and regulations. Moreover, there's competition from other energy suppliers, including propane dealers and electric companies. Finally, pipeline ruptures, leaks, and other unfortunate occurrences can take a major toll on corporate profits if not adequately covered by insurance.

The stock has some investment appeal. Its dividend yield is respectable in comparison with other equities within *Value Line's* Natural Gas Utility Industry. Also, capital appreciation possibilities over the 2027-2029 horizon look worthwhile. Consider, too, the 2 (Above Average) rank for Safety and high Price Stability score of 90 out of 100.

Frederick L. Harris, III *May 24, 2024*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Aug. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	100

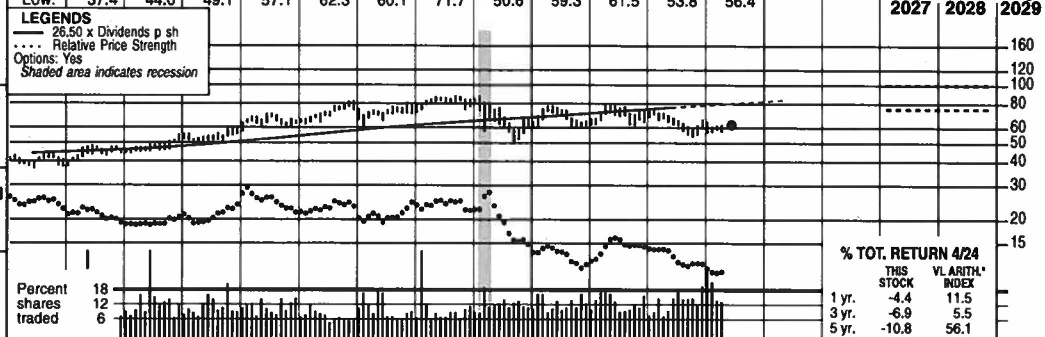
SPIRE INC. NYSE-SR

RECENT PRICE **62.20** | P/E RATIO **14.5** (Trailing: 15.7; Median: 19.0) | RELATIVE P/E RATIO **0.80** | DIV'D YLD **5.0%** | VALUE LINE

TIMELINESS **3** Raised 2/16/24
SAFETY **2** Raised 6/20/03
TECHNICAL **4** Raised 5/17/24
BETA .85 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	79.2	75.8	64.6
Low:	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.5	53.8	56.4

LEGENDS
— 26.50 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2027 | 2028 | 2029

18-Month Target Price Range
Low-High: $44-$72
Midpoint (% to Mid): $58 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+60%)	16%
Low	75	(+20%)	10%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	142	131	140
to Sell	138	144	123
Hld's(000)	46098	48374	48459

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.4	11.5
3 yr.	-6.9	5.5
5 yr.	-10.8	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	50.12	**45.20**	**45.65**	Revenues per sh A	**57.25**
4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	8.60	**8.80**	**9.25**	"Cash Flow" per sh	**11.00**
2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	3.85	**4.30**	**4.55**	Earnings per sh A B	**5.50**
1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.88	**3.02**	**3.16**	Div'ds Decl'd per sh C■	**3.60**
2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	12.45	**13.70**	**13.90**	Cap'l Spending per sh	**14.50**
22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	50.29	**52.65**	**55.75**	Book Value per sh D	**66.05**
21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	53.20	**58.50**	**60.00**	Common Shs Outst'g E	**62.00**
14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	17.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**16.0**
.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01	1.00	*estimates*		Relative P/E Ratio	**.90**
3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%	4.3%			Avg Ann'l Div'd Yield	**4.1%**
						1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	2666.3	**2645**	**2740**	Revenues ($mill) A	**3550**
						84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	217.5	**240**	**260**	Net Profit ($mill)	**340**
						27.6%	31.2%	32.5%	32.4%	--	15.7%	12.3%	20.1%	21.1%	15.1%	**19.5%**	**19.5%**	Income Tax Rate	**24.0%**
						5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	8.2%	**9.1%**	**9.5%**	Net Profit Margin	**9.6%**
						55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	54.9%	**52.0%**	**52.0%**	Long-Term Debt Ratio	**51.0%**
						44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	41.3%	**44.0%**	**44.0%**	Common Equity Ratio	**45.0%**
						3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	6471.3	**7000**	**7600**	Total Capital ($mill)	**9100**
						2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	5778.9	**6150**	**6530**	Net Plant ($mill)	**7675**
						3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	4.8%	**5.0%**	**5.0%**	Return on Total Cap'l	**5.5%**
						5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	7.5%	**8.0%**	**8.0%**	Return on Shr. Equity	**8.5%**
						5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	7.6%	**8.0%**	**8.0%**	Return on Com Equity	**8.5%**
						1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	1.9%	**2.0%**	**1.5%**	Retained to Com Eq	**2.5%**
						73%	58%	59%	60%	51%	66%	NMF	54%	71%	76%	**77%**	**79%**	All Div'ds to Net Prof	**70%**

CAPITAL STRUCTURE as of 3/31/24
Total Debt $4514.4 mill. Due in 5 Yrs $2310.0 mill.
LT Debt $3421.4 mill. LT Interest $140.0 mill.
(Total interest coverage: 2.4x)

Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-9/23 $630.3 mill. **Oblig.** $832.5 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 57,747,978 shs. **as of 4/28/24**

MARKET CAP: $3.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	6.5	5.6	25.6
Other	1585.5	1071.3	980.1
Current Assets	1592.0	1076.9	1005.7
Accts Payable	617.4	253.1	193.4
Debt Due	1318.7	1112.1	1093.0
Other	417.5	390.2	363.9
Current Liab.	2353.6	1755.4	1650.3
Fix. Chg. Cov.	393%	294%	315%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.0%	4.5%	*4.0%*
"Cash Flow"	8.0%	5.0%	*4.0%*
Earnings	5.0%	3.0%	*4.5%*
Dividends	5.0%	5.5%	*4.5%*
Book Value	5.5%	3.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	418.5	310.4	2666.3
2024	756.6	1128.5	*434.9*	*325*	*2645*
2025	*790*	*1135*	*465*	*350*	*2740*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	d.48	d.66	3.85
2024	1.52	3.58	*d.34*	*d.46*	*4.30*
2025	*1.50*	*3.45*	*d.16*	*d.24*	*4.55*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72	.72	.72	2.88
2024	.755	.755			

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2023: 3.2 bill. Revenue mix for regulated operations: residential, 67%; commercial and industrial, 25%; transportation, 5%; other, 3%. Officers and directors own 2.9% of common shares; American Century Companies, 15.4% (12/23 proxy). Chairman: Edward Glotzbach; CEO: Steve Lindsey. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire managed to post decent bottom-line results in the second quarter of fiscal 2024 (which concluded on March 31st). Indeed, earnings per share of $3.58 were 7.5% above the previous year's $3.33 tally. That was brought about, to a certain extent, by the Gas Utility division, which benefited partly from improved results at Spire Alabama. The Gas Marketing segment had a better showing for that period, too.

Higher profits appear to be in store for the year as a whole, as well. The company did get off to a slow start, with first-quarter share net receding 8.4%, to $1.52, relative to last year's $1.66 figure. That was attributed partly to the fact that, for both the Gas Marketing and Midstream divisions, fiscal 2023's very favorable market conditions did not reoccur. But, as mentioned, Spire's second-quarter performance was decent. Furthermore, bottom-line comparisons during the second half ought to be easier. (Losses are typical over that time frame because of the seasonality of the business.) All told, we expect full-year share net to rebound about 12%, to $4.30, versus fiscal 2023's $3.85 result. Concerning next year, profits might increase another 6% or so, to $4.55 a share, assuming additional widening of operating margins.

The Financial Strength rating sits at B++. When the second quarter ended, cash and equivalents were $25.6 million. Furthermore, there was $1.3 billion available through a revolving credit facility expiring in July, 2027. Also, long-term debt resided at a manageable 50% of total capital, and short-term obligations of almost $1.1 billion did not seem to be a major obstacle. So, the company should continue to satisfy its commitments, which include working capital requirements and capital expenditures, with minimal difficulty.

The equity ought to draw the attention of some investors. Its dividend yield stacks up well compared to those of other stocks in *Value Line's* Natural Gas Utility Industry. What's more, capital appreciation potential over the 2027-2029 horizon looks worthwhile. Meanwhile, SR shares are pegged to mimic the market over the next six to 12 months (Timeliness rank 3: Average).

Frederick L. Harris, III *May 24, 2024*

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. (C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '23: $1,171.6 mill., $22.02/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	45

Washington Gas Light Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Six Natural Gas Distribution Companies using Prospective Interest Rates	Proxy Group of Six Natural Gas Distribution Companies using Current Interest Rates
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.14 %	
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.51	
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.65 %	
4.	Current Yield on A2 Rated Public Utility Bonds (3)		5.69 %
5.	Equity Risk Premium (4)	5.17	5.13
6.	Risk Premium Derived Common Equity Cost Rate	10.82 %	10.82 %

Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 7 and 8 of this Exhibit).
(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.51% from page 2 of this Exhibit.
(3) Source of Information: Bloomberg Professional Services
(4) From page 5 of this Exhibit.

Washington Gas Light Company
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1]	[2]	[3]
	Aaa Rated Corporate Bond	A2 Rated Public Utility Bond	Baa2 Rated Public Utility Bond
May-2024	5.25 %	5.74 %	5.97 %
Apr-2024	5.28	5.79	6.01
Mar-2024	5.01	5.55	5.79
Average	5.18 %	5.69 %	5.92 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds: 0.51 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds: 0.23 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

Washington Gas Light Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Six Natural Gas Distribution Companies

Proxy Group of Six Natural Gas Distribution Companies	Moody's Long-Term Issuer Rating May 2024: Long-Term Issuer Rating	Moody's Long-Term Issuer Rating May 2024: Numerical Weighting (1)	Standard & Poor's Long-Term Issuer Rating May 2024: Long-Term Issuer Rating	Standard & Poor's Long-Term Issuer Rating May 2024: Numerical Weighting (1)
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	A-	7.0
Spire Inc.	A1/A2	5.5	BBB+	8.0
Average	A2	6.4	A-	7.0

Notes:
(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 4 of this Exhibit.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Washington Gas Light Company
Judgment of Equity Risk Premium for the
Proxy Group of Six Natural Gas Distribution Companies

Line No.		Proxy Group of Six Natural Gas Distribution Companies using Prospective Interest Rates	Proxy Group of Six Natural Gas Distribution Companies using Current Interest Rates
1.	Calculated equity risk premium based on the total market using the beta approach (1)	6.20 %	6.12 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A2 rated bonds (2)	4.51	4.49
3.	Predicted Equity Risk Premium Based on Regression Analysis of 834 Fully-Litigated Natural Gas Distribution Cases (3)	4.79	4.77
4	Average equity risk premium	5.17 %	5.13 %

Notes: (1) From page 6 of this Exhibit.
(2) From page 9 of this Exhibit.
(3) From page 10 of this Exhibit.

Washington Gas Light Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Six Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Six Natural Gas Distribution Companies using Prospective Interest Rates	Proxy Group of Six Natural Gas Distribution Companies using Current Interest Rates
1.	Kroll Equity Risk Premium (1)	5.96 %	5.96 %
2.	Regression on Kroll Risk Premium Data	6.92 (2)	6.73 (3)
3.	Kroll Equity Risk Premium based on PRPM (4)	8.46	8.46
4	Equity Risk Premium Based on Value Line Summary and Index	6.91 (5)	6.76 (6)
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies	10.05 (7)	9.90 (8)
6.	Conclusion of Equity Risk Premium	7.66 %	7.56 %
7.	Adjusted Beta (9)	0.81	0.81
8.	Forecasted Equity Risk Premium	6.20 %	6.12 %

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll minus the arithmetic mean monthly yield of Moody's average Aaa and Aa2 corporate bonds from 1928-2023.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2023 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the average consensus forecast of Aaa corporate bonds of 5.14% (from page 1 of this Exhibit).

(3) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2023 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the three-month average Aaa and Aa2 rated corporate bond of 5.29%.

(4) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through May 2024.

(5) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.14% (from page 1 of this Exhibit) from the projected 3-5 year total annual market return of 12.05% (described fully in note 1 on page 2 of Exhibit WG (C)-5).

(6) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the current 3 month average of Aaa and Aa2 corporate bonds of 5.29% from the projected 3-5 year total annual market return of 12.05% (described fully in note 1 on page 2 of Exhibit WG (C)-5).

(7) Using data from the Bloomberg Professional Services, Value Line, and S&P Capital IQ for the S&P 500 for the S&P 500, an expected total return of 15.19% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.14% results in an expected equity risk premium of 10.05%.

(8) Using data from the Bloomberg Professional Services, Value Line, and S&P Capital IQ for the S&P 500 for the S&P 500, an expected total return of 15.19% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the current 3 month average of Aaa and Aa2 corporate bonds of 5.29% results in an expected equity risk premium of 9.90%.

(9) Average of mean and median beta from Exhibit WG(C)-5.

Sources of Information:

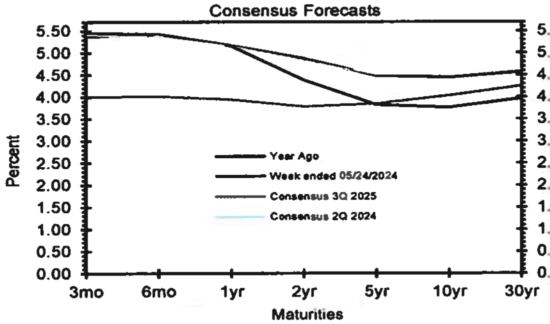
Kroll 2023 SBBI® Yearbook
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, May 31, 2024
S&P Capital IQ
Bloomberg Professional Services

Consensus Forecasts of U.S. Interest Rates and Key Assumptions

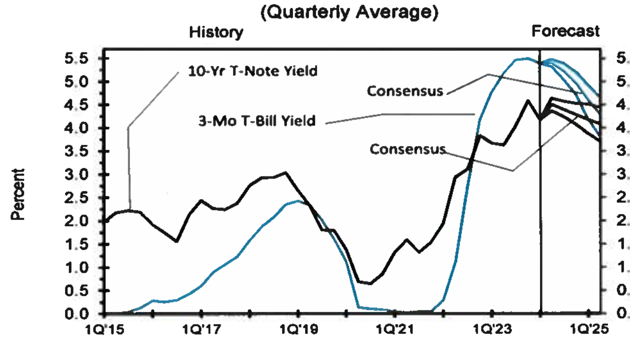
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Qtr	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	May 24	May 17	May 10	May 3	Apr	Mar	Feb	1Q 2024	2024	2024	2024	2025	2025	2025
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.4	5.2	5.0	4.7	4.4	4.1
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.5	8.4	8.1	7.8	7.6	7.3
SOFR	5.31	5.31	5.31	5.32	5.32	5.31	5.31	5.31	5.3	5.3	5.0	4.7	4.4	4.1
Commercial Paper, 1-mo.	5.31	5.33	5.32	5.32	5.31	5.32	5.31	5.32	5.3	5.2	5.0	4.7	4.4	4.0
Treasury bill, 3-mo.	5.45	5.45	5.46	5.46	5.44	5.47	5.44	5.45	5.4	5.2	5.0	4.6	4.3	4.0
Treasury bill, 6-mo.	5.43	5.42	5.42	5.43	5.38	5.36	5.28	5.28	5.4	5.2	4.9	4.6	4.3	4.0
Treasury bill, 1 yr.	5.17	5.14	5.13	5.19	5.14	4.99	4.92	4.90	5.2	5.0	4.7	4.4	4.2	3.9
Treasury note, 2 yr.	4.87	4.80	4.83	4.93	4.87	4.59	4.54	4.48	4.8	4.6	4.4	4.1	3.9	3.8
Treasury note, 5 yr.	4.48	4.43	4.49	4.61	4.56	4.20	4.19	4.12	4.5	4.4	4.2	4.1	3.9	3.9
Treasury note, 10 yr.	4.44	4.42	4.48	4.61	4.54	4.21	4.21	4.16	4.5	4.4	4.3	4.2	4.1	4.0
Treasury note, 30 yr.	4.57	4.56	4.63	4.73	4.66	4.36	4.38	4.33	4.6	4.5	4.5	4.4	4.3	4.3
Corporate Aaa bond	5.28	5.27	5.34	5.45	5.38	5.11	5.13	5.08	5.3	5.2	5.1	5.1	5.0	5.0
Corporate Baa bond	5.76	5.76	5.83	5.94	5.88	5.62	5.65	5.60	6.1	6.0	6.0	5.9	5.9	5.9
State & Local bonds	4.29	4.21	4.23	4.32	4.28	4.12	4.12	4.11	4.4	4.3	4.2	4.2	4.2	4.2
Home mortgage rate	6.94	7.02	7.09	7.22	6.99	6.82	6.78	6.75	7.0	6.9	6.7	6.5	6.4	6.3
	History								Consensus Forecasts-Quarterly					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2022	2022	2022	2023	2023	2023	2023	2024	2024	2024	2024	2025	2025	2025
Fed's AFE $ Index	113.5	118.8	119.8	115.5	114.6	115.0	116.6	115.5	117.1	117.7	116.9	116.5	116.2	116.0
Real GDP	-0.6	2.7	2.6	2.2	2.1	4.9	3.4	1.3	2.2	1.7	1.6	1.8	1.9	2.0
GDP Price Index	9.1	4.4	3.9	3.9	1.7	3.3	1.6	3.0	2.8	2.5	2.3	2.3	2.3	2.2
Consumer Price Index	10.0	5.3	4.0	3.8	3.0	3.4	2.7	3.8	3.5	2.7	2.5	2.4	2.4	2.4
PCE Price Index	7.2	4.7	4.1	4.2	2.5	2.6	1.8	3.3	2.9	2.3	2.2	2.3	2.2	2.2

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).

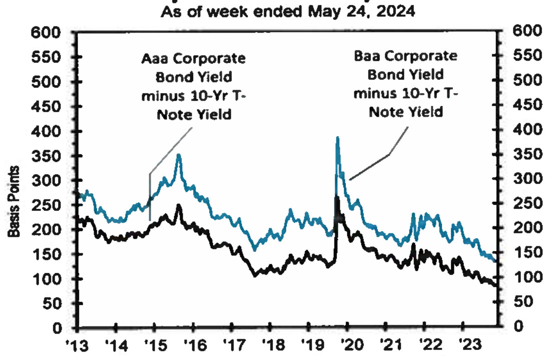
US Treasury Yield Curve
Week ended May 24, 2024 & Year Ago vs. 2Q 2024 & 3Q 2025 Consensus Forecasts



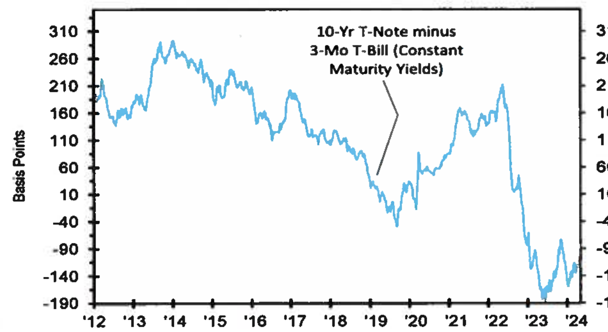
US 3-Mo T-Bills & 10-Yr T-Note Yield
(Quarterly Average)



Corporate Bond Spreads
As of week ended May 24, 2024



US Treasury Yield Curve
As of week ended May 24, 2024



Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2025 through 2030 and averages for the five-year periods 2026-2030 and 2031-2035. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		----- Average For The Year -----						Five-Year Averages	
		2025	2026	2027	2028	2029	2030	2026-2030	2031-2035
1. Federal Funds Rate	**CONSENSUS**	**4.1**	**3.4**	**3.2**	**3.2**	**3.3**	**3.3**	**3.3**	**3.2**
	Top 10 Average	4.5	3.8	3.8	3.8	3.8	3.8	3.8	3.8
	Bottom 10 Average	3.6	3.0	2.7	2.7	2.7	2.7	2.8	2.7
2. Prime Rate	**CONSENSUS**	**7.1**	**6.5**	**6.4**	**6.4**	**6.4**	**6.3**	**6.4**	**6.3**
	Top 10 Average	7.5	6.9	6.9	6.9	6.9	6.9	6.9	6.8
	Bottom 10 Average	6.8	6.1	5.9	5.8	5.8	5.7	5.9	5.7
3. SOFR	**CONSENSUS**	**4.0**	**3.4**	**3.3**	**3.3**	**3.2**	**3.2**	**3.3**	**3.2**
	Top 10 Average	4.3	3.7	3.7	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.8	3.1	2.9	2.8	2.8	2.7	2.8	2.7
4. Commercial Paper, 1-Mo	**CONSENSUS**	**4.0**	**3.4**	**3.4**	**3.3**	**3.3**	**3.3**	**3.4**	**3.3**
	Top 10 Average	4.2	3.6	3.6	3.6	3.5	3.5	3.6	3.6
	Bottom 10 Average	3.8	3.2	3.0	3.0	3.0	2.9	3.0	2.9
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**4.0**	**3.4**	**3.3**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**
	Top 10 Average	4.4	3.7	3.7	3.7	3.7	3.7	3.7	3.7
	Bottom 10 Average	3.6	3.0	2.8	2.7	2.7	2.7	2.8	2.6
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**4.0**	**3.5**	**3.4**	**3.4**	**3.4**	**3.3**	**3.4**	**3.3**
	Top 10 Average	4.3	3.8	3.8	3.7	3.7	3.7	3.8	3.7
	Bottom 10 Average	3.7	3.2	3.0	2.9	2.9	2.8	3.0	2.8
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**4.0**	**3.6**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**	**3.4**
	Top 10 Average	4.3	3.9	3.9	3.9	3.9	3.9	3.9	3.8
	Bottom 10 Average	3.8	3.4	3.2	3.1	3.0	3.0	3.1	3.0
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.8**	**3.7**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**
	Top 10 Average	4.1	4.0	4.1	4.1	4.1	4.1	4.1	4.1
	Bottom 10 Average	3.5	3.3	3.2	3.1	3.1	3.1	3.2	3.0
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.9**	**3.8**	**3.8**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**
	Top 10 Average	4.2	4.2	4.3	4.3	4.5	4.4	4.3	4.5
	Bottom 10 Average	3.6	3.5	3.4	3.3	3.4	3.4	3.4	3.3
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**4.0**	**4.0**	**4.0**	**4.0**	**4.2**	**4.2**	**4.1**	**4.2**
	Top 10 Average	4.4	4.5	4.5	4.6	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.7	3.6	3.5	3.5	3.6	3.6	3.5	3.6
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.2**	**4.2**	**4.2**	**4.3**	**4.4**	**4.4**	**4.3**	**4.4**
	Top 10 Average	4.5	4.6	4.7	4.8	4.9	4.9	4.7	4.9
	Bottom 10 Average	3.9	3.9	3.8	3.8	3.8	3.9	3.8	3.8
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.1**	**5.1**	**5.1**	**5.2**	**5.3**	**5.3**	**5.2**	**5.2**
	Top 10 Average	5.4	5.4	5.6	5.7	5.8	5.8	5.7	5.8
	Bottom 10 Average	4.8	4.7	4.7	4.7	4.7	4.7	4.7	4.7
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.0**	**6.1**	**6.1**	**6.2**	**6.2**	**6.1**	**6.2**
	Top 10 Average	6.3	6.3	6.5	6.6	6.7	6.7	6.5	6.7
	Bottom 10 Average	5.7	5.7	5.6	5.6	5.6	5.7	5.6	5.7
14. State & Local Bonds Yield	**CONSENSUS**	**4.1**	**4.1**	**4.2**	**4.2**	**4.3**	**4.4**	**4.2**	**4.3**
	Top 10 Average	4.4	4.5	4.5	4.6	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.7
15. Home Mortgage Rate	**CONSENSUS**	**6.3**	**6.1**	**6.1**	**6.1**	**6.1**	**6.2**	**6.1**	**6.1**
	Top 10 Average	6.7	6.5	6.5	6.5	6.6	6.6	6.6	6.6
	Bottom 10 Average	6.0	5.7	5.7	5.6	5.6	5.6	5.6	5.5
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**115.6**	**114.6**	**114.3**	**113.9**	**113.4**	**112.8**	**113.8**	**112.3**
	Top 10 Average	116.9	116.3	115.8	115.7	115.3	115.1	115.6	114.8
	Bottom 10 Average	114.2	113.0	112.7	112.1	111.5	110.9	112.0	110.1
		----- Year-Over-Year, % Change -----						Five-Year Averages	
		2025	2026	2027	2028	2029	2030	2026-2030	2031-2035
B. Real GDP	**CONSENSUS**	**1.9**	**2.0**	**2.1**	**2.1**	**2.0**	**2.0**	**2.1**	**2.0**
	Top 10 Average	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.2
	Bottom 10 Average	1.6	1.8	1.9	1.8	1.8	1.8	1.8	1.8
C. GDP Chained Price Index	**CONSENSUS**	**2.3**	**2.2**	**2.2**	**2.1**	**2.2**	**2.1**	**2.2**	**2.1**
	Top 10 Average	2.6	2.4	2.4	2.3	2.3	2.3	2.4	2.3
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.4**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.7	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	Bottom 10 Average	2.1	2.1	2.0	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	**CONSENSUS**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.2
	Bottom 10 Average	2.0	1.9	1.9	1.9	2.0	2.0	1.9	2.0

Projected Market Appreciation of the S&P Utility Index
Derivation of Mean Equity Risk Premium Based Studies Using Holding Period Returns and Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium using Prospective Interest Rates	Implied Equity Risk Premium using Current Interest Rates
1.	Historical Equity Risk Premium (1)	4.02 %	4.02 %
2.	Regression of Historical Equity Risk Premium	4.81 (2)	4.77 (3)
3	Forecasted Equity Risk Premium Based on PRPM (4)	4.39	4.39
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg, Value Line, and S&P Capital IQ Data)	4.81 (5)	4.77 (6)
5.	Average Equity Risk Premium (7)	4.51 %	4.49 %

Notes: (1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2023. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2023 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the prospective A2 rated public utility bond yield of 5.65% (from line 3, page 1 of this Exhibit).

(3) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2023 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the current A2 rated public utility bond yield of 5.69% (from line 4, page 1 of this Exhibit).

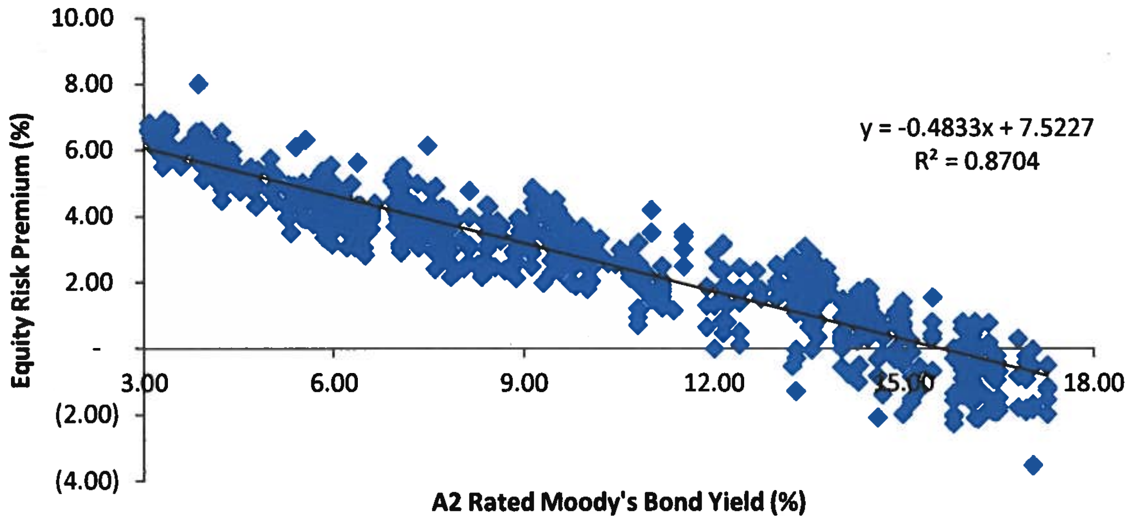
(4) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - May 2024.

(5) Using data from Bloomberg, Value Line, and S&P Capital IQ for the S&P Utilities Index, an expected return of 10.46% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.65%, calculated on line 3 of page 1 of this Exhibit results in an equity risk premium of 4.81%. (10.46% - 5.65% = 4.81%)

(6) Using data from Bloomberg, Value Line, and S&P Capital IQ for the S&P Utilities Index, an expected return of 10.46% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the current A2 rated public utility bond yield of 5.69%, calculated on line 4 of page 1 of this Exhibit results in an equity risk premium of 4.77%. (10.46% - 5.69% = 4.77%)

(7) Average of lines 1 through 4.

Washington Gas Light Company
Prediction of Equity Risk Premiums Relative to Moody's A2 Rated Utility Bond Yields



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.5227 %	-0.4833	5.65 %	4.79 %

Constant	Slope	Current A2 Rated Utility Bond (2)	Prospective Equity Risk Premium
7.5227 %	-0.4833	5.69 %	4.77 %

Notes:

(1) From line 3 of page 1 of this Exhibit.

(2) From line 4 of page 1 of this Exhibit.

Source of Information: Regulatory Research Associates.

Washington Gas Light Company
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Six Natural Gas Distribution Companies Using Prospective Interest Rates

Proxy Group of Six Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Bloomberg Adjusted Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (2)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost Rate (4)
Atmos Energy Corporation	0.85	0.76	0.80	8.59 %	4.41 %	11.28 %	11.71 %	11.50 %
New Jersey Resources Corporation	1.00	0.74	0.87	8.59	4.41	11.89	12.16	12.02
NiSource Inc.	0.95	0.77	0.86	8.59	4.41	11.80	12.10	11.95
Northwest Natural Holding Company	0.85	0.63	0.74	8.59	4.41	10.77	11.33	11.05
ONE Gas, Inc.	0.85	0.64	0.75	8.59	4.41	10.85	11.39	11.12
Spire Inc.	0.85	0.79	0.82	8.59	4.41	11.46	11.84	11.65
Mean			0.81			11.34 %	11.76 %	11.55 %
Median			0.81			11.37 %	11.78 %	11.58 %
Average of Mean and Median			0.81			11.36 %	11.77 %	11.57 %

Proxy Group of Six Natural Gas Distribution Companies Using Current Interest Rates

Proxy Group of Six Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Bloomberg Adjusted Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (3)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost Rate (4)
Atmos Energy Corporation	0.85	0.76	0.80	8.51 %	4.55 %	11.35 %	11.78 %	11.57 %
New Jersey Resources Corporation	1.00	0.74	0.87	8.51	4.55	11.95	12.22	12.09
NiSource Inc.	0.95	0.77	0.86	8.51	4.55	11.86	12.16	12.01
Northwest Natural Holding Company	0.85	0.63	0.74	8.51	4.55	10.84	11.40	11.12
ONE Gas, Inc.	0.85	0.64	0.75	8.51	4.55	10.93	11.46	11.19
Spire Inc.	0.85	0.79	0.82	8.51	4.55	11.52	11.91	11.71
Mean			0.81			11.41 %	11.82 %	11.62 %
Median			0.81			11.44 %	11.84 %	11.64 %
Average of Mean and Median			0.81			11.43 %	11.83 %	11.63 %

Notes on page 2 of this Exhibit.

Washington Gas Light Company
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using five different measures from four sources: Kroll, Value Line, Bloomberg, and S&P Capital IQ as illustrated below:

	Using Prospective Interest Rates	Using Current Interest Rates
Measure 1: Kroll Arithmetic Mean MRP (1926-2023)		
Arithmetic Mean Monthly Returns for Large Stocks 1926-2023:	12.16 %	12.16 %
Arithmetic Mean Income Returns on Long-Term Government Bonds:	4.99	4.99
MRP based on Kroll Historical Data:	7.17 %	7.17 %
Measure 2: Application of a Regression Analysis to Kroll Historical Data (1926-2023)	7.93 %	7.79 %
Measure 3: Application of the PRPM to Kroll Historical Data (January 1926 - May 2024)	9.44 %	9.44 %
Measure 4: Value Line Projected MRP (Thirteen weeks ending May 31, 2024)		
Total projected return on the market 3-5 years hence*:	12.05 %	12.05 %
Risk-Free Rate (see notes 2 and 3):	4.41	4.55
MRP based on Value Line Summary & Index:	7.64 %	7.50 %
*Forcasted 3-5 year capital appreciation plus expected dividend yield		
Measure 5: Bloomberg, Value Line, and S&P Capital IQ Projected Return on the Market based on the S&P 500		
Total return on the Market based on the S&P 500:	15.19 %	15.19 %
Risk-Free Rate (see notes 2 and 3):	4.41	4.55
MRP based on Bloomberg, Value Line, and S&P Capital IQ data	10.78 %	10.64 %
Average of all MRP Measures:	8.59 %	8.51 %

(2) For reasons explained in the Direct Testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 7 and 8 of Exhibit WG (C)-4.) The projection of the risk-free rate is illustrated below:

Second Quarter 2024	4.60 %
Third Quarter 2024	4.50
Fourth Quarter 2024	4.50
First Quarter 2025	4.40
Second Quarter 2025	4.30
Third Quarter 2025	4.30
2026-2030	4.30
2031-2035	4.40
	4.41 %

(3) Three-month average on 30-year Treasury bond yield ended May, 2024 as shown below:

May 2024	4.62 %
April 2024	4.66
March 2024	4.36
	4.55 %

(4) Average of Column 6 and Column 7.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, May 31, 2024
Kroll 2023 SBBI® Yearbook
S&P Capital IQ
Bloomberg Professional Services

Washington Gas Light Company
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Six Natural Gas Distribution Companies

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the proxy group of six natural gas distribution companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.64 - 0.92 and residual standard error of the regression range of 2.7845 - 3.3209 of the proxy group of six natural gas distribution companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1341. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1341 = \frac{3.0527}{\sqrt{518}} = \frac{3.0527}{22.7596}$$

Source of Information: Value Line Proprietary Database, March 2024.
Value Line Investment Survey (Standard Edition).

Washington Gas Light Company
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

	[1]	[2]	[3]	[4]
Proxy Group of Six Natural Gas Distribution Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Atmos Energy Corporation	0.85	0.75	2.9055	0.0650
New Jersey Resources Corporation	0.95	0.92	3.0281	0.0678
NiSource Inc.	0.90	0.83	2.6617	0.0596
Northwest Natural Holding Company	0.85	0.71	3.3660	0.0753
ONE Gas, Inc.	0.85	0.71	3.2528	0.0728
Spire Inc.	0.85	0.74	3.1022	0.0694
Average	0.88	0.78	3.0527	0.0683
Beta Range (+/- 2 std. Devs. of Beta)	0.64	0.92		
2 std. Devs. of Beta	0.14			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.7845	3.3209		
Std. dev. of the Res. Std. Err.	0.1341			
2 std. devs. of the Res. Std. Err.	0.2682			

Source of Information: Value Line Proprietary Database, March 2024.

Washington Gas Light Company
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]
Proxy Group of Fifty-Two Non-Price Regulated Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
3M Company	0.95	0.90	2.8014	0.0627
Abbott Labs.	0.90	0.79	2.9435	0.0659
AbbVie Inc.	0.85	0.71	2.9836	0.0668
Agilent Technologies	0.95	0.86	2.8446	0.0636
Air Products & Chem.	0.90	0.84	3.0254	0.0677
Alphabet Inc.	0.90	0.80	3.1753	0.0710
Altria Group	0.85	0.76	2.8496	0.0638
Apple Inc.	0.95	0.90	3.1817	0.0712
Archer Daniels Midl'	0.95	0.90	3.2558	0.0728
Assurant Inc.	0.90	0.79	3.0402	0.0680
AutoZone Inc.	0.95	0.88	3.2696	0.0732
Booz Allen Hamilton	0.85	0.73	3.2604	0.0730
Brady Corp.	0.95	0.90	2.8700	0.0642
BWX Technologies	0.80	0.67	3.2423	0.0725
CACI Int'l	0.90	0.79	2.9988	0.0671
Casey's Gen'l Stores	0.90	0.79	3.1675	0.0709
Cencora	0.80	0.65	2.9558	0.0661
Cisco Systems	0.85	0.74	2.8338	0.0634
CSW Industrials	0.85	0.77	3.2757	0.0733
Danaher Corp.	0.90	0.81	3.0396	0.0680
Dolby Labs.	0.95	0.86	2.9431	0.0659
Exponent, Inc.	0.95	0.88	3.3207	0.0743
Fastenal Co.	0.90	0.79	2.9654	0.0664
Franklin Electric	0.90	0.82	2.9449	0.0659
GATX Corp.	0.95	0.90	2.9590	0.0662
Henry (Jack) & Assoc	0.85	0.74	3.1969	0.0715
Hunt (J.B.)	0.95	0.91	3.2879	0.0736
L3Harris Technologie	0.90	0.83	3.1265	0.0704
Landstar System	0.80	0.65	2.8850	0.0646
Lockheed Martin	0.85	0.74	2.8649	0.0641
McKesson Corp.	0.85	0.70	3.1414	0.0703
Microsoft Corp.	0.90	0.78	2.8521	0.0638
MSC Industrial Direc	0.90	0.84	2.9743	0.0666
Oracle Corp.	0.85	0.70	3.1087	0.0696
O'Reilly Automotive	0.90	0.84	3.0511	0.0683
OSI Systems	0.90	0.81	3.0233	0.0676
Packaging Corp.	0.95	0.85	2.8655	0.0641
Pfizer, Inc.	0.80	0.67	3.1656	0.0708
Philip Morris Int'l	0.95	0.87	2.8492	0.0638
Prestige Consumer	0.85	0.76	3.2454	0.0726
Selective Ins. Group	0.85	0.74	2.9866	0.0668
Sensient Techn.	0.90	0.84	2.8182	0.0631
Service Corp. Int'l	0.90	0.84	3.1819	0.0712
Sherwin-Williams	0.95	0.89	2.9050	0.0650
Smith (A.O.)	0.90	0.79	3.0917	0.0692
Thermo Fisher Sci.	0.85	0.76	2.8528	0.0638
UniFirst Corp.	0.90	0.81	3.0645	0.0686
UnitedHealth Group	0.95	0.91	3.1317	0.0701
Universal Corp.	0.80	0.68	3.2741	0.0733
VeriSign Inc.	0.90	0.80	2.8918	0.0647
Waters Corp.	0.95	0.85	3.1725	0.0710
Watsco, Inc.	0.85	0.77	3.1365	0.0702
Average	0.89	0.80	3.0441	0.0681
Proxy Group of Six Natural Gas Distribution Companies	0.88	0.78	3.0527	0.0683

Source of Information: Value Line Proprietary Database, March 2024.

Washington Gas Light Company
Summary of Cost of Equity Models Applied to
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Groups

Principal Methods	Proxy Group of Fifty-Two Non-Price Regulated Companies using Prospective Interest Rates		Proxy Group of Fifty-Two Non-Price Regulated Companies using Current Interest Rates	
Discounted Cash Flow Model (DCF) (1)	11.08	%	11.08	%
Risk Premium Model (RPM) (2)	12.53		12.33	
Capital Asset Pricing Model (CAPM) (3)	12.11		12.17	
Mean	11.91	%	11.86	%
Median	12.11	%	12.17	%
Average of Mean and Median	12.01	%	12.02	%

Notes:
(1) From pages 2 of this Exhibit.
(2) From page 3 of this Exhibit.
(3) From pages 6-7 of this Exhibit.

Washington Gas Light Company
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies and Proxy Group of Fifty-Two Non-Price Regulated Companies

Proxy Group of Fifty-Two Non-Price Regulated Companies	[1] Average Dividend Yield	[2] Value Line Projected Five Year Growth in EPS	[3] Zack's Five Year Projected Growth Rate in EPS	[4] Yahoo! Finance Projected Five Year Growth in EPS	[5] S&P Capital IQ Projected Five Year Growth in EPS	[6] Average Projected Five Year Growth Rate in EPS (1)	[7] Adjusted Dividend Yield	[8] Indicated Common Equity Cost Rate (2)	
3M Company	3.00 %	30.50 %	7.50 %	(4.86) %	(3.33) %	19.00 %	3.29 %	22.29 %	(3)
Abbott Labs.	2.02	4.00	9.00	7.50	7.67	7.04	2.09	9.13	
AbbVie Inc.	3.68	4.00	6.90	6.21	7.29	6.10	3.79	9.89	
Agilent Technologies	0.66	8.00	6.80	4.95	5.26	6.25	0.68	6.93	
Air Products & Chem.	2.90	10.50	7.50	6.58	10.48	8.77	3.03	11.80	
Alphabet Inc.	0.50	12.00	17.50	18.24	17.21	16.24	0.54	16.78	
Altria Group	8.98	6.00	3.20	3.39	3.76	4.09	9.16	13.25	
Apple Inc.	0.57	6.50	12.50	9.72	10.63	9.84	0.60	10.44	
Archer Daniels Midl'	3.28	7.50	NA	(4.20)	(2.85)	7.50	3.40	10.90	
Assurant Inc.	1.63	9.50	6.20	6.20	6.19	7.02	1.69	8.71	
AutoZone Inc.	-	12.50	13.20	11.65	14.83	13.05	-	NA	
Booz Allen Hamilton	1.38	8.50	13.70	13.70	11.66	11.89	1.46	13.35	
Brady Corp.	1.56	13.00	7.70	7.70	8.96	9.34	1.63	10.97	
BWX Technologies	1.01	6.50	9.40	2.49	10.44	7.21	1.05	8.26	
CACI Int'l	-	7.00	10.40	6.70	11.17	8.82	-	NA	
Casey's Gen'l Stores	0.54	11.00	9.70	10.31	9.74	10.19	0.57	10.76	
Cencora	0.87	6.50	10.70	9.34	10.03	9.14	0.91	10.05	
Cisco Systems	3.31	4.50	5.50	3.47	3.49	4.24	3.38	7.62	
CSW Industrials	0.35	12.50	15.00	12.00	15.00	13.63	0.37	14.00	
Danaher Corp.	0.43	7.00	8.60	7.52	7.93	7.76	0.45	8.21	
Dolby Labs.	1.47	9.50	NA	16.00	NA	12.75	1.56	14.31	
Exponent, Inc.	1.30	7.50	NA	15.00	NA	11.25	1.37	12.62	
Fastenal Co.	2.20	9.00	9.00	6.33	NA	8.11	2.29	10.40	
Franklin Electric	0.99	7.00	12.00	13.40	12.00	11.10	1.04	12.14	
GATX Corp.	1.76	11.50	NA	12.00	NA	11.75	1.86	13.61	
Henry (Jack) & Assoc	1.31	6.50	7.50	7.50	8.23	7.43	1.36	8.79	
Hunt (J.B.)	0.96	7.50	13.60	7.60	11.29	10.00	1.01	11.01	
L3Harris Technologie	2.18	9.50	9.20	9.22	9.16	9.27	2.28	11.55	
Landstar System	0.73	3.00	NA	12.00	11.00	8.67	0.76	9.43	
Lockheed Martin	2.77	9.50	4.10	3.48	2.73	4.95	2.84	7.79	
McKesson Corp.	0.46	8.00	13.60	11.76	12.40	11.44	0.49	11.93	
Microsoft Corp.	0.72	14.00	16.10	15.03	13.72	14.71	0.77	15.48	
MSC Industrial Direc	3.55	5.00	NA	9.12	NA	7.06	3.68	10.74	
Oracle Corp.	1.32	10.00	9.70	9.91	11.40	10.25	1.39	11.64	
O'Reilly Automotive	-	10.50	13.00	11.40	13.25	12.04	-	NA	
OSI Systems	-	10.50	11.00	8.00	11.50	10.25	-	NA	
Packaging Corp.	2.75	9.00	2.80	(14.29)	4.94	5.58	2.83	8.41	
Pfizer, Inc.	6.13	2.50	10.70	(0.49)	10.01	7.74	6.37	14.11	
Philip Morris Int'l	5.47	5.00	7.50	9.56	8.68	7.69	5.68	13.37	
Prestige Consumer	-	6.00	8.00	8.00	8.50	7.63	-	NA	
Selective Ins. Group	1.38	16.50	16.20	17.15	17.17	16.75	1.50	18.25	
Sensient Techn.	2.30	2.50	NA	3.80	15.00	7.10	2.38	9.48	
Service Corp. Int'l	1.68	5.50	10.10	12.00	10.12	9.43	1.76	11.19	
Sherwin-Williams	0.89	11.00	10.90	11.37	10.42	10.92	0.94	11.86	
Smith (A.O.)	1.49	9.00	9.00	10.00	10.00	9.50	1.56	11.06	
Thermo Fisher Sci.	0.27	6.00	9.90	6.82	9.30	8.01	0.28	8.29	
UniFirst Corp.	0.80	9.50	NA	7.80	NA	8.65	0.83	9.48	
UnitedHealth Group	1.54	12.00	12.50	12.92	10.29	11.93	1.63	13.56	
Universal Corp.	6.36	18.50	NA	NA	NA	18.50	6.95	25.45	(3)
VeriSign Inc.	-	12.50	NA	8.00	NA	10.25	-	NA	
Waters Corp.	-	6.50	5.30	5.54	6.45	5.95	-	NA	
Watsco, Inc.	2.45	9.00	NA	4.42	NA	6.71	2.53	9.24	

NA= Not Available

Mean	11.18 %
Median	10.97 %
Average of Mean and Median	11.08 %

Notes:

(1) Average of columns 2 through 5 excluding negative growth rates.

(2) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Groups. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of 05/31/2024. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, www.yahoo.com, and S&P Capital IQ (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

(3) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information: Value Line Investment Survey.
www.zacks.com, Downloaded on 05/31/2024
www.yahoo.com, Downloaded on 05/31/2024
S&P Capital IQ

Washington Gas Light Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Fifty-Two Non-Price Regulated Companies using Prospective Interest Rates	Proxy Group of Fifty-Two Non-Price Regulated Companies using Current Interest Rates
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	6.01 %	
2.	Current Yield on Baa2 Rated Corporate Bonds (2)		5.90 %
3.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (3)	(0.22)	(0.22)
4.	Adjusted Bond Yield	5.79	5.68
5.	Equity Risk Premium (4)	6.74	6.65
6.	Risk Premium Derived Common Equity Cost Rate	12.53 %	12.33 %

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated May 31, 2024 (see pages 7 and 8 of Exhibit WG (C)-4). The estimates are detailed below.

Second Quarter 2024	6.10 %
Third Quarter 2024	6.00
Fourth Quarter 2024	6.00
First Quarter 2025	5.90
Second Quarter 2025	5.90
Third Quarter 2025	5.90
2026-2030	6.10
2031-2035	6.20
Average	6.01 %

(2) Three-month average Baa2 corporate bond yield ended April, 2024 as reported by

May-24	5.95
Apr-24	6.00
Mar-24	5.75
Average	5.90 %

(3) The average yield spread of Baa2 rated corporate bonds over A2 corporate bonds for the three months ending May 2024. To reflect the A3 average rating of both Non-Price Regulated Proxy Groups, the yield on Baa corporate bonds must be adjusted by 2/3 of the spread between A2 and Baa2 corporate bond yields as shown below:

	A2 Corp. Bond Yield	Baa2 Corp. Bond Yield	Spread
May 2024	5.62 %	5.95 %	0.33 %
April 2024	5.67	6.00	0.33
March 2024	5.42	5.75	0.33
		Average yield spread	0.33
		2/3 of spread	0.22

(4) From page 5 of this Exhibit.

Washington Gas Light Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Fifty-Two Non-Price Regulated Companies

	Moody's Long-Term Issuer Rating May 2024		Standard & Poor's Long-Term Issuer Rating May 2024	
Proxy Group of Fifty-Two Non-Price Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
3M Company	A3	7.0	BBB+	8.0
Abbott Labs.	Aa3	4.0	AA-	4.0
AbbVie Inc.	A3	7.0	A-	7.0
Agilent Technologies	Baa1	8.0	BBB+	8.0
Air Products & Chem.	A2	6.0	A	6.0
Alphabet Inc.	Aa2	3.0	AA+	2.0
Altria Group	A3	7.0	BBB	9.0
Apple Inc.	Aaa	1.0	AA+	2.0
Archer Daniels Midl'	A2	6.0	A	6.0
Assurant Inc.	Baa2	9.0	BBB	9.0
AutoZone Inc.	Baa1	8.0	BBB	9.0
Booz Allen Hamilton	N/A	--	N/A	--
Brady Corp.	N/A	--	N/A	--
BWX Technologies	Ba3	13.0	BB	12.0
CACI Int'l	N/A	--	BB+	11.0
Casey's Gen'l Stores	N/A	--	N/A	--
Cencora	Baa2	9.0	BBB+	8.0
Cisco Systems	A1	5.0	AA-	4.0
CSW Industrials	N/A	--	N/A	--
Danaher Corp.	A3	7.0	A-	7.0
Dolby Labs.	N/A	--	N/A	--
Exponent, Inc.	N/A	--	N/A	--
Fastenal Co.	N/A	--	N/A	--
Franklin Electric	N/A	--	N/A	--
GATX Corp.	Baa2	9.0	BBB	9.0
Henry (Jack) & Assoc	N/A	--	N/A	--
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
L3Harris Technologie	Baa2	9.0	BBB	9.0
Landstar System	N/A	--	N/A	--
Lockheed Martin	A2	6.0	A-	7.0
McKesson Corp.	A3	7.0	BBB+	8.0
Microsoft Corp.	Aaa	1.0	AAA	1.0
MSC Industrial Direc	N/A	--	N/A	--
Oracle Corp.	Baa2	9.0	BBB	9.0
O'Reilly Automotive	Baa1	8.0	BBB	9.0
OSI Systems	N/A	--	N/A	--
Packaging Corp.	Baa2	9.0	BBB	9.0
Pfizer, Inc.	A2	6.0	A	6.0
Philip Morris Int'l	A2	6.0	A-	7.0
Prestige Consumer	N/A	--	BB	12.0
Selective Ins. Group	Baa2	9.0	BBB	9.0
Sensient Techn.	WR	--	NR	--
Service Corp. Int'l	Ba3	13.0	BB+	11.0
Sherwin-Williams	Baa2	9.0	BBB	9.0
Smith (A.O.)	N/A	--	N/A	--
Thermo Fisher Sci.	A3	7.0	A-	7.0
UniFirst Corp.	N/A	--	N/A	--
UnitedHealth Group	A2	6.0	A+	5.0
Universal Corp.	WR	--	BBB-	10.0
VeriSign Inc.	Baa3	10.0	BBB	9.0
Waters Corp.	N/A	--	N/A	--
Watsco, Inc.	N/A	--	N/A	--
Average	A3	7.3	BBB+	7.6

Notes:
(1) From page 4 of Exhibit WG (C)-4

Source of Information:
Bloomberg Professional Services.

Washington Gas Light Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Two Groups of Non-Price Regulated Companies of Comparable Risk to the
Proxy Group of Six Natural Gas Distribution Companies and Proxy Group of Fifty-Two Non-Price Regulated Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Fifty-Two Non-Price Regulated Companies using Prospective Interest Rates		Proxy Group of Fifty-Two Non-Price Regulated Companies using Current Interest Rates	
1.	Kroll Equity Risk Premium (1)	5.96	%	5.96	%
2.	Regression on Kroll Risk Premium Data	6.92	(2)	6.73	(3)
3.	Kroll Equity Risk Premium based on PRPM (4)	8.46		8.46	
4.	Equity Risk Premium Based on Value Line Summary and Index	6.91	(5)	6.76	(6)
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies	10.05	(7)	9.90	(8)
6.	Conclusion of Equity Risk Premium	7.66	%	7.56	%
7.	Adjusted Beta (9)	0.88		0.88	
8.	Forecasted Equity Risk Premium	6.74	%	6.65	%

Notes:
(1) From note 1 of page 6 of Exhibit WG (C)-4.
(2) From note 2 of page 6 of Exhibit WG (C)-4.
(3) From note 3 of page 6 of Exhibit WG (C)-4.
(4) From note 4 of page 6 of Exhibit WG (C)-4.
(5) From note 5 of page 6 of Exhibit WG (C)-4.
(6) From note 6 of page 6 of Exhibit WG (C)-4.
(7) From note 7 of page 6 of Exhibit WG (C)-4.
(8) From note 8 of page 6 of Exhibit WG (C)-4.
(9) Average of mean and median beta from page 6 of this Exhibit.

Sources of Information:
Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll.
Value Line Summary and Index.
Blue Chip Financial Forecasts, May 31, 2024
Bloomberg Professional Services.

Washington Gas Light Company
Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies and Proxy Group of Fifty-Two Non-Price Regulated Companies

Using Prospective Interest Rates

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	
Proxy Group of Fifty-Two Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (4)	
3M Company	0.95	1.02	0.99	8.59 %	4.41 %	12.92 %	12.94 %	12.93 %	
Abbott Labs.	0.90	0.82	0.86	8.59	4.41	11.80	12.10	11.95	
AbbVie Inc.	0.85	0.59	0.72	8.59	4.41	10.60	11.20	10.90	
Agilent Technologies	0.95	1.14	1.04	8.59	4.41	13.35	13.26	13.30	
Air Products & Chem.	0.90	0.84	0.87	8.59	4.41	11.89	12.16	12.02	
Alphabet Inc.	0.90	1.15	1.03	8.59	4.41	13.26	13.20	13.23	
Altria Group	0.85	0.62	0.74	8.59	4.41	10.77	11.33	11.05	
Apple Inc.	0.95	1.09	1.02	8.59	4.41	13.17	13.13	13.15	
Archer Daniels Midl'	0.95	0.71	0.83	8.59	4.41	11.54	11.91	11.72	
Assurant Inc.	0.90	0.78	0.84	8.59	4.41	11.63	11.97	11.80	
AutoZone Inc.	0.95	0.69	0.82	8.59	4.41	11.46	11.84	11.65	
Booz Allen Hamilton	0.85	0.84	0.84	8.59	4.41	11.63	11.97	11.80	
Brady Corp.	0.95	0.76	0.86	8.59	4.41	11.80	12.10	11.95	
BWX Technologies	0.80	0.80	0.80	8.59	4.41	11.28	11.71	11.50	
CACI Int'l	0.90	0.83	0.86	8.59	4.41	11.80	12.10	11.95	
Casey's Gen'l Stores	0.90	0.73	0.81	8.59	4.41	11.37	11.78	11.57	
Cencora	0.80	0.62	0.71	8.59	4.41	10.51	11.13	10.82	
Cisco Systems	0.85	0.78	0.81	8.59	4.41	11.37	11.78	11.57	
CSW Industrials	0.85	0.88	0.86	8.59	4.41	11.80	12.10	11.95	
Danaher Corp.	0.90	1.05	0.98	8.59	4.41	12.83	12.87	12.85	
Dolby Labs.	0.95	0.92	0.93	8.59	4.41	12.40	12.55	12.48	
Exponent, Inc.	0.95	1.02	0.98	8.59	4.41	12.83	12.87	12.85	
Fastenal Co.	0.90	0.99	0.95	8.59	4.41	12.57	12.68	12.63	
Franklin Electric	0.90	0.94	0.92	8.59	4.41	12.31	12.49	12.40	
GATX Corp.	0.95	0.93	0.94	8.59	4.41	12.49	12.62	12.55	
Henry (Jack) & Assoc	0.85	0.87	0.86	8.59	4.41	11.80	12.10	11.95	
Hunt (J.B.)	0.95	1.03	0.99	8.59	4.41	12.92	12.94	12.93	
L3Harris Technologie	0.90	0.91	0.91	8.59	4.41	12.23	12.42	12.33	
Landstar System	0.80	0.89	0.85	8.59	4.41	11.71	12.04	11.87	
Lockheed Martin	0.85	0.63	0.74	8.59	4.41	10.77	11.33	11.05	
McKesson Corp.	0.80	0.53	0.67	8.59	4.41	10.17	10.88	10.52	(5)
Microsoft Corp.	0.90	1.07	0.98	8.59	4.41	12.83	12.87	12.85	
MSC Industrial Direc	0.90	0.91	0.91	8.59	4.41	12.23	12.42	12.33	
Oracle Corp.	0.85	1.03	0.94	8.59	4.41	12.49	12.62	12.55	
O'Reilly Automotive	0.90	0.69	0.80	8.59	4.41	11.28	11.71	11.50	
OSI Systems	0.90	0.97	0.93	8.59	4.41	12.40	12.55	12.48	
Packaging Corp.	0.95	0.87	0.91	8.59	4.41	12.23	12.42	12.33	
Pfizer, Inc.	0.80	0.72	0.76	8.59	4.41	10.94	11.46	11.20	
Philip Morris Int'l	0.95	0.77	0.86	8.59	4.41	11.80	12.10	11.95	
Prestige Consumer	0.85	0.66	0.76	8.59	4.41	10.94	11.46	11.20	
Selective Ins. Group	0.85	0.55	0.70	8.59	4.41	10.42	11.07	10.75	
Sensient Techn.	0.90	1.02	0.96	8.59	4.41	12.66	12.74	12.70	
Service Corp. Int'l	0.95	0.83	0.89	8.59	4.41	12.06	12.29	12.18	
Sherwin-Williams	0.95	1.11	1.03	8.59	4.41	13.26	13.20	13.23	
Smith (A.O.)	0.90	1.05	0.97	8.59	4.41	12.74	12.81	12.78	
Thermo Fisher Sci.	0.85	1.02	0.94	8.59	4.41	12.49	12.62	12.55	
UniFirst Corp.	0.90	0.85	0.88	8.59	4.41	11.97	12.23	12.10	
UnitedHealth Group	0.95	0.48	0.72	8.59	4.41	10.60	11.20	10.90	
Universal Corp.	0.80	0.67	0.73	8.59	4.41	10.68	11.26	10.97	
VeriSign Inc.	0.90	0.99	0.95	8.59	4.41	12.57	12.68	12.63	
Waters Corp.	0.95	1.10	1.03	8.59	4.41	13.26	13.20	13.23	
Watsco, Inc.	0.85	1.21	1.03	8.59	4.41	13.26	13.20	13.23	
		Mean	0.88			11.96 %	12.22 %	12.12 %	
		Median	0.88			11.93 %	12.20 %	12.10 %	
		Average of Mean and Median	0.88			11.95 %	12.21 %	12.11 %	

Notes on page 7 of this Exhibit.

Washington Gas Light Company
Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies and Proxy Group of Fifty-Two Non-Price Regulated Companies

Using Current Interest Rates

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Fifty-Two Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (3)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (4)
3M Company	0.95	1.02	0.99	8.51 %	4.55 %	12.97 %	12.99 %	12.98 %
Abbott Labs.	0.90	0.82	0.86	8.51	4.55	11.86	12.16	12.01
AbbVie Inc.	0.85	0.59	0.72	8.51	4.55	10.67	11.27	10.97
Agilent Technologies	0.95	1.14	1.04	8.51	4.55	13.39	13.31	13.35
Air Products & Chem.	0.90	0.84	0.87	8.51	4.55	11.95	12.22	12.09
Alphabet Inc.	0.90	1.15	1.03	8.51	4.55	13.31	13.25	13.28
Altria Group	0.85	0.62	0.74	8.51	4.55	10.84	11.40	11.12
Apple Inc.	0.95	1.09	1.02	8.51	4.55	13.22	13.18	13.20
Archer Daniels Midl'	0.95	0.71	0.83	8.51	4.55	11.61	11.97	11.79
Assurant Inc.	0.90	0.78	0.84	8.51	4.55	11.69	12.03	11.86
AutoZone Inc.	0.95	0.69	0.82	8.51	4.55	11.52	11.91	11.71
Booz Allen Hamilton	0.85	0.84	0.84	8.51	4.55	11.69	12.03	11.86
Brady Corp.	0.95	0.76	0.86	8.51	4.55	11.86	12.16	12.01
BWX Technologies	0.80	0.80	0.80	8.51	4.55	11.35	11.78	11.57
CACI Int'l	0.90	0.83	0.86	8.51	4.55	11.86	12.16	12.01
Casey's Gen'l Stores	0.90	0.73	0.81	8.51	4.55	11.44	11.84	11.64
Cencora	0.80	0.62	0.71	8.51	4.55	10.59	11.20	10.90
Cisco Systems	0.85	0.78	0.81	8.51	4.55	11.44	11.84	11.64
CSW Industrials	0.85	0.88	0.86	8.51	4.55	11.86	12.16	12.01
Danaher Corp.	0.90	1.05	0.98	8.51	4.55	12.88	12.93	12.91
Dolby Labs.	0.95	0.92	0.93	8.51	4.55	12.46	12.61	12.53
Exponent, Inc.	0.95	1.02	0.98	8.51	4.55	12.88	12.93	12.91
Fastenal Co.	0.90	0.99	0.95	8.51	4.55	12.63	12.74	12.68
Franklin Electric	0.90	0.94	0.92	8.51	4.55	12.37	12.54	12.46
GATX Corp.	0.95	0.93	0.94	8.51	4.55	12.54	12.67	12.61
Henry (Jack) & Assoc	0.85	0.87	0.86	8.51	4.55	11.86	12.16	12.01
Hunt (J.B.)	0.95	1.03	0.99	8.51	4.55	12.97	12.99	12.98
L3Harris Technologie	0.90	0.91	0.91	8.51	4.55	12.29	12.48	12.38
Landstar System	0.80	0.89	0.85	8.51	4.55	11.78	12.10	11.94
Lockheed Martin	0.85	0.63	0.74	8.51	4.55	10.84	11.40	11.12
McKesson Corp.	0.80	0.53	0.67	8.51	4.55	10.25	10.95	10.60 (5)
Microsoft Corp.	0.90	1.07	0.98	8.51	4.55	12.88	12.93	12.91
MSC Industrial Direc	0.90	0.91	0.91	8.51	4.55	12.29	12.48	12.38
Oracle Corp.	0.85	1.03	0.94	8.51	4.55	12.54	12.67	12.61
O'Reilly Automotive	0.90	0.69	0.80	8.51	4.55	11.35	11.78	11.57
OSI Systems	0.90	0.97	0.93	8.51	4.55	12.46	12.61	12.53
Packaging Corp.	0.95	0.87	0.91	8.51	4.55	12.29	12.48	12.38
Pfizer, Inc.	0.80	0.72	0.76	8.51	4.55	11.01	11.52	11.27
Philip Morris Int'l	0.95	0.77	0.86	8.51	4.55	11.86	12.16	12.01
Prestige Consumer	0.85	0.66	0.76	8.51	4.55	11.01	11.52	11.27
Selective Ins. Group	0.85	0.55	0.70	8.51	4.55	10.50	11.14	10.82
Sensient Techn.	0.90	1.02	0.96	8.51	4.55	12.71	12.80	12.76
Service Corp. Int'l	0.95	0.83	0.89	8.51	4.55	12.12	12.35	12.24
Sherwin-Williams	0.95	1.11	1.03	8.51	4.55	13.31	13.25	13.28
Smith (A.O.)	0.90	1.05	0.97	8.51	4.55	12.80	12.86	12.83
Thermo Fisher Sci.	0.85	1.02	0.94	8.51	4.55	12.54	12.67	12.61
UniFirst Corp.	0.90	0.85	0.88	8.51	4.55	12.03	12.29	12.16
UnitedHealth Group	0.95	0.48	0.72	8.51	4.55	10.67	11.27	10.97
Universal Corp.	0.80	0.67	0.73	8.51	4.55	10.76	11.33	11.04
VeriSign Inc.	0.90	0.99	0.95	8.51	4.55	12.63	12.74	12.68
Waters Corp.	0.95	1.10	1.03	8.51	4.55	13.31	13.25	13.28
Watsco, Inc.	0.85	1.21	1.03	8.51	4.55	13.31	13.25	13.28
		Mean	0.88			12.03 %	12.28 %	12.18 %
		Median	0.88			11.99 %	12.26 %	12.16 %
		Average of Mean and Median	0.88			12.01 %	12.27 %	12.17 %

Notes:
(1) From note 1 of page 2 of Exhibit WG (C)-5
(2) From note 2 of page 2 of Exhibit WG (C)-5
(3) From note 3 of page 2 of Exhibit WG (C)-5
(4) Average of CAPM and ECAPM cost rates.
(5) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Washington Gas Light Company
Derivation of Investment Risk Adjustment Based upon
Kroll Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on May 31, 2024 (millions)	(times larger)	[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (1)	[3] Applicable Size Premium (2)	[4] Spread from Applicable Size Premium (3)
1.	Washington Gas Light Company (4)	$ 569.029		8	1.14%	
2.	Proxy Group of Six Natural Gas Distribution Companies (4)	$ 3,862.973	6.8 x	5	0.95%	0.19%

	[A] Decile	[B] Market Capitalization of Smallest Company (millions)	[C] Market Capitalization of Largest Company (millions)	[D] Size Premium (Return in Excess of CAPM)*
Largest	1	$ 36,942.976	$ 2,662,326.048	-0.06%
	2	14,910.719	36,391.113	0.46%
	3	7,493.607	14,820.048	0.61%
	4	4,622.261	7,461.284	0.64%
	5	3,011.224	4,621.785	0.95%
	6	1,864.293	3,010.806	1.21%
	7	1,050.083	1,862.491	1.39%
	8	555.880	1,046.037	1.14%
	9	213.039	554.523	1.99%
Smallest	10	1.576	212.644	4.70%

*From 2024 Kroll Cost of Capital Navigator

Notes:

(1) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(2) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(3) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.19% in Column [4], Line No. 2 is derived as follows 0.19% = 1.14% - 0.95%.
(4) From page 2 of this Exhibit.

Washington Gas Light Company
Market Capitalization of Washington Gas Light Company and the
Proxy Group of Six Natural Gas Distribution Companies and Proxy Group of Fifty-Two Non-Price Regulated Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2023 (millions)	[2] Book Value per Share at Fiscal Year End 2023 (1)	[3] Total Common Equity at Fiscal Year End 2023 (millions)	[4] Closing Stock Market Price on May 31, 2024	[5] Market-to-Book Ratio on May 31, 2024 (2)	[6] Market Capitalization on May 31, 2024 (3) (millions)
Washington Gas Light Company		NA	NA	400.161 (4)	NA		
Based upon Proxy Group of Six Natural Gas Distribution Companies						142.2 (5)	$ 569.029 (6)
Proxy Group of Six Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	148.493	$ 73.203	10,870.064	$ 115.920	158.4 %	$ 17,213.283
New Jersey Resources Corporation	NYSE	97.584	20.400	1,990.735	43.460	213.0	4,241.020
NiSource Inc.	NYSE	447.382	17.398	7,783.500	29.060	167.0	13,000.911
Northwest Natural Holding Company	NYSE	37.631	34.116	1,283.838	37.420	109.7	1,408.152
ONE Gas, Inc.	NYSE	56.546	48.914	2,765.877	61.630	126.0	3,484.925
Spire Inc.	NYSE	53.170	54.867	2,917.300	61.290	111.7	3,258.803
Median		77.065	$ 41.515	$ 2,841.589	$ 52.375	142.2 %	$ 3,862.973

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of Washington Gas Light Company on May 31, 2024 is assumed to be equal to the market-to-book ratio of the Proxy Group of Six Natural Gas Distribution Companies on May 31, 2024 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2023 Annual Forms 10K
yahoo.finance.com
Bloomberg Professional

Washington Gas Light Company
RRA Regulatory Rankings for the
Proxy Group of Six Natural Gas Distribution Companies

Operating Company	Parent	State	RRA Regulatory Ranking [1]	RRA Regulatory Ranking [1]
Atmos Energy	ATO	Colorado	Average / 1	6
Atmos Energy	ATO	Kansas	Below Average / 1	3
Atmos Energy	ATO	Kentucky	Average / 2	5
Atmos Energy	ATO	Louisiana	Average / 2	5
Atmos Energy	ATO	Mississippi	Above Average / 3	7
Atmos Energy	ATO	Tennessee	Above Average / 3	7
Atmos Energy	ATO	Texas	Average / 1	6
Atmos Energy	ATO	Virginia	Average / 1	6
New Jersey Natural Gas	NJR	New Jersey	Below Average / 1	3
Northern Indiana Public Service Company	NI	Indiana	Average / 1	6
Columbia of Kentucky	NI	Kentucky	Average / 2	5
Columbia of Maryland	NI	Maryland	Below Average / 2	2
Columbia of Ohio	NI	Ohio	Average / 2	5
Columbia of Pennsylvania	NI	Pennsylvania	Above Average / 2	8
Columbia of Virginia	NI	Virginia	Average / 1	6
Northwest Natural Gas	NWN	Oregon	Average / 2	5
Northwest Natural Gas	NWN	Washington	Average / 3	4
Kansas Gas Service	OGS	Kansas	Below Average / 1	3
Oklahoma Natural Gas	OGS	Oklahoma	Average / 3	4
Texas Gas Service	OGS	Texas	Average / 1	6
Spire Alabama Inc.	SR	Alabama	Above Average / 1	9
Spire Gulf Inc.	SR	Alabama	Above Average / 1	9
Spire Mississippi Inc.	SR	Mississippi	Above Average / 3	7
Spire Missouri East	SR	Missouri	Average / 3	4
Spire Missouri West	SR	Missouri	Average / 3	4

Proxy Group Company	Parent		RRA Regulatory Ranking [1]	RRA Regulatory Ranking [1]
Atmos Energy Corporation	ATO		Average / 1	5.63
New Jersey Resources Corporation	NJR		Below Average / 1	3.00
NiSource Inc.	NI		Average / 2	5.33
Northwest Natural Gas Company	NWN		Average / 2	4.50
ONE Gas, Inc.	OGS		Average / 3	4.33
Spire Inc.	SR		Above Average / 3	6.60
Proxy Group Average			Average / 2	4.90

Sources:
[1] Regulatory Research Associates, as of May 31st, 2024

Washington Gas Light Company
Summary of Adjustment Clauses & Alternative Regulation/Incentive Plans
Proxy Group of Six Natural Gas Distribution Companies

			Adjustment Clauses					Alternative Regulation / Incentive Plans		
Company	Parent	State	Gas Commodity	Decoupling (F/P) [1]	Capital Investment [2]	Energy Efficiency [3]	Other [4]	Formula-Based Rates	Earnings Sharing/PBR	Forward Test Year Allowed in Jurisdiction [5]
Atmos Energy	ATO	Colorado			✓					
Atmos Energy	ATO	Kansas	✓	P	✓		✓			
Atmos Energy	ATO	Kentucky	✓	P	✓		✓			✓
Atmos Energy	ATO	Louisiana	✓	P	✓			✓		✓
Atmos Energy	ATO	Mississippi	✓	P	✓			✓		K
Atmos Energy	ATO	Tennessee	✓	P	✓			✓		✓
Atmos Energy	ATO	Texas	✓	P	✓		✓	✓		K
Atmos Energy	ATO	Virginia	✓	P	✓		✓			✓
New Jersey Natural Gas	NJR	New Jersey		P	✓	✓				K
Northern Indiana Public Service Company, LL(	NI	Indiana	✓		✓	✓				K
Columbia Gas of Kentucky, Inc.	NI	Ohio	✓	P	✓	✓	✓			✓
Columbia Gas of Ohio, Inc.	NI	Ohio		P	✓	✓				✓
Columbia Gas of Pennsylvania, Inc.	NI	Pennsylvania	✓	P	✓					✓
Columbia Gas of Maryland, Inc.	NI	Pennsylvania	✓	P	✓	✓				✓
Columbia Gas of Virginia, Inc.	NI	Virginia	✓	P	✓	✓				✓
Northwest Natural Gas	NWN	Oregon	✓	P		✓			✓	✓
Northwest Natural Gas	NWN	Washington	✓			✓				K
Kansas Gas Service	OGS	Kansas	✓	P	✓			✓		
Oklahoma Natural Gas	OGS	Oklahoma	✓	P		✓		✓	✓	K
Texas Gas Service	OGS	Texas	✓	P	✓	✓	✓	✓		K
Spire Alabama Inc.	SR	Alabama	✓	P				✓		K
Spire Mississippi Inc.	SR	Mississippi	✓	P				✓		K
Spire Missouri Inc.	SR	Missouri	✓	P	✓		✓			K

Notes:
Note: A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category.
[1] Full or partial decoupling (such as Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs). All full or partial decoupling mechanisms include weather normalization adjustments.
[2] Includes recovery of costs related to infrastructure replacement, system integrity/hardening, and other capital expenditures.
[3] Utility-sponsored conservation, energy efficiency, or other demand side management programs.
[4] Pension expenses, bad debt costs, storm costs, transmission/transportation costs, environmental, regulatory fee, government & franchise fees and taxes, economic development, and low income programs.
[5] K = Known and Measurable or similar language, partially forecasted test years are included.
Sources: Company SEC Form 10-Ks; Operating company tariffs; Regulatory Research Associates.

ATTESTATION

I, DYLAN W. D'ASCENDIS, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

DYLAN W. D'ASCENDIS

7/19/2024

DATE

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

FORMAL CASE NO. 1180

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY
FOR AUTHORITY TO INCREASE EXISTING RATES
AND CHARGES FOR GAS SERVICE

VOLUME 2 OF 3

PUBLIC

DIRECT TESTIMONY
WG (D)

(WITNESS TUORINIEMI)

SUPPORTING EXHIBITS
WG (D)-1 THROUGH WG (D)-9

KAREN M. HARDWICK
SENIOR VICE PRESIDENT AND
GENERAL COUNSEL

JOHN C. DODGE
CATHY THURSTON-SEIGNIOUS
MEERA AHAMED
SPENCER NICHOLS
PAUL BUCKLEY

ATTORNEYS FOR

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1000 MAINE AVENUE, SW, SUITE 700
WASHINGTON, DC 20024
(202) 624-6722

DATED: AUGUST 5, 2024

WITNESS TUORINIEMI
EXHIBIT WG (D)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

PUBLIC VERSION

DIRECT TESTIMONY OF ROBERT E. TUORINIEMI
Exhibit WG (D)
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Exhibits

EXHIBIT WG (D)

PUBLIC

WASHINGTON GAS LIGHT COMPANY

District of Columbia

DIRECT TESTIMONY OF ROBERT E. TUORINIEMI

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Robert E. Tuoriniemi. I am the Chief Regulatory Accountant for Washington Gas Light Company, ("Washington Gas" or the "Company"). My business address is 6801 Industrial Road, Springfield, VA 22151.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I graduated from the University of Michigan in May 1978, with a Bachelor of Business Administration Degree with an emphasis in Accounting. From July 1978 through August 1988, I worked in the Detroit, Michigan, Houston, Texas and Minneapolis, Minnesota offices of Arthur Andersen & Co., independent public accountants. During that time, I managed audits and consulting projects for companies, including electric generation, transmission and distribution, gas transmission and distribution, telephone, and steam utilities. I also assisted in the preparation of testimony presented before several regulatory commissions.

After a brief period with a non-utility employer, I was employed in September 1989 as the Manager of Financial Reporting for Central Maine Power Company ("Central Maine"), an electric utility serving central and southern Maine. I was promoted to Comptroller in August 1995.

As Comptroller, I was Central Maine's Chief Accounting Officer and was responsible for all accounting activities, including internal and external financial reporting, preparation and filing of all tax returns, and cost of service computations.

I was hired by Washington Gas in September 1996 and elected Controller in October 1996. Since then, I have held positions as Executive Assistant to the Chief Financial Officer and Division Head for Cost of Service. In October 2004, I became the Chief Regulatory Accountant. During my employment at Washington Gas, I have had responsibility for internal and external financial reporting, tax return preparation and filing, preparation of the Company's budgets, cash processing, cost of service computations, long-range planning, and budgeting for Washington Gas. In 2019 and in 2021, utility revenue accounting and energy accounting, respectively, were added to my area of responsibility. In 2024, I also added utility derivative accounting and current asset management.

I am a Certified Public Accountant and a member of various state and national accounting organizations. I have also been a member of the American Gas Association Accounting Principles Committee and General Accounting Committee.

Q. HAVE YOU TESTIFIED PREVIOUSLY?

A. Yes. I testified before the Public Service Commission of the District of Columbia ("PSC of DC" or "Commission"), Public Service Commission of Maryland ("PSC of MD"), the State Corporation Commission of Virginia ("SCC of VA"), the Maine Public Utilities Commission and the Federal Energy Regulatory Commission ("FERC").

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to describe and support the test year "per book" amounts, the adjustments to reflect the distribution-only basis, the resulting distribution-only amounts, the ratemaking accounting adjustments, and the resulting ratemaking amounts and to show the calculation justifying the Company's request for a base rate increase of $45.6 million.[1]

The request includes $11.7 million related to the revenue requirement for the transfer of amounts being collected pursuant to the Company's District of Columbia accelerated replacement program through the PROJECT*pipes* surcharge to base rates.[2] The request also includes the impact of new depreciation rates included in the 2024 Depreciation Rate Study sponsored by Company Witness White.[3]

My computations reflect a ratemaking rate base of $761.0 million.[4] Multiplying that amount by the 7.874 percent overall rate of return developed by Company Witness Burrows generates a required return of $59.9 million. Adding this required return to total operating expenses, and adjusting the required return for income taxes, results in a level of required ratemaking revenues of

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[1] In Formal Case No. 1093, *In the Matter of the Investigation Into the Reasonableness of Washington Gas Light Company's Existing Rates and Charges for Gas Service*, Order No. 17132 at 150-151, the Commission directed Washington Gas to submit future rate case filings in such a manner that distribution-only rate base, revenue, and expenses (and any adjustments thereto) are easily discernible from the Company's other regulated matters, such as purchased gas and transmission rate base, revenues, and expenses.

[2] Formal Case No. 1115, A*pplication of Washington Gas Light Company for Approval of a Revised Accelerated Pipe Replacement Program,* Joint Motion and Unanimous Agreement of Stipulation and Full Settlement, at 12 (December 10, 2014).

[3] Exhibit WG (G), the Direct Testimony of Dr. Ronald E. White.

[4] PROJECT*pipes* rate base totaling $81.6 million is included in this total.

$257.2 million for the District of Columbia jurisdiction. Because existing rates will generate revenues of $211.6 million, the Company is requesting an increase to its base rate increase in annual base rate revenues of $45.6 million.

Q. ARE THERE ANY OTHER COST OF SERVICE MATTERS YOU ADDRESS IN THIS TESTIMONY?

A. Yes, there are. I address transactions with Washington Gas affiliates included in the test year, as well as the effect of ongoing merger commitments from Formal Case No. 1142 on the cost of service in this case. (See Section V. Transactions With Affiliates Included In The Test Year and Section IX. Merger-Related Commitments).

Q. CAN YOU PROVIDE A GENERAL OUTLINE OF THE DATA YOUR TESTIMONY COVERS AND THE CONCLUSION YOU REACH FROM ANALYZING THE DATA?

A. Yes, I can. This testimony supports the financial data referred to as the "District of Columbia Per Book" amounts, the adjustments to reflect the distribution-only basis, the resulting distribution-only amounts, the ratemaking accounting adjustments, and the resulting ratemaking amounts and shows the ratemaking adjustments and the financial data for the rate effective period. The financial data for the rate effective period (or "rate year") is labeled the "District of Columbia Ratemaking Amount." This financial data substantiates the Company's request for a $45.6 million annual base rate increase. This request for an increase is predicated on the following: (1) a test year consisting of the twelve months ended ("TME") March 31, 2024; (2) a rate effective period consisting of the TME July 31, 2026;[5] and (3) an overall rate of return of 7.874 percent, including a return on equity ("ROE") of 10.50 percent. It also includes the effects of an increase of $11.7 million related to the transfer of amounts being collected pursuant to the Company's District of Columbia accelerated replacement program through the PROJECT*pipes* surcharge to base rates.

Q. PLEASE SUMMARIZE THE REASONS FOR THE DEFICIENCY IN THE COMPANY'S NET OPERATING INCOME THAT CREATE THE NEED FOR AN INCREASE IN REVENUE AND RATES.

A. Washington Gas has a long-standing commitment to provide its customers with safe, reliable distribution service at just and reasonable rates, which provide a reasonable return to our investors. The Company's last base rate increase for its District of Columbia customers was based on a test year of the twelve months ended December 31, 2021, in Formal Case No. 1169.[6] The rates from Formal Case No. 1169 reflecting a $24.6 million[7] base rate revenue increase were placed into effect on January 19, 2024,[8] or more than 24 months after the end of the test year in that case.[9] Order No. 21939 in Formal Case No. 1169 provided for limited post-test year adjustments. When combined with the lengthy procedural schedule in Formal Case No. 1169, the continued

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[5] The Company is proposing a procedural schedule that would allow it to place new rates into effect in May 2025. The difference between that date and the rate effective period used to develop the ratemaking adjustments in this cost of service has little or no impact on Washington Gas's revenue requirement recommendation.

[6] Formal Case No. 1169, *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges For Gas Service*, Order No. 21939. (December 22, 2023)

[7] The Commission approved a gross revenue increase of $24.6 million, including $4.7 million PROJECTpipes surcharge revenue transfer to base rates.

[8] Formal Case No. 1169, Order No. 21942 (January 11, 2024)

[9] The test year ending March 31, 2024, does not include the full impact of the new rates approved in Formal Case No.1169. Exhibit WG (D)-1, page 1 of 4, column C, lines 21 and 27.

Commission practice of limiting adjustments that affect the rate effective period results in Washington Gas continuing to earn well below the return on equity of 9.65 percent established in Formal Case No. 1169.[10]

Drivers of the Revenue Requirement

Q. PLEASE QUANTIFY THE MAJOR DRIVERS OF THE REVENUE REQUIREMENT INCREASE IN THIS CASE.

A. Exhibit WG (D)-7 presents a reconciliation of the cost of service that underlies the rates approved in Formal Case No. 1169 compared with the cost of service presented in this case. Following is a summary of the items that drive the increase:

	($ in Millions)
Cost of Service Formal Case No. 1169	$ 204.2
Changes in Rate Base Components	
Formal Case No. 1169 Average to End of Period ("EOP")	0.9
Rate Base Net Additions (January 2022-March 2023) EOP	8.6
Test Year Rate Base Net Additions (Average)	4.7
Total Rate Base Changes	14.2
Changes in Net Operating Income Components	
Operation and Maintenance Expenses	9.7
Proposed New Depreciation Rates	7.7
Other Depreciation and Amortization Changes	3.8
General Taxes	8.4
Income Taxes	4.4

[10] Formal Case No. 1169, Order No. 21939, paragraph 2, page 1 (December 22, 2023).

Miscellaneous	0.3
Net Operating Income Changes	34.3
Changes in Cost of Capital Components	
Cost of Debt	1.7
Cost of Equity	2.6
Capital Structure	0.1
Cost of Capital Changes	4.4
Total Increase in Cost of Service	53.0[11]
Cost of Service Current Case	$ 257.2[12]

Q. PLEASE PROVIDE SOME PERSPECTIVE ON THE IMPACT OF THE COMMISSION'S REVENUE INCREASE GRANTED IN FORMAL CASE NO. 1169.

A. While I recognize the per book amounts only include a portion of the $24.6 million rate increase that went into effect on January 16, 2024, the return deficiency between the authorized 9.65 percent and the actual 3.55 percent is 6.10 percent. Using the Distribution[13] amounts only column of Exhibit WG (D)-1, page 1 of 4, column E, lines 20 and 26 which reflects the cost of service exclusive of gas costs, the earned return on equity was 0.52 percent. If I simply add Adjustment 1—Test Year Revenue Normalization to these amounts, I arrive at a return on equity of 2.94 percent. This latter number reflects the full annual revenue increase approved in Formal Case No. 1169 on a normal weather basis. After reflecting the full approved increase in Formal Case No. 1169, the revenue

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[11] The difference between the growth in the cost of service of $53.0 million and the $45.6 million increase in the revenue requirement represents increases in revenue since Formal Case No. 1169.
[12] Exhibit WG (D)-1, Page 1 of 4, line 1, column H.
[13] See the discussion below in Section IV. Summary of Testimony for a description of "Distribution Amounts."

increase required to achieve the 9.65 percent authorized return is $26.1 million. That is the revenue increase required simply to make the Company whole based only on its unadjusted distribution costs and normalized revenues at Formal Case No. 1169 rates.

Q. HAS WASHINGTON GAS COMMUNICATED THE SEVERITY OF ITS EARNINGS DEFICIENCY IN THE DISTRICT OF COLUMBIA TO THE COMMISSION?

A. Yes, it has on multiple occasions. Formal Case No. 1169 included substantial corroborating testimony addressing the challenges Washington Gas faces due to lack of timely recognition of costs in rates. The Commission did not modify its ratemaking practices sufficiently to address these challenges in its decision in Formal Case No. 1169. While Commission Order No. 21939 discusses the Commission's continued reliance upon historical ratemaking practices, it failed to recognize the resulting financial consequences those practices created and continue to create.

Consequently, the $24.6 million change in base rates granted in Formal Case No. 1169 does not remedy the severe under-earning the Company demonstrated it was experiencing in Formal Case No. 1169 and continues to experience today.

Further, based on the December 2023 Quarterly Earned Return report, the Company earned a return on equity of 0.78 percent on a distribution-only basis and 5.17 percent on a ratemaking basis.[14] The March 2024 Quarterly

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[14] WGRORETR2024, Washington Gas - Quarterly Report on Weather Normalized Jurisdictional Earned Return December 31, 2023-[CONFIDENTIAL] (February 29, 2024)

Earned Return report, showed the Company earned a return on equity of 1.03 percent on a distribution-only basis and 6.15 percent on a ratemaking basis.[15]

As Washington Gas has stated, a historical test year is not representative of costs the Company faces over one year later when rates are projected to go into effect for this case. In Formal Case No. 1162, rates went into effect one year and three months after the end of the test period in that case. In Formal Case No. 1169, rates went into effect two years after the end of the test period in that case.[16] As discussed by Company Witness Morrow in his Direct Testimony, the Company manages a large capital program for the District of Columbia. The District of Columbia, as it seeks to continually improve its community, asks companies within its boundaries to work to minimize their impact, imposing these policy costs on the Company and its customers. The Company contends with general inflation including salary and wage increases and as a result, it is impossible for rates based off an historical test year to reflect conditions one and one quarter years later. Given these factors, the Company is filing this rate case to ensure it has a fair opportunity to recover its costs.

Q. WHAT DOES THE HISTORICAL TREND IN PER BOOK AND RATEMAKING RETURN ON EQUITY REFLECT?

A. As shown in the table below, from Formal Case No. 1137[17] to the current case, the return on equity on both a per book and a ratemaking basis have trended downward. During the majority of the period, Washington Gas's

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[15] WGRORETR2024, Washington Gas - Quarterly Report on Weather Normalized Jurisdictional Earned Return March 31, 2023-[CONFIDENTIAL] (May 20, 2024).

[16] Formal Case No. 1169, Order No. 21939. (December 22, 2023).

[17] Formal Case No. 1137, *In The Matter Of The Application Of Washington Gas Light Company For Authority To Increase Existing Rates And Charges For Gas Service.*

authorized return on equity in the District of Columbia was 9.25 percent.[18] The Company never achieved this despite three rate cases during the period.[19]

Period[20]	Per Book ROE	Ratemaking ROE
Sep-2015[21]	10.70%	2.69%
Sep-2016	4.93%	-3.95%
Sep-2017	5.42%	4.44%
Sep-2018[22]	3.00%	7.62%
Dec-2019	5.04%	0.65%
Mar-2021[23]	0.13%	3.23%
Dec-2021[24]	3.31%	0.84%
Dec-2023[25]	3.99%	5.17%
Mar-2024[26]	3.55%	2.45%

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[18] Effective January 19, 2024, the authorized return on equity was 9.65 percent.

[19] Formal Case No. 1137, Formal Case No. 1162, and Formal Case No. 1169.

[20] Data provided for Formal Case No. 1137 and each of the fiscal year ends in 2017-2019. In 2019, the Company moved from a September fiscal year end to December year end. Year-end data was not assembled for 2020 during the pendency of Formal Case No. 1162.

[21] From Formal Case No. 1137 Exhibit WG (D)-1, page 1 of 4 REVISED 05-31-2016.

[22] In the Quarterly Report on Weather Normalized Jurisdictional Earned Return for the twelve months ended September 30, 2018, Washington Gas included a $6.9 million ratemaking adjustment ($5.0 million, net of income taxes) to lower operating expenses, to reflect the anticipated effect of the Commission's decision in Order No. 18712 in Formal Case No. 1137 at 92, that netted balances and fully amortized carrying charges on the pension and other postemployment benefits tracker through October 2019. Actual results for the subsequent period reflected the discontinuation of the carrying cost amortization. The reduction in expenses for the discontinuation of amortization of carrying costs was offset by increases in other costs as demonstrated by the per book ROE in the following period, the twelve months ended December 31, 2019, of 5.04 percent.

[23] For the twelve months ended March 2021, the increase in ROE from 0.13 percent, on a per books basis to 3.23 percent on a ratemaking basis is due to Washington Gas reflecting the $11.6 million annual effect of the April 1, 2021, implementation of new base rates approved in Formal Case No. 1162.

[24] Formal Case No. 1169, Exhibit WG (D)-1, page 1 of 4, line 27, columns D and G.

[25] WGRORETR2024. (February 29,2024).

[26] Exhibit WG (D)-1, page 1 of 4, line 27, columns C and G.

These actual results demonstrate that while the Company continues necessary capital investment to maintain the safety and reliability of our system, as well as contending with general inflation on our operating costs, there has been insufficient rate increases – both amount and frequency – to allow the Company to have a fair opportunity to earn its authorized return.

Q. IS THE SEVERITY OF THE UNDER-EARNINGS YOU PRESENTED ABOVE AMELIORATED BY CASH FLOW?

A. No, it is not. Even when non-cash expenses, such as depreciation, are added back to net income for the District of Columbia, cash flows from operating activities are still **negligible.**[27] During the test year on a per book basis, funds from operations and cash working capital provided only $0.1 million of cash and on a ratemaking basis provided $3.1 million of cash.

This is unusual and unexpected for a utility, where normally revenues and the depreciation expense added back should generate significant positive cash flow from operating activities. In the District of Columbia, the Company requires financing to cover operating activities as well as investing activities. Operating activities are not offsetting the financing needed for the Company's construction program. The Company's District of Columbia operations are requiring significant financing without providing an adequate return for that financing. This is not a sustainable situation.

[27] Exhibit WG (D)-6 presents the calculation of cash flows for the Company's District of Columbia operations on a standalone basis.

Returns in the District of Columbia

Q. DESCRIBE THE APPROACH THE COMPANY USED IN FORMAL CASE NO. 1169 IN AN ATTEMPT TO ADDRESS INSUFFICIENT RETURNS AND THE COMMISSION'S FINDING IN THAT REGARD.

A. In Formal Case No. 1169, the Company proposed forward-looking adjustments including reflecting Construction Work in Progress ("CWIP") in rate base, which the Company also recommended in Formal Case No. 1162. To provide Washington Gas a fair opportunity to earn its return on investment, the Company recommended including CWIP in rate base, with a discontinuation of the accrual for the Allowance for Funds Used During Construction ("AFUDC"). As a less preferable alternative to including CWIP in rate base, Washington Gas offered a modification to the computation of the AFUDC.

The Commission denied allowing CWIP in rate base in the test year because they concluded it does not meet its three-prong test.[28]

For proposed post-test-year Gas Plant in Service ("GPIS") and rate base additions through the rate-effective period, the Commission also rejected the inclusion of these projects because they also do not meet their three-prong test or were found to be well beyond a reasonable post-test year period.[29]

Q. WITHOUT THE OPPORTUNITY TO INCORPORATE CWIP AND POST-TEST YEAR EXPENDITURES, WHAT OPTION IS THE MOST READILY AVAILABLE FOR WASHINGTON GAS TO ADDRESS THE NEGATIVE IMPACT THE USE OF A HISTORICAL TEST YEAR WITH LIMITED POST-TEST YEAR

[28]Formal Case No. 1169, Order No. 21939, paragraph 130, page 41.
[29] Ibid, at paragraph 131, page 41.

ADJUSTMENTS HAS ON ITS ABILITY TO EARN ITS AUTHORIZED RETURN IN THIS CASE?

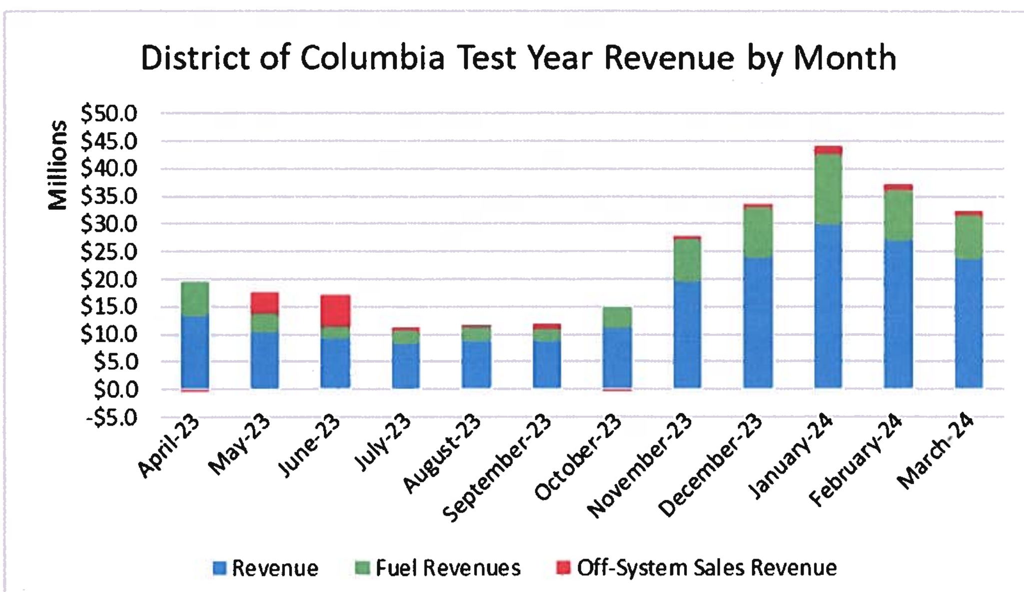
A. The best option is for Washington Gas to file more frequent base rate case applications. Washington Gas has chosen the filing of a new base rate case and seeks the Commission's decision as expeditiously as possible.

Weather Impacts on District of Columbia Results.

Q. PLEASE DISCUSS THE IMPACTS OF WEATHER ON CUSTOMER BILLS AND COMPANY REVENUES IN THE DISTRICT OF COLUMBIA.

A. Because the principal customer usage of natural gas in the District of Columbia is for space heating, under normal weather conditions usage is greatest in the months of October through May. Furthermore, this seasonal variability, as demonstrated in the Chart 1, can be affected greatly when weather conditions are colder or warmer than normal.

Chart 1



Q. PLEASE QUANTIFY THE IMPACT WEATHER HAS HAD ON DISTRICT OF COLUMBIA CUSTOMERS IN THE PAST.

A. The table below quantifies the effect on customer bills due to the variation in weather from normal levels.

	Therms	Revenues
Test Year	(20,633,914)	$(10,840,000)
2023	(36,926,442)	$(10,565,000)
2022	(12,955,647)	$ 1,900,000
2021	(33,741,584)	$ (6,288,000)
2020	(39,234,785)	$(12,619,000)
2019	(1,477,497)	$ (4,393,000)

Q. WHAT PROPOSAL IS WASHINGTON GAS REQUESTING TO ADDRESS THE IMPACTS OF WEATHER IN THIS PROCEEDING?

A. As discussed further below, Washington Gas is proposing the implementation of a Weather Normalization Adjustment ("WNA") to address the impact weather has on customer bills and Washington Gas' fair opportunity to earn its authorized return in the District of Columbia.

III. SUMMARY OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I am sponsoring nine (9) exhibits that have been prepared by me or under my direction and supervision.

Exhibit WG (D)-1, page 1 of 4, summarizes my cost of service presentation. This exhibit discloses the Company's per book results of operations in the District of Columbia during the test year ended March 31, 2024

(Column C) and summarizes the adjustments (Column D) necessary to reflect the Company's per book operations on a distribution-only basis, which is presented in the next column (Column E). The next column (Column F) summarizes the known and measurable ratemaking adjustments that are necessary to present the ratemaking basis and those required by the Company to continue providing the same level of safe and reliable service for Washington Gas customers. The next column (Column G) of Exhibit WG (D)-1 reflects the Company's ratemaking results of operations during the rate effective period prior to any revenue increase in this proceeding. The penultimate column (Column H) shows the requested revenue increase along with its related expense impacts. The final column (Column I) of Exhibit WG (D)-1, shows the resulting cost of service, assuming the Commission's approval of Washington Gas's revenue increase request.

Exhibit WG (D)-1, page 2 of 4, shows per book rate base, the adjustments to reflect the distribution-only amounts, the resulting distribution-only amounts, the ratemaking accounting adjustments, and the resulting ratemaking amounts.

Exhibit WG (D)-1, page 3 of 4, shows the distribution-only effect on the revenue increase and the calculation of the required revenue increase resulting from my cost of service presentation.

Exhibit WG (D)-1, page 4 of 4, shows the proposed cost of capital and was derived from the testimony of Company Witnesses Burrows and D'Ascendis.

Exhibit WG (D)-2, pages 1 and 2 of 3, is a summary of each distribution-only and ratemaking adjustment. I have included the adjustments supported by

Company Witness Smith, and Banks[30] in Exhibit WG (D)-3 so that all adjustments are presented in one exhibit.

Exhibit WG (D)-2, page 3 of 3, presents the effect on the revenue deficiency of each distribution-only and ratemaking adjustment.

Exhibit WG (D)-3 begins with a one-page table of contents listing each accounting adjustment. The table of contents is followed by Distribution-Only Adjustments 1D to 10D and Ratemaking Adjustments 1 to 32, the individual adjustments that are summarized on Exhibit WG (D)-2, pages 1 and 2 of 3. Exhibit WG (D)-3 is provided in PUBLIC and CONFIDENTIAL versions.

Exhibit WG (D)-4, is the reconciliation of the effective income tax rate per books and on a ratemaking basis.

Exhibit WG (D)-5, contains the detailed working papers supporting each of the proposed adjustments that Company Witness Smith, Banks, and I are sponsoring. Exhibit WG (D)-5, is provided in PUBLIC and CONFIDENTIAL versions.

Exhibit WG (D)-6, provides a computation of funds from operations ("FFO") and cash financing requirements using District of Columbia information contained in this filing. This information is used in my testimony as well as by Company Witness Burrows in her Direct Testimony.

Exhibit WG (D)-7, shows a reconciliation of the changes in the revenue requirement from the level approved in Formal Case No. 1169 to the revenue requirement in this case.

[30] See Exhibit WG (F) and Exhibit WG (E), respectively.

Exhibit WG (D)-8, provides the information required by 15 DCMR § 206.25, which includes a summary of each item of revenue and expense entering into the calculation of cash working capital and a complete copy of the lead-lag study.

Exhibit WG (D)-9a, provides a summary of the illustrative revenue calculation for the WNA, using test year information.

Exhibit WG (D)-9b, show the derivation of the revenue impact for the residential customer classes.

Exhibit WG (D)-9c, show the derivation of the revenue impact for the non-residential customer classes.

Exhibit WG (D)-9d, details how the Company converted actual test year calendar Heating Degree Days ("HDDs") to a cycle billing basis. All information in this exhibit is sourced from the National Oceanic and Atmospheric Administration ("NOAA").

Q. WHAT WAS THE BASIS OF THE ACTUAL RESULTS SHOWN IN YOUR SCHEDULES?

A. The basis for the Company's filing is the actual, "per book" financial position and results of operations recorded for the District of Columbia jurisdiction on the Company's accounting books and records for the test year covering the TME March 31, 2024.

Washington Gas maintains its accounting books and records following the Uniform System of Accounts prescribed by the FERC. The Company presents its financial statements in accordance with Generally Accepted Accounting Principles ("GAAP"). The Company's accounting books and records also follow the accounting rules and regulations of the various regulatory agencies, such as the PSC of DC.

Q. WHY DID THE COMPANY SELECT THE TME MARCH 31, 2024, AS ITS TEST PERIOD?

A. The Company selected the TME March 31, 2024, as its test year because it will be the most recently available period at the time of filing this base rate increase. June 30, 2024, financial statements are not available until August 2024. When adjusted to reflect the ratemaking adjustments that Company Witnesses Smith, Banks, and I discuss in our Direct Testimonies, the fully adjusted test period better represents the revenues and costs that the Company is likely to incur during the rate effective period. However, as I indicated earlier in this testimony, the lack of the Commission's consideration of forward-looking adjustments fails to provide Washington Gas a fair opportunity to recover its costs and earn its authorized return on equity.

Q. WHAT IS A "RATE EFFECTIVE PERIOD" AND WHAT IS THE RATE EFFECTIVE PERIOD ANTICIPATED BY THE COMPANY?

A. The term "rate effective period" represents the initial 12-month period that the rates set by the Commission in this proceeding will be fully in effect. Although the Company's request in its Application is to establish a procedural schedule that would implement the new rates by August 1, 2025, for purposes of determining the revenue requirement in this case, I am utilizing the TME July 31, 2026, as the rate effective period.[31]

[31] The Company is proposing a procedural schedule that would allow it to place new rates into effect in May 2025. The difference between that date and the rate effective period used to develop the ratemaking adjustments in this cost of service has little or no impact on Washington Gas's revenue requirement recommendation.

IV. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony supports the Company's request for a $45.6 million revenue increase for the Company's utility operations in the District of Columbia. It also summarizes the financial impacts of the computations, programs and initiatives described in the Direct Testimony of Company Witnesses Lawson and Raab, the proposed depreciation rates of Company Witness White, as well as the financial impacts of the capital structure and cost of capital testimony of Company Witnesses Burrows and D'Ascendis. My testimony and the Direct Testimony of Company Witnesses Smith, Banks and Bell describe the methodology and rationale for developing the adjustments to the test year financial results that are necessary to reflect known and measurable costs that the Company expects to incur during the rate effective period. This testimony also incorporates the new depreciation rates developed in the 2024 Depreciation Rate Study sponsored by Company Witness White. In addition, my testimony describes the computation of the revenue requirement and resulting revenue deficiency, based on the rate base, rate of return, and operating expenses for the rate effective period.

Q. PLEASE SUMMARIZE THE REVENUE INCREASE WASHINGTON GAS IS REQUESTING.

A. My computations reflect a ratemaking rate base of $761.0 million. Multiplying that amount by 7.87 percent overall rate of return developed by Company Witness Burrows generates a required return of $59.9 million. Adding this required return to total operating expenses, and adjusting the required return for income taxes, results in a level of required ratemaking revenues of

$257.2 million for the District of Columbia jurisdiction. Because existing rates will generate revenues of $211.6 million, the Company is requesting an increase to its annual base rate revenues of $45.6 million.

Q. DOES THE COMPANY PROPOSE ANY ADJUSTMENTS TO THE ACTUAL FINANCIAL POSITION AND RESULTS OF OPERATIONS FOR THE TEST YEAR ENDED MARCH 31, 2024?

A. Yes, it does. Company Witnesses Smith, Banks, Bell and I propose "Distribution-only" and Ratemaking Adjustments that are needed to make the financial position and results of operations for the test year ended March 31, 2024, representative of the financial position and results of operations that the Company expects to occur during the rate effective period ended July 31, 2026.[32] As Company Witnesses Smith, Banks and I discuss in more detail, these adjustments are made to reflect previous Commission Orders and precedents, which include the Commission decisions in Formal Case Nos. 989, 1016, 1093, 1137 and 1169.[33] It also includes the elimination of the financial effect of aberrations that may have occurred in the test period, such as the impact of warmer-than-normal weather consistent with the weather normalization approach previously approved by the Commission. Company Witness Bell addresses a recently issued Internal Revenue Service ("IRS") private letter ruling ("PLR") stating that a utility's net operating loss carryforward ("NOLC") cannot be reduced by tax allocation payments under the normalization rules.[34]

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[32] The Company is proposing a procedural schedule that would allow it to place new rates into effect in May 2025. The difference between that date and the rate effective period used to develop the ratemaking adjustments in this cost of service has little or no impact on Washington Gas's revenue requirement recommendation.
[33] Washington Gas's 2020 base rate case, Formal Case No. 1162, was settled.
[34] Bell Direct Exhibit WG (H).

V. WEATHER NORMALIZATION ADJUSTMENT

Q. AS BACKGROUND, PLEASE CLARIFY THE DIFFERENCE BETWEEN THE DISCUSSION IN WASHINGTON GAS ADJUSTMENT 1—TEST YEAR REVENUES AND REVENUE RELATED ADJUSTMENTS SPONSORED BY COMPANY WITNESS BANKS THAT ADDRESSES ADJUSTING TEST YEAR REVENUE TO REMOVE THE IMPACT OF VARIATIONS IN WEATHER FROM NORMAL LEVELS[35] AND THE WASHINGTON GAS PROPOSED WNA IN THIS CASE.

A. Adjustment 1—Test Year Revenues and Revenue Related Adjustments removes the effect variations in weather from normal levels had on test year revenues and therm deliveries thereby presenting them as levels the Company could expect to occur in the rate effective period. This adjustment is computed by calculating the Company's gross revenues for the delivery of gas, using the assumption that normal weather therm deliveries had occurred during the test period.

The proposed WNA is a rate design and billing mechanism that eliminates the variability of weather from the calculation of customer bills and revenues and offers customers more stability in their bills during colder-than-normal winter heating seasons.

Q. HAS WASHINGTON GAS PROPOSED A WNA TO THE COMMISSION IN THE PAST?

[35] Banks Direct Exhibit WG (E).

A. Yes it has. In Formal Case No. 1110,[36] Washington Gas requested the Commission approve a WNA using billing determinants from Washington Gas's then most recent base rate case, Formal Case No. 1093.[37] The Commission found that "the Company's filing outside of a base rate case is not properly before the Commission, and accordingly, the Application is denied..."[38] The merits of the proposed WNA were not addressed.

Q. DESCRIBE THE BENEFITS TO CUSTOMERS AND THE COMPANY OF THE PROPOSED WNA.

A. The proposed WNA benefits customers by stabilizing the non-gas portion of customers' rates through the implementation of a credit or charge to distribution charges in periods of volatile weather. As a result, customers will avoid higher than expected distribution charges due to colder-than-normal weather. Also, adoption of the WNA proposal will not reduce customers' incentive to use energy wisely. The WNA mechanism only applies to the Company's distribution rate. Because the commodity, or gas cost, portion of the bill comprises the majority of the total bill, customers continue to have a strong incentive to benefit from reducing their consumption where possible.

A WNA better aligns the Company's rate structure with its cost structure and would maintain Washington Gas's revenue level consistent with the revenue requirement established by the Commission in this rate case. As a natural gas local distribution company, Washington Gas experiences a high level of fixed

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[36] Formal Case No. 1110, *In the Matter of the Application of Washington Gas Light Company For Approval of a Weather Normalization Adjustment*, Application of Washington Gas Light Company for Approval of a Weather Normalization Adjustment (November 8, 2013).

[37] Formal Case No. 1093, *In the Matter of the Investigation Into the Reasonableness of Washington Gas Light Company's Existing Rates and Charges for Gas Service.*

[38] Formal Case No. 1110, Order No. 17850, at 16 (April 10, 2015).

costs; yet the Company's rate structure collects most of its revenues through volumetric charges. As I demonstrated earlier, customer volumes vary significantly depending on the time of year. Therefore, the manner in which costs are incurred does not match the way costs are recovered. A WNA would give the Company the ability to recover more of its costs consistent with how those costs are incurred, would protect the Company from the revenue impact of warmer-than-normal weather, and would protect customers from the revenue impact of colder-than-normal weather.

Q. WHAT IS THE RATIONALE FOR A WNA?

A. There are two primary reasons that justify consideration and approval of a WNA. First, the probability that sales levels will deviate from the Commission-established weather-normal sales level is virtually 100 percent. Without a WNA, there is certainty that one party (either the Company or District of Columbia customers) will be disadvantaged because of weather. Because sales levels are so dependent upon weather variations that are obviously outside of customer or Company control, it makes little sense to reward (or punish) the Company with higher revenues simply because it is colder than normal (warmer than normal).

Second, traditional rate structures have a mismatch between cost incurrence and the way customers are charged for service. The majority of the Company's costs to serve its customers can be characterized as "fixed" in the short run, *i.e.*, they are either customer-related or demand-related costs. In contrast, under current rates and normal weather, about 83 percent of the Company's distribution revenues are obtained through volumetric charges.[39]

[39] Exhibit WG (D)-5, Adjustment No. 1, Page 5 of 46.

There is a significant mismatch between the Company's cost and rate structures. As a result, minor variations in usage can have significant financial consequences for the utility.

Q. WHY IS IT IMPORTANT FOR A NATURAL GAS UTILITY TO SYNCHRONIZE ITS RATE STRUCTURE WITH ITS COST STRUCTURE?

A. Washington Gas, like every natural gas distribution utility, has three types of costs:

1. Customer-related costs—the costs that can be directly assigned to an individual customer (*e.g.*, meters, services, and regulators);
2. Demand-related costs—the costs that vary according to the customer's peak demand (*e.g.*, a portion of mains costs); and
3. Commodity-related costs—the costs that vary with usage (*e.g.*, gas costs and the cost of odorant).

Customer-related and demand-related costs are fixed for 40-50 years or more. Despite the high level of fixed costs, gas utility rate structures historically collect most of the resulting revenues through variable (volumetric) charges. As a result, there is a mismatch between cost-incurrence and cost recovery.

Q. WHAT TYPES OF MECHANISMS HAVE COMMISSIONS ADOPTED TO ADDRESS THE MISMATCH BETWEEN COST AND RATE STRUCTURES?

A. There are several mechanisms which address this issue to varying degrees. Because the basic issue is that the vast majority of non-gas costs for a natural gas local distribution company are fixed in nature, it is reasonable to alter the volumetric nature of billing distribution costs. Several states have addressed the issue in this direct fashion. The majority of states that have taken corrective action on this issue have chosen forms of decoupling, such as a

Revenue Normalization Adjustment ("RNA"),[40] like the mechanism in place for Washington Gas in its Maryland service territory. In Virginia, Washington Gas uses a combination of a WNA, to address the financial implications due to variations in customer usage due to weather, and a Conservation and Ratemaking Efficiency ("CARE") Plan, which contains a billing mechanism designed to minimize the effect of non-weather-related factors such as conservation on utility net revenues.

Q. WHAT DISTINGUISHES THE PROPOSED WNA FROM THE MARYLAND RNA AND VIRGINIA CARE MECHANISMS?

A. The principal difference is that the WNA **only** addresses the variance in usage of natural gas due to weather. The measure of normal weather HDDs[41] and usage variation per HDD will be approved by the Commission when it establishes the billing determinants in the case.

Consequently, the WNA is unaffected by energy efficiency programs or an adjustment for changes in consumption for whatever the reason. Proposing a normalization clause that only adjusts for changes in consumption due to weather will obviate any need to track changes in usage due to conservation or to discuss whether the customer conservation programs are readily available for natural gas customers.

The District of Columbia's clean energy goals, decarbonization activities, electrification progress, economic conditions or unusual or infrequent events

[40] The Maryland RNA is a regulatory billing mechanism in the state of Maryland designed to stabilize the level of net revenues collected from customers by eliminating the effect of deviations in customer usage caused by variations in weather from normal levels, and other factors such as conservation.
[41] An HDD is a measurement designed to quantify the demand for energy needed to heat a building. It is the number of degrees that a day's average temperature is below 65 degrees Fahrenheit, which is the temperature below which buildings need to be heated.

impacting consumption, such as the COVID-19 pandemic, have no bearing on the WNA computation. It is a simple mathematical comparison using the same billing determinants employed in the derivation of the revenue requirement in this case.

Q. WOULD THE ADOPTION OF A WNA DISCOURAGE CONSERVATION?

A. No, it would not. Actions taken to reduce or minimize usage through voluntary conservation will still positively impact a customer's bill. The reduced usage will result in a lower charge for both the distribution and gas components of the bill. The proposed WNA adjusts for the impact of changes in usage due to weather and does not impact changes in usage due to conservation efforts.

The WNA only applies to the distribution, or non-gas, component of rates. The gas cost component of a customer's bill would not be affected under the proposal. Gas costs still represent the majority of a customer's annual bill, even with the moderate cost of gas of recent years. Thus, even where changes in usage due to weather would adjust for the distribution, or non-gas revenues, it would not impact the gas component of a customer's bill. Customers that take actions to reduce or minimize their usage will see lower gas costs that they would have otherwise experienced.

Operation of the WNA

Q. DESCRIBE YOUR TESTIMONY ON THE PROPOSED WNA.

A. The purpose of this testimony is to describe and support the calculation of revenue collected under the proposed WNA. This testimony also supports the calculation of the WNA billing factor as described in the testimony of Company Witness Lawson.

Q. WHICH EXHIBITS SUPPORT YOUR WNA TESTIMONY?

A. Exhibit WG (D)-9a-d, which are described in the Summary of Exhibits below, support the Company's recommended WNA and demonstrate the revenue impact had the WNA been in effect during the test year.

Q. PLEASE SUMMARIZE THE OPERATION OF THE PROPOSED WNA.

A. In order to determine the revenues to refund or collect under the proposed WNA, I used the formulae and methodology consistent with how the Company's weather normalization adjustment in this case is calculated.[42] I propose using the HDDs that the Commission adopts in this case to represent normal HDDs. Company Witness Raab recommends the use of 3,729 HDDs in this case.[43] I use that HDD measure for illustrative purposes in this testimony to demonstrate the operation of the WNA. For the usage variation per HDD (or weather sensitivity), I have also used the coefficients calculated by Company Witness Raab in this case.[44] Those coefficients were the basis of the annual therms used in the calculation of volumetric distribution rates in this case.[45] The results of comparing actual HDDs with normal HDDs multiplied by a usage variation per HDD will yield the revenue that was either over-collected or under-collected due to variations in weather.[46] This amount would then either be refunded to or collected from customers as specified in the tariff provisions sponsored by Company Witness Lawson.

Q. PLEASE DESCRIBE THE CALCULATION OF WNA REVENUES.

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[42] Company Witness Banks sponsors Adjustment 1—Test Year Revenues and Revenue Related Adjustments (Exhibit WG (E).

[43] Direct Testimony of Paul H. Raab, Exhibit WG (N)-2.

[44] Exhibit WG (N)-4, Page 8 of 28, Schedule 2A, Normal.

[45] See Exhibit WG (O)-1, the Direct Testimony of Company Witness Lawson.

[46] The variation per HDD is computed by Customer Class, which recognizes inherent class usage differences.

A. The calculation would work in the same way that the Company calculates the normal weather adjustment in base rate cases based on the Commission approved normal weather HDDs in this case. (Washington Gas's computation reflects 3,729 HDDs). The formula below produces the required revenue adjustment due to weather variation:

Revenue = Number of Customers x HDD Variance from Normal x Usage Variation per HDD per Customer x Tariff Distribution Rate

In the computation, the number of customers would be determined based on the customers billed during the applicable heating season as reported by the Company's billing system. The HDD Variance and Variation per HDD components would be based on calculations consistent with the final decision in this case and more fully described below. The Tariff Distribution Rate is the final approved rate in the Company's tariff by customer class. The result of this calculation, the WNA revenue adjustment, would be the basis for determining refunds to be credited or collections to be billed to customers during the WNA billing adjustment period. As an example of how this calculation would work, I have prepared Exhibit WG (D)-9a-d that details the calculation for a sample period. In this case, I used the test year in the case, April 2023 through March 2024.

Q. HOW WOULD THE HDD VARIANCE BE CALCULATED?

A. The HDD Variance would be calculated by subtracting the actual HDDs during the heating season from the normal HDDs. The Company would use actual HDDs for the heating season as reported by NOAA for Ronald Reagan Washington National Airport on a calendar basis. Normal HDDs would be the normal weather HDDs adopted in this case. Washington Gas recommended 3,729 HDDs. The heating season would be defined as starting in October and concluding in May of the following year.

Because customers are billed on a cycle basis rather than a calendar month basis, the Company would convert calendar HDDs from NOAA for both actual and normal HDDs to a cycle billing basis. Company Witness Raab and the Company used the same process in this and all prior base rate case proceedings.[47] The Company would utilize its meter reading schedule that was used to determine normal weather in the case to convert daily HDD values to a billing month basis. In order to make this conversion, each meter read date would provide the number of actual HDDs billed on that cycle day. The total HDDs billed each cycle day in the month divided by the number of cycle days in the month would yield the actual cycle basis HDDs for a month. Exhibit WG (N)-2 and 3 details the conversion of calendar basis normal weather HDDs to a cycle basis as described here in the illustrative example based in the test year. Actual calendar and cycle HDDs are included in Exhibit WG (D)-9d.

Q. HOW WOULD THE VARIATION PER HDD BE CALCULATED?

A. The Company would use the variations per HDD that were the basis of the normal revenue adjustment adopted in the case. In the illustrative example these coefficients were calculated by month and customer class by Company Witness Raab as part of his normal weather computation.[48]

Q. DID THE COMMISSION ADOPT A SPECIFIC METHOD FOR CALCULATING VARIATION PER HDD IN FORMAL CASE NO. 1169?

[47] Exhibit WG (N)-2 (Calendar Normal) and Exhibit WG (N)-3 (Billing Normal).
[48] Exhibit WG (N)-4 (Raab Direct).

A. The Commission Order did not address the use of a specific approach to calculating the variation per HDD.[49] The Commission adopted Office of the People's Counsel for the District of Columbia ("OPC") Witness Dismukes' recommended normal weather adjustment, which incorporated the same variation per HDD[50] as Washington Gas's recommendation.[51] In this instant proceeding, the Company has used the normal weather HDDs and variations per HDD as put forward by Company Witness Raab as these are the basis of the normal weather revenues and normal weather therms used by the Company in this case. Using these inputs from the case makes the WNA calculation consistent with the normal weather revenue calculation in the case and billing determinants in this case.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. For the purpose of a WNA billing adjustment, the calculation of the revenues to be refunded or collected under the billing adjustment should utilize the formulas and methodology I have described here. The formulas and methodology presented would be equivalent to how the Commission adjusted revenues for normal weather in this proceeding.

Q. WHICH WASHINGTON GAS WITNESS DISCUSSES THE MECHANISM WASHINGTON GAS PROPOSES TO REFUND OR COLLECT THE WNA DIFFERENCES?

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[49] Formal Case No. 1169, Order No. 21939 (December 22, 2023).

[50] Formal Case No. 1169, Exhibit OPC (A)-9, Direct Testimony of David E. Dismukes, page 1 of 3 presents OPC's normal weather adjustment recommendation. See the supporting workpapers for Exhibit OPC (A)-9, tab "Sch 2A Reports(DC) (Alt)", column E.

[51] Formal Case No. 1169, Exhibit WG (N)-5, Direct Testimony of Paul H. Raab, page 8 of 28 Schedule 2A, column E.

A. Company Witness Lawson addresses the tariff provisions and the WNA. The WNA is designed so that during a colder-than-normal heating season, customers can receive the benefit of the WNA as soon as possible. In contrast, by accruing any revenue deficiency and spreading the adjustment over the following heating season, the Company can minimize any impact of a surcharge during higher usage (and higher bill) periods. Further, the asymmetric nature of this mechanism (immediate credits versus delayed charges) gives time-value of money consideration to customers.

Q. IS IT APPROPRIATE FOR WASHINGTON GAS TO ACCRUE CARRYING COSTS ON THE ACCUMULATED REVENUE DEFICIENCY?

A. Yes, it is. The proposed collection mechanism defers any accumulated deficiency incurred in one heating season and amortizes it over the following hearing season. Washington Gas proposed the mechanism to minimize the impact on customers. Consequently, Washington Gas will incur additional financing costs while the balance remains recoverable from customers. Including carrying cost on the uncollected balance provides a fair balance of interests between the Company and customers. Washington Gas proposes accruing carrying costs at the approved interest rate for short term debt included in the determination of the final revenue requirement in this case as its most closely represents the cost of financing seasonal costs.[52]

[52] Washington Gas proposed an interest rate on short-term debt of 4.48 percent. Exhibit WG (D)-1, page 4 of 4.

VI. TRANSACTIONS WITH AFFILIATES INCLUDED IN THE TEST YEAR

Q. PLEASE SUMMARIZE THE TEST YEAR CHARGES TO AND FROM AFFILIATES.

A. Company Witnesses Block, Quenum and Baryenbruch address transactions with affiliates. My testimony demonstrates how those costs are reflected in the development of the revenue requirement in this case.

Company Witness Quenum sponsors Exhibit WG (J)-1 which provides the Affiliate Cost of Service Study ("ACOSS") for the test year ending March 31, 2024, consistent with the requirement in Formal Case No. 1169.[53] The ACOSS provides a detailed listing of the charges provided by affiliates to Washington Gas and to affiliates by Washington Gas during the test year in this case, the 12 months ended March 31, 2024. The table that follows summarizes the transactions included in Exhibit WG (J)-3 during the test year on a system basis, by affiliate providing or receiving the service.

	Income Statement	Balance Sheet	Total
O&M Expense Before			
Affiliate Activity	$ 853,403,253		
Pass Through Amounts			
and Cash Payments[54]			
To Affiliates	(1,233,076)	$ (51,058,246)	$ (52,291,322)
From Affiliates	-	5,616,850	5,616,850
Net Pass Through Amounts	(1,233,076)	(45,441,396)	(46,674,472)
Services			

[53] Formal Case No. 1169, Order No. 21939, at 134, paragraph 465, (December 22, 2023) and Order No. 21959, at 12 (February 22, 2024).
[54] See Exhibit WG (J) for a discussion of pass-through amounts and cash payments.

Direct Assignment To Affiliates	-	(4,505,469)	(4,505,469)
Allocations to Affiliates	(1,528,400)	(3,340,618)	(4,869,018)
Direct Assignment From Affiliates			
AltaGas, LTD	1,845,186		1,845,186
SEMCO	748,675	-	748,675
Hampshire	12,006,572	-	12,006,572
Total Direct Assignment	14,600,433	-	14,600,433
Total Allocations From ALA	26,051,443	2,207,172	28,258,615
Net Services Received From			
(Provided to) Affiliates	39,123,476	(5,638,915)	33,484,561
Total Affiliate Transactions	37,890,400	$(51,080,311)	$(13,189,911)
Per Book O&M	$ 891,293,653		

Services provided to individual Affiliates by Washington Gas, excluding pass through amounts and cash payments are summarized in the table presented below:

Services Provided by Affiliates to Washington Gas

AltaGas, Ltd. ("ALA")	
Allocated	$ 26,051,443
Direct	1,845,186
SEMCO Energy Inc. ("SEMCO")	748,675
Hampshire Gas Company ("Hampshire")[55]	12,006,572
Total Services Provided by Affiliates	40,651,876

[55] Hampshire Gas Company provides storage service (a component of purchased gas) to Washington Gas under a FERC-approved tariff. Pursuant to Commission Order No. 17132 in Formal Case No. 1093, Washington Gas eliminates purchased gas in base rate cases. See Adjustment 1D—Purchased Gas Revenues and Costs and Gas Supplier Balancing Charges.

Amount Allocated to Affiliates	(1,528,400)
Net Services Provided by Affiliates	39,123,476
Services Provided to Affiliates by Washington Gas	
WGL Holdings, Inc. Affiliates:	
WGL Holdings, Inc.	241,367
Hampshire Gas Company	1,299,492
WGL Energy Services, Inc.	2,035,474
WGL Energy Systems	100,904
WGL Midstream MVP, LLC	106,929
SEMCO Energy Inc.	252,630
AltaGas Affiliates:	
AltaGas Services (U.S.) Inc.	837,148
AltaGas, Ltd.	675,244
All Other AltaGas Affiliates	89,727
Services Provided to Affiliates TOTAL	5,638,915
Net Service Provided to (by) Affiliates	$ 33,484,561

Q. PLEASE SUMMARIZE THE DISTRICT OF COLUMBIA SHARE OF SERVICES PROVIDED BY AFFILIATES AND HOW THEY ARE REFLECTED IN THE TEST YEAR IN THIS CASE.

A. During the test year in this case the **charges from affiliates for services** are reflected as follows:

Service/Account	System Amount	Factor	DC Amount
ALA			
Allocated			

Labor	920188	$ 16,058,651	19.5408%[56]	$ 3,137,989
Non-Labor	921001	9,992,792	19.5408%[57]	1,952,671
Total		26,051,443[58]		5,090,660
Direct Charges				
Labor	921000	93,386	19.5408%	18,249
Non-Labor	923000	1,751,800	18.6429%	326,586
Total		1,845,186		344,835
SEMCO				
Labor	921000	207,429	19.5408%	40,533
Non-Labor	923000	541,246	18.6429%[59]	100,904
Total		$ 748,675		$ 141,437
Hampshire				
Gas Purchased	805014	12,006,572[60]	14.7025%[61]	1,765,527
Total		$ 40,651,876		$ 7,342,459

Q. PLEASE DESCRIBE THE SERVICES PROVIDED BY SEMCO TO WASHINGTON GAS IN THE TEST YEAR.

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56 DC Factor—Comp_A&G. See Exhibit WG (F)-2, Schedule AL, Page 4 of 5, line 23, column H.

57 Ibid.

58 See Exhibit WG (J)-2— Schedule F—Amounts the Utility Allocated or assigned (Net Costs Billed To/From) for the Test Year, the Twelve Months Ending March 31, 2024, By Type of Cost, as follows:

Line/Col.	Description	Amount
18/H	ALA Corp Svcs – Labor	$ (889,152)
19/H	ALA Corp Svcs - Non Labor	(1,318,020)
51/L	ALA Corp Svcs – Labor	11,383,896
52?L	ALA Corp Svcs - Non Labor	16,874,719
	Total	$26,051,443

59 DC Factor—Three Part Factor. See Exhibit WG (F)-2, Schedule AL, Page 5 of 5, line 30, column H.

60 See Exhibit WG (J)-2— Schedule F—Amounts the Utility Allocated or assigned (Net Costs Billed To/From) for the Test Year, the Twelve Months Ending March 31, 2024, Line 57, Column B:

61 DC Factor—Firm_Weather_NW. See Exhibit WG (F)-2, Schedule AL, Page 1 of 5, line 2, column H.

A. As discussed in Order No. 21939, in 2023 Washington Gas insourced Accounts Payable processing to SEMCO.[62] The services provided by SEMCO to Washington Gas in the test year principally relates these Accounts Payable processing services, and other small amounts as shown in the following table:

Service	System	Factor[63]	DC
Accounts Payable	$ 712,845	18.8835%	$ 134,610
Talent Development	19,554	18.6649%	3,650
Executive	16,276	19.5228%	3,178
Total	$ 748,675		$ 141,437

Q. ARE THERE ANY **CHARGES TO AFFILIATES FOR SERVICES** RENDERED IN THE TEST YEAR REFLECTED IN THE COST OF SERVICE IN THIS CASE?

A. No, there are not. As demonstrated by Company Witness Quenum, the ACOSS properly excludes the costs related to services provided by Washington Gas in the development of the Jurisdictional Allocation Study sponsored by Company Witness Smith.[64]

VII. ADJUSTMENTS TO PER BOOK DATA

Q. PLEASE SUMMARIZE THE ADJUSTMENTS YOU ARE PROPOSING.

A. The index to Exhibit WG (D)-3 lists each adjustment in numerical order. Each of these adjustments is also summarized on Exhibit WG (D)-2, pages 1 and 2 of 3 and reflected on Exhibit WG (D)-2, page 3 of 3, which computes the revenue requirement impact of each individual adjustment. The column

[62] Formal Case No. 1196, Order No. 21939, at 88-89.
[63] Composite factors based on underlying accounts charged.
[64] Exhibit WG (F)-2.

headings of Exhibit WG (D)-2, page 3 of 3 denote the cost of service elements being adjusted. The dollar effect of each adjustment on its respective cost of service element is summarized in Exhibit WG (D)-2, page 3 of 3. Column I shows the effect of the adjustments on our revenue deficiency.

Q. WHAT IS THE STARTING POINT FOR YOUR COMPUTATIONS?

A. I begin with the District of Columbia per book amounts for rate base and net operating income that were derived through the jurisdictional allocation study, which is described further in Section VI—Jurisdictional Allocation Study in Company Witness Smith's Direct Testimony and related Exhibits.[65]

Q. WHY IS IT NECESSARY TO ADJUST PER BOOK FINANCIAL INFORMATION?

A. The results of any given test year provide a reasonable starting point to determine the revenues and expenses that will occur during the rate effective period. However, adjustments must be made to the Company's test year data to provide an accurate and equitable representation of the rate effective period.

"Distribution-Only" adjustments modify the per book amounts to remove any items that are unrelated to the development of distribution rates. They include items that are either recovered through other ratemaking mechanisms, such as the Purchased Gas Charge ("PGC"), or as part of another rate. Washington Gas has accumulated these in compliance with Commission Order No. 17132 in Formal Case No. 1093. The presentation used in this case shows distribution-only rate base, revenues, and expenses (and any adjustments thereto) so that they are easily discernible from the Company's other regulated matters.

[65] Exhibit WG (F)-2.

"Ratemaking" adjustments include items to remove the effect of aberrations included in the historical test period that are beyond the Company's control. The best example of a ratemaking adjustment is weather normalization, which eliminates the effect that warmer-than-normal or colder-than-normal weather, which may have occurred during the test period, had on the Company's revenues, income taxes, uncollectible accounts expense, and District of Columbia taxes. Historically, the Commission has set rates for Washington Gas based on a weather-normalized test year. Setting rates on a weather-normalized basis ensures that the Company's customers are neither burdened nor benefited by rates predicated on unusually low or high consumption levels. Company Witness Raab sponsors the normal weather study utilized in the Company's presentation in this case and discusses its development and preparation in Section V of his Direct Testimony.

In addition to the adjustments described above, the Company also makes ratemaking adjustments to the test year that reflect known and measurable changes that must be considered to match, as accurately as possible, the conditions that will exist in the rate effective period. By factoring in known and measurable ratemaking adjustments, the Commission can ameliorate the likelihood that the rates it sets for the rate effective period will be too low or too high.

Q. DO THE COMPANY'S RATEMAKING ADJUSTMENTS RECOGNIZE POTENTIAL INCREASES IN ITS CUSTOMER BASE AND THE ASSOCIATED REVENUES THAT COULD RESULT FROM INCREASED CAPITAL EXPENDITURES?

A. No, they do not. My proposed ratemaking adjustments reflect the increased cost of serving the Company's existing customer base. I am not proposing adjustments to recognize the revenue and cost impact of adding new customers.

VIII. DISTRIBUTION-ONLY ADJUSTMENTS

Q. PLEASE IDENTIFY THE DISTRIBUTION-ONLY ADJUSTMENTS PRESENTED BY WASHINGTON GAS IN THIS FILING.

A. Washington Gas is proposing the following Distribution-Only adjustments. Each adjustment is denoted with a "D" in its identifier.

- Adjustment 1D—Purchased Gas Revenues and Costs and Gas Supplier Balancing Charges
- Adjustment 2D—Uncollectible Gas Costs and Gas Administrative Charge Revenues
- Adjustment 3D—Gas Procurement Costs
- Adjustment 4D— Storage Gas Inventory and Storage Carrying Costs
- Adjustment 5D—Asset Optimization Revenues
- Adjustment 6D—Supplier Refunds
- Adjustment 7D—Purchase of Receivables
- Adjustment 8D—Interest on Debt
- Adjustment 9D—Cash Working Capital
- Adjustment 10D—District of Columbia and Federal Income Taxes

Purchased Gas Revenues and Costs and Gas Supplier Balancing Charges (Adjustment 1D)

Q. PLEASE DESCRIBE THE TYPES OF COSTS THAT ARE CLASSIFIED AS "PURCHASED GAS COSTS."

A. The term "purchased gas costs" is used to describe two broad categories of costs incurred by the Company—capacity costs and commodity costs. Capacity costs are the fixed amounts the Company pays to secure the capability to move gas to its city-gate for ultimate delivery to its customers. These costs are composed of fees paid to pipeline suppliers for transportation and storage service necessary to meet customers' demands for gas when needed.

Q. PLEASE SUMMARIZE ADJUSTMENT 1D—PURCHASED GAS REVENUES AND COSTS AND GAS SUPPLIER BALANCING CHARGES.

A. To present the cost of service in this case on a "distribution-only" basis, I removed the District of Columbia per book gas cost recovery amounts of $66.1 million as well as the per book cost of gas of $66.1 million.

Q. DID YOU MAKE ANY ADJUSTMENTS TO MISCELLANEOUS REVENUES TO REFLECT AMOUNTS THAT ARE RECOVERED FROM CUSTOMERS THROUGH OTHER EXISTING RECOVERY MECHANISMS?

A. Yes, I did. Included in the $66.1 million is $6.6 million of balancing charge revenues received from third-party marketers because these revenues are credited to customers via the PGC and the Actual Cost Adjustment ("ACA") in the Company's approved tariffs.

Uncollectible Gas Costs and Gas Administrative Charges (Adjustment 2D)

Q. PLEASE DISCUSS ADJUSTMENT 2D—UNCOLLECTIBLE GAS COSTS AND GAS ADMINISTRATIVE CHARGES ("GAC").

A. Washington Gas General Service Provision No. 16 (II) (9)—Purchased Gas Charge provides that each computed Purchased Gas Charge be adjusted to provide for the recovery of uncollectible accounts expense through a fixed GAC. The fixed GAC amount is calculated by dividing the uncollectible accounts expense related to firm sales service gas revenue calculated in the Company's latest rate case divided by the number of normal weather sales service therms. In addition, the GAC includes the purchased gas administration costs for PGC-related expenses.

Q. PLEASE DISCUSS THE GAS ADMINISTRATIVE CHARGES PORTION OF THE ADJUSTMENT.

A. The Gas Administrative Charges portion removes the per book GAC revenues included in test year revenues of $1.7 million, which are recovered as a component of the cost of gas included in the Purchased Gas Charge and not through base rates. To present distribution-only revenues and costs these amounts must be eliminated. The $1.7 million includes revenues collected for the Gas Procurement Costs discussed in Adjustment 3D below.

GAC Uncollectible Accounts Expense Recovery	$ 1,773,001
GAC Gas Procurement Expense Recovery	(78,171)
Totals	$ 1,694,830

Q. HOW IS ADJUSTMENT 2D—UNCOLLECTIBLE GAS COSTS RELATED TO GAS ADMINISTRATIVE CHARGES?

A. Adjustment 2D—Uncollectible Gas Costs removes $1.7 million of uncollectible accounts expense in an amount equal to the revenues removed for Gas Administrative Charges less the gas procurement costs removed in Adjustment 3D. These operating expenses are recovered through the GAC and therefore must also be eliminated to present results on a distribution-only basis. As discussed further in Adjustment 1—Revenues, sponsored by Company Witness Banks, Adjustment 2 separately adjusts uncollectible gas costs to reflect adjustments to distribution revenues and the historical net charge off rate consistent with Commission practice.

Gas Procurement Costs (Adjustment 3D)

Q. PLEASE DISCUSS ADJUSTMENT 3D—GAS PROCUREMENT COST.

A. In Formal Case No. 1093, the Commission determined that purchased gas administrative expenses (*i.e.*, hedging, purchasing, and billing costs) should be removed from the determination of the Company's distribution revenue and collected with gas costs through the PGC.[66]

Q. PLEASE QUANTIFY THE RATEMAKING ADJUSTMENT YOU ARE PROPOSING.

A. I have removed the District of Columbia's allocated share of the $463,159 of gas supply expenses from the cost of service in this proceeding, totaling $78,171.

Storage Gas Inventory and Storage Carrying Costs (Adjustment 4D)

Q. PLEASE DESCRIBE THE PORTION OF ADJUSTMENT 4D RELATED TO STORAGE GAS INVENTORY.

A. Adjustment 4D eliminates the storage gas inventory balance of $16,895,300 from rate base, which is consistent with prior cases and the Commission Order on this issue in Formal Case No. 1093.[67] These costs are attributable to sales service customers only and removed as part of this

[66] Order No. 17132 at 60-61.
[67] Order No. 17132 at 23.

adjustment. Storage gas carrying costs are recovered as part of the PGC provision with an annual reconciliation in the ACA.

Q. PLEASE EXPLAIN THE PORTION OF ADJUSTMENT 4D RELATED TO STORAGE CARRYING COSTS.

A. The revenue amount of $1,558,766 consisting of carrying costs on storage gas inventory and ACA amounts, has been eliminated from ratemaking revenues because it is recovered through the PGC/ACA and not base rates.

Asset Optimization Revenues (Adjustment 5D)

Q. WHAT HAVE YOU PROPOSED REGARDING ASSET OPTIMIZATION REVENUES?

A. Washington Gas generates revenues through asset optimization activities. I have eliminated, as a ratemaking adjustment, the District of Columbia's $14.2 million share of the asset optimization revenues as it is unrelated to distribution service. This is consistent with the treatment approved by the Commission in Formal Case Nos. 989, 1016, 1093, 1137 and 1169. Because these activities do not relate to distribution service, they must be removed from the cost of service computations.

Supplier Refunds (Adjustment 6D)

Q. PLEASE DESCRIBE ADJUSTMENT 6D—SUPPLIER REFUNDS.

A. Adjustment 6D—Supplier Refunds removes the District of Columbia's share of the per book balance of supplier refunds totaling $626,315 from rate base and the District of Columbia's share of the per book amount of interest on supplier refunds totaling $11,533, consistent with the Commission's approved treatment in Formal Case Nos. 989, 1016, 1093, 1137 and 1169 because these amounts are refunded through the PGC mechanism.[68]

Purchase of Receivables (Adjustment 7D)

Q. PLEASE EXPLAIN ADJUSTMENT 7D—PURCHASE OF RECEIVABLES ("POR").

A. Adjustment 7D—Purchase of Receivables removes all of the amounts included in the test year that are recovered from competitive gas suppliers relating to the purchase of receivables, which was approved in Formal Case No. 1140.

Q. PLEASE DESCRIBE YOUR ADJUSTMENT.

A. Related to rate base, I removed $770,154 of property, plant, and equipment (software), and the related reserve for depreciation of $356,329 relating to the POR implementation costs.

As reflected in the table below, for items related to revenues, I am removing discount rate revenues received from the competitive gas suppliers and the late payment fees on the purchased receivables, which total $1,097,063. Both of these items are incorporated in Adjustment 1—Revenues, sponsored by Company Witness Banks. POR-related expense adjustments total $523,388 as detailed below.

Late Payment Charges	$ (360,143)
Discount Revenues	(736,920)
Total Revenue Adjustments	$(1,097,063)
Implementation Costs Amortization	$ (97,980)

[68] Order No. 17132 at 23.

Incremental Collection Expense	(226,115)
Uncollectible Accounts Expense	(141,274)
Interest Expenses	(58,019)
Total Expense Adjustments	$ (523,388)

Interest on Debt (Adjustment 8D)

Q. PLEASE EXPLAIN ADJUSTMENT 8D—INTEREST ON DEBT.

A. Adjustment 8D reflects the amount needed to adjust the test year interest expense to the distribution-only level using the weighted cost of debt presented by Company Witness Burrows, applied to the distribution-only level of net rate base. The computation determines the total amount of interest expense, which is a deductible item in determining taxable income.

To compute the amount, I multiplied the weighted-average debt component of the capital structure times the distribution-only level net investment. This computation generated a distribution-only level of interest expense of $18,811,557.[69] The per book interest expense was $19,142,496 generating a $330,939 distribution-only adjustment to decrease interest expense in the income tax computation.

Adjustment 29—Interest on Debt, discussed below further, adjusts interest on debt to synchronize the taxes on interest resulting from the changes in rate base due to ratemaking adjustments.

Cash Working Capital (Adjustment 9D)

Q. PLEASE EXPLAIN ADJUSTMENT 9D—CASH WORKING CAPITAL.

[69] $ $796,176,491 X 2.36%= $18,811,557.

A. I have performed a lead/lag study which is the basis for the Company's inclusion of a cash working capital allowance of $39.9 million in rate base on a distribution only basis. All lead/lag amounts, excepting gas costs and revenue lag, are updated every 5 years, and were prepared as of December 2020. The Company updates the Revenue Lag and Gas Purchase Lead quarterly. Consequently, the study reflects the most recent updates for those two items as of March 2024. Exhibit WG (D)-8, provides a narrative discussion of the lead/lag methodology. The full description of the history of the methodology is discussed below in Adjustment 30—Cash Working Capital. Adjustment 9D develops the Company's distribution-only cash working capital allowance consistent with the Commission's methodology established in Formal Case No. 1016 and used in Formal Case Nos. 1093, 1137 and 1169 by adjusting the per book amounts for the distribution-only adjustments. The total of the lead/lag and account analysis components results in a distribution-only cash working capital allowance of $39,871,701 which, when compared to the per book cash working capital allowance of $39,219,091, results in a ratemaking adjustment of $652,610 to increase rate base.

District of Columbia and Federal Income Taxes (Adjustment 10D)

Q. PLEASE EXPLAIN ADJUSTMENT 10D—DISTRICT OF COLUMBIA AND FEDERAL INCOME TAXES.

A. I have adjusted District of Columbia income taxes to reflect the change in taxable income that resulted from the distribution-only adjustments to revenues and expenses and the synchronization of interest that I discuss in this testimony using the District of Columbia tax rate of 8.25 percent.

I have also adjusted federal income taxes to reflect the change in taxable income that resulted from the distribution-only adjustments to revenues and expenses and the synchronization of interest that I discuss in this testimony. Federal tax expense is computed at the statutory federal tax rate of 21.00 percent applied to federal net taxable income.

Q. PLEASE SUMMARIZE THE ADJUSTMENTS RELATED TO INCOME TAXES INCLUDED IN YOUR DISTRIBUTION-ONLY COST OF SERVICE PRESENTATION.

A. The following table accumulates the income tax adjustments into three categories which are reflected in Exhibit WG (D)-2 page 3 of 3:

Net Operating Income	$ (4,505,581)
Interest Synchronization	91,066
Tax Adjustments[70]	1,325,038
Total	$ (3,089,477)

Adjustment 31—District of Columbia and Federal Income Taxes computes the income tax impact of all of the Ratemaking Adjustments discussed below.

IX. RATEMAKING ADJUSTMENTS

Q. PLEASE IDENTIFY THE ADJUSTMENTS SUPPORTED BY COMPANY WITNESS BANKS.

[70] Tax adjustments reflect the effect of stating District of Columbia taxes at the composite District of Columbia and federal tax rate of 27.52 percent.

A. Company Witness Banks supports Adjustment 1—Revenues, which reflects ratemaking adjustments associated with reflecting the effect of normal weather and includes the following components:

Revenues.

Uncollectible Gas Accounts.

Sustainable Energy and Energy Assistance Trust Fund.

District of Columbia Delivery Tax and Rights-of Way Fees.

Q. PLEASE IDENTIFY THE ADJUSTMENTS SUPPORTED BY COMPANY WITNESS SMITH.

A. Company Witness Smith supports the following employee wages and salaries and labor-related adjustments:

- Adjustment 5—Wages and Salaries
- Adjustment 6—Long-Term Incentive Elimination
- Adjustment 7—Other Post-Employment Benefit ("OPEB") Costs
- Adjustment 8—Pension Expense
- Adjustment 9—401(k) Employer Contributions
- Adjustment 10—Executive Fringe Elimination
- Adjustment 11—Medical Inflation
- Adjustment 12—FICA/Medicare Taxes
- Adjustment 13—Involuntary Separation Expense Reduction

I discuss the remaining ratemaking and pro forma adjustments that the Company is proposing in this case. In addition, I assemble in my exhibits all the adjustments, including those supported by Company Witnesses Smith, Banks, and Bell to facilitate their review.

PLANT-RELATED ADJUSTMENTS

Q. PLEASE SUMMARIZE THE PLANT-RELATED ADJUSTMENTS INCLUDED IN THIS CASE.

A. The plant-related adjustments comprise three elements: (1) removal from rate base of the test year average balance of CWIP, (2) adjustments to reflect the transfer of PROJECT*pipes* amounts from the surcharge to base rates, and (3) the incorporation of new proposed depreciation rates reflected in the 2024 Depreciation Rate Study sponsored by Company Witness White. The adoption of the new proposed depreciation rates affects the depreciation expense, accumulated depreciation and accumulated deferred income taxes ("ADIT") impacts of the PROJECT*pipes* transfer from the surcharge to base rates. That impact is computed in Adjustment 4—New Depreciation Rates.

Plant-Related Adjustment Summary (Adjustments 2 through 4)

Q. PLEASE DISCUSS THE PLANT-RELATED ADJUSTMENTS IN THIS CASE.

A. The table below presents a summary of the plant related adjustments in this case.

	CWIP[71]	PROJECT *pipes*	Depreciation Rate Study[72]	Total
Total Rate Base	$(66,213,700)	$ 9,165,984[73]	$ (4,863,354)	$(61,911,070)
.Operating Expense	$ -	$ 231,158[74]	$ 7,691,665	$ 7,922,823

CWIP (Adjustment 2)

Q. PLEASE DISCUSS THE CWIP PORTION OF THESE ADJUSTMENTS.

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[71] See Adjustment 2—CWIP.
[72] See Adjustment 4—New Depreciation Rates.
[73] Comprises Adjustment 3—PROJECT*pipes* GPIS and CWIP; Reserve for Depreciation and PROJECT*pipes* ADIT.
[74] See Adjustment 3—PROJECT*pipes* Depreciation Expense.

A. Adjustment 2—CWIP removes from rate base $66.2 million representing the test year average balance of CWIP, excluding the $13.1 million of CWIP related to PROJECT*pipes*, which is discussed in Adjustment 3—PROJECT*pipes* GPIS and CWIP, below.

Q. DID THE COMMISSION CONSIDER ALTERNATE TREATMENTS OF CWIP IN FORMAL CASE NO. 1169?

A. Yes it did; however, the Commission declined to change its policy and rejected Washington Gas's recommendation to include CWIP in rate base.[75]

PROJECT*pipes* Plant-Related Adjustment Summary

Q. PLEASE DEFINE "PROJECT*PIPES*."

A. PROJECT*pipes*, as used in this case, reflects the costs related to the Commission's approval, plus the approved extensions, of the Company's Accelerated Pipe Replacement Plan. The Company is authorized to recover the costs through a tariff surcharge mechanism called the Accelerated Pipe Replacement Plan ("APRP") billed to customers monthly.[76]

Q. PLEASE SUMMARIZE ADJUSTMENT 3—PROJECT*PIPES* AVERAGE TO END OF PERIOD REFLECTED IN WASHINGTON GAS'S REVENUE REQUIREMENT IN THIS CASE.

A. The revenue requirement in this case reflects plant-related adjustments for the PROJECT*pipes* transfers from the surcharge. The table below summarizes the adjustments.

Rate Base Adjustments

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[75] Formal Case No. 1169, Order No. 21939 , at 39-42.

[76] Formal Case No. 1115, *In the Matter of Washington Gas Light Company's Request for Approval of a Revised Accelerated Pipe Replacement Program*, Order No. 17431.

GPIS	$ 27,107,163
CWIP	(6,223,998)
Depreciation Reserve[77]	(3,681,961)
ADIT	(8,035,220)
Total Rate Base Adjustments	$ 9,165,984
Operating Expense Adjustments	
Depreciation Expense	$ 231,158

PROJECT*pipes* GPIS and CWIP (Adjustment 3)

Q. HOW DID THE COMMISSION TREAT PROJECT*PIPES* EXPENDITURES IN FORMAL CASE NO. 1169?

A. Order No. 21939 in Formal Case No. 1169 included a net rate base adjustment for PROJECT*pipes* totaling $39,425,224.[78] The total comprises $53,787,550 of PROJECT*pipes* expenditures incurred as of December 31, 2021, on an end of period basis, together with the related depreciation and deferred income tax effects.[79] The Commission allowed test year CWIP that was placed into service at November 2022.

Q. HOW ARE THE PROJECT*PIPES* AMOUNTS APPROVED IN ORDER NO. 21939 IN FORMAL CASE NO. 1169 REFLECTED IN THE TEST YEAR IN THIS CASE?

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[77] Includes COR and the depreciation reserve.

[78] Order No. 21939 at 84.

[79] Source: Data Request No. 1169, WGL Response to Commission Data Request No. 3-4 at 4-5 (September 22,2023)

Gas Plant In Service	$ 48,181,568
Cost of Removal ("COR")	5,605,982
PROJECT*pipes* In Service	53,787,550
Accumulated Depreciation	(1,043,464)
ADIT	(13,318,862)
Project Pipes In Service Net Rate Base	$ 39,425,224

A. They are appropriately included in March 2024 test year rate base and operating expenses and therefore no test year adjustment is necessary to reflect their transfer for recovery from the PROJECT*pipes* surcharge to base rates related to Formal Case No. 1169.

Q. WITH THAT BACKGROUND, PLEASE SUMMARIZE ADJUSTMENT 3 RELATED TO PROJECT*PIPES* EXPENDITURES YOU ARE PROPOSING TO TRANSFER FROM THE CURRENT SURCHARGE TO BASE RATES IN THIS CASE.

A. Adjustment 3 reflects adjustments of test year amounts related to PROJECT*pipes* incurred as of March 31, 2024, from average to end-of-period amounts.[80] This is the same approach approved by the Commission in Formal Case No. 1169.

	CWIP	COR	GPIS	Total
Rate Base				
Test Year Average	$ 13,108,574	$ 10,419,701	$ 80,506,896	$104,035,171
End of Period	6,884,576	8,327,576	107,614,059	122,826,211
Plant Costs	$ (6,223,998)	$ 2,092,125	$ 27,107,163	22,975,290
Reserve for Depreciation				(1,589,836)
ADIT				(8,035,220)
Total				$ 9,165,984
Operating Expenses				
Depreciation Expense				$ 231,158

[80] Exhibit WG (D)-5, Adjustment No. 3, Page 2 of 2.

Q. PLEASE DISCUSS THE COMPONENT OF ADJUSTMENT 3—PROJECT*PIPES* GPIS AND CWIP TO ADJUST THE PLANT BALANCES FROM AN AVERAGE BASIS TO AN END OF PERIOD BASIS.

A. Consistent with the approach adopted in Formal Case Nos. 1137 and 1169, and the Stipulation in Formal Case No. 1162, the PROJECT*pipes* component is necessary to transfer the costs incurred related to the Accelerated Replacement Plan from recovery via the approved PROJECT*pipes* surcharge to base rate recovery. The test year amounts are presented using averages. Additionally, the test year amounts move from CWIP to completed plant over the course of the year as individual projects are placed into service. Cost of removal ("COR") has no construction period and is recorded as an increase in net plant as incurred.[81] To facilitate a clean transfer from the surcharge, the amounts are reflected in base rates at end of period amounts. This will ensure that there will be no potential for recovery of costs in both base rates and the surcharge. Equally, this will make it easy to verify the end of period amounts that have been removed from the surcharge.

Consistent with Order No. 21939, I have included CWIP amounts for PROJECT*pipes* as the surcharge is based on total expenditures.[82]

Q. PLEASE DISCUSS THE PROJECT*PIPES* COMPUTATIONS IN THE ADJUSTMENT.

A. Since the last base rate case, net additions to gas plant in service, CWIP and COR related to PROJECT*pipes* totaled $104,035,171 on an average rate

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[81] COR is recorded as a debit to accumulated depreciation, which lowers accumulated depreciation and increases rate base.

[82] Formal Case No. 1115 Settlement Agreement, Section 1 Surcharge Mechanism.

base basis. The cumulative PROJECT*pipes* net costs as of March 31, 2024, the end of the test year, were $122,826,211. Therefore, I reflected a $18,791,040 increase to plant in service to reflect PROJECT*pipes* at end of test year amounts ($122,826,211 - $104,035,171 = $18,791,040).

Q. IN FORMAL CASE NOS. 1137 AND 1169, THE COMMISSION ONLY ALLOWED PROJECT*PIPES* CWIP PLACED INTO SERVICE BY THE TIME OF THE HEARINGS IN RATE BASE. HOW WILL YOU ADDRESS THAT IN THIS CASE?

A. During the Rebuttal phase of this case, Washington Gas will update the individual projects that comprise the PROJECT*pipes* CWIP to quantify the amount placed in service. Additionally, at the time of the hearings, Washington Gas will be able to provide a second quantification of any additional PROJECT*pipes* CWIP placed into service. Any remaining amounts will remain in the PROJECT*pipes* surcharge until Washington Gas files its next base rate case.

PROJECT*pipes* Depreciation Expense (Adjustment 3)

Q. PLEASE EXPLAIN ADJUSTMENT 3, THE RATEMAKING ADJUSTMENT FOR THE APPROPRIATE LEVELS OF DEPRECIATION RELATED TO PROJECT *PIPES*.

A. I am proposing a $231,158 ratemaking level increase to depreciation expense. This updated adjustment reflects the effect of transfers of the PROJECT*pipes* property from the surcharge totaling $107,614,058. This updated ratemaking level adjustment recognizes the anticipated depreciation expense that the Company will reflect on its accounting books and records during the rate effective period.

I multiplied the depreciation expense for the last period of the test year by twelve to derive the ratemaking level of depreciation expense totaling $2,950,160. Subtracting the per book depreciation expense of $2,719,002, I calculated depreciation expense on the end-of-period adjustment for PROJECT*pipes* in a total adjustment of $231,158 ($2,950,160 - $2,719,002 = $231,158).

Additionally, Adjustment 4—New Depreciation Rates reflects an increase in depreciation expense reflecting the application of the proposed depreciation rates from the 2024 Depreciation Rate Study, submitted in this proceeding by Company Witness White. Applying the 2024 Depreciation Rate Study to plant balances generates a depreciation expense increase of $7,755,586.

PROJECT*pipes* Reserve for Depreciation (Adjustment 3)

Q. PLEASE EXPLAIN THE PROJECT*PIPES* RESERVE FOR DEPRECIATION COMPONENT.

A. The depreciation expense from above has been included as an adjustment to the accumulated depreciation reserve. In addition, the reserve for depreciation has been adjusted to reflect the end-of-period reserves (including the incurred cost of removal) for PROJECT*pipes* to synchronize the depreciation reserve with the end-of-period plant discussed above.

PROJECT*pipes* ADIT (Adjustment 3)

Q. PLEASE DISCUSS THE ADJUSTMENTS TO ADIT INCLUDED IN ADJUSTMENT 3.

A. The final component of the PROJECT*pipes* adjustment reflects an increase in accumulated deferred income taxes of $8,035,220 to adjust the accumulated deferred income tax balance related to the PROJECT*pipes* plant roll-in in Adjustment 3— PROJECT*pipes* GPIS and CWIP.

New Depreciation Rates Summary (Adjustment 4)

Q. PLEASE SUMMARIZE THE APPLICATION OF THE NEW DEPRECIATION RATES SPONSORED BY COMPANY WITNESS WHITE TO TEST YEAR GPIS AND PROJECT*PIPES*.

A. The table below summarizes the application of the proposed new depreciation rates to rate base and operating expenses related to test year plant and PROJECT*pipes*.

	Test Year	PROJECT *pipes*	Total
Rate Base Adjustments			
Depreciation Reserve	$ 3,877,793	(63,921)	$ 3,813,872
ADIT	1,067,071	(17,589)	1,049,482
Total Rate Base Adjustments	$ 4,944,864	$ (81,510)	$ 4,863,354
Operating Expense Adjustments			
Depreciation Expense	$ 7,755,586	$ (63,921)	$ 7,691,665

Q. PLEASE DISCUSS THE ADJUSTMENTS RELATED TO WASHINGTON GAS'S RECOMMENDATION TO MODIFY ITS EXISTING DEPRECIATION RATES.

A. In Order No. 17789, in Formal Case No. 1115, the Commission directed Washington Gas to conduct a new depreciation study and file it at least 90 days prior to the filing of each of two new base rate cases. On October 26, 2015, the Company filed the first of these studies, *i.e.*, a 2015 Depreciation Rate Study for the District of Columbia.

In Formal Case No. 1137, the Commission ordered "WGL shall file a new depreciation study at least 90 days before WGL's next rate case and shall revisit its policy to allocate 16.5 percent of the cost of main and service replacements to cost of removal in developing its new depreciation study."[83] On October 8, 2019, the Company filed a 2019 Depreciation Rate Study for the District of Columbia in accordance with the Commission's directives in Formal Case Nos. 1115 and 1137.

In Formal Case No. 1162, the Company incorporated the new depreciation rates developed in that 2019 Depreciation Rate Study into its cost of service presented therein. However pursuant to the Non-Unanimous Agreement of Stipulation and Full Settlement ("Settlement Agreement"), filed December 8, 2020 (Attachment A) the settling parties agreed there would be no change to Washington Gas's depreciation rates in that proceeding.[84] Washington Gas did not propose a change to depreciation rates in Formal Case No. 1169.

New Depreciation Rates—Depreciation Expense

Q. PLEASE EXPLAIN THE COMPONENT OF ADJUSTMENT 4—NEW DEPRECIATION RATES RELATED TO DEPRECIATION EXPENSE.

A. I am proposing a $7,691,665 ratemaking level increase to depreciation expense reflecting the application of the proposed depreciation rates from the 2024 Depreciation Rate Study, This updated ratemaking level adjustment recognizes the anticipated depreciation expense that the Company will reflect on

[83] Formal Case No. 1137, Opinion and Order No. 18712 at 153 (March 3, 2017).

[84] Formal Case No. 1162, *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*, Order No. 20705, paragraph 8, page 4 (February 24, 2021).

its accounting books and records during the rate effective period using the depreciation rates reflected in the 2024 Depreciation Rate Study.

I applied the composite functional depreciation rates from the 2024 Depreciation Rate Study for storage, transmission, distribution, and general property to the plant balances before the incorporation of the PROJECT*pipes* adjustments discussed previously to determine the updated ratemaking level adjustment. This generated an updated ratemaking level of depreciation expense totaling $37,298,462. Subtracting the per book depreciation expense of $29,542,876, from the depreciation expense at new rates of $37,298,462 generates an adjustment of $7,755,586.

Separately, I calculated the reduction to depreciation expense of applying the new depreciation rates on the end-of-period adjustment for PROJECT*pipes* resulting in an adjustment of $(63,921). The combination of the test year and PROJECT*pipes* depreciation expense adjustments for the adoption of the new proposed depreciation rates is $7,691,665. ($7,755,586 - $63,921= $7,691,666).

New Depreciation Rates—Reserve for Depreciation

Q. PLEASE EXPLAIN THE RESERVE FOR DEPRECIATION COMPONENT OF ADJUSTMENT 4.

A. The depreciation expense from the adoption of the new proposed depreciation rates computed in the previous section have been included as an adjustment to the accumulated depreciation reserve of $3,877,793. In addition, the reserve for depreciation has been adjusted by $(63,921) to reflect a new proposed depreciation rate effect on the end-of-period reserves for PROJECT*pipes*.

The combination of the test year and PROJECT*pipes* depreciation expense adjustments on the reserve for depreciation for the adoption of new proposed depreciation rates is $3,813,872. ($3,877,793 - $63,921 = $3,813,872).

New Depreciation Rates—ADIT

Q. PLEASE DISCUSS THE ADJUSTMENTS TO ADIT INCLUDED IN ADJUSTMENT 4—NEW DEPRECIATION RATES.

A. ADIT is a derivative computation that needs to be synchronized with the impact changes in depreciation expense and accumulated depreciation have on income tax temporary differences. The test year components of Adjustment 6—New Depreciation Rates from the adoption of the new proposed depreciation rates adjustments for depreciation expense and accumulated depreciation components of Adjustment 4—New Depreciation Rates generates an ADIT impact of $1,067,072. In addition, ADIT has been adjusted by $(17,589) to reflect a new proposed depreciation rate effect for PROJECT*pipes*.

The combination of the test year and PROJECT*pipes* depreciation expense and reserve for depreciation for the adoption of the new proposed depreciation rates is $1,049,482 ($1,067,072 - $17,589 = $1,049,482).

LABOR AND LABOR RELATED ADJUSTMENTS

Employee Wages, Salaries and Labor Related Adjustments (Adjustments 5 through 13)

Q. DO YOU HAVE ANY COMMENTS ON ADJUSTMENTS 5 THROUGH 13?

A. Company Witness Smith supports employee wages, salaries, and labor related Adjustments 5 through 13. I have incorporated the results of these adjustments into the overall computation of the revenue requirement in my testimony. Additionally, I have included a copy of the adjustments in Exhibit WG (D)-3. As with the forecasted rate base adjustments and the pro forma operating expense adjustments I discuss below, the labor adjustments are an integral part of determining an adequate and reasonable rate year cost of service.

PRO FORMA ADJUSTMENTS (NON-LABOR)

Involuntary Separation Cost to Implement Amortization (Adjustment 14)

Q. PLEASE DISCUSS ADJUSTMENT 14—INVOLUNTARY SEPARATION COST TO IMPLEMENT AMORTIZATION.

A. As discussed in the Direct Testimony of Company Witness Steffes, the Company's Involuntary Separation Program resulted in the reduction in Washington Gas's headcount. Company Witness Smith discusses the impact the headcount reduction will have on labor and related costs.

In order for the Company to generate the benefits shared with customers in this case, the Company incurred costs to implement the initiative. Examples of these types of costs include severance costs, accrued incentive compensation Consolidated Omnibus Budget Reconciliation Act ("COBRA") medical and dental benefits, and outplacement benefits and certain consultant costs.

These costs are an integral part of the action that generated the benefits; however, they occurred prior to benefits they generate. To properly align these costs and benefits, the Company is proposing that incremental costs incurred that are a result of the action that generated the benefits be amortized for ratemaking purposes over a 5-year period.

Q. PLEASE SUMMARIZE THE COSTS TO IMPLEMENT THE INVOLUNTARY SEPARATION.

A. The total cost incurred to implement the Involuntary Separation and the District of Columbia share of those costs are as follows:

Severance	$ 4,479,772
Short-term Incentives	144,628
COBRA	730,291
Outplacement Services	32,000
Paid Time Off	360,408
Consulting Services	1,216,372
Other (security, etc.)	35,112
Total Cost to Implement	6,998,583
Amortization Period	5
Costs to Achieve Amortization	1,399,717
District of Columbia Labor Factor	19.3618%[85]
District of Columbia Share	$ 271,011

Certain other costs such as the effects on pensions and postretirement benefits expenses are not reflected above because they have not been determined and they are significantly affected by the workforce involved and the timing of the programs.

Q. HOW HAS THE COMMISSION TREATED COSTS TO IMPLEMENT IN PRIOR CASES?

[85] DC Total_Labor Factor. See Exhibit WG (F)-2, Schedule AL, Page 4 of 5.

A. Pursuant to the terms of the Formal Case No. 1054 stipulation and Order No. 14694, the Company amortized costs over the 10-year life of the Original Master Services Agreement ("MSA") between the Company and Accenture LLC.

In Formal Case No. 1093, the Commission approved Washington Gas's continued inclusion of one-tenth of the amortization in the test year in that proceeding.[86]

In Formal Case No. 1137, which addresses the second iteration of outsourcing, Business Process Outsourcing ("BPO") 2.0, prior to its execution, the Commission found:

> ...WGL, for accounting purposes only, may defer and amortize the actual costs to achieve on the Company's books of account over a 5-year period. The Commission's approval of the Company's accounting treatment for these costs shall not constitute either express o[r] implicit approval of their inclusion in customer rates, or express or implicit agreement that these costs constitute a "regulatory asset" for ratemaking purposes.[87]

In Formal Case No. 1162, Washington argued that the BOP 2.0 costs to achieve meet the standards for inclusion in the cost of service in that base rate case. They were known and measurable and represent reasonable expenses for inclusion in ratemaking expense as they were integral in allowing customers to receive the customer service enhancements and savings. Therefore, the

[86] Formal Case No. 1093, *In the Matter of the Investigation Into the Reasonableness of Washington Gas Light Company's Existing Rates and Charges for Gas Service*, Order No. 17132 (May 15, 2013), at 208-209.

[87] Formal Case No. 1137, Order No. 18712, paragraph 327, at page 112.

Company proposed to amortize the costs over a 5-year period, consistent with the savings generated, and reflect one year of amortization in operating expenses in this case.

Formal Case No. 1162 was settled, and the Washington Gas recommended amortization of BPO 2.0 costs to achieve were not addressed in the stipulation.[88]

COVID-19 Regulatory Asset Amortization (Adjustment 15)

Q. HOW DID THE COMMISSION RULE ON WASHINGTON GAS'S REQUEST TO INCLUDE A 5-YEAR AMORTIZATION OF WASHINGTON GAS'S REGULATORY ASSET RELATED TO COVID-19 COSTS IN FORMAL CASE NO. 1169?

A. The Company requested $1,831,075 which represented a 5-year amortization of the COVID-19 Regulatory Asset, as of December 31, 2021 ($9,155,375[89] / 5 = $1,831,075).[90] The Commission disallowed late payment fees and uncollectible expenses recorded in Washington Gas's regulatory asset account.[91] The amount remaining in the regulatory asset account of $368,163 for Personal Protective Equipment ("PPE") was approved to be amortized over a five-year period in the amount of $73,633 ($368,163 / 5 = $73,633).[92]

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[88] Formal Case No. 1162, Order No. 20705 (February 24, 2021).

[89] Incremental Costs due to Waiver of Disconnections

Incremental Bad Debt Expense	$ 3,112,279
Late Fee Revenue	5,673,295
Waived Reconnect Fee	1,638
Subtotal	8,787,212
Incremental PPE, Cleaning, Other	368,163
COVID-19 Regulatory Asset, as of December 31, 2021	$ 9,155,375

[90] Formal Case No. 1169, Order No. 21939, paragraph 254-255, page 75-76.

[91] Ibid.

[92] Ibid.

Q. HAS WASHINGTON GAS FILED FOR RECONSIDERATION OF THE COMMISSION DECISION IN FORMAL CASE NO. 1169 ON THE COST RECOVERY OF THE COVID-19 REGULATORY ASSET?

A. Yes it has. The Company filed an Application for Clarification and/or Reconsideration of Order No. 21939.[93] The Company argued that the Commission's disallowance of recovery for all foregone late payment and reconnection fee revenues, as well as incremental bad debt expense, in the COVID-19 regulatory asset was unreasonable and unsupported by record evidence.[94]

On February 22, 2024, in Order No. 21959, the Commission denied Washington Gas's request.[95]

Q. PLEASE DESCRIBE ADJUSTMENT 15—COVID-19 REGULATORY ASSET AMORTIZATION.

A. The test year ended March 31, 2024, contains no COVID-19 regulatory asset amortization. Adjustment 15—COVID 19 Regulatory Asset amortization reflects an increase in operating expenses totaling $73,633, to adjust the test year amortization to the amount approved in Formal Case No. 1169.

Regulatory Commission Expenses (Adjustment 16)

Q. PLEASE EXPLAIN ADJUSTMENT 16—REGULATORY COMMISSION EXPENSES.

A. Before I discuss the proposed adjustment in this case, I believe that a brief history would be helpful. In Formal Case No. 870, the Commission accepted a

[93] Formal Case No. 1169, Washington Gas's Application for Clarification and/or Reconsideration of Order No. 21939 (January 22, 2024).
[94] Ibid. at 2-7.
[95] Formal Case No. 1169, Order No. 21959, at 4 (February 22, 2024).

Washington Gas proposal to establish a policy allowing the Company to recover costs incurred after the test period associated with Commission proceedings. In Formal Case No. 922, the Commission established a three-year amortization for such regulatory expenses. The Commission continued to adopt this method of accounting for rate case costs in Formal Case Nos. 934, 989, 1016, 1054, 1093, 1137 and 1169.

Q. PLEASE DISCUSS THE DETAILS OF THIS ADJUSTMENT.

A. Since Formal Case No. 1137, the Company has incurred additional regulatory commission expenses in connection with Formal Case Nos. 1115, 1137, 1151, 1162, 1169 and this case. Combined with the on-going recovery of costs, this has resulted in a cumulative under-collection of regulatory commission expenses as of March 31, 2024, of $4,640,510. Adjustment 16 combines this under-collected balance, the continued amortization in approved rates of prior-approved regulatory commission expenses through July 31, 2025 of $1,366,724, and the $3,613,012 of costs that the Company expects to incur in this proceeding.[96] This results in an under-collected balance as of August 1, 2025 of $6,886,798 which I propose be amortized over a three-year period, consistent with the Commission's conclusion in Order Nos. 12589, 17132, 18712 and 21939. This approach, which was used in Formal Case Nos. 1093, 1137 and 1169, was uncontested.[97] This results in an annual amortization expense of $2,295,599 and the need for a ratemaking adjustment to amortization expense.

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[96] For the 16-month period from January 2024 through July 2025, total amortization was based on the annual amortization of $1,025,043 the amount approved in Order No. 21939 in Formal Case No. 1169 ($1,025,043 / 12 X 16 =$1,366,724).

[97] Order No. 17132 at 59.

Also, in conformance with prior precedent, Adjustment 16 includes the adjustment of carrying costs on the under-collected balance of regulatory commission expenses during the three-year recovery period. This is composed of $268,732 of unrecovered carrying costs at March 31, 2024, $656,002[98] of net carrying costs collected and accrued through the start of the rate effective period, and $1,441,091 of carrying costs through the three-year recovery period for a total of $2,365,825 ($268,732 + $656,002 + $1,441,091).[99] This net balance is also amortized over a three-year period, or $788,608, annually.

The test year amount totaled $475,776. Therefore, the total operating expense ratemaking adjustment for regulatory commission expenses is $2,608,431 ($2,295,599 + $788,608 - $475,776).

Q. WHAT CARRYING COST RATES DID YOU USE IN THE COMPUTATIONS?

A. For the period through July 31, 2025, I used the currently approved carrying cost rates used when setting rates in Formal Case No. 1169.[100] For the period from August 1, 2025, forward, I used carrying cost rates that are derived from the Company's proposed capital structure and cost of capital in this proceeding.[101]

Q. IF THE COMMISSION APPROVES A DIFFERENT COST OF CAPITAL IN THIS CASE, DO YOU HAVE A RECOMMENDATION?

A. Yes, I do. The underlying carrying cost computations included in Adjustment 16—Regulatory Commission Expenses will need to be modified to

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[98] Collected	$ (373,521)
Accrued	1,029,523
Total	$ 656,002

[99] Exhibit WG (D)-5, Adjustment No. 16, page 3 of 7.

[100] Formal Case No. 1169, Order No. 21939, paragraph 104, at page 32.

[101] Exhibit WG (D)-1, page 4 of 4.

incorporate the impact the changes in the cost of capital has on the accumulated carrying costs and their amortization.

Environmental Costs (Adjustment 17)

Q. PLEASE EXPLAIN ADJUSTMENT 17—ENVIRONMENTAL COSTS.

A. In Formal Case No. 922, the Commission permitted the deferral of environmental remediation costs that were incurred for the former East Station manufactured gas plant site. In Order No. 10464, issued during Formal Case No. 934, the Commission stated that it would consider the recovery of such costs during the Company's next base rate proceeding. In Formal Case No. 989, the Company presented testimony to support the recovery of these environmental remediation costs. In Order No. 12589 in Formal Case No. 989, the Commission concluded that the costs incurred by the Company since Formal Case No. 934 were appropriate for recovery over a three-year period and that the unamortized balance of the environmental costs should be included in rate base. In Formal Case No. 1016, the Commission once again confirmed a three-year amortization period for previously unrecovered charges. The environmental cost adjustments in Formal Case Nos. 1093, 1137 and 1169 were uncontested.[102]

Q. HOW DID THE COMMISSION TREAT ENVIRONMENTAL COSTS IN ORDER NO. 21939 IN FORMAL CASE NO. 1169?

A. The Commission approved Washington Gas's recommendation and included an annual amortization expense of $329,841 in the development of the revenue requirement in that case.

[102] Order No. 17132 at 23, Order No. 18712 at 82 and Order No. 21939 at 33, respectively.

Q. WAS THE COMMISSION'S DECISION IN ORDER NO. 21939 IN FORMAL CASE NO. 1169 REFLECTED IN THE TEST YEAR IN THIS CASE?

A. Yes, it was. Washington Gas began reflecting the new amortization expense in its financial results in January 2024, consistent with the implementation of new rates from Formal Case No. 1169. The test year included three months of amortization.

Q. WITH THAT BACKGROUND, PLEASE DISCUSS ADJUSTMENT 17—ENVIRONMENTAL COSTS.

A. I have developed Adjustment 17—Environmental Costs in this proceeding in conformance with the Company's proposal in Formal Case Nos. 989, 1016 1093, 1137, 1162, and 1169. I have calculated the District of Columbia portion of environmental costs incurred after Formal Case No. 1169 to be $1,580,712. After adjusting for $1,126,956 of under-collections from Formal Case No. 1169 through the start of the rate effective period, the balance of incurred expenditures to be amortized is $2,707,668. I propose amortizing the balance over a five-year period, or $541,534 per year, consistent with what was reflected in the approved adjustment in Formal Case No. 1169. The per book amortization expense for the test year was $263,068, resulting in an increase to environmental amortization expense of $278,465. Consistent with prior practice, the unamortized balance of environmental costs of $1,766,327, which is net of deferred taxes of $670,574,[103] has been included in rate base, which is a $690,481 increase from the $1,075,846 included in the test year.

[103] $1,766,327/ (1- 27.51750%) - $1,766,327 = $670,574.

The Company is receiving revenues in connection with the real estate development of the East Station property which is shared with customers pursuant to the Commission's decision in Formal Case No. 989 (Order No. 14104). Adjustment 1—Revenues sponsored by Company Witness Banks incorporates the revenue sharing.[104]

Insurance Expense (Adjustment 18)

Q. PLEASE DISCUSS ADJUSTMENT 18—INSURANCE EXPENSE.

A. During the test year, each of the Company's insurance policies was renewed. Based on those new contracts, I developed a ratemaking level for insurance costs. I have updated the information to reflect in the cost of service the newly negotiated increase in premiums to ensure that the rate effective period accurately reflects the cost of insurance.

I accumulated the change in premiums for each new policy and allocated the applicable percentage of the costs to the operations of Washington Gas. To determine the percentage applicable to Washington Gas, I used a labor factor for allocating workers' compensation. For property, excess liability, professional, commercial crime, cyber liability, and service fees, I used the allocation to the utility for the test period to allocate the increase. General liability and Directors and Officers insurance premiums reflected Washington Gas amounts and did not require allocation. The total ratemaking insurance premiums were compared to the previous policy premiums and the difference is allocated to the District of Columbia using two factors. I allocated property insurance based on the District of Columbia net gas plant in service allocation factor of 18.6176 percent. All

[104] Exhibit WG (D)-5, Adjustment 1, page 29 of 46.

other insurance expense is allocated based on the District of Columbia total labor allocation factor of 19.3618 percent, which is consistent with the factor used in previous cases.

As summarized in the following table, the increase in the Company's total insurance premium costs is expected to be approximately $1,796,405 during the rate effective period, of which the District of Columbia's portion is $347,779.

	Total Company	District of Columbia
Property	$ 5,127	$ 954
Excess Public Liability	1,225,502	237,280
Director & Officer Liability	40,201	7,784
General Liability	38,759	7,504
Workers' Compensation	410,501	79,481
Cyber/ Crime	90,071	17,439
Professional	20,210	3,913
Service fees	(33,966)	(6,576)
Total Ratemaking Adjustment	$ 1,796,405	$ 347,779

Adjustment 18 reflects a $347,779 ratemaking increase in the cost of insurance allocated to the District of Columbia jurisdiction.

Interest on Customer Deposits (Adjustment 19)

Q. PLEASE DESCRIBE ADJUSTMENT 19—INTEREST ON CUSTOMER DEPOSITS.

A. In Formal Case No. 712, Order No. 10256, issued July 19, 1993, the Commission established a procedure for setting the interest rate that regulated utilities in the District of Columbia pay on customers' deposits. This Order provided that by January 15th of each year, an interest rate would be established for the calendar year based on the average annual yields on one-year Treasury bills for September, October, and November of the preceding year. In Order No. 21935, issued December 6, 2023, the Commission set an interest rate of 5.38 percent for calendar year 2024. Consistent with the historical methodology that was utilized in Formal Case Nos. 1137 and 1169 and uncontested, Adjustment 19 recognizes $35,315 of increased interest expense that will be incurred in the rate effective period.[105] I am not proposing any changes in the level of deposits in the rate effective period.

Commission-Mandated Fees (Adjustment 20)

Q. PLEASE DISCUSS ADJUSTMENT 20—COMMISSION-MANDATED AUDIT FEES.

A. Commission-Mandated Audit Fees are the cost of audits related to the Company's Accelerated Replacement Plans. In Formal Case No. 1115, the Commission ordered an annual audit of PROJECT*pipes*.[106]

Q. HOW DID THE COMMISSION ADDRESS THESE AUDIT FEES IN ITS DECISION IN FORMAL CASE NO. 1169?

A. In Formal Case No. 1169, Washington Gas's Adjustment for Audit Fees was uncontested and approved by the Commission.[107] For PROJECT*pipes*, the Company recorded $1,481,248 of audit fees incurred since July 2017 as a regulatory asset related to the audit fees incurred through March 31, 2024.[108]

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[105] Order No. 17132 at 59.

[106] Formal Case No. 1115, *Application of Washington Gas Light Company for Approval of a Revised Accelerated Pipe Replacement Plan,* Order No. 17789.

[107] Formal Case No. 1137, Order No. 18712, paragraph 231 at 82 and paragraph 450 (ff), at 150.

[108]
PROJECT*pipes* 1 fees	$ 649,023
PROJECT*pipes* 2 fees	632,225

The Company began amortizing the audit fee in April 2021 effective with the new rates approved in Formal Case No. 1169.

Q. HOW HAVE YOU REFLECTED THE COMMISSION-MANDATED AUDIT FEES IN THE COST OF SERVICE IN THIS CASE?

A. The test year included $17,091 of amortization expense[109]. For PROJECT*pipes* audits, I included a $333,242 adjustment to test year expense to reflect a three-year amortization of the remaining unamortized fees from August 1, 2025, the start of the rate effective period[110] of $350,333 ($1,050,998 / 3 = $350,333), less test year expense of $17,091 ($350,333 - $17,091= $333,242).[111]

Non-Labor Inflation (Adjustment 21)

Q. PLEASE DISCUSS ADJUSTMENT 21—NON-LABOR INFLATION.

A. In Formal Case No. 1169, the Commission acknowledged that inflation had increased substantially in the post-test-year period. Due to these circumstances, the Commission accepted Washington Gas's non-labor inflation adjustment only for 2022, the year immediately following the test year in that

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Total	$ 1,481,248

[109] The Company recorded PROJECT*pipes* audit amortization expense of $91,675 to Account 923000. Account 923000 was allocated using the District of Columbia Three_Part_Factor of 18.6429 percent resulting in test year expenses of $17,091 ($91,679 x 18.5190% = $17,091).

[110] The Company is proposing a procedural schedule that would allow it to place new rates into effect in May 2025. The difference between that date and the rate effective period used to develop the ratemaking adjustments in this cost of service has little or no impact on Washington Gas's revenue requirement recommendation.

[111]

Audit fees incurred	$ 1,481,248
Amortization	
April 1, 2021 to March 31, 2024	(242,035)
April 1, 2024 to August 1, 2025	(188,215)
Total amortization	(430,240)
Balance August 1, 2025	$ 1,050,998

case, because these costs are not too remote in time from the test year and provide a more accurate reflection of the current economic situation.[112]

Adjustment 21—Non-labor Inflation reflects the impact of applying an inflation factor to test-year non-labor expenses. The adjustment was prepared consistent with the adjustment approved by the Commission in Order No. 21939 in Formal Case No. 1169.

Q. HOW DID WASHINGTON GAS COMPUTE THE EFFECT OF GENERAL INFLATION ON NON-LABOR EXPENSES?

A. Washington Gas used the Survey of Professional Forecasters' ("SPF"), published by the Philadelphia Federal Reserve, forecasted inflation rates. The SPF presents median forecasted inflation rates for the current quarter, the next four quarters, the current year, and the next two years. In addition, the SPF includes five-year and ten-year inflation forecasts, but those are beyond the time horizon of this case and when rates in this case will go into effect. Thus, I used the projected inflation for 2024 First Quarter 2024 Survey of Professional Forecasters (February 2024).[113] That rate was 2.49 percent. I applied the inflation rate to adjusted test year non-labor Operation and Maintenance ("O&M") expense of $41,904,967 by the annual 2024 inflation rate.[114] The resulting inflation amount is a $1,043,643 increase in operating expenses.

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[112] Formal Case No. 1169, Order No. 21939, paragraph 270, page 80.

[113] Median Responses for CPIA https://www.philadelphiafed.org/surveys-and-data/cpi-spf

[114] Adjusted test year non-labor expense was computed as follows:

Test Year Operations Expense (excl. Gas Purchased Expense)	$ 57,084,597
Test Year Maintenance Expense	25,568,839
Labor Expense in Test Year O&M	(28,256,576)
Test Year Non-Labor O&M Expense	54,396,860
Add: Non-Labor Expense Adjustments to Cost of Service	(12,491,893)
Test Year Non-Labor O&M Expense (Adjusted)	$ 41,904,967

Q. PLEASE DESCRIBE WHY YOU EXCLUDED CERTAIN NON-LABOR EXPENSES IN YOUR DETERMINATION OF INFLATION EFFECTS.

A. There are items included in the test year that Washington Gas addresses through separate ratemaking adjustments that provide actual cost increases or have been eliminated from the test year; therefore, these amounts do not require an inflation factor. These total $12,491,893 and include the adjustments listed below:

- Adjustments 1, 2 and 7—Uncollectible Gas Accounts / GAC / POR
- Adjustment 10—Employee Benefits Expense (Fringe) Elimination
- Adjustment 16—Regulatory Commission Expenses
- Adjustment 17—Environmental Costs
- Adjustment 18—Insurance Expense
- Adjustment 20—Commission Mandated Fees
- Adjustment 22—Commission Directed Exclusions
- Adjustment 23—General Advertising Expense Elimination
- Adjustment 25—Legal Costs
- Adjustment 26—Prior Period Adjustments.
- Adjustment 27—Transition Cost Amortization
- Adjustment 28—Credit/Debit Card Transaction Fees Elimination.

Q. WHY IS A DIFFERENT INFLATION FACTOR USED FOR NON-LABOR EXPENSES THAN FOR LABOR?

A. As explained by Company Witness Smith, salaries and wages are increasing at a rate greater than inflation. This is also supported by an external cost index: the Employment Cost Index. That index could, in fact, be relevant to the Company's non-labor O&M as well. Much of non-labor O&M is related to contractor and consultant costs. The costs of these suppliers are also driven by labor. We have seen salary and wage increases lead to higher contractor and consultant costs. However, the inflation forecast used here is more conservative.

Q. THE PHILADELPHIA FEDERAL RESERVE WILL ISSUE ADDITIONAL FORECASTS FOR 2024. WOULD YOU ACCEPT AN UPDATE TO THE INFLATION RATES USED IN THIS ADJUSTMENT?

A. Yes, if the rates were updated to reflect the most current forecast from the SPF, then I would accept those as revisions to my adjustment. I accept that the most recent forecasts should be used. Equally, actual inflation for 2024 may become known during this proceeding. I also accept that actual inflation experience during that period as measured and published by the Bureau of Labor Statistics should be used for the purpose of this adjustment.

ELIMINATIONS

Commission Directed Exclusions (Adjustment 22)

Q. PLEASE EXPLAIN ADJUSTMENT 22.

A. Consistent with this Commission's Order Nos. 6051, 7193, 9146, 10307, 12589, 12986, 17132, 18712 and 21939 in Formal Case Nos. 686, 722, 870, 922, 989, 1016, 1093, 1137 and 1169, respectively, I eliminated all District of Columbia per book test year expenses totaling $97,796[115] for: (a) trade association dues, business and civic memberships, and support payments of $48,991; and (b) American Gas Association dues of $59,768. In addition, I

[115] The amounts are reflected in Adjustment 22—Commission Directed Exclusions as follows:

Direct Charges	$ 17,683
Allocable Charges	80,114
Total District of Columbia Commission Directed Exclusions	$ 97,796

eliminated a net credit amount of $10,962 associated with the Company's community affairs program in the District of Columbia.[116]

General Advertising (Adjustment 23)

Q. PLEASE DESCRIBE ADJUSTMENT 23—GENERAL ADVERTISING.

A. Adjustment 23—General Advertising of $125,884 eliminates per book test year general advertising expenses consistent with this Commission's Order Nos. 6051, 7193, 9146, 10307, 12589, 12986, 17132, 18712 and 21939 in Formal Case Nos. 686, 722, 870, 922, 989, 1016, 1093, 1137 and 1169, respectively.

Non-Includable ADIT (Adjustment 24)

Q. PLEASE DISCUSS ADJUSTMENT 24—NON-INCLUDABLE ADIT.

A. I propose adjustments to plant-related and non-plant-related accumulated deferred income taxes. These ADIT balances relate to items that are excluded from the determination of the cost of service in the District of Columbia. Because customers in the District of Columbia are not responsible for these costs, the related deferred income tax balances must also be eliminated to ensure consistent treatment.

ADIT Reclassification and Elimination—This component of the adjustment eliminates the District of Columbia's $151,322 share of accumulated deferred tax related to the abandoned peaking plant and is removed because the regulatory asset is not included in rate base and, therefore the taxes are also excluded. It also aligns the remaining ADIT related to regulatory asset and liabilities by

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[116] The credit reflects the reclassification of an amount incorrectly charged to Account 930200 in January 2023 (outside of the test year), that was reclassified out of Account 923000 in August 2023 (within the test year).

jurisdiction such that the regulatory asset and liabilities and the related ADIT are jurisdictionally aligned. All that remains in the District of Columbia rate base related to miscellaneous ADIT balances are those related to District of Columbia regulatory assets and liabilities.[117] The per book ADIT assigned to the District of Columbia was $0 and generates an adjustment of ($225,491).[118] [$0 - $225,491 = ($225,491)]

Contributions in Aid of Construction ("CIAC")—The removal of the District of Columbia's $994,920 of CIAC ADIT asset that have been grossed-up for taxes is necessary because customers have paid the income tax attributable to the CIAC. The ADIT associated with this temporary difference is removed from rate base.

Environmental—The elimination of the $118,865 of book accumulated deferred income tax liability is necessary because Adjustment 17—Environmental already presents this item net of adjusted deferred income taxes.

Merger Commitments—The District of Columbia's $186,630 of this ADIT asset balance is eliminated pursuant to Order No. 19369, in Formal Case No. 1142.[119] Order No. 19369 requires all costs related to Washington Gas's merger with ALA not be reflected in rates charged to customers. Therefore, any related ADIT is removed.

Legal Expense (Adjustment 25)

Q. PLEASE DESCRIBE ADJUSTMENT 25—LEGAL EXPENSE.

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[117] The ADIT related to District of Columbia regulatory assets and liabilities is composed of the following item:

Formal Case No. 1115 Audit Fees	$ (225,491)

[118] Includes the peaking plant elimination.

[119] Formal Case No. 1142, *In the Matter of the Merger of AltaGas, Ltd. and WGL Holdings, Inc.*, Order No. 19396, Appendix A, page 16.

A. During the preparation of this Direct Testimony, I identified certain legal costs that were: (1) charged or allocated to the incorrect jurisdiction; or (2) should be removed because they represent costs that are not recoverable through rates charged to District of Columbia customers. Adjustment 25—Legal Expense corrects the jurisdictional alignment and removes those costs that are not recoverable in the District of Columbia.

Q. HOW DID YOU DEVELOP THE ADJUSTMENT YOU ARE PROPOSING TO LEGAL EXPENSES?

A. I began with a query of transactions that have been identified in the Company's accounting system as being related to legal activities.[120] I sorted those transactions by vendor, together with the account and jurisdiction where the transactions were recorded. Together with legal professionals with knowledge of the transactions, we determined whether the activity related to a specific jurisdiction (DC, MD, or VA), was common to all jurisdictions, or related to an affiliate or an activity not appropriate for recovery through rates.

The costs identified as being related to the District of Columbia jurisdiction were combined with the District of Columbia's allocated share of the costs common to all jurisdictions.[121] I compared that total of $475,607 to the amounts recorded during the test year of $338,684. Adjustment 25—Legal Expense

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[120] The Company uses the following process codes to identify legal costs:
30101—General &Corporate Legal Activity Torts/Contracts.
30102—General &Corporate Legal Activity-3rd Party Damages.
30109—Outside Services – Legal.
30302—General Regulatory Expenses.
30303—Outside Services – Legal.

[121] The District of Columbia allocation factors used were applied by account and obtained from the jurisdictional cost allocation study included in Exhibit WG (F)-2:

Account 921000	Comp_A&G	19.5408%
Account 923000	Three_Part_Factor	18.6429%

reflects an adjustment to increase legal expense by $136,923 ($475,607 - $338,684 = $136,923).

Prior Period Adjustments (Adjustment 26)

Q. PLEASE DESCRIBE ADJUSTMENT 26 RELATING TO PRIOR PERIOD ADJUSTMENTS.

A. During the preparation of this Direct Testimony, I identified a transaction included in test-year expenses that related to a correction of an amount for a prior accounting period. This amount is not representative of the level of expenses Washington Gas will incur in the rate effective period, so I eliminated the District of Columbia share of this item totaling $26,978. The item was the result of Washington Gas implementing Commission Order No. 21939, in Formal Case No. 1169, to remove a portion of Short-Term Incentive Compensation from gas plant in service.[122]

Transition Cost Amortization (Adjustment 27)

Q. PLEASE DISCUSS THE COMPLETION OF THE AMORTIZATION OF TRANSITION COSTS TO ACHIEVE INCURRED IN CONNECTION WITH THE MERGER BETWEEN ALA AND WGL HOLDINGS, INC.[123]

A. Washington Gas started amortizing the transition costs in July 2018 and the 5-year amortization period ending in June 2023, which is in the test tear of this case. Adjustment 27—Transition Cost Amortization reflects removal of the District of Columbia share of test year transition cost amortization of $52,311.

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[122] Formal Case No. 1169, Order No. 21939, at 69 (December 22, 2023).
[123] Formal Case No. 1142, Order No. 19396, Appendix A, page 16.

Credit/Debit Card Transaction Fees Elimination (Adjustment 28)

Q. PLEASE DISCUSS ADJUSTMENT 28—CREDIT/DEBIT CARD TRANSACTION FEES ELIMINATION.

A. Company Witness Lawson is proposing a modification to General Service Provision No. 4 to eliminate its current practice of payment by Washington Gas of the vendor fee for the customer use of a credit/debit card to pay bills. If approved, customers will be directly responsible for any vendor fees that result from their specific bill payment with a credit/debit card.

Q. BASED ON COMPANY WITNESS LAWSON'S RECOMMENDATION, HOW HAVE YOU TREATED TEST YEAR CREDIT /DEBIT CARD FEES IN THE CASE?

A. Adjustment 28—Credit/Debit Card Transaction Fees Elimination removes the District of Columbia jurisdiction's 13.587 percent share of test year fees of $3,520,829 totaling $478,381. The District of Columbia portion was computed using the ratio of the number of credit/debit card transactions in the District of Columbia to total system transactions.

Q. DOES THE COMPANY ANTICIPATE INCURRING ADDITIONAL COSTS AFTER MAKING THIS CHANGE?

A. Yes, it does. The Company's Customer Service organization predicts that certain customers will forgo the Credit/Debit card options in the future and will select one of the Company's other payment options. As a result, the Company will incur additional costs for Automated Clearing House ("ACH") fees which will increase by $66,585.

Q. ARE THERE OTHER AREAS THAT COULD BE AFFECTED BY THIS CHANGE?

A. There may be, but the effect depends on the extent to which customers' bill payment times lengthen or stop altogether. The Company is unable to predict the extent to which this might occur and the impact on cash working capital or uncollectible accounts expense.

Q. PLEASE SUMMARIZE ADJUSTMENT 28—CREDIT/DEBIT CARD TRANSACTION FEES ELIMINATION.

A. Adjustment 28—Credit/Debit Card Transaction Fees Elimination comprises the following components:

Credit/Debit Card Fee Elimination	$ (478,381)
ACH Fees	66,585
Total	$ (411,796)

Q. IF THE COMMISSION WERE TO DENY WASHINGTON GAS'S REQUEST TO MODIFY GSP NO. 4, IS THERE A NECESSARY MODIFICATION TO WASHINGTON GAS'S REVENUE REQUIREMENT IN THIS CASE?

A. Yes, there is. Operating expenses would need to be increased by $411,796, thereby increasing the requested base rate revenue increase in this case.

SYNCHRONIZATION AND TAX EXPENSE ADJUSTMENTS

Interest on Debt (Adjustment 29)

Q. PLEASE EXPLAIN ADJUSTMENT 29—INTEREST ON DEBT.

A. Adjustment 29 reflects the amount needed to adjust the test year interest expense to the ratemaking level based on the weighted cost of debt presented by Company Witness Burrows. The ratemaking cost of debt is applied to the ratemaking level of net rate base to determine the total ratemaking interest expense in the rate effective period, which is a deductible item in determining taxable income.

To compute the ratemaking level of interest expense, I multiplied the weighted-average debt component of the capital structure times the ratemaking level of net investment ($760,992,964 x 2.36 percent = $17,980,262). The distribution-only interest expense was $18,811,557, generating a $(831,295) ratemaking adjustment to decrease interest expense in the income tax computation.

Cash Working Capital (Adjustment 30)

Q. PLEASE EXPLAIN ADJUSTMENT 30—CASH WORKING CAPITAL ("CWC") ADJUSTMENT.

A. I have performed a lead/lag study for the test year ended March 31, 2024, which is the basis for the Company's inclusion of a cash working capital allowance of $40.8 million in rate base. Adjustment 30 develops the Company's ratemaking cash working capital allowance consistent with the Commission's methodology established in Formal Case No. 1016 and used to develop rates in Formal Case Nos. 1093, 1137 and 1169. Exhibit WG (D)-8, provide a narrative discussion of the lead/lag methodology. This methodology employs the use of a lead/lag study and includes certain specific accounts requiring cash working capital. The lead/lag portion of the cash working capital allowance is calculated by multiplying the average daily amount of ratemaking expense elements that give rise to a cash working capital requirement times their respective net lead/lag days (revenue lag days minus expense lead/lag days).

The study also includes the 13-month average for contributions made under the Multi-Family Piping Pilot Program.

Q. HAS THE COMMISSION EXPRESSED A PREFERENCE AS TO THE USE OF A LEAD/LAG METHODOLOGY TO COMPUTE THE CASH WORKING CAPITAL REQUIREMENT IN BASE RATE PROCEEDINGS?

A. Yes it has. The Company and the Commission have a long history related to the methodology that should be used to compute the Cash Working Capital allowance. In Formal Case No. 922, the Commission provided a comprehensive discussion of the history.[124] That discussion is presented below, with the footnote references excluded:

> The Commission's decision in Formal Case No. 768, Order No. 7469, represents the starting point for the transition from the lead-lag method to the 1/12th formula method in determining the Company's cash working capital requirement. In that proceeding, the Commission expressed its frustration with "the most confusing analysis it had ever been our displeasure to encounter." That analysis, presented by the parties for the purpose of determining the Company's cash working capital requirement, was based upon the lead-lag method.
>
> Thus, the Commission acknowledged that while lead-lag might provide a more exact approximation of WG's cash working capital, on balance, the benefits, including reduced

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[124] Formal Case No. 922. *In the Matter of the Application of Washington Gas Light Company District of Columbia Division For Authority to Increase Existing Rates and Charges for Gas Service.* Order No. 10307, at 57-59 (October 8, 1993)

litigation costs, resulting from the use of the formula method outweighed the precision of the lead-lag methodology.

Nevertheless, the Commission indicated that the parties would be free to challenge the 1/12th formula method, and that sometime within the five-year period following that case, the Company should provide information that would permit the parties to reevaluate the formula.

In Formal Case No, 870, the Commission strengthened its resolve that the Company should provide the parties and Staff with information to reevaluate the 1/12th formula method and directed WG "to provide information in its next rate case to allow the other parties an opportunity to reevaluate the one-twelfth method in that proceeding."

In this proceeding, OPC contends that the lead-lag study is the most appropriate method for the determination of WG's cash working capital allowance. Staff Witness Boyd presents evidence of a trend in the divergence between the results obtained using the formula method versus the lead-lag approach.

The Commission is concerned that the trend described by Staff Witness Boyd is indicative of a serious defect in the formula method. If the divergence in the results under the two formulae increases over time, then the Commission is unable to conclude, as it did in Formal Case Nos. 768 and 870, that the formula method remains a reasonably accurate approximation of the Company's actual working capital requirement.

The Commission initially adopted the formula method as a reasonably accurate representation of the Company's cash working capital requirements, based upon a comparison of the results under the formula method to the results of the lead-lag method. Accordingly, we reasonably base our analysis of the current merits of the formula method upon the same comparison.

Based upon the evidence in this record regarding the current variance between the lead-lag method and the formula method, **the Commission cannot find that the formula method is, at this time, a reasonable approximation of the Company's cash working capital needs.** WG indicates that in Formal Case No. 768, decided in 1982, the formula method produced a cash working capital requirement level $2.5 million lower than the lead-lag method. In Formal Case No. 890, decided in 1990, the formula method resulted in a cash working capital recurrent $0.9 million higher than the lead-lag method. In this proceeding, the formula method presents a cash working capital requirement $3.1 million higher than WG's lead-lag study. The Commission is concerned that these figures suggest a trend. Company Witness Bortel is unable to provide substantial, reasoned guidance as to how long the trend will continue, or the exact causes of the trend. Thus, it would be inappropriate to simply "rubber-stamp" the continued use of the formula method which seems to have outlived its purpose. Accordingly, we reject Witness Bortel's interpretation of PSC Exhibit (D)-I as an indication that the differences between the lead-lag method and the formula method have remained relatively equal over time. (Emphasis added)

Based upon a careful review of OPC and Staff's analysis of the results obtained using the formula method and the lead-lag methodology, the Commission approves an adjustment to cash working capital based upon the more exacting lead-lag approach...

Q. PLEASE SUMMARIZE THE CHANGE IN CASH WORKING CAPITAL IN THIS CASE FROM THE LEVEL USED TO SET RATES IN FORMAL CASE NO. 1169.

A. The following table shows the drivers of the change in the CWC from Formal Case No. 1169 to the amount requested in this proceeding.

Cash Working Capital Formal Case No. 1169	$ 39,134,118
Increase in Revenue Lag	(319,097)

Decrease in Expenses	1,094,368
Change in Other Lead/Lag Items	916,936
Total Change in Cash Working Capital	1,692,207
Requested Cash Working Capital	$ 40,826,325

Revenue Lag

Q. HOW WAS THE REVENUE LAG COMPUTED IN THIS CASE?

A. Using the same District of Columbia-specific data, the total lag days in operating revenues of 89.00 days represents the average number of days in the test year, the twelve months ended March 31, 2024, between the time the Company provided service to District of Columbia customers and the time it receives payment from those customers for that service.

The lag is developed in three parts. The first two are common to all customers regardless of jurisdiction and are embedded within the Company's meter reading and billing schedules. The third reflects the specific experience of District of Columbia customer bill payments.

Q. PLEASE DISCUSS THE TWO PARTS COMMON TO ALL CUSTOMERS.

A. The first part (the service lag) measures the average number of days from the time the customer receives gas service to the time his meter is read. Customer meter reads occur on a cycle basis throughout the month and therefore, on average a customer would have 15.21 days of service at the time his meter is read. [(365/12) = 30.42/2 = 15.21].

The second part (the billing lag) determines the average number of days from the meter reading date to the billing date. This computes to 4.34 days. This was calculated by applying the actual meter reading schedule for the twelve months beginning January 1, 2024, which reflects a two business day lag between meter read date and bill preparation date and a one business day lag between bill preparation date and mailing date. The 4.34 days incorporates the timing of weekends and holidays.

Q. PLEASE DISCUSS THE THIRD PART OF THE DISTRICT OF COLUMBIA REVENUE LAG.

A. The third part (the collection lag) of the revenue lag reflects the period of time in the test year from billing District of Columbia customers to the receipt of payment of those bills from those customers. In the District of Columbia for 2023, it totals 69.45 days. This number of days comprises a traditional Days Sales Outstanding computation computed by dividing the District of Columbia 13-month average accounts receivable balance of $48,686,497 by the District of Columbia average daily amounts billed of $700,972.

The 13-month average accounts receivable balance is developed from the monthly balances of the District of Columbia aging of accounts receivable adjusted to reflect (1) the cash in collection banks not yet recorded on the books of the Company; (2) the net differences in the amounts billed to customers on the budget plan versus their actual consumption; and (3) balances from customers that have elected to buy gas from third-party marketers who are being provided a single gas bill for gas and delivery service from Washington Gas.

The average daily amount billed is determined by dividing the total amount debited to Account 142.101 – "Accounts Receivable – Gas" for the District of Columbia during the period of $255,854,652 by 365 days.

Q. HOW ARE THESE THREE PARTS USED TO DETERMINE THE DISTRICT OF COLUMBIA-SPECIFIC REVENUE LAG FOR THE TEST YEAR?

A. The sum of the revenue lag part days as determined is the composite District of Columbia lag days in operating revenues.

Service Lag	15.21 days
Billing Lag	4.34 days
District of Columbia Collection Lag	69.45 days
District of Columbia Revenue Lag	89.00 days

Q. IS IT APPROPRIATE TO USE ANYTHING OTHER THAN A DISTRICT OF COLUMBIA-BASED CALCULATION TO COMPUTE THE COLLECTION LAG?

A. No, it is not. District of Columbia customers have historically taken a longer period of time to pay their bills as demonstrated by the table below that presents the historical trend in revenue lag days by period and jurisdiction.

12 Months Ended	DC	MD	VA
March 2024	89.00	72.18	50.50
December 2023	91.04	73.91	51.14
December 2022	89.04	65.39	50.61
Dec ember2021	86.96	62.00	51.51
December 2020	79.28	61.34	50.39
December 2019	79.37	54.49	45.82
December2018	78.53	54.81	46.50
December 2017	74.23	52.44	41.63
December 2016	64.02	41.60	30.86
December 2015	67.29	47.65	36.91
December 2014	65.58	52.43	45.60

Gas Purchased Expense Lead

Q. HOW WAS THE PURCHASED GAS LEAD COMPUTED IN THIS CASE?

A. The gas purchased expense lead of 38.19 days was developed based on actual test year purchases and payments for gas from suppliers based on invoices paid during the test year. The total lead days in the payment of gas purchased was determined by netting the leads in payments to all suppliers for each month during the twelve months ended March 31, 2024. The lead payment for each month is the sum of the average number of days in the service period (*i.e.*, one month) and the number of days from the end of the service period to the date paid. The computed lead days of 38.19 is applied to cost of gas allocated to the District of Columbia.[125]

All Other Expense Leads

Q. HOW WERE THE OTHER EXPENSE LEADS COMPUTED?

A. Each of the other expense leads was computed based on a review of service periods and payments specific to each category of payments. The lead calculations reflect data for calendar year 2020. Because payment terms for these items do not vary over time, lead data for 2020 is representative of test year 2023 lead data.[126]

Q. ARE THERE ANY OTHER EXPENSE LEADS THAT YOU WANT TO DISCUSS?

A. Yes there is one. The expense lead related to federal income tax needs to reflect the actual cash flow that Washington Gas is experiencing. Washington Gas is in a net operating loss position and as a result is not paying any current income taxes. As a result, the Company is not generating any federal income tax lead related to current income tax expense. Therefore, the expense lead for

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[125] The gas purchased lead based on calendar year 2021 information, used in Formal Case No. 1169 was 39.21 days. (Formal Case No. 1169, Exhibit WG (5)-D, Lead-Lag No. 2. Page 14 of 18.)

[126] Employee salaries are paid biweekly, benefits and tax payment occur on regular schedules.

federal income taxes must be set to zero days to ensure the true cash effect is incorporated into the CWC analysis.

Affiliate Lead/Lag

Q. WHAT WORKING CAPITAL REQUIREMENTS HAS WASHINGTON GAS ATTRIBUTED TO AFFILIATED ENTITIES?

A. The ACOSS sponsored by Company Witness Quenum provides detail for the test year on the magnitude of the services provided both to and by Washington Gas and its affiliates.[127] My Direct Testimony demonstrates that customers **receive the benefit of the expense lead related to services provided by affiliates** but are not responsible for the lag related to service provided **to affiliates**. The lead/lag study incorporates the cash working capital effect of all transactions included in the expenses on Washington Gas books.

Q. WHAT DOES THE DETAIL WASHINGTON GAS PRESENTED RELATED TO SERVICES PROVIDED BY AFFILIATES SHOW?

A. Because the **payment to affiliates** for services received occurs the month after the service is rendered, services provided by affiliates generate cash working capital benefits which are included in the determination of the revenue requirement in this case of $611,872.[128]

Because the **payment by affiliates** for services rendered occurs the month after the service is rendered, service provided to affiliates generates cash working capital requirements, none of which were included in the determination

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[127] Exhibit WG (J)-3.

[128] In the test year, Washington Gas received service provided by affiliates totaling:

Services Provide by Affiliates (Section VI. Transactions With Affiliates)	$ 40,651,876
Average Factor (1/12=8.3333%)	8.3333%
Test Year Average	3,387,656
District of Columbia Share (Composite rate based on accounts charged)	18.0618%
Working Capital Benefit included in the test year	$ 611,872

of the revenue requirement in this case.[129] The costs are not presumed to be the responsibility of customers and not reflected in the revenue requirement in this case. This is consistent with my understanding of what the Apartment and Office Building Association of Metropolitan Washington ("AOBA") Witness Bruce Oliver recommended occur in Formal Case No. 1169.

Q. PLEASE SUMMARIZE ADJUSTMENT 30—CASH WORKING CAPITAL.

A. The total of the lead/lag and account analysis components results in a ratemaking cash working capital allowance of $40,826,325 which, when compared to the distribution-only per book cash working capital allowance of $39,871,701 results in a ratemaking adjustment of $954,625 to increase rate base.

District of Columbia and Federal Income Taxes (Adjustment 31)

Q. PLEASE EXPLAIN ADJUSTMENT 31—DISTRICT OF COLUMBIA AND FEDERAL INCOME TAXES.

A. I have adjusted District of Columbia income taxes to reflect the change in taxable income that resulted from the normal weather adjustment and the other adjustments to revenues and expenses and the synchronization of interest that I discuss in this testimony. District of Columbia income taxes are also computed from District of Columbia net taxable income adjusted for all applicable ratemaking adjustments and the District of Columbia tax rate of 8.25 percent.

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[129] In the test year, Washington Gas provided services to affiliates totaling:

Services Provide by Affiliates (Section VI. Transactions With Affiliates)	
Direct	$ 4,505,469
Allocated	4,869,018
Total	9,374,487
Average Factor (1/12=8.3333%)	8.3333%
Test Year Average	(781,207)
District of Columbia Share (none)	0.0000%
Working Capital Requirement included in the test year	$ -

I have also adjusted federal income taxes to reflect the change in taxable income that resulted from the normal weather adjustment and the other adjustments to revenues and expenses and the synchronization of interest that I discuss in this testimony. Federal tax expense is computed at the current statutory federal tax rate of 21.00 percent applied to federal net taxable income.

Q. PLEASE DESCRIBE THE DISTRICT OF COLUMBIA EFFECTIVE TAX RATE SCHEDULE INCLUDED AS EXHIBIT WG (D)-4 AND IN THE WORKING PAPERS FOR ADJUSTMENT 31.

A. Exhibit WG (D)-4, the District of Columbia effective tax rate reconciliation, was prepared to demonstrate that, after the Company makes all ratemaking adjustments, the only items with remaining differences that affect total tax expense are those permanent and flow-through tax items that are appropriately reflected in the rates charged to customers.

The schedule begins with net operating income before income taxes and shows each individual permanent and flow-through item. Total taxes, as adjusted, include the following permanent and flow-through items:

- Meals and Entertainment—the portion of meals and entertainment expenses that are not deductible for income tax purposes. The Tax Cuts and Jobs Act of 2017 ("TCJA") expanded the definition of meals that are not deductible. This permanent difference increases current tax expense.
- Parking—Effective January 1, 2018, the IRC disallows deductions for business expenses incurred or paid to provide qualified transportation fringes ("QTFs") after December 31, 2017. QTFs are transportation in a commuter highway vehicle between the employee's residence and

place of employment, transit passes, and qualified parking. Therefore, the Company treats these expenses as a permanent tax adjustment.

- Excess Deferred Income Taxes ("EDIT")—taxes recorded on a normalized basis for ratemaking purposes in prior periods at tax rates in excess of the current statutory tax rates. For ratemaking purposes, this item turns around the benefit of the taxes collected in the past at a higher tax rate than the current rate and returns it to customers. As a result, this amount reduces ratemaking income tax expenses. The excess deferred taxes reflect the Company's filing in Formal Case No. 1151. The protected property-related amounts are amortized using the Average Rate Assumption ("ARAM"), while the unprotected property-related, Net Operating Losses and non-plant-related excess deferred tax balances are amortized over 15 years.[130] The ARAM amount has been updated consistent with normalization requirements.
- Order No. 21939, in Formal Case No. 1169 approved Washington Gas's proposal to implement a change in tax accounting related to cost of removal ("COR") to ensure compliance with the normalization requirements of two recent IRS Private Letter Rulings necessitating a change in the amortization of EDIT.[131] The approval came after the test year in this case so the impact of the change in accounting on EDIT amortization must be incorporated into the income tax computation in this case.

[130] Formal Case No. 1151, Order No. 19395, at 6-8.
[131] Formal Case No. 1169, Order No. 21939, at 1, paragraph 5 (December 22, 2023).

- Excess Deferred Taxes Formal Case No. 1027 Write Off—as indicated in the Commission's Order in Formal Case No. 1137, Washington Gas has never included any cost of Vintage Mechanically Coupled Replacement ("VMCR") program capital expenditures in excess of the $28 million rates charged to customers.[132] Washington Gas agreed to not seek recovery of the Formal Case No. 1027 VMCR amounts in excess of $28 million in connection with its merger agreement with AltaGas that occurred on July 6, 2018.[133] Consequently, all costs related to the VMCR program in excess of the $28 million reflected in rates are the responsibility of Washington Gas's shareholders. Customers have not paid any return on or return of (depreciation) the VMCR program above the initial $28 million. Deferred income taxes are a derivative of book/tax timing differences related to depreciation and, therefore, the tax deductions and ADIT resulting from the VMCR are also shareholder items. The item reflects the removal of the Excess Deferred Income Taxes related to Formal Case No. 1027 expenditures in excess of $28 million.
- AFUDC Equity—the equity component of the Allowance for Funds Used During Construction ("AFUDC equity") is recorded on an after-tax basis. It results in a decrease to the effective rate in the year recognized and results in an increase to the effective rate in the years that the assets are depreciated. The permanent item reflected here

[132] Formal Case No. 1137, Order No. 18712, paragraph 103, at page 40.
[133] The Commission issued Order No. 19396 in Formal Case No. 1142, on June 29, 2018.

mirrors the regulatory recovery of depreciation expense which is recovering AFUDC that has been capitalized.

- Amortization of Prior Flow-Through Depreciation and Cost of Removal—In Formal Case No. 1151, the Commission approved the Company's proposal to cease flow-through treatment and move to full normalization in this case over a period of 15 years.[134]

The sum of these permanent and flow-through tax differences decreases the statutory federal income tax expense by $2,153,621. Combining these federal taxes with state taxes computed at the statutory District of Columbia tax rate of 8.25 percent (6.52 percent net of federal benefit at 21.00 percent) less investment tax credits generate a ratemaking level tax expense of $614,762.

Q. WHY IS THIS SCHEDULE IMPORTANT TO THE ACCURATE CALCULATION OF THE INCOME TAX ADJUSTMENTS?

A. The tax adjustments are not simply the effects of the Net Operating Income ("NOI") adjustments and interest synchronization from rate base. As stated above, there are permanent book-to-tax differences and flow-through items that are unaffected by NOI and rate base adjustments. Therefore, it is necessary to demonstrate the individual components of changes in the effective tax rate from the per-book amount to the ratemaking amount. This verifies that the ultimate effective tax rate arrived at on a ratemaking basis is reasonable in the context of the statutory composite tax rate. Thus, if you have an effective tax rate higher or lower than the statutory rate, your permanent and flow-through

[134] Formal Case No. 1151 Stipulation SECTION 1 CALCULATION OF RATE REDUCTION.

items should account for that difference. This also provides context to the changes from the per book effective tax rate to the ratemaking effective tax rate.

Q. PLEASE SUMMARIZE THE ADJUSTMENTS RELATED TO INCOME TAXES INCLUDED IN YOUR COST OF SERVICE PRESENTATION.

A. The following table accumulates the income tax adjustments into three categories which are reflected in Exhibit WG (D)-2, Page 3 of 3.

Net Operating Income	$ 1,905,301
Interest Synchronization	228,752
Tax Adjustments	(1,967,306)
Total	$ 166,747

DEFERRED TAX ASSET-NOLC TAX NORMALIZATION-PLR (ADJUSTMENT 32)

Q. PLEASE DESCRIBE ADJUSTMENT 32— DEFERRED TAX ASSET FOR NET OPERATING LOSS CARRYFORWARDS ("DTA-NOLC") TAX NORMALIZATION PLR.

A. As described in the Direct Testimony of Company Witness Bell, a recent series of IRS PLRs necessitates a change in the treatment of federal income tax sharing payments received by Washington Gas from its participation in the filing of a consolidated federal income tax return on the federal DTA related to the NOLC related to depreciation reflected in rate base in this case.

Adjustment 32—DTA-NOLC-Tax Normalization PLR comprises three items: (1) a correction of the jurisdictional allocation of the NOLC; (2) the effect on the amount of DTA-NOLC included in Rate Base in this case; and (3) the effect on EDIT recorded pursuant to the TCJA.

Summary

Q. PLEASE SUMMARIZE ADJUSTMENT 32—DTA-NOLC TAX NORMALIZATION PRIVATE LETTER RULING.

A. The result of complying with the PLR requires the following adjustments to increase rate base and decrease income tax expense.

Rate Base Adjustments

Jurisdictional Realignment	
Decrease to DC NOLC	$ (878,155)
DTA-NOLC	
Federal DTA- NOLC Depreciation	$ 24,088,259

Net Operating Income Adjustments

EDIT	
Income Tax Expense	$ (140,599)

Q. WHAT IS THE IMPACT ON THE REVENUE REQUIREMENT OF ADJUSTMENT 32— DTA-NOLC-TAX NORMALIZATION PLR?

A. The combination of the rate base increase and income tax decrease is to increase the revenue requirement in this case by $2,840,840.

Per Book Jurisdictional Realignment

Q. BEFORE YOU DISCUSS ADJUSTMENT 32— DTA- NOLC- TAX NORMALIZATION PLR, IS THERE A RECLASSIFICATION NECESSARY TO THE PER BOOK DTA-NOLC AMOUNTS INCLUDED IN THE JURISDICTIONAL COST ALLOCATION STUDY SPONSORED BY COMPANY WITNESS SMITH TO FIX THE ALLOCATION OF THE NOLC AMONG JURISDICTIONS?

A. Yes, there is. Washington Gas's general ledger shows the following amounts related to the NOLC on a system basis and allocated to the District of Columbia:

Account[135]	System	DC[136]
190867 - ADIT- Federal NOL	$ (31,146,839)	$ (5,943,350)
190868 - ADIT - State NOL	(64,134,187)	(12,237,900)
Total General Ledger Amount	$ (95,281,026)	$(18,181,249)

The Jurisdictional Cost of Service Study shows different amounts by account for the system and DC NOLC:[137]

Account	System	DC
NOL Carryforward Federal	$ (78,173,336)	$(14,916,809)
NOL Carryforward State	(68,626,785)	(13,095,164)
NOL Federal Benefit of State	14,411,625	2,749,985
Sub Total	(132,388,496)	(25,261,989)
Other Tax Credits[138]	37,107,470	6,202,585
Total Jurisdictional Cost of Service Study	$ (95,281,026)	$(19,059,404)

Q. PLEASE SUMMARIZE THE ADJUSTMENT YOU ARE PROPOSING TO CORRECT THE DTA-NOLC ALLOCATED TO THE DISTRICT OF COLUMBIA.

A. The following table summarizes the DTA-NOLC tax adjustments necessary to decrease the District of Columbia NOLC.

Total General Ledger Amount	$(18,181,249)

[135] NOLC amounts are assets. In the jurisdictional cost allocation study the amounts are shown as contra-liabilities and therefore are presented in brackets.
[136] See Exhibit WG (F)-2 Schedule AL, page 3 of 5—DC Net_Rate_Base factor-19.0817 percent.
[137] Exhibit WG (F)-2, Schedule RB, page 1 of 12, lines 18-20.
[138] See Exhibit WG (F)-2, Schedule MACRS AL, Page 1 of 1—DC APB 11 Factor-16.7152 percent and Schedule RB, page 11 of 12.

Total Jurisdictional Cost of Service Study	(19,059,404)
Total Decrease to DC DTA-NOLC	$ 878,155[139]

Impact of the PLR on the federal DTA-NOLC

Q. PLEASE SUMMARIZE THE TREATMENT OF TAX SHARING PAYMENTS RECEIVED BY WASHINGTON GAS ON THE FEDERAL DTA-NOLC INCLUDED IN RATE BASE IN FORMAL CASE NO. 1169.

A. In Adjustment 5—Accumulated Deferred income Tax, in Formal Case No. 1169, Washington Gas proposed adjusting the federal DTA-NOLC balances through March 31, 2024, based on actual amounts through December 2021 and forecasted amounts through March 2024. Starting on April 1, 2023, the start of the rate effective period, the Company employed the Proration Method for including the projected accruals of deferred taxes related to depreciation timing differences.[140]

The workpapers for Adjustment 5—Accumulated Deferred income Tax in Formal Case No. 1169 show the derivation of the proposed adjustment to the federal DTA-NOLC.[141] Specifically, pages 12 and 13 of 17 showed the reduction in the federal DTA-NOLC in December 2022 reflecting the receipt by Washington Gas of a tax sharing payment.

Q. DID THE COMMISSION ADOPT WASHINGTON GAS'S RECOMMENDATION?

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[139] The following show the breakdown of the adjustment by line as presented in Exhibit WG (D)-1, page 2 of 4

NOL Carryforward Federal	$ 6,403,501
NOL Carryforward State	857,265
NOL Federal Benefit of State	(180,026)
ADIT: M.A.C.R.S. Depreciation Federal	(5,451,639)
ADIT: M.A.C.R.S. Depreciation State	(750,946)
Total Decrease to DC DTA-NOLC	$ 878,155

[140] Formal Case No. 1169, Exhibit WG (D), page 78, line 25 to page 79, line 5.

[141] Formal Case No. 1169, Exhibit WG (D)-5, Adjustment No. 5, pages 3, 12 and 13 of 17.

A. No, it did not. The Commission denied the Company's original Adjustment 5 proposal because it included forecasted ADIT and federal DTA-NOLC post-test year through March 2024.[142]

Q. DOES THIS MEAN THAT THE RATE BASE IN FORMAL CASE NO. 1169 IS PRESENTED CONSISTENT WITH THE PLR?

A. No, it does not. While the December 2022 tax sharing payment impact was not included in the federal DTA-NOLC, any prior period tax sharing payments have been reflected as a rate base reduction in prior base rate cases.

Q. DOES THE APPLICATION OF THE PLR REQUIRE RETROACTIVE APPLICATION?

A. No, the cumulative increase can be included in the determination of rate base in this case.

Q. WHAT IS THE TEST YEAR AMOUNT OF FEDERAL DTA-NOLC INCLUDED IN RATE BASE IN THIS CASE?

A. The table below summarizes per book federal DTA-NOLC in average rate base.

	System	DC [143]
13-month Average Federal DTA-NOLC [144]	$ 31,146,839	$ 5,943,350

Q. WHAT IS THE NECESSARY ADJUSTMENT TO THE NOLC INCLUDED IN THE TEST YEAR TO COMPLY WITH THE IRS PLR?

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[142] Formal Case No. 1169, Order No. 21939, at 45 (December 22, 2023).
[143] District of Columbia Net_Rate_Base average factor is 19.0817 percent.
[144] NOL Carryforward amounts are assets and as such are shown in the Rate Base Deduction section Exhibit WG (F)- 2 and Exhibit WG (D)-1, page 2 of 4, page with brackets.

A. Company Witness Bell determined that Washington Gas's federal DTA-NOLC, excluding any tax sharing impacts (Washington Gas stand-alone) at December 31, 2023, is as follows:

	System
System Federal NOLC Total	$1,259,747,192
System Federal NOLC Other Than Depreciation	394,791,932
System Federal NOLC Depreciation[145]	864,955,260
Statutory Tax Rate	21.00%
System Federal DTA-NOLC Depreciation	$ 181,640,604

Q. HOW DID YOU COMPUTE THE ADJUSTMENT TO THE 13-MONTH AVERAGE TEST YEAR ENDING MARCH 31, 2024, FOR THE DISTRICT OF COLUMBIA'S SHARE OF THE FEDERAL DTA NOLC DEPRECIATION ONLY?

A. The workpapers for Adjustment 32—NOLC Tax Normalization Private Letter Ruling perform three tasks: (1) compute the test year 13-month average of the federal DTA-NOLC and related tax effect of the PLR; (2) compute the District of Columbia's share of the test year 13-month average of the federal DTA-NOLC and related tax effect; and (3) compute the adjustment required to adjust the per book amount of DTA-NOLC included in rate base to incorporate the required change because of the DTA-NOLC addback.

The computations are summarized in the following section and support the proposed adjustment to increase the District of Columbia's DTA-NOLC (an increase in rate base) of $27,248,768:

	End of period	Average

[145] IRS Normalization rules are applicable to depreciation related deductions.

System Federal NOLC Depreciation	$ 864,955,260	$ 828,320,426
Statutory Tax Rate	21.00%	21.00%
System Federal DTA-NOLC Depreciation	181,640,604	173,947,289
Test Year Amount	(36,519,150)	(31,146,839)
Increase in Federal DTA-NOLC	$ 145,121,454	142,800,451
DC Share		19.08171%[146]
Increase in DC DTA- NOLC Depreciation		$ 27,248,768

Impact of the PLR on EDIT

Q. ARE THERE OTHER COMPONENTS OF THE COST OF SERVICE THAT ARE AFFECTED BY PLR?

A. Yes, there are. As discussed in the Direct Testimony of Company Witness Bell, the PLR also has an impact on the NOLC-related EDIT resulting from the income tax rate reduction provided by the TCJA. A DTA-NOLC existed at the time the TCJA rate reduction took effect. This DTA-NOLC was adjusted to reflect the reduction in the amount of the carryforward as a result of the tax rate decrease from 35 percent to 21 percent. In Formal Case No. 1151, the Commission approved a settlement agreement that allowed Washington Gas to establish a regulatory asset to reflect the deficient deferred taxes associated with the NOLC that were required to be collected from customers in the future. The amortization period for this amount was established to be 15 years.[147] Because a portion of this regulatory asset is associated with deductions that arose from

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[146] Net_Rate_Base factor See Exhibit WG (F)-2, Net Schedule AL, page 3 of 5 , line 6 Column H.

[147] Formal Case No. 1151, *In the Matter of the Impact of The Tax Cuts and Jobs Act of 2017 on the Existing Distribution Service Rates and Charges for Potomac Electric Power Company and Washington Gas Light Company*, Order No. 19395 Settlement, Agreement, Appendix A, Schedule C, page 4 of 6, col. D (June 29, 2018).

accelerated tax deductions, the amortization of the regulatory asset for the NOL derived by accelerated tax depreciation must be adjusted to reflect the ARAM required by the normalization rules provided by the TCJA. The Private Letter Ruling effect on the amount the EDIT amortization of the DTA-NOLC decreases income tax expense by $815,584 on a system basis.

Q. WHAT IS THE IMPACT ON EDIT AMORTIZATION FOR THE DISTRICT OF COLUMBIA?

A. Adjustment 32—DTA-NOLC Tax Normalization Private Letter Ruling computes the District of Columbia share of the impact of the PLR on EDIT amortization of is a decrease in income tax expense of $140,599 ($815,584 * 17.2388%[148] = $140,599.)

X. MERGER-RELATED COMMITMENTS

Q. DEFINE THE TERM "MERGER-RELATED COMMITMENTS" IN THE CONTEXT OF THIS DIRECT TESTIMONY.

A. Merger-Related Commitments relate to the set of specific commitments identified in Order No. 19396, Appendix A, in Formal Case No. 1142, that relate to cost of service matters that Washington Gas is required to address in its base rate case proceedings.

Q. ARE THERE ANY COSTS RELATED TO THE MERGER INCLUDED IN THE REVENUE REQUIREMENT IN THIS CASE?

A. No, none of the costs associated with the Merger or Merger-Related Commitments are included in the revenue requirement included in this case and,

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[148] In Formal Case No. 1151, the EDIT related to the NOL was allocated using the District of Columbia Net_Rate_Base factor at September 30, 2017, of 17.2388 percent.

therefore, none are included in the rates that our District of Columbia customers pay or will pay.

Q. FOR WHICH MERGER RELATED COMMITMENTS DO YOU DEMONSTRATE THIS TO BE THE CASE?

A. My testimony discusses the following Merger-Related Commitments that could affect the cost of service in this case:

- Commitment 24, which addresses the Company's Cost Allocation Manual ("CAM") and transactions with ALA.
- Commitment 72, which addresses the annual average costs of replacing/ remediating the necessary infrastructure to reduce leaks within the PROJECT*pipes* program.

Commitment 24

Q. PLEASE EXPLAIN COMMITMENT 24 AND ITS RELEVANCE TO THIS BASE RATE CASE.

A. Commitment 24 requires Washington Gas to meet the following conditions regarding affiliate transactions.

> **To comply with its CAM in transactions with AltaGas and its affiliates.**[149] On April 30, 2024, in Docket WGCAM 2024, Washington Gas filed its updated CAM with the Commission for the twelve months ended December 31, 2023. This filing also includes Washington Gas's certification regarding compliance with the Cost Allocation Manual and the

[149] Formal Case No. 1142, Order No. 19396, Appendix A, page 10.

Commission's Requirements, as mandated by Commitment 24. [150]

To use pricing protocols consistent with the rules of the Commission for transfer prices of any intercompany transfers of supplies and services related to Washington Gas.[151] This matter was also addressed in Washington Gas's April 30, 2024 filing, in Docket WGCAM 2024.

To agree that Washington Gas will continue to use its CAM (as updated) for all entities that allocate costs to Washington Gas's regulated operations.[152] This matter was also addressed in Washington Gas's April 30, 2024 filing, in Docket WGCAM 2024.

To provide current service agreements between Washington Gas and any affiliates that Washington Gas either provides services to or receives services from with the 21-day compliance filing in any future rate case proceedings.[153] The Supplemental Information Pursuant to the District of Columbia Public Service Commission's Rules Governing Utility Rate Cases ("Compliance Filing") filed

[150] WGCAM2024
[151] Formal Case No. 1142, Order No. 19396, Appendix A, page 10.
[152] Ibid.
[153] Ibid.

concurrent with this base rate case includes the current service agreements between Washington Gas and its affiliates.

Commitment 72

Q. PLEASE EXPLAIN COMMITMENT 72 AND ITS RELEVANCE TO THIS BASE RATE CASE.

A. Commitment 72, as agreed in Formal Case No. 1142, required Washington Gas to calculate, on an annual basis, the average costs from the prior two (2) years of replacing/remediating the necessary infrastructure to reduce leaks within its PROJECT*pipes* program. Further, Commitment 72 states Washington Gas will not be allowed to recover any replacement/remediation expenditures for completed program work incurred post-Merger Close (Fiscal Year 2019 and beyond) in the surcharge tracker mechanism that are above defined criteria. Furthermore, any excess costs for leak replacement/ remediation under the PROJECT*pipes* program will be treated as normal replacement costs and will be reviewed by the Commission and stakeholders in a prudence review in Washington Gas's next base rate case to determine if the costs were prudently incurred and are appropriate for recovery through base rates.[154]

Q. WHAT HAS OCCURRED TO DATE REGARDING COMMITMENT 72?

[154] Formal Case No. 1142, Order No. 19396, Appendix A, pages 26-27.

A. On July 31, 2019, Washington Gas filed a methodology of calculating the baseline and actual cost for the program year 2019.[155] That filing demonstrated that 2019 costs exceeded the prior two-year average by $93,061.[156]

Q. HOW WERE THOSE EXCESS COSTS TREATED IN DETERMINING THE REVENUE REQUIREMENT IN FORMAL CASE NO. 1162?

A. In September 2019, Washington Gas removed the $93,061 from the PROJECT*pipes* surcharge. As a result, the amounts were included in normal replacements in the test year.[157]

Q. WHAT OCCURRED IN THE SECOND TWO-YEAR ASSESSMENT PURSUANT TO COMMITMENT 72?

A. On December 22, 2020, Washington Gas submitted its compliance filing regarding the calculation for the twelve months ended September 30, 2020. That assessment showed that for 2020, the two-year average was exceeded by $30,987.[158] In September 2020, Washington Gas removed the $30,987 from the PROJECT*pipes* surcharge. As a result, the amounts were included in normal replacements in the test year.

Q. WHAT OCCURRED IN THE THIRD AND FOURTH TWO-YEAR ASSESSMENTS PURSUANT TO COMMITMENT 72?

A. On December 21, 2021, Washington Gas submitted its compliance filing regarding the calculation for the twelve months ended September 30, 2021.[159] That assessment showed for 2021, there were no costs in excess of the two-

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[155] For Commitment 72, "2019" refers to the twelve months ended September 30, 2019.
[156] Formal Case No. 1142-2019 G.
[157] Formal Case No. 1162 Settlement Agreement, Attachment 2.
[158] Formal Case No. 1142-2020 G.
[159] Formal Case No. 1142-2021 G.

year average and no costs were removed from the PROJECT*pipes* surcharge for the twelve months ended September 30, 2021.

On December 28, 2022, Washington Gas submitted its compliance filing regarding the calculation for the twelve months ended September 30, 2022.[160] That assessment showed for 2022, there were no costs in excess of the two-year average and no costs were removed from the PROJECT*pipes* surcharge for the twelve months ended September 30, 2022.

On January 2, 2024, Washington Gas submitted its annual compliance filing for the twelve months ended September 30, 2023.[161] That assessment showed for 2023, the costs exceeded the two-year average by $2,988,381. In December 2023, Washington Gas removed the $2,988,381 from the PROJECT*pipes* surcharge. As a result, the amounts were included in normal replacements in the test year.

XI. SUMMARY

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR TESTIMONY.

A. As demonstrated by the Direct Testimony, Washington Gas's current rates are inadequate to cover the cost of its operations and provide it a fair rate of return on its investment. If fact, the rates generate cash flow that is insufficient to fund Washington Gas District of Columbia operations. For the test year ending March 31, 2024, the Company significantly under earned generating only 4.22 percent on rate base in the District of Columbia based on actual weather. The distribution-only portion of the business equally under earned generating

[160] Formal Case No. 1142-2022 G.
[161] Formal Case No. 1142-2024 G

only 2.64 percent on rate base in the District of Columbia. After consideration of the base rate revenue increase effective January 19, 2024, Washington Gas's rates are still deficient. Based on the ratemaking results developed herein, absent rate relief, the Company will earn 3.65 percent on rate base and 2.45 percent on common equity in the District of Columbia during the rate effective period ending July 31, 2026, continuing the deficient level of revenues.[162] In fact, the results demonstrate that Washington Gas will earn just enough to meet its interest cost on debt.

That rate of return requires $45.6 million of increased base rate revenues to allow the Company's District of Columbia operations the opportunity to earn its requested overall return on rate base of 7.874 percent and return on equity of 10.50 percent.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

[162] The Company is proposing a procedural schedule that would allow it to place new rates into effect in May 2025. The difference between that date and the rate effective period used to develop the ratemaking adjustments in this cost of service has little or no impact on Washington Gas's revenue requirement recommendation.

Washington Gas Light Company
District of Columbia Jurisdiction

Income Statement and Rate of Return Summary

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Books C	Distribution Adjustments D	Distribution Amounts E = C + D	Ratemaking Adjustments F	Ratemaking Amounts G = E + F	Revenue Deficiency H	ROE Amounts I = G + H
1	Operating Revenues	Adj List Pg 1, Ln. 11	$ 276,904,880	$ (84,692,285)	$ 192,212,595	$ 19,414,936	$ 211,627,531	$ 45,572,411	$ 257,199,942
2	Operating Expenses								
3	Operation	Adj List Pg 1, Ln. 41	$ 125,293,859	$ (68,209,263)	$ 57,084,597	$ (267,932)	$ 56,816,665	$ 1,200,094	$ 58,016,759
4	Maintenance	Adj List Pg 1, Ln. 20	25,568,839	-	25,568,839	356,972	25,925,811	-	25,925,811
5	Depreciation	Adj List Pg 1, Ln. 47	23,907,431	-	23,907,431	7,922,823	31,830,254	-	31,830,254
6	Amortization of General Plant	Per Books	1,878,281	-	1,878,281	-	1,878,281	-	1,878,281
7	Amortization of Capitalized Software	Adj List Pg 1, Ln. 43	3,757,163	(97,980)	3,659,183	-	3,659,183	-	3,659,183
8	Amortization of Unrecovered Plant Loss	Per Books	100,274	-	100,274	-	100,274	-	100,274
9	Interest on Customer Deposits	Adj List Pg 1, Ln. 48	41,769	-	41,769	35,315	77,084	-	77,084
10	Interest on Supplier Refunds	Per Books	11,533	(11,533)	-	-	-	-	-
11	General Taxes	Adj List Pg 2, Ln. 7	58,992,535	-	58,992,535	4,443,796	63,436,331	-	63,436,331
12	Expenses Before Income Taxes	Sum of Lns. 3 > 11	$ 239,551,685	$ (68,318,776)	$ 171,232,910	$ 12,490,974	$ 183,723,884	$ 1,200,094	$ 184,923,978
13	Income Taxes	Adj List Pg 2, Ln. 10	3,537,493	(3,089,477)	448,015	166,747	614,762	12,210,152	12,824,914
14	Total Operating Expenses	Sum of Lns. 12 + 13	$ 243,089,178	$ (71,408,253)	$ 171,680,925	$ 12,657,721	$ 184,338,646	$ 13,410,246	$ 197,748,892
15	Net Operating Income	Ln. 1 - Ln. 14	$ 33,815,702	$ (13,284,032)	$ 20,531,669	$ 6,757,215	$ 27,288,885	$ 32,162,165	$ 59,451,050
16	Net Income Adjustments								
17	AFUDC	Per Books	467,443	-	467,443	-	467,443	-	467,443
18	Net Operating Income - Adjusted	Sum of Ln.s 15 > 17	$ 34,283,145	$ (13,284,032)	$ 20,999,112	$ 6,757,215	$ 27,756,328	$ 32,162,165	$ 59,918,493
19	Net Rate Base	Rate Base Stmt, Ln.23	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (35,183,527)	$ 760,992,964	$ -	$ 760,992,964
20	Return Earned	Ln. 18 / Ln. 19	4.22%		2.64%		3.65%		7.87%
21	Return on Common Equity								
22	Interest Expense		$ 19,142,496	$ (330,939)	$ 18,811,557	$ (831,295)	$ 17,980,262		$ 17,980,262
23	Net Income Available for Common Equity	Ln. 18 - Ln. 22	$ 15,140,649		$ 2,187,555		$ 9,776,066		$ 41,938,231
24	Common Equity Ratio	Cost of Capital, Ln. 3	52.49%		52.49%		52.49%		52.49%
25	Common Equity Capital	Ln. 19 * Ln. 24	$ 426,291,579		$ 417,878,033		$ 399,411,746		$ 399,411,746
26	Return Earned on Common Equity	Ln. 23 / Ln. 25	3.55%		0.52%		2.45%		10.50%

Washington Gas Light Company
District of Columbia Jurisdiction

Average Rate Base Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Books Amount	Distribution Adjustments	Distribution Amount	Ratemaking Adjustments	Ratemaking Amount
	A	B	C	D	E = C + D	F	G = E + F
1	Gas Plant in Service		$ 1,317,182,832	$ (770,154)	$ 1,316,412,678	$ 27,107,163	$ 1,343,519,841
2	Construction Work in Progress		79,322,274	-	79,322,274	(72,437,698)	6,884,577
3	Materials & Supplies	Adj List Pg 2, Ln. 14	19,836,447	(16,895,300)	2,941,148	-	2,941,148
4	Non-Plant ADIT		(3,062,666)		(3,062,666)	(293,256)	(3,355,922)
5	FC 1027 - Rate Base CWIP (Reg Asset) _a/		(0)	-	(0)	-	(0)
6	Unamortized East Station _a/	Adj List Pg 2, Ln. 19	1,075,846	-	1,075,846	690,481	1,766,327
7	Sub-Total	Sum of Lns. 1 > 6	$ 1,414,354,734	$ (17,665,454)	$ 1,396,689,281	$ (44,933,310)	$ 1,351,755,971
8	Cash Working Capital	Adj List Pg 2, Ln. 17	39,219,091	652,610	39,871,701	954,625	40,826,325
9	Gross Rate Base	Ln. 7 + Ln. 8	$ 1,453,573,825	$ (17,012,844)	$ 1,436,560,981	$ (43,978,685)	$ 1,392,582,296
10	LESS:						
11	Reserve for Depreciation	Per Books	$ 449,057,859	$ (356,329)	$ 448,701,530	$ 7,495,833	$ 456,197,363
12	ADIT: M.A.C.R.S. Depreciation	Per Books	212,149,665	-	212,149,665	3,877,037	216,026,702
13	ADIT: Gains/Losses on Reaquired Debt (Federal)	Per Books	29,300	-	29,300	-	29,300
14	ADIT: Gains/Losses on Reaquired Debt (State)	Per Books	10,143	-	10,143	-	10,143
15	NOL Carryforward Federal	Per Books	(14,916,809)	-	(14,916,809)	(20,845,267)	(35,762,077)
16	NOL Carryforward State	Per Books	(13,095,164)	-	(13,095,164)	857,264	(12,237,900)
17	NOL Federal Benefit of State	Per Books	2,749,985	-	2,749,985	(180,026)	2,569,959
18	Customer Advances for Construction	Per Books	305,769	-	305,769	-	305,769
19	Customer Deposits	Per Books	1,432,785	-	1,432,785	-	1,432,785
20	Supplier Refunds	Adj List Pg 2, Ln. 25	626,315	(626,315)	-	-	-
21	Deferred Tenant Allowance	Per Books	3,017,287	-	3,017,287	-	3,017,287
22	Total Rate Base Deductions	Sum of Lns. 11 > 21	$ 641,367,135	$ (982,644)	$ 640,384,490	$ (8,795,158)	$ 631,589,332
23	Net Rate Base	Ln. 9 - Ln. 22	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (35,183,527)	$ 760,992,964

a/ Net of deferred taxes

Washington Gas Light Company
District of Columbia

Determination of Revenue Deficiency

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	DC Distribution Amount	DC Ratemaking Amount
	A	B	C	D
1	Revenue Deficiency			
2	Net Rate Base	Rate Base Stmt, Ln.23	$ 796,176,491	$ 760,992,964
3	Overall Rate of Return	Cost of Capital, Ln. 4	7.87%	7.87%
4	Required Return	Line 2 x Line 3	$ 62,688,747	$ 59,918,493
5	Net Utility Operating Income	DC Inc Stmt, Ln. 18	20,999,112	27,756,328
6	Return Deficiency	Line 4 - Line 5	$ 41,689,635	$ 32,162,165
7	DC Income Taxes	Line 9 x footnote a/	4,745,138	3,660,716
8	Federal Income Taxes	Line 9 x footnote b/	11,082,055	8,549,436
9	Revenue Deficiency before Uncollectibles	Line 6 / footnote c/	$ 57,516,828	$ 44,372,317
10	Allowance for Uncollectible Accounts	Line 9 x footnote d/	1,555,600	1,200,094
11	Total Revenue Deficiency	Line 9 + Line 10	$ 59,072,428	$ 45,572,411
a/	DC Income Tax Rate		8.2500%	8.2500%
b/	Federal Income Tax Rate (1 - 8.25%)*21%		19.2675%	19.2675%
	Composite Tax Rate		27.5175%	27.5175%
c/	Complement of Composite Tax Rate (1 - 27.518%)		72.483%	72.483%
d/	Uncollectible Rate		2.7046%	2.7046%

Washington Gas Light Company
District of Columbia Jurisdiction

Utility Cost of Capital

Twelve Months Ended March 31, 2024

Line No.	Description	Ratio	Cost	Weighted Cost
	A	C	D	E = C x D
1	Long-term Debt	42.88%	4.84%	2.08%
2	Short-term Debt	4.63%	6.20%	0.29%
3	Common Equity	52.49%	10.50%	5.51%
4	Total	100.00%		7.87%

Washington Gas Light Company
District of Columbia Jurisdiction

Summary of Distribution / Ratemaking Adjustments

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Distribution	Ratemaking	Total
	A	B	C	D	E
1	**Revenue Adjustments**				
2	Fuel Revenues	Adj. No. 1D	$ (59,477,160)	$ -	$ (59,477,160)
3	Third Party Balancing Charges	Adj. No. 1D	(6,609,061)	-	(6,609,061)
4	GAC Revenues Elimination	Adj. No. 2D	(1,773,001)	-	(1,773,001)
5	Carrying Costs on Storage Gas Inventory - Gas Sales	Adj. No. 4D	(1,558,766)	-	(1,558,766)
6	Asset Optimization Revenues Elminiation	Adj. No. 5D	(14,177,234)	-	(14,177,234)
7	POR Elimination - Other Revenues	Adj. No. 7D	(736,920)	-	(736,920)
8	POR Elimination - Late Payment	Adj. No. 7D	(360,143)	-	(360,143)
9	Revenues	Adj. No. 1	-	19,456,025	19,456,025
10	East Station Revenue Sharing	Adj. No. 1	-	(41,088)	(41,088)
11	**Total Revenue Adjustments**	**Ln. 2 > Ln. 10**	**$ (84,692,285)**	**$ 19,414,936**	**$ (65,277,349)**
12	**Operation Expense Adjustments**				
13	Purchased Gas Costs Elimination	Adj. No. 1D	$ (66,068,873)	$ -	$ (66,068,873)
14	GAC Uncollectibles Elimination	Adj. No. 2D	(1,694,830)		(1,694,830)
15	Gas Procurement Costs Elimination	Adj. No. 3D	(78,171)	-	(78,171)
16	Purchase of Receivables Collection Expense	Adj. No. 7D	(226,115)	-	(226,115)
17	Purchase of Receivables Bad Debt Expense	Adj. No. 7D	(141,274)	-	(141,274)
18	Uncollectibles Gas Accounts	Adj. No. 1	-	1,038,168	1,038,168
19	Wages & Salaries Expense Adjustment - Operations	Adj. No. 5	-	644,085	644,085
20	Wages & Salaries Expense Adjustment - Maintenance	Adj. No. 5	-	356,972	356,972
21	Long-Term Incentive Elimination	Adj. No. 6	-	(3,390,371)	(3,390,371)
22	OPEB Expense	Adj. No. 7	-	(630,366)	(630,366)
23	Pension Expense	Adj. No. 8	-	(565,665)	(565,665)
24	401(k) Employer Contribution	Adj. No. 9	-	79,796	79,796
25	Executive Fringe Elimination	Adj. No. 10	-	(39,094)	(39,094)
26	Medical Inflation	Adj. No. 11	-	195,423	195,423
27	Involuntary Separation Labor Expense Reduction	Adj. No. 13	-	(1,978,270)	(1,978,270)
28	Involuntary Separation Cost to Implement Amortization	Adj. No. 14	-	271,011	271,011
29	Amortization of COVID Regulatory Asset - Expenses	Adj. No. 15	-	73,633	73,633
30	Regulatory Commission Expenses	Adj. No. 16	-	2,608,431	2,608,431
31	Environmental Expense	Adj. No. 17	-	278,465	278,465
32	Insurance Expense	Adj. No. 18	-	347,779	347,779
33	Commission-Mandated Audit Fees	Adj. No. 20	-	333,242	333,242
34	Non-Labor Inflation	Adj. No. 21	-	1,043,643	1,043,643
35	Trade Dues, Bus Memberships, and Community Affairs	Adj. No. 22	-	(97,796)	(97,796)
36	General Advertising Expense	Adj. No. 23	-	(125,884)	(125,884)
37	Legal Expenses	Adj. No. 25	-	136,923	136,923
38	Prior Period & One Time Entries	Adj. No. 26	-	(26,978)	(26,978)
39	Meger Cost to Achieve Amortization Elimination	Adj. No. 27	-	(52,311)	(52,311)
40	Credit/Debit Card Transaction Fees Elimination	Adj. No. 28	-	(411,796)	(411,796)
41	Total Non-tax Operations Expense Adjustments	Ln. 13 > Ln. 40	$ (68,209,263)	$ 89,040	$ (68,120,223)
42	**Depreciation & Amortization Expense Adjustments**				
43	Purchase of Receivables Depreciation Expense	Adj. No. 7D	$ (97,980)	$ -	$ (97,980)
44	Depreciation Expense	Adj. No. 4	-	7,691,665	7,691,665
45	Amortization Expense	Adj. No. 4	-	-	-
46	Projectpipes - Depreciation Expense	Adj. No. 3	-	231,158	231,158
47	Total Depreciation Expense Adjustments	Ln. 43 > Ln. 46	$ (97,980)	$ 7,922,823	$ 7,824,843
48	**Interest on Customer Deposits**	Adj. No. 19	$ -	$ 35,315	$ 35,315
49	**Supplier Refunds Interest Elimination**	Adj. No. 6D	$ (11,533)	$ -	$ (11,533)

Washington Gas Light Company
District of Columbia Jurisdiction

Summary of Distribution / Ratemaking Adjustments

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Distribution C	Ratemaking D	Total E
1	**General Tax Adjustments**				
2	DC Delivery Tax	Adj. No. 1	$ -	$ 2,241,912	$ 2,241,912
3	DC Rights-of-Way Fee	Adj. No. 1	-	(2,608,388)	(2,608,388)
4	DC Sustainable Energy Fund Revenue	Adj. No. 1	-	4,577,879	4,577,879
5	DC Energy Assistance Fund Revenue	Adj. No. 1	-	210,071	210,071
6	FICA/Medicare Taxes	Adj. No. 12	-	22,322	22,322
7	Total General Taxes	Ln. 2 > Ln. 6	$ -	$ 4,443,796	$ 4,443,796
8	**Sub-total Expense Adjs. before Income Taxes & Interest**		$ (68,318,776)	$ 12,490,974	$ (55,827,802)
9	**Income Tax Adjustments**				
10	Income Taxes	Adj. No. 10D & Adj. No. 31	$ (3,089,477)	$ 166,747	$ (2,922,730)
11	Total Income Tax Expense Adjustment		$ (3,089,477)	$ 166,747	$ (2,922,730)
12	**Total Expense Adjustments**	**Ln. 8 + Ln. 11**	**$ (71,408,253)**	**$ 12,657,721**	**$ (58,750,532)**
13	**Rate Base Adjustments**				
14	Storage Gas Inventory Rate Base Elimination	Adj. No. 4D	$ (16,895,300)	$ -	$ (16,895,300)
15	Purchase of Receivables Capitalized Software	Adj. No. 7D	(762,920)	-	(762,920)
16	Purchase of Receivables Hardware	Adj. No. 7D	(7,234)	-	(7,234)
17	Cash Working Capital	Adj. No. 9D & Adj. No. 30	652,610	954,625	1,607,235
18	CWIP Elimination	Adj. No. 2	-	(66,213,700)	(66,213,700)
19	Environmental - Ratebase	Adj. No. 17	-	690,481	690,481
20	Projectpipes - Gas Plant in Service	Adj. No. 3	-	27,107,163	27,107,163
21	Projectpipes - Construction Work in Progress	Adj. No. 3	-	(6,223,998)	(6,223,998)
22	Reclassification & Elimination of Non-Plant ADIT	Adj. No. 24	-	(293,256)	(293,256)
23	Gross Rate Base Adjustments	Ln. 14 > Ln. 22	$ (17,012,844)	$ (43,978,685)	$ (60,991,529)
24	**Rate Base Deduction Adjustments**				
25	Supplier Refunds Elimination	Adj. No. 6D	$ (626,315)	$ -	$ (626,315)
26	Purchase of Receivables Reserve for Depreciation	Adj. No. 7D	(356,329)	-	(356,329)
27	Reserve for Depreciation	Adj. No. 4	-	3,813,872	3,813,872
28	Accumulated Deferred Income Tax for new depreciation ra	Adj. No. 4	-	1,049,482	1,049,482
29	Projectpipes - Depreciation Reserve	Adj. No. 3	-	1,589,836	1,589,836
30	Projectpipes - Cost of Removal	Adj. No. 3	-	2,092,125	2,092,125
31	Projectpipes - Accumulated Deferred Income Tax	Adj. No. 3	-	8,035,220	8,035,220
32	Elimination of CIAC ADIT	Adj. No. 24	-	994,920	994,920
33	NOL Carryforward Federal Correction	Adj. No. 32		6,403,501	6,403,501
34	NOL Carryforward State Correction	Adj. No. 32		857,264	857,264
35	NOL Federal Benefit of State	Adj. No. 32		(180,026)	(180,026)
36	Other Tax Credits	Adj. No. 32		(6,202,585)	(6,202,585)
37	Accumulated Deferred Income Taxes - NOL DTA	Adj. No. 32		(27,248,768)	(27,248,768)
38	Rate Base Deductions	Ln. 25 > Ln. 37	$ (982,644)	$ (8,795,158)	$ (9,777,803)
39	**Net Rate Base Adjustments**	**Ln. 23 - Ln. 38**	**$ (16,030,199)**	**$ (35,183,527)**	**$ (51,213,726)**
40	**Total**	**Ln. 11 + Ln. 12 + Ln. 39**	**$ (172,130,738)**	**$ (3,110,869)**	**$ (175,241,607)**
41	**Interest Sync Adjustments**				
42	Interest on Debt	Adj. No. 8D & Adj. No. 29	$ (330,939)	$ (831,295)	$ (1,162,234)
43	Total Interest Adjustments		$ (330,939)	$ (831,295)	$ (1,162,234)
44	**Total Adjustments**	**Sum Lns. (11 , 12 , 39 , 43)**	**$ (172,461,676)**	**$ (3,942,164)**	**$ (176,403,841)**

Washington Gas Light Company
District of Columbia Jurisdiciton

Reconciliation of Revenue Requirement

Twelve Months Ended March 31, 2024

Line No.	ADJ. No.	Description	Actual Adjustment A	Rate Base B	Revenues C	Expenses D	Interest E	Income Tax F	Other G	Net Income H	Revenue Deficiency I
1		**Per Books Revenue Requirement**									
2		Per Books Revenue Requirement		$ 812,206,690	$ 276,904,880	$ 239,551,685	$ 19,142,496	$ 3,537,493	$ 467,443	$ 34,283,145	$ 42,037,96
3		Interest Synchronization		-	-	-	47,812	(13,157)		13,157	(18,64
4		**Per book adjusted for interest synchronization**		$ 812,206,690	$ 276,904,880	$ 239,551,685	$ 19,190,308	$ 3,524,336	$ 467,443	$ 34,296,302	$ 42,019,32
5											
6		**REVENUE ADJUSTMENTS**	$ (65,277,349)	$ -	$ (65,277,349)	$ -	$ -	$ (17,962,694)		$ (47,314,654)	$ 67,042,83
7											
8		**EXPENSE ADJUSTMENTS**									
9	1D	Purchased Gas Costs	(66,068,873)	-	-	(66,068,873)	-	18,180,502		47,888,371	(67,855,77
10	2D	Uncollectible Gas Accounts	(1,694,830)	-	-	(1,694,830)	-	466,375		1,228,455	(1,740,66
11	3D	Gas Procurement Costs	(78,171)	-	-	(78,171)	-	21,511		56,660	(80,28
12	7D	Purchase of Receivables Collection Expense	(226,115)	-	-	(226,115)	-	62,221		163,894	(232,23
13	7D	Purchase of Receivables Bad Debt Expense	(141,274)	-	-	(141,274)	-	38,875		102,399	(145,09
14	1	Uncollectibles Gas Accounts	1,038,168	-	-	1,038,168	-	(285,678)		(752,490)	1,066,24
15	5	Wages and Salaries	1,001,057	-	-	1,001,057	-	(275,466)		(725,591)	1,028,13
16	6	Long-Term Incentive Elimination	(3,390,371)	-	-	(3,390,371)	-	932,945		2,457,426	(3,482,06
17	7	OPEB Expense	(630,366)	-	-	(630,366)	-	173,461		456,905	(647,41
18	8	Pension Expense	(565,665)	-	-	(565,665)	-	155,657		410,008	(580,96
19	9	401(k) Employer Contribution	79,796	-	-	79,796	-	(21,958)		(57,838)	81,95
20	10	Executive Fringe Elimination	(39,094)	-	-	(39,094)	-	10,758		28,336	(40,15
21	11	Medical Inflation	195,423	-	-	195,423	-	(53,776)		(141,647)	200,70
22	13	Involuntary Separation Labor Expense Reduction	(1,978,270)	-	-	(1,978,270)	-	544,371		1,433,900	(2,031,77
23	14	Involuntary Separation Cost to Implement Amortization	271,011	-	-	271,011	-	(74,575)		(196,435)	278,34
24	15	Amortization of COVID Regulatory Asset - Expenses	73,633	-	-	73,633	-	(20,262)		(53,371)	75,62
25	16	Regulatory Commission Expenses	2,608,431	-	-	2,608,431	-	(717,775)		(1,890,656)	2,678,97
26	17	Environmental Expense	278,465	-	-	278,465	-	(76,627)		(201,838)	285,99
27	18	Insurance Expense	347,779	-	-	347,779	-	(95,700)		(252,079)	357,18
28	20	Commission-Mandated Audit Fees	333,242	-	-	333,242	-	(91,700)		(241,542)	342,25
29	21	Non-Labor Inflation	1,043,643	-	-	1,043,643	-	(287,185)		(756,459)	1,071,87
30	22	Trade Dues, Bus Memberships & Support Payments	(97,796)	-	-	(97,796)	-	26,911		70,885	(100,44
31	23	General Advertising Expense	(125,884)	-	-	(125,884)	-	34,640		91,244	(129,28
32	25	Legal Expenses	136,923	-	-	136,923	-	(37,678)		(99,245)	140,62
33	26	Prior Period & One Time Entries	(26,978)	-	-	(26,978)	-	7,424		19,554	(27,70
34	27	Meger Cost to Achieve Amortization Elimination	(52,311)	-	-	(52,311)	-	14,395		37,917	(53,72
35	28	Credit/Debit Card Transaction Fees Elimination	(411,796)	-	-	(411,796)	-	113,316		298,480	(422,93
36	7D	Purchase of Receivables Depreciation Expense	(97,980)	-	-	(97,980)	-	26,962		71,018	(100,63
37	4	Depreciation Expense	7,691,665	-	-	7,691,665	-	(2,116,554)		(5,575,111)	7,899,69
38	4	Amortization Expense	-	-	-	-	-	-		-	
39	3	Projectpipes - Depreciation Expense	231,158	-	-	231,158	-	(63,609)		(167,549)	237,41
40	19	Interest on Customer Deposits	35,315	-	-	35,315	-	(9,718)		(25,597)	36,27
41	6D	Supplier Refund Interest	(11,533)	-	-	(11,533)	-	3,174		8,359	(11,84
42	1	Delivery Tax	2,241,912	-	-	2,241,912	-	(616,918)		(1,624,994)	2,302,54
43	1	DC Rights-of-Way Fee	(2,608,388)	-	-	(2,608,388)	-	717,763		1,890,625	(2,678,93
44	1	Sustainable Energy Trust Fund	4,577,879	-	-	4,577,879	-	(1,259,718)		(3,318,161)	4,701,69
45	1	Energy Assistance Trust Fund	210,071	-	-	210,071	-	(57,806)		(152,265)	215,75
46	12	FICA / Medicare Taxes	22,322	-	-	22,322	-	(6,142)		(16,180)	22,92
47	8D & 28	Interest on Debt	(1,162,234)	-	-	-	-	-		-	
48		Tax Deductions	(642,269)					(642,269)		642,269	(910,06
49											
50		**RATE BASE ADJUSTMENTS**									
51		**Additions**									
52	4D	Storage Gas Inventory	(16,895,300)	(16,895,300)	-	-	(399,191)	109,848		(109,848)	(1,729,31
53	7D	Purchase of Receivables Capitalized Software	(762,920)	(762,920)	-	-	(18,026)	4,960		(4,960)	(78,08
54	7D	Purchase of Receivables Hardware	(7,234)	(7,234)	-	-	(171)	47		(47)	(74
55	9D & 30	Cash Working Capital	1,607,235	1,607,235	-	-	37,975	(10,450)		10,450	164,50
56	2	CWIP Elimination	(66,213,700)	(66,213,700)	-	-	(1,564,456)	430,499		(430,499)	(6,777,28
57	17	Environmental Expense (Rate Base)	690,481	690,481	-	-	16,314	(4,489)		4,489	70,67
58	3	Projectpipes - Gas Plant in Service	27,107,163	27,107,163	-	-	640,471	(176,242)		176,242	2,774,54
59	3	Projectpipes - Construction Work in Progress	(6,223,998)	(6,223,998)	-	-	(147,057)	40,466		(40,466)	(637,05
60	24	Reclassification & Elimination of Non-Plant ADIT	(293,256)	(293,256)	-	-	(6,929)	1,907		(1,907)	(30,01
61		**Deductions**									
62	6D	Supplier Refunds	626,315	626,315	-	-	14,798	(4,072)		4,072	64,10
63	7D	Purchase of Receivables Depreciation Reserve	356,329	356,329	-	-	8,419	(2,317)		2,317	36,47
64	3	Projectpipes - Depreciation Reserve	(1,589,836)	(1,589,836)	-	-	(37,564)	10,337		(10,337)	(162,72
65	3	Projectpipes - Cost of Removal	(2,092,125)	(2,092,125)	-	-	(49,431)	13,602		(13,602)	(214,13
66	3	Projectpipes - Accumulated Deferred Income Tax	(8,035,220)	(8,035,220)	-	-	(189,851)	52,242		(52,242)	(822,44
67	4	Reserve for Depreciation	(3,813,872)	(3,813,872)	-	-	(90,112)	24,797		(24,797)	(390,36
68	4	Accumulated Deferred Income Tax for new depreciation rate	(1,049,482)	(1,049,482)	-	-	(24,797)	6,823		(6,823)	(107,41
69	24	Elimination of CIAC ADIT	(994,920)	(994,920)	-	-	(23,507)	6,469		(6,469)	(101,83
70	32	NOL Carryforward Federal Correction	(6,403,501)	(6,403,501)	-	-	(151,298)	41,633		(41,633)	(655,42
71	32	NOL Carryforward State Correction	(857,264)	(857,264)	-	-	(20,255)	5,574		(5,574)	(87,74
72	32	NOL Federal Benefit of State	180,026	180,026	-	-	4,254	(1,170)		1,170	18,42
73	32	Other Tax Credits	6,202,585	6,202,585	-	-	146,551	(40,327)		40,327	634,86
74	32	Accumulated Deferred Income Taxes - NOL DTA	27,248,768	27,248,768	-	-	643,817	(177,162)		177,162	2,789,04
75		**Ratemaking Operating Results**		$ 760,992,964	$ 211,627,531	$ 183,723,884	$ 17,980,262	$ 614,763	$ 467,443	$ 27,756,328	$ 45,572,41

Tax Deducts = Rate Base Adjustment * Weighted Cost of Debt Factor	
Long-term Debt, Weighted Cost	2.075%
Short-term Debt, Weighted Cost	0.287%
Weighted Cost of Debt Factor	**2.363%**

Federal/State Current Tax = (Revenues - Expenses - Tax Deducts) * (Composite Tax Rate)	
Federal Tax Rate (net of state taxes)	19.2675%
State Tax Rate	8.2500%
Composite Tax Rate	**27.5175%**

Revenue Deficiency = ((Rate Base * ROI) - Net Income) * Total Gross Up Factor	
Return on Investment (ROI)	7.874%
Total Gross Up Factor	
Composite Tax Rate Gross Up Factor	137.964%
Bad Debt Gross Up Factor	3.731%
Total Gross Up Factor	**141.696%**

Tax Deductions Calculation	Total	Distribution	Ratemaking
Change in Tax Rate on Per Book Revenues	175,210	175,210	-
Changes to Flow-throughs & Perm Items	(10,719)	3,463	(14,18
Changes in Tax Amortizations	(1,067,374)	1,156,047	(2,223,42
Prior Year and Other Tax Adjustments	260,614	(9,682)	270,29
Total Tax Deductions	**(642,269)**	**1,325,037**	**(1,967,30**

Interest Synchronitzation Calculation	Total	Distribution	Ratemaking
Interest Expense (Adj 8D / Adj 28)	(1,162,234)	(330,939)	(831,29
Interest Synchronitzation (Taxes on Interest)	**(319,818)**	**(91,066)**	**(228,76**

NOI Tax Adjustments Calculation	Total	Distribution	Ratemaking
Interest Synchronization	319,818	91,066	228,75
Tax Deducts	(642,269)	1,325,037	(1,967,30
Tax Adjustments (Adj 9D / Adj 30)	(2,922,730)	(3,089,477)	166,74
NOI Tax Adjustments	**(2,600,280)**	**(4,505,581)**	**1,905,30**
Total Tax Adjustments	**(2,922,730)**	**(3,089,477)**	**166,74**

Washington Gas Light Company
District of Columbia
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Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1D - Purchased Gas Costs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		Amount C
1	*Purchased Gas Revenues*			
2	Fuel Revenues	RV:1:13	$	(59,477,160)
3	Third Party Balancing Charges	RV:1:27		(6,609,061)
4	Balancing Charges Reconciliation Factor	Analysis		-
5	Total Adjustment for Purchased Gas Revenues	Lines 2 > 4	$	(66,086,221)
6	*Purchased Gas Costs*			
7	Hampshire Exchange Service	EX:2:9	$	(40,957)
8	Storage - Allocable	EX:2:12		(1,765,271)
9	Gas Purchase Costs	EX:3:3		(66,068,873)
10	Propane Gasified	EX:3:4		1,806,227
11	Total Adjustment for Purchased Gas Costs	Lines 7 > 10 (EX:3:3)	$	(66,068,873)

Adjustment Description: To remove fuel revenues, purchased gas costs, and gas supplier revenues from distribution revenues and expenses.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 2D - GAC Revenues and Uncollectible Expense Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Gas Administration Charge Revenues		
2	Residential	Analysis	$ (1,074,697)
3	Commercial and Industrial Other Than Group Metered Apartments	Analysis	(507,259)
4	Group Metered Apartments	Analysis	(191,045)
5	Gas Administration Charge Revenues Elimination Amount	1/	(1,773,001)
6	Less: Gas Procurement Cost		
7	Residential	Analysis	47,400
8	Commercial and Industrial Other Than Group Metered Apartments	Analysis	22,294
9	Group Metered Apartments	Analysis	8,477
10	Gas Procurement Cost Total	Adj No. 3D	78,171
11	GAC Uncollectible Expense Elimination Amount 2/	Line 5 + Line 9	$ (1,694,830)

12 **Adjustment Description:** To remove Gas Administration Charge uncollectible amounts.

1/ For Class Cost purposes, note that this adjustment relates to RV:1:14.
2/ For Class Cost purposes, note that this adjustment relates to EX:7:21.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 3D - Gas Procurement Costs

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Amount
	A	B	C
1	Gas Purchasing Expenses (Total System)	Financial Statements	$ 463,159
2	DC Per Book Amount	EX 2:3	78,171
3	Pro forma Adjustment Amount	-Ln. 2	$ (78,171)

4 **Adjustment Description:** To eliminate Gas Purchasing Expenses associated with sales service
5 customers twelve months ended March 31, 2024.

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Adjustment No. 4D - Storage Gas Inventory & Related Carrying Costs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	**Rate Base:**		
2	Elimination of Storage Gas Inventory 1/	RB:6:10	$ (16,895,300)
3	**Carrying Costs:**		
4	Billed PGC Carrying Costs		
2	Residential	Analysis	$ (1,030,532)
3	Commercial and Industrial Other Than Group Metered Apartments	Analysis	(481,013)
4	Group Metered Apartments	Analysis	(180,575)
5	Carrying Cost Adjustment - Gross	Lns. 2 > 4	$ (1,692,120)
6	Billed ACA Carrying Costs	Financial Statement	$ -
7	Unbilled Carrying Costs	Financial Statement	$ 133,354
8	Total Carrying Costs 2/	Lns. 5 > 7	$ (1,558,766)

9 **Adjustment Description:** To remove storage gas inventory and related carrying costs from distribution
10 revenues.

1/ For Class Cost purposes, note that -$16,895,299.51 of the adjustment relates to RB:6:10.
2/ For Class Cost purposes, note that -$1,692,120.27 of the adjustment relates to RV:1:2 and $133,354.22 of the adjustment relates to RV:1:27.

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Adjustment No. 5D - Asset Optimization Revenues

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Asset Optimization Revenues	RV 1:29	$ (14,177,234)

2 **Adjustment Description:** To remove asset optimization revenues from distribution
3 revenues.

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Adjustment No. 6D - Supplier Refunds and Supplier Interest Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Amount C
1	**Per Book Rate Base**		
2	Elimination of Interest on Supplier Refund Expense	RB:1:23	$ (626,315)
3	**Per Book Expense**		
4	Elimination of Interest on Supplier Refunds	SM:1:12	$ (11,533)

5 **Adjustment Description:** To remove all supplier refunds and interest related to supplier refunds.

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Adjustment No. 7D - Purchase of Receivables (POR) Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Book Amount C	Ratemaking Adjustment D
1	**Capitalized Software**			
2	Capitalized Software (POR)	303006 (RB:2:2)	$ 762,920	$ (762,920)
3	Computer Equipment (POR)	373106 (RB:2:35)	7,234	(7,234)
4	Total Plant in Service	Ln. 2 + Ln. 3	$ 770,154	$ (770,154)
5	**Reserve for Depreciation**			
6	DC POR Software	Property Analysis	$ 352,999	$ (352,999)
7	DC POR Equipment	Property Analysis	3,331	(3,331)
8	Total Depreciation Reserve	Ln. 6 + Ln. 7	$ 356,329	$ (356,329)
9	**Other Operating Revenues**			
10	Late Payment Charges (POR)	487107 (RV:1:16)	$ 360,143	$ (360,143)
11	Other Gas Revenues	495306 (RV:1:32)	736,920	(736,920)
12	Total Revenues	Ln. 10 + Ln. 11	$ 1,097,063	$ (1,097,063)
13	**Depreciation and Amortization**			
14	Amortization of Capitalized Software (POR)	404311 (SM:1:7)	$ 97,980	$ (97,980)
15	**Customer Accounts**			
16	Collection Expense (POR)	903307 (EX:7:19)	$ 226,115	$ (226,115)
17	Uncollectible Accounts (POR)	904107 (EX:7:22)	141,274	(141,274)
18	Total Customer Accounts	Ln. 16 + Ln. 17	$ 367,389	$ (367,389)
19	**Interest Expense**			
20	POR CWC Costs	431135 (EX:9:12)	$ 58,019	$ (58,019) a/

21 a/ Adjustment is reflected in the Interest on Debt Adjustment #8D.

22 **Adjustment Description:** To eliminate purchase of receivables costs incurred during the study period.
Note:

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Adjustment No. 8D & 29 - Interest on Debt (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	Distribution Amount D	Ratemaking Amount E
1	**Interest on Total Debt**				
2	Net Rate Base	Rate Base Stmt, Ln.23	$ 4,284,239,876	$ 796,176,491	$ 760,992,964
3	Weighted Average Cost of Debt	Cost of Capital, Ln. 1 + Ln. 2	2.36%	2.36%	2.36%
4	Interest on Debt	Ln. 2 * Ln. 3	$ 101,225,321	$ 18,811,557	$ 17,980,262
5	Per Books Interest Expense	Per Books	100,062,947	19,142,496	18,811,557
6	Adjustment to Interest Expense _1/	Ln. 4 - Ln. 5	$ 1,162,374	$ (330,939)	$ (831,295)

7 **Adjustment Description**: To synchronize interest expense used in determining the overall return requirement with the interest
8 expense used to calculate income taxes.

_1/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line 9:16.

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Adjustment No. 9D - Cash Working Capital (Distribution)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	DC Per Books	DC Dist. Adjustment	DC Dist. Amount	DC Lag Days	DC Dollar Days
	A	B	C	D	E	F	G = E x F
1	Composite Revenue Lag					89.00	
2	Gas Purchased	Per Books Adj 2D	$ 64,262,645	$ 1,806,227	$ 66,068,873	38.19	$ 2,523,164,162
3	Payroll	Per Books	25,573,530	-	25,573,530	11.71	299,504,692
4	<u>Other Operations and Maintenance Expenses</u>						
5	Employee Health Benefits	Per Books	4,793,783	-	4,793,783	30.37	145,571,833
6	Property and Public Liability Insurance	Per Books	3,677,954	-	3,677,954	(163.46)	(601,213,770)
7	Other O&M	Adj 8D WP 1 Adj 2D	52,683,423	(3,946,617)	48,736,805	25.47	1,241,251,457
8	Less: Pension Benefit (Non Cash)	Per Books	42,494	-	42,494	25.47	1,082,247
9	Less: OPEB Benefit (Non Cash)	Per Books	6,584,462	-	6,584,462	25.47	167,696,128
10	Property Taxes	Per Books	2,013,868	-	2,013,868	71.02	143,032,994
11	Delivery Tax	Per Books	23,451,041	-	23,451,041	26.13	612,799,160
12	Rights-of-Way Fee	Per Books	12,518,268	-	12,518,268	(54.53)	(682,621,127)
13	FICA Taxes	Per Books	2,103,553	-	2,103,553	9.97	20,970,937
14	Unemployment Tax	Per Books	(6,961)	-	(6,961)	9.99	(69,562)
15	Environmental Tax	Per Books	-	-	-	-	-
16	Federal Excise Tax	Per Books	(21,714)	-	(21,714)	(17.51)	380,156
17	Sustainable Trust Fund	Per Books	16,761,017	-	16,761,017	26.13	437,982,135
18	Energy Assistance Fund	Per Books	2,156,914	-	2,156,914	26.13	56,362,323
19	Firm Storage Service	Per Books	29	-	29	308.86	8,840
20	Other Taxes - Direct Assignment	Per Books	16,520	-	16,520	79.00	1,305,080
21	Income Taxes (Current)	Per Books Adj 10D	(1,897,447)	(3,089,477)	(4,986,924)	-	-
22	Subtotal	Sum of Lns. 2 > 21	214,713,379	(5,229,867)	209,483,512	20.85	$ 4,367,207,685
23	Lead Lag Requirement	Ln. 22, Col/ E / 365			$ 573,927	68.16	$ 39,116,900
24	<u>Other Lead-Lag Items</u>						
25	Imprest Funds	Per Books	-	-	-	-	-
26	Special Deposits	Per Books	-	-	-	-	-
27	Interest on Long-Term Debt	Adj 8D	-	(330,939)	(330,939)	91.25	2,036
28	Economic Evaluation of Facility Extenstion (GSP 14)	Accts. 186.200 & 174.400	752,764	-	752,764	-	752,764
29	Cash Working Capital - Distribution						$ 39,871,701
30	Cash Working Capital - Per Books						39,219,091
31	Cash Working Capital Distribution Adjustment	RB:1:10					$ 652,610

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Adjustment No. 10D & 31 - State and Federal Income Taxes (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Distribution Amount C	Ratemaking Amount D
1	**Net Operating Income - Adjusted**	**DC Inc Stmt, Ln. 18**	**$ 20,999,112**	**$ 27,756,328**
2	Add: Income Taxes	DC Inc Stmt, Ln. 12	448,015	614,762
3	Less: Interest Expense	Adj 8D / Adj 29, Ln. 4	(18,811,557)	(17,980,262)
4	Taxable Income	Ln. 1 + Ln. 2 + Ln. 3	2,635,571	10,390,828
5	Flow-Throughs and Permanent Items (Basis)			
6	AFUDC Equity	Per Book ETR / Analysis	70,134	18,597
7	Meals and Entertainment	Per Book ETR / Analysis	184,959	184,959
8	Compensation Limitation	Per Book ETR / Analysis	-	-
9	Parking	Per Book ETR / Analysis	96,216	96,216
10	R&D credit	Per Book ETR / Analysis	-	-
11	Return to Provision True Up	Per Book ETR / Analysis	(806,112)	-
12	Other Tax Adjustments	Per Book ETR / Analysis	(176,160)	-
13	NOL Flow-through	Adj. 32	-	-
14	Total Flow-Throughs and Permanent Items	Ln. 6 > Ln. 12	(630,964)	299,771
15	Taxable Income (Adjusted)	Ln. 4 + Ln. 14	2,004,607	10,690,600
16	Federal Income Tax	Ln. 15 * 21.00%	420,968	2,245,026
17	Add: Excess Deferred Tax (Protected)		-	5,397,883
18	Add: Excess Deferred Tax (Unprotected)		-	(7,908,370)
19	Add: Excess Deferred Tax on PLR NOL			(140,599)
20	Less: Remove EDIT amortization related to FC 1027 Write Off			343,555
21	Add: Capitalizated OPEB		(12,689)	-
22	Add: ITC		(90,913)	(90,913)
23	Add: Amortization of Prior Flow-Through Balance		-	71,421
24	Total Federal Income Taxes	Ln. 17 > Ln. 22	317,365	(81,998)
25	Per Book / Ratemaking Federal Income Taxes		2,780,984	317,365
26	Federal Income Tax Adjustment	Ln. 24 - Ln. 25	(2,463,619)	(399,363)
27	State Income Tax (Net of Federal Tax Benefit)	Ln. 15 * 6.52%	130,650	696,760
28	Per Book / Ratemaking State Income Taxes		756,509	130,650
29	State Income Tax Adjustment	Ln. 27 - Ln. 28	(625,859)	566,110
30	Income Tax Adjustment	Ln. 26 + Ln. 29	(3,089,477)	166,747

31 **Adjustment Description:** To adjust state and federal income tax to rate year amounts.

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Adjustment No. 1 - Ratemaking Revenues and Related Expenses Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Book Amount	Distribution Adjustments	Distribution-Only Amount	Ratemaking Adjustments	Ratemaking Amount _2/
	A	B	C	D	E = C + D	F	G = E + F
1	**Operating Revenues**						
2	Base Revenues						
3	Base Rate Revenues (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	$ 127,731,965	$ -	$ 127,731,965	$ 18,877,467	$ 146,609,432
4	Distribution Charge & Plant Recovery Adjustments	Rev WP 1 + Adj 1 WP 7	(8,444,784)	-	(8,444,784)	8,444,784	-
5	Peak Usage Charge	Rev WP 1 + Adj 1 WP 7	4,254,611	-	4,254,611	229,056	4,483,667
6	Fuel Revenues _1/	Rev WP 1 + Adjs 1D, 2D, 4D	69,417,982	(69,417,982)	-	-	-
7	Revenue Taxes						
8	DC Right of Way Tax (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	12,367,741	-	12,367,741	(2,457,862)	9,909,879
9	Delivery Tax (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	19,243,088	-	19,243,088	1,978,792	21,221,880
10	Sustainable Energy Trust Fund (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	16,438,143	-	16,438,143	4,900,753	21,338,896
11	Energy Assistance Trust Fund (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	2,109,146	-	2,109,146	257,838	2,366,984
12	Non-District of Columbia Tariff Rates & Revenue Taxes	Rev WP 1 + Adj 1 WP 7	(50,138)	-	(50,138)	50,138	-
13	Off-System Sales Revenue (Asset Optimization)	Rev WP 1 + Adj 5D	14,177,234	(14,177,234)	-		-
14	PROJECTpipes	Rev WP 1 + Adj 1 WP 7	13,157,184	-	13,157,184	(13,157,184)	-
15	Sales of Gas to Customers (excl. CNG customers)	Sum Lns. 2 to 14	$ 270,402,172	$ (83,595,216)	$ 186,806,956	$ 19,123,782	$ 205,930,738
16	Late Payment Fees	Rev WP 1 + Adj 7D + Adj 1 WP 8	3,605,596	(360,143)	3,245,453	332,243	3,577,696
17	Other Operating Revenues	Adj No. 1, Page 2, Line 40	2,897,112	(736,920)	2,160,192	(41,088)	2,119,103
18	**Total Operating Revenues (RV 1:35)**	**Sum Lns. 15 to 17**	**$ 276,904,880**	**$ (84,692,279)**	**$ 192,212,601**	**$ 19,414,936**	**$ 211,627,537**
19	**Revenue Related Expenses**						
20	Uncollectible Accounts Expense	EX 7:19 + Adj 2D + Adj 1 WP 9	$ 6,226,265	$ (1,694,830)	$ 4,531,435	$ 1,038,168	$ 5,569,603
21	Delivery Tax Expense Expense (excl. PSC assessment)	EX 8:8 + Adj 1 WP 10	18,979,968	-	18,979,968	2,241,912	21,221,880
22	Rights of Way Fee Expense	EX 8:9 + Adj 1 WP 11	12,518,268	-	12,518,268	(2,608,389)	9,909,879
23	Sustainable Energy Trust Fund	EX 8:17 + Adj 1 WP 12	16,761,017	-	16,761,017	4,577,879	21,338,896
24	Energy Assistance Trust Fund Fee	EX 8:17 + Adj 2 WP 13	2,156,914	-	2,156,914	210,070	2,366,984
25	**Total Revenue Related Expenses**	**Sum Lns. 20 to 24**	**$ 56,642,432**	**$ (1,694,830)**	**$ 54,947,602**	**$ 5,459,640**	**$ 60,407,242**

26 **Adjustment Description:** To adjust Operating Revenues to a Ratemaking basis.

1/ Includes purchased gas costs, storage gas, ACA carrying costs, and gas administrative charge.
2/ Special contracts are shown within amount shown. For further detail, see the Revenue by Class tab.

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Adjustment No. 1 - Other Operating Revenues Breakout

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Book Amount	Distribution Adjustments	Distribution-Only Amount	Ratemaking Adjustments	Ratemaking Amount _3/
	A	B	C	D	E = C + D	F	G = E + F
27	**Other Operating Revenues**						
28	Miscellaneous Service Revenues						
29	Reconnect Revenues	RV 1:19	$ 174,354	$ -	$ 174,354	$ -	$ 174,354
30	Reconnect Revenue Premium	RV 1:20	-	-	-	-	-
31	Dishonored Check Charge	RV 1:21	44,740	-	44,740	-	44,740
32	Service Initiation Charge	RV 1:22	838,570	-	838,570	-	838,570
33	Field Collection Charge	RV 1:23	433	-	433	-	433
34	IRATE Non-Compliance Meter Charge	RV 1:24	-	-	-	-	-
35	Other Miscellaneous Revenues						
36	Rents	RV 1:17 + Adj 1 WP 5	$ 139,688	$ -	$ 139,688	$ (41,088)	$ 98,600
37	CNG Sales for Natural Gas Vehicles _3/	RV 1:28	847,959	-	847,959	-	847,959
38	Other Gas Revenues (POR)	RV 1:32 + Adj 7D	736,920	(736,920)	-	-	-
39	Third Party Billing	RV 1:33	114,447	-	114,447	-	114,447
40	**Total Other Operating Revenues**	**Sum Lns. 29 to 38**	**$ 2,897,112**	**$ (736,920)**	**$ 2,160,192**	**$ (41,088)**	**$ 2,119,103**

3/ For purposes of this adjustment, all components of CNG revenues (distribution revenues plus revenue taxes) are reflected in the Other Operating Revenues line. There are no ratemaking adjustments for CNG revenues or related expense.

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Adjustment No. 1 Workpaper 9 - Ratemaking Adjustment to Uncollectible Accounts Expense

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Amount
	A	B	C
1	Ratemaking Sales and Delivery Revenues 1/	Adj 1 WP 7, Column C, Line 27	$ 205,930,738
2	Accrual Rate for Uncollectible Gas Accounts	Adj 1 WP 2	2.7046%
3	Ratemaking Uncollectible Gas Accounts Expense	Line 1 x Line 2	$ 5,569,603
4	Per Books Uncollectible Gas Accounts Expense	Per Books	6,226,265
5	Distribution Adjustment to Uncollectible Expense	Adjustment No. 2D	(1,694,830)
6	Distribution Only, Per Book Uncollectible Expense	Line 4 + Line 5 + Line 6	4,531,435
7	Ratemaking Adjustment to Uncollectible Gas Accounts 2/	Line 3 - Line 6	$ 1,038,168

8 **Adjustment Description:** To adjust per book uncollectible accounts expense to reflect adjusted non-gas ratemaking revenues.

1/ Less: Gas Cost.
2/ For Class Cost purposes, note that this adjustment relates to EX:7:22.

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Adjustment No. 1 Workpaper 10 - Ratemaking Adjustment to Delivery Tax Expense

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	DC Amount
	A	B	C
1	Ratemaking Delivery Tax Expense	Adj 1 WP 7, Column C, Line 20	$ 21,221,880
2	Delivery Tax in PBCOSA		23,451,041
3	Less: PSC Assessment Fees included in PBCOSA		4,471,073
4	Per Books Delivery Tax Expense	Per Books	18,979,968
5	Adjustment to Delivery Tax Expense 1/	Line 1 - Line 4	$ 2,241,912

6 **Adjustment Description:** To adjust per books Delivery Tax to reflect normal weather therms.

1/ For Class Cost purposes, note that this adjustment relates to EX:8:8.

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Adjustment No. 1 Workpaper 11 - Ratemaking Adjustment to Rights of Way Fee

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Amount C
1	Total Normal Weather Therms	Adj 1 WP 7, Column C, Line 1	283,950,711
2	Rights of Way Fee Surcharge	Adj 1 WP 3	$ 0.0349
3	Ratemaking Rights of Way Fee	Line 1 x Line 2	$ 9,909,880
4	Per Books Rights of Way Fee	Per Books	12,518,268
5	Adjustment to Rights of Way Fee 1/	Line 3 - Line 4	$ (2,608,388)

6 **Adjustment Description:** To adjust the Rights of Way Fee to a Ratemaking basis.

1/ For Class Cost purposes, note that this adjustment relates to EX:8:9.

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Adjustment No. 1 Workpaper 12 - Ratemaking Adjustment to Sustainable Energy Trust Fund

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Amount C
1	Total Normal Weather Therms	Adj 1 WP 7, Column C, Line 1	283,950,711
2	SETF Fee Surcharge	Current Filed Rate	$ 0.07515
3	Ratemaking SETF Fee	Line 1 x Line 2	$ 21,338,896
4	Per Books SETF Fee	Per Books	16,761,017
5	Adjustment to SETF Fee 1/	Line 3 - Line 4	$ 4,577,879

6 **Adjustment Description:** To adjust the Sustainable Energy Trust Fund Fee to a Ratemaking
7 basis.

1/ For Class Cost purposes, note that this adjustment relates to EX:8:18.

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Adjustment No. 1 Workpaper 13 - Ratemaking Adjustment to Energy Assistance Trust Fund Fee

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Amount C
1	Total Normal Weather Therms	Adj 1 WP 7, Column C, Line 1	283,950,711
2	EATF Surcharge	Current Filed Rate	$ 0.0083359
3	Ratemaking EATF Fee	Line 1 x Line 2	$ 2,366,985
4	Per Books EATF Fee	Per Books	2,156,914
5	Adjustment to EATF Fee 1/	Line 3 - Line 4	$ 210,071

6 **Adjustment Description:** To adjust the Energy Assistance Trust Fund Fee to a Ratemaking basis.

1/ For Class Cost purposes, note that this adjustment relates to EX:8:19.

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Adjustment No. 2 - CWIP Elimination

Test Period Twelve Months Ended March 31, 2024

Line No.	Description	Reference	DC Amount
	A	B	C
1	Construction Work in Progess (CWIP)	RB 5:29	$ 79,322,274
2	Less: Projectpipes CWIP	Adj. 3	$ 13,108,574
3	Total Non-Projectpipes CWIP per book	Ln. 1 - Ln. 2	$ 66,213,700
4	**Total Ratemaking Adjustment**		**$ (66,213,700)**

5 **Adjustment Description:** To eliminate non-PROJECT*pipes* Construction Work in Progress (CWIP)
6 from test year ratebase.

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Adjustment No. 3 - PROJECT*pipes* Average to End of Period

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Test Year Average Amount C	Test Year EOP Amount D	Ratemaking Adjustment E = D - C
1	**Expense (12 Months)**				
2	Depreciation	EX:6:22	$ 2,719,002	$ 2,950,160	$ 231,158
3	**Net GPIS (13 Month Average)**				
4	Gas Plant in Service	RB:3:17	$ 80,506,896	$ 107,614,058	$ 27,107,163
5	Construction Work in Progress	RB:5:29	$ 13,108,574	$ 6,884,577	$ (6,223,998)
6	Depreciation Reserve	RB:10:35	$ 5,674,931	$ 7,264,766	$ 1,589,836
7	Cost of Removal	RB:10:35	$ (10,419,702)	$ (8,327,576)	$ 2,092,125
8	Accumulated Deferred Income Tax	RB:11:21	$ 25,914,685	$ 33,949,905	$ 8,035,220
9	Net Rate Base Change	+ Ln. 4 + Ln. 5 - Ln. 6 - Ln. 7 - Ln.8	$ 72,445,556	$ 81,611,539	$ 9,165,984

10 **Adjustment Description:** To adjust test year PROJECT*pipes* expense and rate base to end of period amounts.

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Adjustment No. 4 - New Depreciation Rates
Twelve Months Ended Mar 31, 2024

Line No.	Description A	Reference B	Depreciable Property C	PROJECT*pipes* Adjustment D	Depreciation Rates E	Amount F = C × E or D × E
1	**Property Other Than PROJECTpipes**					
2	Intangible - Capitalized Software	SM 1:7				$ 3,757,16
3	Storage	RB 2:3	12,565,793		1.90%	238,98
4	Transmission					
5	Spurlines & Related Regulating					
6	Equipment and Structures	RB 2:8	56,197,740		1.37%	$ 767,82
7	Other	RB 2:12	108,628,696		2.42%	2,631,28
8	Total Transmission	Ln. 6 + Ln. 7				$ 3,399,11
9	Distribution					
10	Compressor Station Equipment	RB 2:18	450,802		3.71%	$ 16,74
11	Other	Sum of RB 2:1-28 Less ARO	1,030,846,267		2.60%	26,829,54
12	Total Distribution	Ln. 10 + Ln. 11				$ 26,846,28
13	General					
14	Enscan	Analysis	11,557,700		5.93%	$ 685,37
15	Other - Direct	Analysis	7,234		4.52%	32
16	Other - Allocable	Sum of RB 2:35-36 - Ln. 14	52,462,958		4.52%	2,371,21
17	Total General	Ln. 15 + Ln. 16				$ 3,056,91
18	Ratemaking Depreciation Expense - Safety Plant	Sum of Lns. 2,3,8,12,17				$ 37,298,46
19	Less: Per Book Depreciation Expense	Sum of SM1:6+7+9				29,542,87
20	**Tatal Adjustment Other Than PROJECTpipes**	Ln. 18 - Ln. 19				$ 7,755,58
21	**PROJECTpipes**					
22	PROJECTpipes Net Rate Base (EOP)	Adjustment No. 3, Ln. 9		107,614,058	2.68%	$ 2,886,23
23	PROJECTpipes Depreciation Expense (EOP)	Adjustment No. 3, Ln. 2				2,950,1
24	**Total PROJECT*pipes* Depreciation Expense Adjustment**	Ln. 22 - Ln. 23				$ (63,92
25	**Total Depreciation Expense Adjustment**	Ln. 20 + Ln. 22				$ 7,691,66
26	**Reserve for Depreciation**					
27	Reserve for Depreciation adjustment based on Other than PROJECTpipes	Analysis	7,755,586	One Half Year		$ 3,877,79
28	Reserve for Depreciation adjustment based on Adjusted Gas Plant in Service - PROJECTpipes	Adjustment No. 3, Ln. 6	(63,921)	EOP		$ (63,92
29	**Total Reserve for Depreciation Adjustment**	Ln. 27 + Ln. 28				$ 3,813,87
30	**ADIT**					
31	Reserve Adjsutmentn Other than project pies	Ln. 20				$ 3,877,79
32	Composite Tax Rate	Composite Tax Rate Calc				27.52
33	ADIT Adjustment - Other that project pipes	Ln. 31 * Ln. 32				$ 1,067,07
34	Deferred Tax Basis - PROJECTpipes	Ln. 24				$ (63,92
35	Composite Tax Rate	Composite Tax Rate Calc				27.52
36	ADIT Adjustment - PROJECTpipes	Ln. 34 * Ln. 35				$ (17,58
37	**Total ADIT Adjustment**	Ln. 33 + Ln. 36				$ 1,049,48

38 **Adjustment Description:** To reflect the depreciation expense based on the 2024 Depreciation Rate Study, on 13 months average depreciable gas plant in service as of March 3
39 2024. Also including expense related to Pro Forma safety related projects through Mar 2024. Also to synchronize depreciation reserve with the depreciation expense adjustment
40 Deferred Income Taxes for Safety and PROJECTpipes Plant.

NOTES: General Other includes amortized plant (Office Furn, & Equip., Stores, Comm. Equip, etc.) and depreciable plant (Stuctures and Improv.).

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 5 - Wages and Salaries Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		Frederick/Shen Unions C	Teamsters & Local 2 Unions D	Management E	Total F=C+D+E
1	**Annual Payroll (Gross) TME March 31, 2024**	Analysis		$ 5,108,819	$ 72,615,991	$ 106,452,220	$ 184,177,030
2	Pro Forma Increase - Test Year (Apr-2023 to Mar-2024)	Workpaper 2		50,086	320,862	3,138,466	3,509,414
3	Pro Forma Gross Payroll TME March 31, 2024	Ln. 1 + Ln. 2		$ 5,158,906	$ 72,936,853	$ 109,590,685	$ 187,686,444
4	Pro Forma Increase - (Apr-2024 to Mar-2025)	Workpaper 2		103,178	1,857,618	1,362,578	3,323,373
5	Pro Forma Gross Payroll in Rate Effective Period (Aug-2025 to Jul-2026)	Ln. 3 + Ln. 4		$ 5,262,084	$ 74,794,471	$ 110,953,263	$ 191,009,817
6	Pro Forma Payroll Increase	(Ln. 5 - Ln. 1)		$ 153,265	$ 2,178,480	$ 4,501,043	$ 6,832,788
7	Operations & Maintenance Allocation Factor	Analysis		75.53%	75.53%	75.53%	75.53%
8	Proforma Payroll Increase Allocable to Operations & Maintenance (System)	Ln. 6 * Ln. 7		$ 115,757	$ 1,645,354	$ 3,399,531	$ 5,160,643
9	District of Columbia Allocation Factor			19.36%	19.36%	19.36%	19.36%
10	Proforma Payroll Increase Allocable to Operations & Maintenance (District of Columbia)	Ln. 8 * Ln. 9		$ 22,411	$ 318,541	$ 658,149	$ 999,100
11	Adjust to reflect amortization of ratification bonus	Workpaper 3					$ 1,957
12	**Total Wages and Salaries Adjustment**	Ln. 10 + Ln. 11					**$ 1,001,057**
13	Wages & Salaries Expense Adjustment - Operations	Ln. 10 * 0.6434	_2/				$ 644,085
14	Wages & Salaries Expense Adjustment - Maintenance	Ln. 10 * 0.3566	_2/				$ 356,972

15 **Adjustment Description:** To reflect pro forma labor wage increases through the rate effective period.

1/ Per book Short-term incentive compensation and benefits expenses are excluded from the cost of service here rather than in 401(k) adjustment (#8).
2/ For class cost purposes, the full amount of this adjustment relates to COSA line EX 5:3.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 6 - LTI Expense Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	Factor Comp_A&G	DC Amount
	A	B	C	D	E = C * D
1	Long-Term Incentive - Performance Shares	Acct 920411 & 920412	$ (40,509)		
2	Long-Term Incentive - Performance Units	Acct 920421 & 920422	$ (17,309,695)		
3	**Total Expense Adjustment _1/**	Ln. 1 + Ln. 2	$ (17,350,204)	19.54%	$ (3,390,371)

4 **Adjustment Description:** To remove 100% of per book long-term incentive expense.

_1/ For class cost purposes, the full amount of this adjustment relates to COSA line EX:5:3.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 7 - Postretirement Benefits Other Than Pensions (OPEB) Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	DC Amount D = C * 19.36%
1	**Current Employees**			
2	Employer Service Cost	Actuarial Rpt	$ [redacted]	
3	Washington % of Basic Pay (eliminates Hampshire)	Analysis	[redacted]	
4	Washington Gas Portion of Expense	Ln. 2 * Ln. 3	$ [redacted]	
5	O&M Factor (OPEB Service Costs)	Analysis	[redacted]	
6	Total Employer Service Cost	Ln. 4 * Ln. 5	$ [redacted]	$ [redacted]
7	Other Components of Net Periodic Expense	Actuarial Rpt	$ [redacted]	
8	Washington % of Basic Pay (eliminates Hampshire)	Analysis	[redacted]	
9	Washington Gas Portion of Expense	Ln. 7 * Ln. 8	$ [redacted]	
10	O&M Factor (OPEB Other Costs)	Analysis	[redacted]	
11	Total Other Components of Net Periodic Expense	Ln. 9 * Ln. 10	$ [redacted]	$ [redacted]
12	Total Net Periodic Post-Retirement Benefit Expense	Ln. 6 + Ln. 11	$ [redacted]	$ [redacted]
13	District of Columbia OPEB Costs Per Book	EX: 5:15		[redacted]
14	Adjustment to OPEB Cost	Ln. 12 - Ln. 13		$ (630,366)

15 **Adjustment Description:** To calculate OPEB expense on a pro forma basis.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 8 - Pension & SERP Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	DC Amount D = C [redacted]	
1	Pro Forma Employer Service Cost	Workpaper 1	$ [redacted]		
2	O&M Factor (Pension Service Cost)		[redacted]		
3	PF Employer Service Cost	Ln. 1 * Ln. 2	$ [redacted]	$ [redacted]	
4	Pro Forma Other Components of Net Periodic Expense	Workpaper 1	$ [redacted]		
5	O&M Factor (Pension Other Costs)		[redacted]		
6	PF Other Components of Net Periodic Expense	Ln. 4 * Ln. 5	$ [redacted]	$ [redacted]	
7	Total Pro Forma Pension Expense	Ln. 3 + Ln. 6	$ [redacted]	$ [redacted]	
8	Per Book Qualified Pension Expense	EX:5:9	$ [redacted]	$ [redacted]	a/
9	Per Book SERP/Restoration	EX:5:9	$ [redacted]	$ [redacted]	b/
10	Total Per Book Pension Expense	Ln. 8 + Ln. 9		$ [redacted]	
11	Pro Forma Pension Adjustment	Ln. 7 - Ln. 10		$ (565,665)	

12 **Adjustment Description:** To calculate pension expense on a pro forma basis.

a/ Qualified Pension Expense Accounts are: 926101, 926107, 926109, 926115, 926116, 926116
b/ SERP/Restoration Expense Accounts are: 926103, 926105, 926106, 926113, 926114, 926114

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 9 - Employee Benefits Expense 401(k)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Amount
	A	B	C
1	Per Book Test Year Contributions	Account 926207 (EX:5:14)	$ 10,900,486
2	Test Year Contribution Related to Organizational redesign	Analysis	$ (579,010)
3	Test Year Contributions Adjusted	Ln. 1 + Ln. 2	$ 10,321,475
4	Three Year Average Growth Factor	Workpaper 1	5.29%
5	Employee Savings Plans Expense Increase	Ln. 3 * Ln. 4	$ 545,669
6	Operations & Maintenance Allocation Factor	Analysis	75.53%
7	Expense Adjusment (System)	Ln. 5 * Ln.6	$ 412,131
8	District of Columbia Allocation Factor	Total_Labor	19.36%
9	Expense Adjusment (District of Columbia)	Ln. 7 * Ln. 8	$ 79,796

10 **Adjustment Description:** To adjust 401(k) employee benefits expense for current employees to a pro forma basis.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 10 - Employee Benefits Expense (Fringe) Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	O&M Factor	DC Factor	DC Amount _2/	
	A	B	C	D	E	F=C*D*E	
1	Professional Services	Workpaper 2	$ (22,490)	100.00%	19.36%	$ (4,354)	_1/
2	Physicals	Workpaper 2	(7,150)	100.00%	19.36%	(1,384)	_1/
3	Parking	Workpaper 3	(71,760)	86.17%	19.36%	(11,972)	
4	Car Allowance	Workpaper 4	(110,439)	100.00%	19.36%	(21,383)	_1/
5	**Adjustment to Fringe Benefits (Current Employees)**	**Ln. 1 > Ln. 4**	**$ (211,838)**			**$ (39,094)**	

6 **Adjustment Description:** To remove executive fringe benefits expense.

_1/ O&M factor not applicable because this amount already excludes affiliate transactions.
_2/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line EX:5:14.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 11 - Medical Plans Inflation

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	O&M Factor	Labor Factor	MD Amount
	A	B	C	D	E	F=C*D*E
1	Insurance Benefits Expense - Carefirst / BCBS	Account 926.274	$ 17,091,522			
2	Insurance Benefits Expense - Kaiser-Permanente	Account 926.264	$ 1,590,804			
3	Insurance Benefits Expense - Delta Dental	Account 926.215	$ 1,173,961			
4	Test Year Expense Related to Involuntary Sep. Prog.	Analysis	(765,460)			
5	Total Group Meidcal Expense (Test Year)	Ln. 1 + Ln. 2 + Ln. 3 + Ln. 4	19,090,827			
6	Inflation Rate	Analysis	7.00%			
7	**Total Expense Adjustment _1/**	Ln. 5 * Ln. 6	**$ 1,336,358**	75.53%	19.36%	**$ 195,423**

8 **Adjustment Description:** To adjust employee medical benefits expense for current employees to a pro forma basis.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 12 - FICA / Medicare Tax Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	Labor Factor D	DC Amount E
1	Incremental Payroll Expense	Adj. No. 5	$ 5,160,643		
2	Adjust to reflect 5 year amortization of ratification bonus	Adj. No. 5	1,957		
3	Labor Adjustment Change	Ln. 1 + Ln. 2	**$ 5,162,599**		
4	Factor - SSI Wages to Gross Wages	Analysis	91.23%		
5	Social Security Insurance (SSI) Base	Ln. 1 * Ln. 4	$ 4,709,839		
6	SSI Rate		6.20%		
7	SSI Tax	Ln. 5 * Ln. 6	292,010	19.36%	56,538
8	Base - Medicare (Payroll Increase)	Ln. 3	$ 5,162,599		
9	Base - Medicare (Long-Term Incentive Elimination)	Adj. No. 6	(17,350,204)		
10	Total Medicare Base	Ln. 8 + Ln. 9	(12,187,604)		
11	Medicare Rate		1.45%		
12	Medicare Tax - Medicare	Ln. 10 * Ln. 11	(176,720)	19.36%	(34,216)
13	Total Pro Forma Adjustment	Ln. 7 + Ln. 12	**$ 115,290**	19.36%	**$ 22,322** _1/
14					

15 **Adjustment Description:** To reflect increase in employer's portion of FICA taxes to reflect proforma increase in salaries and wages.

_1/ For class cost purposes, $56,538 relates to EX:8:10 and -$34,216 relates to EX:8:11.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 13 - Involuntary Separation Program Labor O&M Expense Reduction

Twelve Months Ended March 31, 2024

Line	Description	Reference		Amount
1	Reduction in salaries	Workpaper 1	$	(7,233,986)
2	Reduction in short-term incentives	Workpaper 1		(986,995)
3	Reduction in medical plans	Workpaper 2		(730,291)
4	Reduction in 401(k)	Workpaper 2		(556,223)
5	Reduction in payroll taxes	Workpaper 2		(697,386)
6	Reduction in life insurance	Workpaper 2		(12,492)
7	Reduction in rate year labor expenses (System)	Sum Lns. 1 to 6	$	(10,217,373)
8	DC Labor Factor	AL 4:11		19.36%
9	**Reduction in rate year labor expense (DC)**	**Ln. 7 * Ln. 8**	**$**	**(1,978,270)**

10 **Adjustment Description:** To reflect the reduction in salaries and other related expenses
11 related to the Involuntary Separation Program in April 2024.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 14 - Involuntary Separation Program Cost to Implement Amortization

Twelve Months Ended March 31, 2024

Line	Description	Reference		System
1	Severance	Workpaper 1	$	4,479,772
2	COBRA Continuation Coverage	Adj 13		730,291
3	Short-Term Incentive	Workpaper 1		144,628
4	Paid Time Off	Workpaper 1		360,408
5	Outplacement Services	ledger		32,000
6	Additional Security Costs	ledger		35,112
7	Consultant Services	Analysis		1,216,372
8	Cost to Implement	Lns. 1 to 7	$	6,998,583
9	Annual Amortization (System)	Ln. 8 / 5	$	1,399,717
10	DC Labor Factor	AL 4:11		19.36%
11	Annual Amortization (DC)	Ln. 9 * Ln. 10	$	271,011

12 **Adjustment Description:** To reflect the costs associated with implementing the April 2024
13 Involutary Separation Program amortized over 5 years.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 15 - Amortization of COVID Regulatory Asset

Twelve Months Ended March 31, 2024

Line	Description		Reference	Amount
1	Total Regulatory Asset Balance allowed in FC 1169		Order No. 21939	$ 368,163
2	Amortization Period (Years)		5 Years	5
3	Annual Amortization		Ln. 1 / Ln. 2	$ 73,633
4	Test Year Amortization Expense (Per Book)			-
5	**Total Adjustment to Amortization Expense**	_1/	**Ln. 3 - Ln. 4**	**$ 73,633**

6 Adjustment Description: To amortize the COVID regulatory asset over 5 years.

1/ For class cost purposes:
$73,633 relates to EX:5:5

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 16 - Regulatory Commission Expenses

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Calculation		Amount to be Collected from Customers
	A	B	C	D	E
1	Costs from Prior Rate Cases @ 03/31/2024				$ 4,640,510
2	Prior Rate Case Costs from 4/1/2024 - 7/31/2025				(1,366,724)
3	Ratemaking Expenses For Current Case				
4	Estimated OPC Assessment				
5	Ratemaking Ratebase - Case No. 1169	Order No. 21939	$580,402,431		
6	OPC Rate		0.25%		
7	Estimated OPC Adjustment	= Ln. 5 * Ln. 6	1,451,006	1,451,006	
8	Estimated PSC Assessment				
9	Ratemaking Ratebase - Case No. 1169	Order No. 21939	$580,402,431		
10	PSC Rate		0.25%		
11	Estimated PSC Assessment	= Ln. 9 * Ln. 10	1,451,006	1,451,006	
12	Company Consultants:				
13	External Counsel		175,000		
14	Tax		50,000		
15	Return on Equity		155,000		
16	Depreciation Study		50,000		
17	Affiliate Costs		70,000		
18	Normal Weather		211,000	711,000	
19	Estimated Cost of Current Case	Σ 7 > 18			$ 3,613,012
20	Balance Due From Customers	= 1 + 2 + 19			$ 6,886,798
21	Amortization of Regulatory Commission Expenses	Ln. 20 / 3 years			$ 2,295,599
22	Ratemaking Adjustment to Regulatory Expense	= Ln. 21			$ 2,295,599
23	Carrying Costs on Unamortized Balance	Analysis			788,608
24	Removal of book amortization expense	GL Account No: 928001			(475,776)
25	Total Ratemaking Expense Adjustment	= Ln. 22 > Ln. 24			$ 2,608,431

26 **Adjustment Description:** To amortize both the collection of prior regulatory commission expenses and the regulatory commission
27 expenses that are expected to be incurred during the current rate case. To include the annual carrying costs on the unamortized balance of
28 regulatory commission expenses.

1/ For Class Cost purposes, note that $2,608,431 relates to EX:5:16.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 17 - Environmental Costs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Actual Remediation Expenses as of March 31, 2024	Financial Statement	$ 37,232,664
2	Less: Expenses approved in Prior Cases	Order 21939	27,639,236
3	Total Environmental Expenses Incurred Subsequent to FC Case No. 1169	= Ln. 1 - Ln. 2	$ 9,593,428
4	District of Columbia Factor (Total_Weather_All_NW)	AL:1:19	0.164770
5	Environmental Expenses Applicable to DC	= Ln. 3 * Ln. 4	$ 1,580,712
6	Less: Amount over (under) collected since FC 1169 through July 2025	Financial Statement	(1,126,956)
7	Balance of expenditures incurred to be amortized over 5 years	= Ln. 5 - Ln. 6	2,707,668
8	Annual amortization for 5-year period	= Ln. 7 / 5	$ 541,534
9	Less: Per book annual amortization expense	EX: 5:21	263,068
10	**Total DC Amortization Expense adjustment**	Ln. 8 - Ln. 9	**278,465**
11	Rate Base:		
12	Deferred Balance of Environmental Cost, Net of Deferred Taxes	[Ln. 7 - (Ln. 8/2)] * 0.724825	$ 1,766,327
13	Less: Unamortized East Station Cost (Net of Deferred Taxes) March 31, 2024	RB:1:8	1,075,846
14	**Total DC Ratebase Adjustment**	**= Ln. 12 - Ln. 13**	**$ 690,481**

15 **Adjustment Description:** To reflect additional environmental cost incurred since Formal Case No. 1169.

1/ For class cost purposes the total adjustment relates to COSA line EX:5:21.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 18 - Insurance Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Incremental Insurance Premiums, Excluding Property Insurance		
2	Excess Public Liability	Insurance Analysis	$ 1,225,502
3	Director and Officer Liability	Insurance Analysis	40,201
4	General Liability	Insurance Analysis	38,759
5	Professional	Insurance Analysis	20,210
6	Commercial Crime/Cyber Liability	Insurance Analysis	90,071
7	Workers Compensation	Insurance Analysis	410,501
8	Service Fees	Insurance Analysis	(33,966)
9	Total Incremental Expense, Excluding Property Insurance	= Sum (Ln. 2 > Ln. 8)	$ 1,791,278
10	DC Factor (Total_Labor)	AL:4:10	19.3618%
11	DC Insurance Expense Adjustment Excluding Property	= Ln. 9 * Ln. 10	$ 346,824
12	Incremental Property Insurance	Insurance Analysis	$ 5,128
13	DC Factor (Net_GPIS)	AL:3:13	18.6176%
14	DC Property Insurance Expense Adjustment	= Ln. 12 * Ln. 13	$ 955
15	Adjustment Total 1/	= Ln. 11 + Ln. 14	$ 347,779

16 **Adjustment Description:** To reflect insurance premium increases.

1/ For class cost purposes, the full amount of the adjustment relates to COSA line EX:5:8.

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 19 - Interest On Customer Deposits

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Amount C
1	**Expense**		
2	Customer Deposits	RB 1:22	$ 1,432,785
3	Interest Rate	Per Order	5.38%
4	Rate Year Customer Deposit Interest Expense	Ln. 2 * Ln. 3	$ 77,084
5	Test Year Customer Deposit Interest Expense	SM 1:11	41,769
6	Adjustment to Interest Expense	Ln. 4 - Ln. 5	$ 35,315

7 **Adjustment Description:** To reflect interest rate authorized for customer deposits.

Washington Gas Light Company
District of Columbia Jurisidiction

Adjustment No. 20 - Commission-Mandated Audit Fees

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Amount	
	A	B	C	
1	Regulatory Asset Balance as of July 31, 2025 (FC 1115 Pipes 1)	Analysis	$ 218,773	
2	Regulatory Asset Balance as of July 31, 2025 (FC 1175 Pipes 2)	Analysis	$ 832,225	
3	Total Annual Amortization (Rate Year)	(Ln. 1 + Ln. 2)/3	$ 350,333	
4	Test Year Expense (System)	Analysis	$ 91,675	
5	Three_Part_Factor	AL:5:30	18.64%	
6	Per Book Expense (District of Columbia)	Ln. 4 * Ln. 5	$ 17,091	
7	Adjustment	Ln. 3 - Ln. 6	$ 333,242	1/

8 **Adjustment Description:** To reflect the amortization of ProjectPipes audit fees at rate year amount.

1/ For Class Cost purposes, note that $333,242 of the adjustment relates to EX:5:6.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 21 - Non-Labor Inflation

Twelve Months Ended March 31, 2024

Line No.	Description	Allocator	Non-Labor Expense	Calculated Increase
	A	B	C	D
1	Test Year Operations Expense _1/	DC Inc Stmt, Ln. 3, Col. E	$ 57,084,597	
2	Test Year Maintenance Expense	DC Inc Stmt, Ln. 4, Col. E	25,568,839	
3	Labor Expense in Test Year O&M	Workpaper 1	(28,256,576)	
4	Test Year Non Labor O&M Expense	Sum (Ln. 1 > Ln. 3)	$ 54,396,860	
5	Non Labor Expense Adjustments to Cost of Service	Workpaper 2	(12,491,893)	
6	Test Year Non Labor O&M Expense (Adjusted)	Ln. 4 + Ln. 5	$ 41,904,967	
7	Inflation Rate (2024)	1 + (2.49% * 1)	102.49%	
8	Non Labor O&M Expense @ 12/31/2024	Ln. 6 * Ln. 7	$ 42,948,611	
9	Incremental Increase	Ln. 8 - Ln. 6		1,043,643
10	**Adjustment Total**	**Ln. 8**		**1,043,643**

1/ excludes Gas Purchased Expense

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 22 - Trade Dues, Business Memberships, and Community Affairs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Allocator C	System Amount D	DC Factor E	Ratemaking Adjustment F = C * D * E
1	Direct Charges - District of Columbia	Analysis	100% DC	$ 17,683	100%	$ (17,683)
2	Allocated Charges - Support Payments	Analysis	Comp_A&G	$ 409,981	19.54%	$ (80,114)
3	Direct Charges - Other Jurisdictions					
4	Maryland		100% MD	$ 275,283	0%	$ -
5	Virginia		100% VA	$ 318,274	0%	$ -
6	Total Other Jurisdictions	Ln. 4 + Ln. 5		$ 593,557		$ -
7	Total Company Memberships & Trade Dues	Ln. 1 + Ln. 2 + Ln. 7	1/	$ 1,021,220		$ (97,796)
8	Trade Dues & Business Associations					$ (48,991)
9	American Gas Association Dues					$ (59,768)
10	Community Affairs					$ 10,962
11	Total					$ (97,796)

12 **Adjustment Description:** To exclude Trade Dues, Business Memberships, and Community Affairs payments, as directed in prior
13 Commission Orders.

1/ For class cost purposes the total adjustment relates to COSA line EX:5:29

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 23 - General Advertising Expense Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Allocator B	Reference C	DC Amount D
1	Eliminate Advertising Expense Direct	Financial Statement	EX:5:19	$ -
2	Eliminate Advertising Expense Allocable	Comp A&G	EX:5:20	(125,884)
3	Total Adjustment		Ln. 1 + Ln. 2	$ (125,884)

4 **Adjustment Description:** To eliminate direct and indirect general advertising expenses (account 930100)
5 incurred during the study period.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 24 - Elimination of CIAC & Non-Includable ADIT

Twelve Months Ended March 31, 2024

Line No.	Description	COSA Reference	Reference	Test Year	Adjustment
	A	B	C	D	E
1	ADIT Reclassification and Elimination	RB:12:2	Workpaper 1	$ -	$ (225,491)
2	CIAC Grossup Balance	RB:11:4	Workpaper 2	$ (994,920)	$ 994,920
3	Environmental ADIT	RB:12:1	Per Book	$ (118,865)	$ 118,865
4	Merger Commitment Costs ADIT	RB:12:12	Per Book	$ 186,630	$ (186,630)

5 **Adjustment Description:** To eliminate CIAC and non-includable ADIT.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 25 - Legal Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C	
1	Legal Expenses (DC - Per Book Amount)	Financial Statements	$ 338,684	
2	DC Corrected Per Book Amount	Analysis	475,607	
3	Proforma Adjustment Amount	Line 2 - Line 1	$ 136,923	1/

4 **Adjustment Description:** To correct Legal expenses on a jurisdictional basis for
5 twelve months ended March 31, 2024.

1/ For Class Cost purposes, note that -$65.07 of the adjustment relates to EX:5:5, and $136,988.08 of the adjustment relates to EX:5:6.

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 26 - Prior Period Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description	Account	DC Total
	A	B	C
1	Prior Period Items		
2	Short Term Incentive Reclass	920432 (EX:5:2)	$ (26,978)
3	Adjustment Total		$ (26,978)

4 **Adjustment Description:** To adjust test year expense to remove prior period adjustments.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 27 - Merger Transition Cost to Achieve Amortization Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Total Company	Allocation Factor	District of Columbia
	A	B	C	D = B * C
1	**Transition Cost Amortization**			
2	Account 921003 - Merger Transition Amortization Expense	$ 308,014	16.98%	$ 52,311
3	**Elimination of Merger Transition Amortization Expense**			**$ (52,311)**

4 **Adjustment Description:** To eliminate merger-related cost to achieve amortizaton for the period for twelve months
5 ending March 2024.

Note: The merger amortizations ended in July 2023

_1/ For class cost purposes, the full amount of this adjustment relates to COSA line EX 5:5.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 28 - Credit/Debit Card Transaction Fees Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		MD Amount C
1	Credit/Debit Card Transaction Fees (Per Book)	EX:7:16	$	478,381
2	ACH Payment Increase	Analysis	$	66,585
3	Net Credit/Debit Card Fees	Ln. 1 - Ln. 2	$	411,796
4	Elimination of Credit/Debit Card Transaction Fees		$	(411,796)

5 **Adjustment Description:** To eliminate credit/debit card fees for twelve months ended March 31, 2024.

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 8D & 29 - Interest on Debt (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	Distribution Amount	Ratemaking Amount
	A	B	C	D	E
1	**Interest on Total Debt**				
2	Net Rate Base	Rate Base Stmt, Ln.23	$ 4,284,239,876	$ 796,176,491	$ 760,992,964
3	Weighted Average Cost of Debt	Cost of Capital, Ln. 1 + Ln. 2	2.36%	2.36%	2.36%
4	Interest on Debt	Ln. 2 * Ln. 3	$ 101,225,321	$ 18,811,557	$ 17,980,262
5	Per Books Interest Expense	Per Books	100,062,947	19,142,496	18,811,557
6	Adjustment to Interest Expense _1/	Ln. 4 - Ln. 5	$ 1,162,374	$ (330,939)	$ (831,295)

7 **Adjustment Description**: To synchronize interest expense used in determining the overall return requirement with the interest
8 expense used to calculate income taxes.

_1/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line 9:16.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 30 - Cash Working Capital (Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Dist. Amount C	DC RM Adjustment D	DC RM Amount E	DC Lag Days F	DC Dollar Days G = E x F
1	Composite Revenue Lag					89.00	
2	Gas Purchased	Adj 1	$ 66,068,873	$ 7,674,914	$ 73,743,787	38.19	$ 2,816,268,422
3	Payroll	Adj 5 & Adj 6	25,573,530	(2,389,314)	23,184,216	11.71	271,522,214
4	Other Operations and Maintenance Expenses						
5	Employee Health Benefits	Adj 9	4,793,783	79,796	4,873,579	30.37	147,994,982
6	Property and Public Liability Insurance	Adj 18	3,677,954	347,779	4,025,733	(163.46)	(658,063,186)
7	Other O&M	Various	48,736,805	(557,652)	48,179,153	25.47	1,227,048,919
8	Less: Pension Benefit (Non Cash)		42,494	-	42,494	25.47	1,082,247
9	Less: OPEB Benefit (Non Cash)		6,584,462	-	6,584,462	25.47	167,696,128
10	Property Taxes		2,013,868	-	2,013,868	71.02	143,032,994
11	Delivery Tax	Adj 1	23,451,041	2,241,912	25,692,953	26.13	671,382,563
12	Rights-of-Way Fee	Adj 1	12,518,268	(2,608,388)	9,909,880	(54.53)	(540,385,729)
13	FICA Taxes	Adj 12	2,103,553	22,322	2,125,875	9.97	21,193,472
14	Unemployment Tax		(6,961)	-	(6,961)	9.99	(69,562)
15	Environmental Tax		-	-	-	-	-
16	Federal Excise Tax		(21,714)	-	(21,714)	(17.51)	380,156
17	Sustainable Trust Fund	Adj 1	16,761,017	4,577,879	21,338,896	26.13	557,606,691
18	Energy Assistance Fund	Adj 1	2,156,914	210,071	2,366,985	26.13	61,851,688
19	Firm Storage Service		29	-	29	308.86	8,840
20	Other Taxes - Direct Assignment		16,520	-	16,520	79.00	1,305,080
21	Income Taxes	Adj. 31	(4,986,924)	166,747	(4,820,177)	-	-
22	Subtotal	Sum of Lns. 2 > 21	$ 209,483,512	$ 9,766,066	$ 219,249,578	22.30	$ 4,889,855,917
23	Lead Lag Requirement	Ln. 22, Col. E / 365			$ 600,684	66.70	$ 40,066,410
24	Other Lead-Lag Items						
25	Interest on Long-Term Debt	Adj 29	(330,939)	(831,295)	(1,162,234)	91.25	7,152
26	Economic Evaluation of Facility Extenstion (GSP 14)	Accts. 186.200 & 174.400	752,764	-	752,764	-	752,764
27	Cash Working Capital - Ratemaking						$ 40,826,325
28	Cash Working Capital - Distribution Amount						39,871,701
29	Cash Working Capital Ratemaking Adjustment	RB:1:10					$ 954,625

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 10D & 31 - State and Federal Income Taxes (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Distribution Amount C	Ratemaking Amount D
1	**Net Operating Income - Adjusted**	**DC Inc Stmt, Ln. 18**	**$ 20,999,112**	**$ 27,756,328**
2	Add: Income Taxes	DC Inc Stmt, Ln. 12	448,015	614,762
3	Less: Interest Expense	Adj 8D / Adj 29, Ln. 4	(18,811,557)	(17,980,262)
4	Taxable Income	Ln. 1 + Ln. 2 + Ln. 3	2,635,571	10,390,828
5	Flow-Throughs and Permanent Items (Basis)			
6	AFUDC Equity	Per Book ETR / Analysis	70,134	18,597
7	Meals and Entertainment	Per Book ETR / Analysis	184,959	184,959
8	Compensation Limitation	Per Book ETR / Analysis	-	-
9	Parking	Per Book ETR / Analysis	96,216	96,216
10	R&D credit	Per Book ETR / Analysis	-	-
11	Return to Provision True Up	Per Book ETR / Analysis	(806,112)	-
12	Other Tax Adjustments	Per Book ETR / Analysis	(176,160)	-
13	NOL Flow-through	Adj. 32	-	-
14	Total Flow-Throughs and Permanent Items	Ln. 6 > Ln. 12	(630,964)	299,771
15	Taxable Income (Adjusted)	Ln. 4 + Ln. 14	2,004,607	10,690,600
16	Federal Income Tax	Ln. 15 * 21.00%	420,968	2,245,026
17	Add: Excess Deferred Tax (Protected)		-	5,397,883
18	Add: Excess Deferred Tax (Unprotected)		-	(7,908,370)
19	Add: Excess Deferred Tax on PLR NOL			(140,599)
20	Less: Remove EDIT amortization related to FC 1027 Write Off			343,555
21	Add: Capitalizated OPEB		(12,689)	-
22	Add: ITC		(90,913)	(90,913)
23	Add: Amortization of Prior Flow-Through Balance		-	71,421
24	Total Federal Income Taxes	Ln. 17 > Ln. 22	317,365	(81,998)
25	Per Book / Ratemaking Federal Income Taxes		2,780,984	317,365
26	Federal Income Tax Adjustment	Ln. 24 - Ln. 25	(2,463,619)	(399,363)
27	State Income Tax (Net of Federal Tax Benefit)	Ln. 15 * 6.52%	130,650	696,760
28	Per Book / Ratemaking State Income Taxes		756,509	130,650
29	State Income Tax Adjustment	Ln. 27 - Ln. 28	(625,859)	566,110
30	Income Tax Adjustment	Ln. 26 + Ln. 29	(3,089,477)	166,747

31 **Adjustment Description:** To adjust state and federal income tax to rate year amounts.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 32 - NOLC Deferred Tax Asset (DTA) - Tax Normalization - Private Letter Ruling

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	DC Amount
	A	B	C	D
	Jurisdictional Realignment			
1	NOL Carryforward Federal Change	Workpaper 1 Ln. 14	$ 33,558,317	$ 6,403,501
2	NOL Carryforward State Change	Workpaper 1 Ln. 16	4,492,597	857,264
3	NOL Federal Benefit of State	Workpaper 1 Ln. 15	(943,445)	(180,026)
4	**Total NOL Change**	**Ln. 1 + Ln. 2 + Ln. 3**	**$ 37,107,469**	**$ 7,080,740**
5	Other Tax Credits - FED Change	Workpaper 1 Ln.	$ (32,614,872)	$ (5,451,639)
6	Other Tax Credits - STATE Change	Workpaper 1 Ln. 18	(4,492,597)	(750,946)
7	**Total Other Tax Credits Change**	**Ln. 5 + Ln. 6**	**$ (37,107,469)**	**$ (6,202,585)**
8	Net Change to Rate Base Deductions	Ln. 4 + Ln. 7	$ -	$ 878,155
9	**NOLC DTA**			
10	System Federal NOLC Depreciation	Workpaper 2	828,320,426	
11	Statutory Tax Rate		21%	
12	System Federal DTA- NOLC Depreciation	Ln. 10 * Ln. 11	173,947,289	
13	Test Year Amount	Analysis	$ (31,146,839)	
14	Increase in Federal DTA	Ln. 12 - Ln. 13	142,800,451	
15	District of Columbia Net Rate Base as of 03/31/2024	AL 3:6		19.08%
16	**Increase in DC DTA-NOLC Depreciation**	**Ln. 14 * Ln. 15**		**$ (27,248,768)**
	EDIT			
17	PLR effect on EDIT	Analysis	(815,594)	
18	District of Columbia Net Rate Base as of 9/30/2017	AL 3:6		17.24%
19	**Income Tax Expense**	**Ln. 17 * Ln. 18**		**$ (140,599)**

20 **Adjustment Description:** To adjust rate base and expenses to comply with the IRS PLR and correct per book NOL and other tax credit
21 balances.

Washington Gas Light Company
District of Columbia Jurisdiction

Income Tax Proof

Twelve Months Ended March 31, 2024

Line No.	Description	Per Books Amount	Per Books Tax Rate	Per Books Taxes	Distribution Amount	Distribution Tax Rate	Distribution Taxes	Ratemaking Amount	Ratemaking Tax Rate	Ratemaking Taxes	After Required Increase Amount	After Required Increase Tax Rate	After Required Increase Taxes
	A	C	D	E	F	G	H	I	J	K	I	J	K
1	**Net Operating Income - Adjusted**	**$ 34,283,145**			**$ 20,999,112**			**$ 27,756,328**			**$ 59,918,493**		
2	Income Taxes	3,537,493			448,015			614,762			12,824,914		
3	Net Operating Income, Before Tax	37,820,638			21,447,128			28,371,090			72,743,407		
4	Less: Interest Expense	19,142,496			18,811,557			17,980,262			17,980,262		
5	**Taxable Income**	**18,678,142**			**2,635,571**			**10,390,828**			**54,763,145**		
6	Effective Tax Rate	18.94%			17.00%			5.92%			23.42%		
7	**Reconciliation of the Effective Tax Rate**												
8	Taxable Income Before Permanent Items	18,678,142	26.58%	4,964,548	2,635,571	27.52%	725,243	10,390,828	27.52%	2,859,296	54,763,145	27.52%	15,069,448
9	Flow-Through and Permanent Items												
10	AFUDC Equity	70,134	0.10%	18,608	70,134	0.73%	19,299	18,597	0.05%	5,117	18,597	0.01%	5,117
11	Meals and Entertainment	184,959	0.26%	49,073	184,959	1.93%	50,896	184,959	0.49%	50,896	184,959	0.09%	50,896
12	Compensation Limitation	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
13	Parking	96,216	0.14%	25,528	96,216	1.00%	26,476	96,216	0.25%	26,476	96,216	0.05%	26,476
14	R&D credits	-	-0.78%	(145,577)	-	0.00%	-	-	0.00%	-	-	0.00%	-
15	Amortization of Prior Flow-Through Bal (COR)	-	0.00%	-	-	0.00%	-	259,549	0.69%	71,421	259,549	0.13%	71,421
16	Excess Deferred (Protected) _1/	-	-5.41%	(1,010,925)	-	0.00%	-	19,616,181	50.60%	5,257,284	19,616,181	9.60%	5,257,284
17	Excess Deferred (Unprotected) _1/	-	0.00%	-	-	0.00%	-	(28,739,422)	-76.11%	(7,908,370)	(28,739,422)	-14.44%	(7,908,370)
18	Excess Deferred - FC 1027 Write Off		0.00%		-	0.00%	-	1,248,495	3.31%	343,555	1,248,495	0.63%	343,555
19	Capitalized OPEB	(46,113)	-0.07%	(12,235)	(46,113)	-0.48%	(12,689)		0.00%	-		0.00%	-
20	Return to Provision True-up	(806,112)	-1.15%	(213,876)	(806,112)	-8.42%	(221,822)		0.00%	-		0.00%	-
21	Other Tax Adjustments	(176,160)	-0.25%	(46,738)	(176,160)	-1.84%	(48,475)		0.00%	-		0.00%	-
22	Total Flow-through and Permanent Items	(677,077)	-7.15%	(1,336,142)	(677,077)	-7.07%	(186,315)	(7,315,425)	-20.73%	(2,153,621)	(7,315,425)	-3.93%	(2,153,621)
23	Investment Tax Credit (ITC)	(90,913)	-0.49%	(90,913)	(90,913)	-3.45%	(90,913)	(90,913)	-0.87%	(90,913)	(90,913)	-0.17%	(90,913)
24	Total	17,910,152	18.94%	3,537,492	1,867,581	17.00%	448,015	2,984,490	5.92%	614,762	47,356,807	23.42%	12,824,914
25	Tax Variance			-			-			-			-
26	Pre-tax Variance			-			-			-			-

Calculation of Combined Income Tax Rates	(a) Per Book		(b) Distribution		(c) Ratemaking		(d) Revenue Requirement	
Federal Income Tax Rate				21.00%		21.00%		21.00%
State Income Tax Rate			8.25%		8.25%		8.25%	
Federal Benefit of State Taxes			-1.73%		-1.73%		-1.73%	
State Income Tax Rate net of Federal Benefit				6.52%		6.52%		6.52%
Combined Tax Rate		26.58%		27.5175%		27.52%		27.52%

Notes

_1/ "Excess Deferred (Protected)" tax basis and tax amount includeds both the protected and unprotected amount for per book and distribution. Protected and unprocted excess deferred taxes are calcualted separately

Washington Gas Light Company
District of Columbia
Exhibit (D)-5 Index of Adjustments & Excel Files

Adjustment #	Distribution Adjustments	Excel Spreadsheet Name
1D	Purchased Gas Costs	Exhibit WG (D)-5 Adj-D# 1D - Purchased Gas Costs Mar 2024
2D	Uncollectibles Gas Accounts / GAC Revenues	Exhibit WG (D)-5 Adjustment 1 - Revenue Study (TME Mar-2024) DC 2024 Rate Case
3D	Gas Procurement Costs	Exhibit WG (D)-5 Adj-D# 3D - Gas Procurement Costs Mar 2024
4D	Storage Gas Inventory & Carrying Costs	Exhibit WG (D)-5 Adj-D# 4D - Storage Gas Inventory and Carrying Costs Mar 2024
5D	Asset Optimization Revenues	Exhibit WG (D)-5 Adj-D# 5D - Asset Optimization Revenues Mar 2024
6D	Remove Supplier Refunds	Exhibit WG (D)-5 DC RMPF Mar 2024
7D	Purchase of Receivables	Exhibit WG (D)-5 DC RMPF Mar 2024
8D	Interest on Debt - Distribution	Exhibit WG (D)-5 DC RMPF Mar 2024
9D	Cash Working Capital - Distribution	Exhibit WG (D)-5 DC RMPF Mar 2024
10D	Income Taxes - Distribution	Exhibit WG (D)-5 DC RMPF Mar 2024

Adjustment #	Ratemaking/ Pro Forma Adjustments	Excel Spreadsheet Name
	Revenues	
1	Revenues and Related Expenses	Exhibit WG (D)-5 Adjustment 1 - Revenue Study (TME Mar-2024) DC 2024 Rate Case
	Rate Base	
2	CWIP Elimination	Exhibit WG (D)-5 DC RMPF Mar 2024
3	ProjectPIPES Average to EOP	Exhibit WG (D)-5 Adjustment 3 - DC PROJECTpipes Average to EOP - Mar 2024 v4
4	Depreciation Rates	Exhibit WG (D)-5 Adjustment 4 - New Depreciation Rates - Mar 2024 v3
	Labor and Labor Related	
5	Wages and Salaries	Exhibit WG (D)-5 Adjustment 5-6,9-12 - Labor Adjustment - Mar 2024
6	Long-Term Incentive Elimination	Exhibit WG (D)-5 Adjustment 5-6,9-12 - Labor Adjustment - Mar 2024
7	OPEB Costs	Exhibit WG (D)-5 Adjustment 7-8 - OPEB & Pension Adjustment - Mar 2024
8	Pension Expense	Exhibit WG (D)-5 Adjustment 7-8 - OPEB & Pension Adjustment - Mar 2024
9	401(k) Employer Contribution	Exhibit WG (D)-5 Adjustment 5-6,9-12 - Labor Adjustment - Mar 2024
10	Executive Fringe Benefit Elimination	Exhibit WG (D)-5 Adjustment 5-6,9-12 - Labor Adjustment - Mar 2024
11	Medical Plans Inflation	Exhibit WG (D)-5 Adjustment 5-6,9-12 - Labor Adjustment - Mar 2024
12	FICA / Medicare Taxes	Exhibit WG (D)-5 Adjustment 5-6,9-12 - Labor Adjustment - Mar 2024
13	Organizational Redesign Labor Expense Reduction	Exhibit WG (D)-5 Adjustment 13-14 - Involuntary Separation Program Expense Reduction and CTI TME Mar 2024
	Proforma Non-Labor	
14	Organizational Redesign Cost to Implement Amortization	Exhibit WG (D)-5 Adjustment 13-14 - Involuntary Separation Program Expense Reduction and CTI TME Mar 2024
15	Amortization of COVID Regulatory Asset	Exhibit WG (D)-5 Adjustment 15 - Amortization of COVID Reg Asset - Mar 2024
16	Regulatory Commission Expense	Exhibit WG (D)-5 Adjustment 16 - Regulatory Commission Expenses - Mar 2024
17	Environmental Adjustment	Exhibit WG (D)-5 Adjustment 17 - Environmental Cost - Mar 2024
18	Insurance Expense	Exhibit WG (D)-5 Adjustment 18 - Insurance Expense - Mar 2024
19	Interest on Customer Deposits	Exhibit WG (D)-5 Adjustment 19 - Interest on Customer Deposits - Mar 2024
20	Commission-Mandated Audit Fees	Exhibit WG (D)-5 Adjustment 20 - Audit Fees - Mar 2024
21	Non-Labor Inflation	Exhibit WG (D)-5 DC RMPF Mar 2024
	Eliminations	
22	Trade Dues, Bus Memberships, and Community Affairs Expense	Exhibit WG (D)-5 Adjustment 22 - Trade Dues, Bus Memberships, & Community Affairs - Mar 2024
23	General Advertising Expense	Exhibit WG (D)-5 DC RMPF Mar 2024
24	Non-Includable ADIT	Exhibit WG (D)-5 Adjustment 24 - Elimination of CIAC & Non-Includable ADIT - Mar 2024
25	Legal Expense	Exhibit WG (D)-5 Adjustment 25 - Legal Expense - Mar 2024
26	Prior Period or One-time entries	Exhibit WG (D)-5 Adjustment 26 - Prior Period Items Mar 2024
27	Merger Cost to Achieve Amortization Elimination	Exhibit WG (D)-5 Adjustment 27 - Merger Cost to Achieve Amortization Elimination Mar 2024
28	Credit/Debit Card Transaction Fees Elimination	Exhibit WG (D)-5 Adjustment 28 - Credit - Debit Card Transaction Fees Elimination - Mar 2024
	Synchronization & Tax Expense Adjustments	
29	Interest on Debt	Exhibit WG (D)-5 DC RMPF Mar 2024
30	Cash Working Capital	Exhibit WG (D)-5 DC RMPF Mar 2024
31	Income Taxes	Exhibit WG (D)-5 DC RMPF Mar 2024
	Other Adjustments	
32	Private Letter Ruling NOL Adjustment	Exhibit WG (D)-5 Adjustment 32 - NOLC Deferred Tax Asset - Tax Normalization PLR Mar 2024

Adjustment No. 1D

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1D - Purchased Gas Costs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		Amount C
1	*Purchased Gas Revenues*			
2	Fuel Revenues	RV:1:13	$ 2/	(59,477,160)
3	Third Party Balancing Charges	RV:1:27	4/	(6,609,061)
4	Balancing Charges Reconciliation Factor	Analysis		-
5	Total Adjustment for Purchased Gas Revenues	Lines 2 > 4	$	(66,086,221)
6	*Purchased Gas Costs*			
7	Hampshire Exchange Service	EX:2:9	$ 2/	(40,957)
8	Storage - Allocable	EX:2:12		(1,765,271)
9	Gas Purchase Costs	EX:3:3		(66,068,873)
10	Propane Gasified	EX:3:4		1,806,227
11	Total Adjustment for Purchased Gas Costs	Lines 7 > 10 (EX:3:3)	$	(66,068,873)

Adjustment Description: To remove fuel revenués, purchased gas costs, and gas supplier revenues from distribution revenues and expenses.

- GL Data

Account	Description		T 01	T 10
X_826201	Rents-Hampshire Strge Faclties	$	-	5/ $ 12,006,572
	DC's Allocated Share of 826201			$ 1,765,271 1

- PBCOSA Data

Firm Weather_NW	14.7025%	
OE Hampshire Exchange Service	5/ 40,957 1	
CWC GAS PURCHASED	6/ 51,891,638 A	Sum of A: 66,068,872 1
off system margins	14,177,234 A	
Propane Gasified Sch EX3	(1,806,227) 1	

- Supplemental Information for Revenue Study

Fuel Revenues (Per GL - See "DC Fuel Revenues" tab of the Revenue Classification WP) **$ 59,477,160**

	PGC % Allocation		DC
Residential	3/ 59.93%	$	35,644,608
Commercial and Industrial Other Than Group Metered Apartments	28.92%		17,197,983
Group Metered Apartments	11.15%		6,634,569
Interruptibles	0.00%		-
	100.00%	$	59,477,160 1

- Rate Stats Data

	Normal									
Level	Total System Level	Total System Level	Total System Level	1	2	Total System Level	1	2	Total System Level	Total System Level
Class	DC Res Htg / HC (NWS)	DC Res Non Htg - IMA (NWS)	DC Res Non Htg - OTH (NWS)	DC C&I Htg / HC < 3075 (Less Special Contracts)	DC C&I Htg / HC > 3075	DC C&I Non Htg (Less Special Contracts)	DC GMA Htg / HC < 3075	DC GMA Htg / HC > 3075	DC GMA Non Htg (NWS)	DC Interruptible (Plus Special Contracts)
Mar-2024	4,370,268	30,964	84,240	233,937	1,531,384	165,125	44,757	623,846	80,994	-
Feb-2024	5,782,948	34,378	109,269	312,863	1,515,064	182,658	(223,245)	875,532	99,785	-
Jan-2024	6,679,031	43,097	127,670	373,693	1,896,476	216,631	90,065	761,983	99,534	-
Dec-2023	4,197,531	19,654	83,381	220,697	1,542,417	148,299	42,589	608,333	68,530	-
Nov-2023	2,370,343	23,677	52,089	117,194	1,074,861	120,527	949	351,395	69,975	-
Oct-2023	943,043	7,202	21,127	49,173	633,538	113,397	33,550	140,780	44,116	-
Sep-2023	736,483	9,980	15,500	36,058	417,244	93,998	11,461	122,044	45,759	-
Aug-2023	629,858	17,657	12,911	65,784	615,170	93,970	790	228,446	38,435	-
Jul-2023	827,871	18,671	16,064	39,980	408,404	107,414	29,553	146,593	47,980	-
Jun-2023	1,084,029	12,084	22,981	101,950	558,883	120,318	26,544	392,165	56,330	-
May-2023	1,697,858	21,675	35,248	107,192	1,043,180	130,995	31,848	315,090	72,044	-
Apr-2023	3,786,476	32,498	74,146	241,861	1,558,412	231,131	47,978	799,192	108,676	-
	33,105,742	271,537	654,625	1,900,382	12,795,032	1,724,463	136,839	5,365,398	832,158	-

	Purchased Gas Charge Adjusted	Allocation Percentage
Total Residential	34,031,903.25	59.93%
Total C&I	16,419,877.29	28.92%
Total GMA	6,334,394.80	11.15%
Total Interruptible	-	0.00%
	56,786,175.34	100.00%
	-	

2

Washington Gas Light Company
Revenues
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operating Revenues**							
2	Sales of Gas and Transportation to Customers							
3	Residential		Financial Stmt.	$ 917,499,221	$ 114,679,781	$ 387,260,842	$ 415,558,598	$ -
4	Commercial and Industrial other than Group Metered Apts		Financial Stmt.	185,406,991	45,038,920	68,772,040	71,596,030	-
5	Group Metered Apartments		Financial Stmt.	37,945,816	16,671,589	10,825,850	10,448,377	-
6	Commercial and Industrial - Interruptible		Financial Stmt.	2,467,672	1,970,320	414,562	82,789	-
7	Transportation Sales / Mountaineer		Financial Stmt.	313,468,665	78,440,325	136,629,702	95,065,801	3,332,837
8	WSSC Revenues			586,938		586,938		-
9	Total Heating/Cooling and Other Uses	=3>7		$ 1,457,375,303	$ 256,800,936	$ 604,489,935	$ 592,751,595	$ 3,332,837
10	Rate Adjustment due Customers		Financial Stmt.	(1,841,180)	(268,728)	(805,138)	(767,313)	-
11	Unbilled Gas Accrual/Reversal		Financial Stmt.	(6,749,446)	(6,782,977)	446,100	(412,569)	-
12	Provision for Rate Refunds		Financial Stmt.	3,798,715	-	2,211,388	1,587,327	-
13	Total Gas Sales & Transportation Revenues	=8 > 11		$ 1,452,583,392	$ 249,749,231	$ 606,342,285	$ 593,159,040	$ 3,332,837
14	Other Operating Revenues							
15	Forfeited Discounts (Non POR)		Financial Stmt.	11,349,728	3,245,453	4,328,263	3,776,011	-
16	Forfeited Discounts (POR)		Financial Stmt.	582,776	360,143	222,583	50	-
17	Rent from Gas Property		Annual Firm_ ACT	967,406	139,688	416,107.68	411,610.20	-
18	Miscellaneous Service Revenues							
19	Reconnect Revenues		Financial Stmt.	847,711	174,354	568,927	104,430	-
20	Reconnect Revenues - Premium		Financial Stmt.	(234)	-	(234)	-	-
21	Dishonored Check Charge		Financial Stmt.	647,108	44,740	303,282	299,086	-
22	Service Initiation Charge		Financial Stmt.	3,947,838	838,570	1,816,987	1,292,280	-
23	Field Collection Charge		Financial Stmt.	4,951	433	3,528	990	-
24	IRATE Non Compliance MTR. Charge		Financial Stmt.	-	-	-	-	-
25	Other Gas Revenues							
26	Watergate Revenues		Financial Stmt.	-	-	-	-	-
27	Third Party Balancing Charges		Financial Stmt.	50,236,702	6,609,061 1	25,841,472	17,786,168	-
28	CNG Sales for Natural Gas Vehicles		Financial Stmt.	1,934,788	847,959	606,779	480,050	-
29	Off System Sales Revenue Net of Gas Cost		EX:3:2	86,111,467	14,177,234	38,508,187	33,426,045	-
30	Miscellaneous							
31	Other Allocable Miscellaneous		Financial Stmt.	(2,331,859)	(133,354)	(1,653,845)	(544,660)	-
32	Oth Gas Rev - MD RM-35		Financial Stmt.	1,374,694	736,920	637,773	-	-
33	Third Party Billing		Financial Stmt.	459,364	114,447	-	344,917	-
34	Total Other Operating Revenues	=14>32		$ 156,132,439	$ 27,155,649	$ 71,599,810	$ 57,376,979	$ -
35	Total Operating Revenues	=13+34		$ 1,608,715,831	$ 276,904,880	$ 677,942,095	$ 650,536,019	$ 3,332,837

Washington Gas Light Company
Operations Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	—— Reference —— Sc-Pg-Ln	Allocator			WG	DC	MD	VA	FERC
	A	B	C			D	E	F	G	H
1	**Operation Expenses**									
2	Gas Purchased	EX:3:5				$ 454,828,378	$ 64,262,645	$ 200,704,535	$ 189,861,198	$ -
3	Purchased Gas Expenses		Financial Stmt.	807500	Purch Gas Exp-Oth Purch Gs Exp	896,834	151,366	394,233	351,236	-
4	Purchased Gas Expenses		Financial Stmt.	807500	Purch Gas Exp-Oth Purch Gs Exp	54,868	596	17,799	36,473	-
5	Purchased Gas Expenses - Hexane		Financial Stmt.	807505	Hexane Additive (O&M Portion)	3,460,797	-	-	3,460,797	-
6	Purchased Gas Expenses- Chalk Point		Financial Stmt.	807510	Oth Purch Gas Exp-Chalk Point	32,044	-	32,044	-	-
7	Propane Holding	AL:1:2	Firm_Weather_NW	Sub Total		-	-	-	-	-
8	Watergate		Financial Stmt.	Sub Total		102,248	102,248	-	-	-
9	Hampshire Exchange Service	AL:1:2	Firm_Weather_NW	Sub Total		278,568	40,957 (2)	119,726	117,885	-
10	Property Modifications - Chalk Point		Financial Stmt.			-	-	-	-	-
11	Storage - Direct		Financial Stmt.	Sub Total		245	-	105	140	-
12	Storage - Allocable	AL:1:2	Firm_Weather_NW	Sub Total		16,757,838	2,463,828	7,202,383	7,091,628	-
				814000	Op Superv & Eng-Undrgrnd Strge	39				
				815000	Maps And Records	-				
				816000	Well Expenses	-				
				817000	Lines Expenses	-				
				818000	Compressor Station Expenses	1,588				
				820000	Meas & Regulating Sta Expenses	-				
				821000	Purification Expenses	-				
				824000	Other Expenses	-				
				825000	Storage Well Royalties	-				
				826000	Rents	622,037				
				826201	Rents-Hampshire Strge Facilties	12,006,572 (2)				
				826202	Rnt-Gs Used-Hamp Gs Co Str Fac	-				
				840000	Operation Supervision & Eng	333,268				
				841000	Operation Labor And Expenses	3,794,334				
13	Transmission	AL:2:8	Transmission_Plnt	Sub Total		3,214,585	474,160	1,246,238	1,410,951	83,237
14	Transmission - Chalk Point		Financial Stmt.	857101	Meas & Reg Sta Exp-Chalk Point	24,972	-	24,972	-	-
15	Transmission - Panda		Financial Stmt.	857104	Oper-Trans Meas&Reg Stat-Panda	8,960	-	8,960	-	-
16	Distribution									
17	Supervision and Engineering -									
18	Distribution	AL:5:17	Dist_X_Admin	Sub Total		955,435	218,452	389,587	347,396	-
19	Appliance Service - Direct		Financial Stmt.	870002	Appliance Service Department	-	-	-	-	-
20	Appliance Service - Allocable	AL:5:6	Appl_Svc_X_Admin	870002	Appliance Service Department	-	-	-	-	-
21	Other	AL:2:22	Tot_Dist_Plnt	870003	Oth Than T&D Or App Service	5,208,625	1,004,253	1,886,834	2,317,538	-
22	Load Dispatching	AL:1:32	Comp_Peak_Ann_NW	871000	Distribution Load Dispatching	2,154,642	335,980	941,514	877,148	-
23	Load Dispatching - Chalk Point		Financial Stmt.	871001	Distr Load Disptch-Chalk Point	-	-	-	-	-
24	Compressor Station Equipment	AL:1:32	Comp_Peak_Ann_NW	872000	Compressor Sta Labor & Exp	-	-	-	-	-
25	Mains	AL:2:16	Dist_Mains_Plnt	874000	Mains And Service Expenses	1,368,210	291,861	471,936	604,413	-
26	Mains - Chalk Point		Financial Stmt.	856001	Mains Expenses-Chalk Point	-	-	-	-	-
27	Removing/Setting Meters - Direct		Financial Stmt.	878000	Meter & House Reg Expenses	1,689,348	121,682	1,105,374	462,292	-
28	Removing/Setting Meters - Allocable	AL:5:2	Direct_Meter_Exp	878000	Meter & House Reg Expenses	-	-	-	-	-
29	Measuring and Regulating Station Equipment	AL:2:17	Dist_Meas_Reg_Plnt	875000	Meas & Reg Station Exp-General	509,583	303,237	123,239	83,107	-
30	Measuring and Reg Station Equip - Chalk Point		Financial Stmt.	875001	Inactive-See Legacy FRS System	-	-	-	-	-
31	Services On Customer Premises-Direct		Financial Stmt.	Sub Total		44,751	1,533	8,132	35,086	-
32	Services On Customer Premises-Allocable	AL:5:4	Direct_SOCP	Sub Total		0	0	0	0	-
33	Office Expenses -					-				-
34	Distribution	AL:5:17	Dist_X_Admin	Sub Total		12,555,986	2,870,823	5,119,808	4,565,354	-
35	Appliance Service - Direct		Financial Stmt.	880002	Other Expenses - App Service	-	-	-	-	-
36	Appliance Service - Allocable	AL:5:6	Appl_Svc_X_Admin	880002	Other Expenses - App Service	-	-	-	-	-
37	Other	AL:2:16	Dist_Mains_Plnt	880003	Oth Exp-Oth Thn T&D Or App Srv	245,147	52,294	84,559	108,295	-
38	Rents		Financial Stmt.	881000	Rents	14,652	-	298	14,355	-
39	Customer Accounts	EX:7:23				52,124,547	12,768,405	19,560,728	19,795,414	-
40	Customer Service and Information Exp - Allocable	AL:4:12	Avg_Meters	Sub Total		3,156,065	437,277	1,246,549	1,472,238	-
41	Information Exp - Direct		Financial Stmt.	909000	Info & Instruct Advert Exp	240,680	75,837	150,863	13,981	-
42	Sales Expense	AL:4:12	Avg_Meters	Sub Total		602,426	83,467	237,940	281,019	-
43	Advertising Exp - Direct	AL:4:12	Financial Stmt.	913000	Advertising Expenses	1,770	-	1,770	-	-
44	Administrative and General	EX:5:31				215,854,266	39,138,720	97,390,911	79,297,762	26,873
45	Interest on Financing Leases	AL:3:6	Net_Rate_Base	427420		$ 493,872	$ 94,239	$ 183,968	$ 215,665	$ -
46	Total Operation Expenses	=2>44				$ 776,880,340	$ 125,293,859	$ 338,655,003	$ 312,821,368	$ 110,110

Washington Gas Light Company
Development of Gas Purchased Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
A	B	C	D	E	F	G	H
1 Gas Purchase Costs		Financial Stmt.	$ 381,002,051	$ 51,891,638	$ 167,476,401	$ 161,634,012	$ -
2 Less: Off System Sales Cost of Gas Recovered			$ (86,111,467)	$ (14,177,234)	$ (38,508,187)	$ (33,426,045)	$ -
3 PGC Recovered - DC/MD/VA	=1-2		$ 467,113,518	$ 66,068,873	$ 205,984,588	$ 195,060,057	$ -
4 Propane Gasified		Financial Stmt.	$ (12,285,140)	$ (1,806,227)	$ (5,280,054)	$ (5,198,859)	$ -
5 Total Gas Purchased & Propane Gasified	=3+4	Financial Stmt.	$ 454,828,378	$ 64,262,645	$ 200,704,535	$ 189,861,198	$ -

Adjustment No. 2D

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 2D - GAC Revenues and Uncollectible Expense Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Gas Administration Charge Revenues		
2	Residential	Analysis	$ 2/ (1,074,697)
3	Commercial and Industrial Other Than Group Metered Apartments	Analysis	(507,259)
4	Group Metered Apartments	Analysis	(191,045)
5	Gas Administration Charge Revenues Elimination Amount	1/	(1,773,001)
6	Less: Gas Procurement Cost		
7	Residential	Analysis	2/ 47,400
8	Commercial and Industrial Other Than Group Metered Apartments	Analysis	22,294
9	Group Metered Apartments	Analysis	8,477
10	Gas Procurement Cost Total	Adj No. 3D	78,171
11	GAC Uncollectible Expense Elimination Amount 2/	Line 5 + Line 9	$ (1,694,830)

12 **Adjustment Description:** To remove Gas Administration Charge uncollectible amounts.

1/ For Class Cost purposes, note that this adjustment relates to RV:1:14.
2/ For Class Cost purposes, note that this adjustment relates to EX:7:21.

TM1 Data

- GAC Detail from Customer Billing System

CUBE:	**tm1serv:Rate Statistics DB**
RS_ACTUAL_AREA	**DC**
RS_ACTUAL_TYPE	**GAC Current**
RS_ACTUAL_CLASS	*See Below*
RS_ACTUAL_LEVEL	**Total System Level**
RS_ACTUAL_PERIOD	**Mar-2024 T12**

Customer Class		Amount	Allocation		Allocated Gas	
RESIDENTIAL	$	A 1,079,638	60.64%		47,400	1
COMMERCIAL		B 507,782	28.52%		22,294	
GROUP METERED		C 193,075	10.84%		8,477	
TOTAL ALL CUSTOMER CLASSES	**$**	**1,780,495**	**100.00%**	**$**	**78,171**	

A 1,079,638
4/ (4,941)
1,074,697 1

B 507,782
4/ (523)
507,259 1

C 193,075
4/ (2,030)
191,045 1

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 3D - Gas Procurement Costs

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Amount
	A	B	C
1	Gas Purchasing Expenses (Total System)	Financial Statements	$ 463,159
2	DC Per Book Amount	EX 2:3	78,171
3	Pro forma Adjustment Amount	-Ln. 2	$ (78,171) 2

4 **Adjustment Description:** To eliminate Gas Purchasing Expenses associated with sales service
5 customers twelve months ended March 31, 2024.

- Supplemental Information for Adjustment #2D

Unit	01
Oper Unit	01
Ledger	ACTUALS
DC Revenue Grouping	(Multiple Items)

Sum of Sum Amount	**Column Labels**	
Row Labels	**EXL**	**Grand Tot**
GAC Current	**7,494**	**7,494**
Commercial Customer	523	523 ②
Group Meter Apartments	2,030	2,030
Residential Customer	4,941	4,941
Grand Total	**7,494**	**7,494**

Adjustment No. 3D

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 3D - Gas Procurement Costs

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Amount
	A	B	C
1	Gas Purchasing Expenses (Total System)	Financial Statements	$ 2/ 463,159
2	DC Per Book Amount	EX 2:3	2/ 78,171
3	Pro forma Adjustment Amount	-Ln. 2	$ (78,171)

4 **Adjustment Description:** To eliminate Gas Purchasing Expenses associated with sales service
5 customers twelve months ended March 31, 2024.

- Actual Test Period (TME Mar-2024)

Unit	01

Sum of Amount	Account	Oper Unit		Grand Total
	807500			
Dept	10	01	03	
614	(3,256)	82	-	(3,174)
615	(3,164)	-	-	(3,164)
605	499,383	416	34,308	534,107
613	(29,804)	-	-	(29,804)
Grand Total	463,159 ①	497	34,308	497,965

Pipeline_NW	3/ 16.88%
DC Allocable Amount	**$ 78,171** ①

Washington Gas Light Company
Allocation Factors Based on Normal Weather Study

Twelve Months Ended March 2024 - AVG

Description	—— Reference —— Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Firm Annual Weather Gas**									
2 TOTAL FIRM WEATHER GAS - NW	NW Study	Firm_Weather_NW	966,262,395	142,065,096	415,291,747	408,905,552	0.147025	0.429792	0.423183
3 TOTAL FIRM THERM SALES - NW	NW Study	Annual_ Firm_NW	1,418,556,506	206,081,756	605,693,246	606,781,504	0.145276	0.426979	0.427746
4 TOTAL FIRM THERM SALES - NW(sales only)		Annual_ Firm_Sales_NW	914,452,500	122,542,753	382,007,337	409,902,410	0.134007	0.417744	0.448249
5 **Non-Firm Annual Weather Gas**									
6 June Sales	Financial Stmt.		19,106,249	4,878,086	10,601,572	3,626,591			
7 July Sales	Financial Stmt.		16,385,284	4,144,577	9,130,761	3,109,946			
8 Aug. Sales	Financial Stmt.		15,994,187	4,074,410	9,020,913	2,898,865			
9 Total Summer Usage	=+6+7+8		51,485,720	13,097,073	28,753,246	9,635,401			
10 Annualization Factor	Constant		4	4	4	4			
11 Annualized Summer Usage	=9*10		205,942,881	52,388,293	115,012,983	38,541,605			
12 Watergate Usage	Financial Stmt.		-	-	-	-			
13 Calculated Base Usage	=11+12		205,942,881	52,388,293	115,012,983	38,541,605			
14 Actual Usage	NW Study		239,874,935	73,882,136	116,925,204	49,067,596			
15 Weather Usage	=14-13		33,932,054	21,493,843	1,912,220	10,525,990			
16 Total Interruptible Therm Sales - NW			263,839,380	77,868,955	133,858,923	52,111,502			
17 Weather Gas Interruptible - NW			57,843,990	26,677,272	19,855,837	11,310,880			
18 TOTAL FIRM THERM SALES - NW(Delivery only)		Annual_ Firm_Delivery_NW	509,207,172	81,663,741	227,864,492	199,678,939	0.160374	0.447489	0.392137
19 TOTAL ALL WEATHER GAS	=2+18	Total_Weather_All_NW	1,024,106,385	168,742,368	435,147,584	420,216,432	0.164770	0.424905	0.410325
20 TOTAL ANNUAL THERM SALES	=4+17	Annual_Total_NW	1,682,395,886	283,950,710.85	739,552,169	658,893,006	0.168778	0.439583	0.391640
25 ANNUAL THERMS ADJUSTED	=20-24	Pipeline_NW	1,682,395,886	283,950,711	739,552,169	658,893,006	0.1688 2	0.4396	0.3916
26 FIRM ANNUAL PIPELINE	=3-24	Firm_Pipe_ Ann_ Adj	1,418,556,506	206,081,756	605,693,246	606,781,504	0.145276	0.426979	0.427746
27 FIRM ANNUAL PIPELINE(Sales only)	=4-24	Firm_Pipe_ Ann_Sales_ Adj	914,452,500	122,542,753	382,007,337	409,902,410	0.134007	0.417744	0.448249
28 **Peak Day Therm Sales- Normal Weather**									
29 Weather Gas	NW Study	Peak_Day _Weather	15,991,500	2,290,271	6,959,692	6,741,537	0.143218	0.435212	0.421570
30 Base Gas	NW Study	Peak_Day_Base	1,218,969	172,345	515,804	530,820	0.141386	0.423148	0.435466
31 Total Peak Day Therms	=29+30	Peak_Day_Total	17,210,469	2,462,616	7,475,496	7,272,357	0.143088	0.434357	0.422554
32 PEAK DAY AND ANNUAL SALES	=(20+31)/2	Comp_Peak_ Ann_NW					0.155933	0.436970	0.407097
33 TOTAL WINTER THERMS (NOV-APR)	NW Study	Wintr_Pipe_NW	1,277,081,957	214,413,097	552,242,395	510,426,464	0.167893	0.432425	0.399682

Adjustment No. 4D

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 4D - Storage Gas Inventory & Related Carrying Costs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	**Rate Base:**		
2	Elimination of Storage Gas Inventory 1/	RB:6:10	$ 2/ (16,895,300)
3	**Carrying Costs:**		
4	Billed PGC Carrying Costs		
2	Residential	Analysis	$ 2/ (1,030,532)
3	Commercial and Industrial Other Than Group Metered Apartments	Analysis	(481,013)
4	Group Metered Apartments	Analysis	(180,575)
5	Carrying Cost Adjustment - Gross	Lns. 2 > 4	$ (1,692,120)
6	Billed ACA Carrying Costs	Financial Statement	$ -
7	Unbilled Carrying Costs	Financial Statement	$ 4/ 133,354
8	Total Carrying Costs 2/	Lns. 5 > 7	$ (1,558,766)

9 **Adjustment Description:** To remove storage gas inventory and related carrying costs from distribution
10 revenues.

1/ For Class Cost purposes, note that -$16,895,299.51 of the adjustment relates to RB:6:10.
2/ For Class Cost purposes, note that -$1,692,120.27 of the adjustment relates to RV:1:14 and $133,354.22 of the adjustment relates to RV:1:37.

- PBCOSA Data

Storage Gas Purchased	$	3/ 16,895,300 ①

- Rate Statistics Data

	STORAGE GAS CHRG	ACA - Inventory Carrying Charge
RESIDENTIAL-SALES	1,030,532	-
COMMERCIAL-SALES	481,013	-
GROUP METERED-SALES	180,575	-
Total	1,692,120	-

- GL Data

X_495304	$	133,354

Washington Gas Light Company
Materials and Supplies
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
Average Rate Base

Description	Reference Sc-Pg-Ln	Reference Allocator	WG	DC	MD	VA	FERC
A	B	C	D	E	F	G	H
1 **Materials and Supplies**							
2 General Supplies : 1/							
3 Construction	AL:3:2	Stores _Stock	$ 2,091,723	$ 58,422	$ 721,129	$ 1,312,171	$ -
4 Operation	AL:1:20	Annual_Total_NW	5,670,176	956,999	2,492,511	2,220,666	-
5 Total General Supplies	=3+4		$ 7,761,899	$ 1,015,421	$ 3,213,641	$ 3,532,837	$ -
6 Fuel Stock:							
7 Watergate		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
8 Propane Fuel Stock	AL:1:2	Firm_Weather_NW	12,445,064	1,829,740	5,348,787	5,266,536	-
9 Total Fuel Stock	=7+8		$ 12,445,064	$ 1,829,740	$ 5,348,787	$ 5,266,536	$ -
10 Storage Gas Purchased	AL:1:19	Total_Weather_All_NW	$ 102,538,469	$ 16,895,300 (2)	$ 43,569,074	$ 42,074,095	$ -
11 Fuel Stock Materials - Hexane	AL:1:19	Total_Weather_All_NW	582,550	$ 95,987	$ 247,528 #	$ 239,035	$ -
12 Total Materials and Supplies	=5+9+10+11		$ 123,327,981	$ 19,836,447 #	$ 52,379,031 #	$ 51,112,503	$ -

1/ Apportionment of supplies balance between Construction and Operation is based on actual issues from stores stock during the test period.

Construction	781,698	$ 0
Operation	2,119,003	$ 1
Total	$ 2,900,702	$ 1

Washington Gas Light Company
Revenues
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	—— Reference —— Sc-Pg-Ln	Allocator	Ferc Accounts	Account	WG	DC	MD	VA	FERC
	A	B	C			D	E	F	G	H
1	**Operating Revenues**									
2	Sales of Gas and Transportation to Customers									
3	Residential		Financial Stmt.	Rpts. - Residentail Sales		$ 917,499,221	$ 114,679,781	$ 387,260,842	$ 415,558,598	$ -
4	Commercial and Industrial other than Group Metered Apts		Financial Stmt.	Rpts. - Commerial and Industrial Sales		185,406,991	45,038,920	68,772,040	71,596,030	-
5	Group Metered Apartments		Financial Stmt.	Rpts. - Group Metered Apts. Sales		37,945,816	16,671,589	10,825,850	10,448,377	-
6	Commercial and Industrial - Interruptible		Financial Stmt.	Rpts. - Commerial and Industrial-Interruptible Sales		2,467,672	1,970,320	414,562	82,789	-
7	Transportation Sales / Mountaineer		Financial Stmt.			313,468,665	78,440,325	136,629,702	95,065,801	3,332,837
				Rpts. - Transportation Sales	ecia	310,135,828	78,440,325	136,629,702	95,065,801	-
				489100-5200		3,332,837	-	-	-	3,332,837
8	WSSC Revenues					586,938		586,938		-
9	Total Heating/Cooling and Other Uses	=3>7				$ 1,457,375,303	$ 256,800,936	$ 604,489,935	$ 592,751,595	$ 3,332,837
10	Rate Adjustment due Customers		Financial Stmt.	Rpts. - Rate Adjustment Due Customers		(1,841,180)	(268,728)	(805,138)	(767,313)	-
11	Unbilled Gas Accrual/Reversal		Financial Stmt.	Rpts. - Unbilled Gas Accrual_Reversal		(6,749,446)	(6,782,977)	446,100	(412,569)	-
12	Provision for Rate Refunds		Financial Stmt.	Rpts. - Provision for Rate Refund		3,798,715	-	2,211,388	1,587,327	-
13	Total Gas Sales & Transportation Revenues	=8 > 11				$ 1,452,583,392	$ 249,749,231	$ 606,342,285	$ 593,159,040	$ 3,332,837
14	Other Operating Revenues									
15	Forfeited Discounts (Non POR)		Financial Stmt.	Rpts. - Forfeited Discounts (Non POR)		11,349,728	3,245,453	4,328,263	3,776,011	-
16	Forfeited Discounts (POR)		Financial Stmt.	Rpts. - Forfeited Discounts (POR)		582,776	360,143	222,583	50	-
17	Rent from Gas Property		Annual Firm_ ACT	Rpts. - Rent from Gas Property		967,406	139,688	416,107.68	411,610.20	-
18	Miscellaneous Service Revenues									
19	Reconnect Revenues		Financial Stmt.	Rpts. - Reconnect Revenues		847,711	174,354	568,927	104,430	-
20	Reconnect Revenues - Premium		Financial Stmt.	Rpts. - Reconnect Revenues Premium		(234)	-	(234)	-	-
21	Dishonored Check Charge		Financial Stmt.	Rpts. - Dishonered Check Charge		647,108	44,740	303,282	299,086	-
22	Service Initiation Charge		Financial Stmt.	Rpts. - Service Intiation Fee		3,947,838	838,570	1,816,987	1,292,280	-
23	Field Collection Charge		Financial Stmt.	Rpts. - Field Collection charge		4,951	433	3,528	990	-
24	IRATE Non Compliance MTR. Charge		Financial Stmt.	Rpts. - IRATE Non Compliance Charge		-	-	-	-	-
25	Other Gas Revenues									
26	Watergate Revenues		Financial Stmt.	Rpts. - Watergate Revenues		-	-	-	-	-
27	Third Party Balancing Charges		Financial Stmt.	Rpts. - Thrid Party Balancing Charges		50,236,702	6,609,061	25,841,472	17,786,168	-
28	CNG Sales for Natural Gas Vehicles		Financial Stmt.	Rpts. - CNG Sales for NGV		1,934,788	847,959	606,779	480,050	-
29	Off System Sales Revenue Net of Gas Cost		EX:3:2			86,111,467	14,177,234	38,508,187	33,426,045	-
30	Miscellaneous									
31	Other Allocable Miscellaneous		Financial Stmt.	Rpts. - Other Allocable Misc.		(2,331,859)	(133,354) 1	(1,653,845)	(544,660)	-
32	Oth Gas Rev - MD RM-35		Financial Stmt.	Rpts. - Other Gas Rev - MD RM-35		1,374,694	736,920	637,773	-	-
33	Third Party Billing		Financial Stmt.	Rpts. - Thrid Party Billing		459,364	114,447	-	344,917	-
34	Total Other Operating Revenues	=14>32				$ 156,132,439	$ 27,155,649	$ 71,599,810	$ 57,376,979	$ -
35	Total Operating Revenues	=13+34				$ 1,608,715,831	$ 276,904,880	$ 677,942,095	$ 650,536,019	$ 3,332,837

Adjustment No. 5D

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 5D - Asset Optimization Revenues

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Asset Optimization Revenues	RV 1:29	$ [2/] (14,177,234)

2 **Adjustment Description:** To remove asset optimization revenues from distribution
3 revenues.

Washington Gas Light Company
Revenues
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operating Revenues**							
2	Sales of Gas and Transportation to Customers							
3	Residential		Financial Stmt.	$ 917,499,221	$ 114,679,781	$ 387,260,842	$ 415,558,598	$ -
4	Commercial and Industrial other than Group Metered Apts		Financial Stmt.	185,406,991	45,038,920	68,772,040	71,596,030	-
5	Group Metered Apartments		Financial Stmt.	37,945,816	16,671,589	10,825,850	10,448,377	-
6	Commercial and Industrial - Interruptible		Financial Stmt.	2,467,672	1,970,320	414,562	82,789	-
7	Transportation Sales / Mountaineer		Financial Stmt.	313,468,665	78,440,325	136,629,702	95,065,801	3,332,837
8	WSSC Revenues			586,938		586,938		-
9	Total Heating/Cooling and Other Uses	=3>7		$ 1,457,375,303	$ 256,800,936	$ 604,489,935	$ 592,751,595	$ 3,332,837
10	Rate Adjustment due Customers		Financial Stmt.	(1,841,180)	(268,728)	(805,138)	(767,313)	-
11	Unbilled Gas Accrual/Reversal		Financial Stmt.	(6,749,446)	(6,782,977)	446,100	(412,569)	-
12	Provision for Rate Refunds		Financial Stmt.	3,798,715	-	2,211,388	1,587,327	-
13	Total Gas Sales & Transportation Revenues	=8 > 11		$ 1,452,583,392	$ 249,749,231	$ 606,342,285	$ 593,159,040	$ 3,332,837
14	Other Operating Revenues							
15	Forfeited Discounts (Non POR)		Financial Stmt.	11,349,728	3,245,453	4,328,263	3,776,011	-
16	Forfeited Discounts (POR)		Financial Stmt.	582,776	360,143	222,583	50	-
17	Rent from Gas Property		Annual Firm_ ACT	967,406	139,688	416,107.68	411,610.20	-
18	Miscellaneous Service Revenues							
19	Reconnect Revenues		Financial Stmt.	847,711	174,354	568,927	104,430	-
20	Reconnect Revenues - Premium		Financial Stmt.	(234)	-	(234)	-	-
21	Dishonored Check Charge		Financial Stmt.	647,108	44,740	303,282	299,086	-
22	Service Initiation Charge		Financial Stmt.	3,947,838	838,570	1,816,987	1,292,280	-
23	Field Collection Charge		Financial Stmt.	4,951	433	3,528	990	-
24	IRATE Non Compliance MTR. Charge		Financial Stmt.	-	-	-	-	-
25	Other Gas Revenues							
26	Watergate Revenues		Financial Stmt.	-	-	-	-	-
27	Third Party Balancing Charges		Financial Stmt.	50,236,702	6,609,061	25,841,472	17,786,168	-
28	CNG Sales for Natural Gas Vehicles		Financial Stmt.	1,934,788	847,959	606,779	480,050	-
29	Off System Sales Revenue Net of Gas Cost		EX:3:2	86,111,467	14,177,234 1	38,508,187	33,426,045	-
30	Miscellaneous							
31	Other Allocable Miscellaneous		Financial Stmt.	(2,331,859)	(133,354)	(1,653,845)	(544,660)	-
32	Oth Gas Rev - MD RM-35		Financial Stmt.	1,374,694	736,920	637,773	-	-
33	Third Party Billing		Financial Stmt.	459,364	114,447	-	344,917	-
34	Total Other Operating Revenues	=14>32		$ 156,132,439	$ 27,155,649	$ 71,599,810	$ 57,376,979	$ -
35	Total Operating Revenues	=13+34		$ 1,608,715,831	$ 276,904,880	$ 677,942,095	$ 650,536,019	$ 3,332,837

Adjustment No. 6D

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 6D - Supplier Refunds and Supplier Interest Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	DC Amount
	A	B	C
1	**Per Book Rate Base**		
2	Elimination of Supplier Refunds	RB:1:23	$ 2/ (626,315)
3	**Per Book Expense**		
4	Elimination of Interest on Supplier Refunds	SM:1:12	$ 3/ (11,533)

5 **Adjustment Description:** To remove all supplier refunds and interest related to supplier refunds.

Washington Gas Light Company
Rate Base Summary
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	Allocator	WG	DC	MD	VA	FERC
	A	C	D	E	F	G	H
1	Gas Plant in Service		$ 7,249,016,177	$ 1,317,182,832	$ 2,711,617,252	$ 3,190,657,625	$ 29,558,468
2	Gas Plant Held for Future Use		-	-	-	-	-
3	Unrecovered Plant - Peaking Facility	Total_Weather_All_NW	-	-	-	-	-
4	Construction Work in Progress		397,111,025	79,322,274	134,339,566	183,449,185	-
5	Materials & Supplies		123,327,981	19,836,447	52,379,031	51,112,503	-
6	Non Plant - ADIT	Financial Stmt.	(34,509,521)	(3,062,666)	(21,491,098)	(9,955,757)	0
7	FC 1027 - Rate Base CWIP (Reg Asset)		(0)	(0)			
8	Unamortized East Station Cost (Net of Deferred Taxes)	Financial Stmt.	1,075,846	1,075,846	-	-	-
9	Sub-Total		$ 7,736,021,508	$ 1,414,354,734	$ 2,876,844,750	$ 3,415,263,556	$ 29,558,468
10	Cash Working Capital		$ 121,292,100	$ 39,219,091	$ 67,230,077	$ 14,826,433	$ 16,500
11	Total Rate Base Additions		$ 7,857,313,609	$ 1,453,573,825	$ 2,944,074,827	$ 3,430,089,989	$ 29,574,968
12	LESS:						
13	Reserve for Depreciation		$ 2,370,279,045	$ 449,057,859	$ 864,931,885	$ 1,054,487,285	$ 1,802,016
14	Accumulated DIT re Depreciation		1,298,608,831	212,149,665	532,439,389	554,019,777	0
15	Accumulated DIT re Gains/Losses On Reacquired Debt						
16	Federal	Net_Rate_Base	175,290	29,300	70,009	75,981	-
17	State	Net_Rate_Base	57,829	10,143	22,631	25,055	-
18	NOL Carryforward Federal	Net_Rate_Base	(78,173,336)	(14,916,809)	(29,119,631)	(34,136,895)	-
19	NOL Carryforward State	Net_Rate_Base	(68,626,785)	(13,095,164)	(25,563,533)	(29,968,088)	-
20	NOL Federal Benefit of State	Net_Rate_Base	14,411,625	2,749,985	5,368,342	6,293,298	-
21	Customer Advances for Construction	Financial Stmt.	2,698,381	305,769	244,862	2,147,750	-
22	Customer Deposits	Financial Stmt.	12,871,928	1,432,785	2,467,234	8,971,908	-
23	Supplier Refunds	Financial Stmt.	4,509,391	626,315 1	1,675,549	2,207,527	-
24	Deferred Tenant Allowance	Non_Genl_Plnt	16,261,534	3,017,287	6,000,718	7,243,529	-
25	Total Rate Base Deductions		$ 3,573,073,733	$ 641,367,135	$ 1,358,537,454	$ 1,571,367,128	$ 1,802,016
26	Net Rate Base		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952

Washington Gas Light Company
Income Statement Summary -- Combined
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Allocator	WG	DC	MD	VA	FERC
	A	C	D	E	F	G	H
1	**Operating Revenues**		$ 1,608,715,831	$ 276,904,880	$ 677,942,095	$ 650,536,019	$ 3,332,837
2	Operating Expenses						
3	Gas Purchased		$ 454,828,378	$ 64,262,645	$ 200,704,535	$ 189,861,198	$ -
4	Operation - Other than Gas Purchased		322,051,962	61,031,214	137,950,468	122,960,170	110,110
5	Maintenance		114,413,313	25,568,839	46,799,501	41,961,616	83,356
6	Depreciation		135,410,640	23,907,431	41,034,291	70,456,187	12,731
7	Amortization of Capitalized Software	Financial Stmt.	21,433,284	3,757,163	8,810,769	8,785,972	79,380
			2,512,710	465,325	930,290	1,107,746	9,349
			18,822,562	3,193,858	7,880,446	7,678,226	70,031
			98,012	97,980	32	-	-
8	Amortization of Chalk Point / MD Post 1989 Inter	Financial Stmt.	94,718	-	94,718	-	-
9	Amortization of General Plant		14,127,280	1,878,281	5,415,781	6,833,217	-
10	Amortization of Unrecovered Plant Loss Chillum	Financial Stmt.	-	-	-	-	-
11	Interest on Customer Deposits		528,578	41,769	128,646	358,163	-
12	Interest on Supplier Refunds		73,600	11,533	31,581	30,486	-
13	General Taxes		171,665,153	58,992,535	88,254,140	24,335,027	83,452
14	Other Income Taxes	Financial Stmt.	13,182,317	756,509	5,234,557	7,027,005	164,246
15	Expenses Before Federal Income Taxes		$ 1,247,809,223	$ 240,207,920	$ 534,458,986	$ 472,609,042	$ 533,275
16	Federal Income Tax Expense		$ 50,043,363	$ 2,871,897	$ 19,871,685	$ 26,676,264	$ 623,518
17	ITC Adjustment		(305,994)	(90,913)	(108,018)	(107,064)	-
18	Loss- Disposition of Utility Plant	Financial Stmt.	451,758	100,274	351,484	-	-
19	Total Operating Expenses		$ 1,297,998,351	$ 243,089,178	$ 554,574,138	$ 499,178,242	$ 1,156,793
20	Net Operating Income		$ 310,717,480	$ 33,815,702	$ 123,367,957	$ 151,357,777	$ 2,176,044
21	Net Income Adjustments						
22	AFUDC	ADJ_CWIP	1,259,101	467,443	791,658	-	-
23	LCP Equity Accrual		-	-	-	-	-
24	Net Operating Income - Adjusted		$ 311,976,581	$ 34,283,145	$ 124,159,615	$ 151,357,777	$ 2,176,044
25	Net Rate Base		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952
26	Return Earned		7.28%	4.22%	7.83%	8.14%	7.84%

Adjustment No. 7D

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 7D - Purchase of Receivables (POR) Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Book Amount C	Ratemaking Adjustment D
1	**Capitalized Software**			
2	Capitalized Software (POR)	303006 (RB:2:2)	$ 2/ 762,920	$ (762,920)
3	Computer Equipment (POR)	373106 (RB:2:35)	2/ 7,234	(7,234)
4	Total Plant in Service	Ln. 2 + Ln. 3	$ 770,154	$ (770,154)
5	**Reserve for Depreciation**			
6	DC POR Software	Property Analysis	$ 3/352,999	$ (352,999)
7	DC POR Equipment	Property Analysis	4/ 3,331	(3,331)
8	Total Depreciation Reserve	Ln. 6 + Ln. 7	$ 356,329	$ (356,329)
9	**Other Operating Revenues**			
10	Late Payment Charges (POR)	487107 (RV:1:16)	$ 5/ 360,143	$ (360,143)
11	Other Gas Revenues	495306 (RV:1:32)	5/ 736,920	(736,920)
12	Total Revenues	Ln. 10 + Ln. 11	$ 1,097,063	$ (1,097,063)
13	**Depreciation and Amortization**			
14	Amortization of Capitalized Software (POR)	404311 (SM:1:7)	$ 6/97,980	$ (97,980)
15	**Customer Accounts**			
16	Collection Expense (POR)	903307 (EX:7:19)	$ 7/ 226,115	$ (226,115)
17	Uncollectible Accounts (POR)	904107 (EX:7:22)	7/ 141,274	(141,274)
18	Total Customer Accounts	Ln. 16 + Ln. 17	$ 367,389	$ (367,389)
19	**Interest Expense**			
20	POR CWC Costs	431135 (EX:9:12)	$ 8/ 58,019	$ (58,019) a/

21 a/ Adjustment is reflected in the Interest on Debt Adjustment #8D.

22 **Adjustment Description:** To eliminate purchase of receivables costs incurred during the study period.
Note:

Washington Gas Light Company
Depreciable Gas Plant In Service
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	Allocator	WG	DC	MD	VA	FERC
	A	C	D	E	F	G	H
1	**Depreciable Gas Plant in Service**						
2	Capitalized Software	Non_Genl_Plnt	$ 168,881,787	$ 31,956,957	$ 62,038,051	$ 74,886,780	$ -
			762,920	762,920 (1)	-	-	-
			140,842,594	26,132,992	51,972,751	62,736,851	-
	Cloud Computing - Prepaid		27,276,273	5,061,044	10,065,300	12,149,929	-
		Non_Genl_Plnt	25,027	4,644	9,235	11,148	-
		Non_Genl_Plnt	27,251,247	5,056,401	10,056,065	12,138,781	-
3	Storage	Total_Weather_All_NW	76,262,465	$ 12,565,793	$ 32,404,277	$ 31,292,394	$ -
4	Storage - AFUDC	Financial Stmt.	(511,776)	-	-	(511,776)	0
5	Total Storage		$ 75,750,689	$ 12,565,793	$ 32,404,277	$ 30,780,618	$ -
6	Transmission						
7	Spurlines and Related Regulating						
8	Equipment and Structures	Financial Stmt.	$ 414,164,974	$ 56,197,740	$ 120,198,620	$ 209,444,575	$ 28,324,039
9	WSSC		5,547	-	5,547	-	-
10	ChalkPoint	Financial Stmt.	13,995,741	-	13,995,741	-	-
11	Panda	Financial Stmt.	2,034,808	-	2,034,808		-
12	Other	Comp_Peak_ Ann_NW	696,637,349	108,628,696	304,409,695	283,598,957	-
13	Transmission Mains - ARO		6,956,762	2,515	3,954,742	2,999,506	-
14	Post 1989 MD Interruptible Customers	Financial Stmt.	2,477,416	-	2,477,416	-	-
15	AFUDC	Financial Stmt.	(5,268,645)	-	-	(5,268,645)	0
16	Total Transmission		$ 1,131,003,953	$ 164,828,951	$ 447,076,569	$ 490,774,393	$ 28,324,039
17	Distribution						
18	Compressor Station Equipment	Total_Weather_All_NW	$ 2,735,941	$ 450,802	$ 1,162,514	$ 1,122,625	$ -
19	Mains	Financial Stmt.	2,573,799,925	549,032,913	887,779,494	1,136,987,518	-
20	Distribution Mains - ARO		61,255,520	1,086,978	34,552,539	25,616,002	-
21	Measuring and Regulator Station Equipment	Financial Stmt.	17,875,325	10,637,047	4,323,013	2,915,266	-
22	Services	Financial Stmt.	2,297,650,823	399,729,625	873,174,680	1,024,746,517	-
23	Distribution Services - ARO		61,635,355	967,723	35,467,125	25,200,508	-
24	Meters	Financial Stmt.	138,243,994	26,892,685	53,287,464	58,063,846	-
25	Meter Installations	Financial Stmt.	252,239,013	35,970,717	91,047,414	125,220,882	-
26	House Regulators	Financial Stmt.	43,226,309	4,731,358	15,452,640	23,042,310	-
27	House Regulator Installations	Financial Stmt.	15,195,671	3,744,785	6,522,287	4,928,599	-
28	Gas Light Services	Financial Stmt.	5,022,656	107,137	1,977,956	2,937,563	-
29	Post 1989 MD Interruptible Customers	Financial Stmt.	2,917,888	-	2,917,888	-	-
30	AFUDC	Financial Stmt.	(17,294)	-	-	(17,294)	-
31	Total Distribution		$ 5,471,781,126	$1,033,351,770	$ 2,007,665,014	$ 2,430,764,342	$ -
32	General						
33	Transportation	Non_Genl_Plnt	$ 42,991,069	$ 7,947,207	$ 15,805,240	$ 19,078,670	$ 159,953
34	POE	Non_Genl_Plnt	4,988,314	922,126	1,833,904	2,213,725	18,560
35	Other - Direct	Financial Stmt.	65,528,429	11,564,934	36,619,764	17,343,732	-
	379200 - General - Misc Equipment		5,073,753	-	4,871,300	202,453	-
	379600 - General - Comm Equip Ensca		2,266,128	-	196,107	2,070,021	-
			63,496	-	63,496	-	-
			14,281	-	14,281	-	-
			7,234	7,234 (1)	-	-	-
			30,182	-	30,182	-	-
			896,500	-	245,396	651,104	-
			724,737	-	659,905	64,832	-
			154,766	-	63,995	90,772	-
			56,027,833	11,557,700	30,205,583	14,264,550	-
			269,519	-	269,519	-	-
36	Other - Allocable	Non_Genl_Plnt	283,802,687	52,462,958	104,337,239	125,946,573	1,055,916
37	AFUDC	Financial Stmt.	(5,105,363)	-	-	(5,105,363)	-
38	Total General		$ 392,205,136	$ 72,897,224	$ 158,596,147	$ 159,477,337	$ 1,234,428
42	Total Depreciable Gas Plant in Service		$ 7,239,622,691	$1,315,600,695	$ 2,707,780,058	$ 3,186,683,470	$ 29,558,468

Amortization Expense for DC POR Software

company	01 DC Washington Gas Light Company
asset_id	1112445058
depr_group	DC 303006-Intangible - DC- POR
utility_account	303006 - Intangible - DC POR
vintage	2019
ldg_work_order_number	W1000221

gl_posting_mo_yr	init_life	remaining_life	month_calc_rate	current_value	depreciation_base	beginning_reserve	curr_depr_expense	ending_reserve
2/1/2019 0:00	120	120	0.00833333	754,391.00	754,391.00	-	6,286.59	6,286.59
3/1/2019 0:00		119	0.00833333		748,104.41	6,286.59	6,234.20	12,520.80
4/1/2019 0:00		119	0.00840336	8,529.16	741,870.20	12,520.80	6,234.20	18,755.00
5/1/2019 0:00		118	0.00847458		744,165.16	18,755.00	6,306.48	25,061.48
6/1/2019 0:00		117	0.00854701		737,858.68	25,061.48	6,306.48	31,367.97
7/1/2019 0:00		116	0.00862069		731,552.19	31,367.97	6,306.48	37,674.45
8/1/2019 0:00		115	0.00869565		725,245.71	37,674.45	6,306.48	43,980.94
9/1/2019 0:00		114	0.00877193		718,939.22	43,980.94	6,306.48	50,287.42
10/1/2019 0:00		113	0.00884956		712,632.74	50,287.42	6,306.48	56,593.90
11/1/2019 0:00		112	0.00892857		706,326.26	56,593.90	6,306.48	62,900.39
12/1/2019 0:00		111	0.00900901		700,019.77	62,900.39	6,306.48	69,206.87
1/1/2020 0:00		110	0.00909091		693,713.29	69,206.87	6,306.48	75,513.36
2/1/2020 0:00		109	0.00917431		687,406.80	75,513.36	6,306.48	81,819.84
3/1/2020 0:00		108	0.00925926		681,100.32	81,819.84	6,306.48	88,126.33
4/1/2020 0:00		107	0.00934579		674,793.83	88,126.33	6,306.48	94,432.81
5/1/2020 0:00		106	0.00943396		668,487.35	94,432.81	6,306.48	100,739.30
6/1/2020 0:00		105	0.00952381		662,180.86	100,739.30	6,306.48	107,045.78
7/1/2020 0:00		104	0.00961538		655,874.38	107,045.78	6,306.48	113,352.26
8/1/2020 0:00		103	0.00970874		649,567.90	113,352.26	6,306.48	119,658.75
9/1/2020 0:00		102	0.00980392		643,261.41	119,658.75	6,306.48	125,965.23
10/1/2020 0:00		101	0.00990099		636,954.93	125,965.23	6,306.48	132,271.72
11/1/2020 0:00		100	0.01000000		630,648.44	132,271.72	6,306.48	138,578.20
12/1/2020 0:00		99	0.01010101		624,341.96	138,578.20	6,306.48	144,884.69
1/1/2021 0:00		98	0.01020408		618,035.47	144,884.69	6,306.48	151,191.17
2/1/2021 0:00		97	0.01030928		611,728.99	151,191.17	6,306.48	157,497.66
3/1/2021 0:00		96	0.01041667		605,422.50	157,497.66	6,306.48	163,804.14
4/1/2021 0:00		95	0.01052632		599,116.02	163,804.14	6,306.48	170,110.62
5/1/2021 0:00		94	0.01063830		592,809.54	170,110.62	6,306.48	176,417.11
6/1/2021 0:00		93	0.01075269		586,503.05	176,417.11	6,306.48	182,723.59
7/1/2021 0:00		92	0.01086957		580,196.57	182,723.59	6,306.48	189,030.08
8/1/2021 0:00		91	0.01098901		573,890.08	189,030.08	6,306.48	195,336.56
9/1/2021 0:00		90	0.01111111		567,583.60	195,336.56	6,306.48	201,643.05
10/1/2021 0:00		89	0.01123596		561,277.11	201,643.05	6,306.48	207,949.53
11/1/2021 0:00		88	0.01136364		554,970.63	207,949.53	6,306.48	214,256.02
12/1/2021 0:00		87	0.01149425		548,664.14	214,256.02	6,306.48	220,562.50
1/1/2022 0:00		86	0.01162791		542,357.66	220,562.50	6,306.48	226,868.98
2/1/2022 0:00		85	0.01176471		536,051.18	226,868.98	6,306.48	233,175.47
3/1/2022 0:00		84	0.01190476		529,744.69	233,175.47	6,306.48	239,481.95
4/1/2022 0:00		83	0.01204819		523,438.21	239,481.95	6,306.48	245,788.44
5/1/2022 0:00		82	0.01219512		517,131.72	245,788.44	6,306.48	252,094.92
6/1/2022 0:00		81	0.01234568		510,825.24	252,094.92	6,306.48	258,401.41
7/1/2022 0:00		80	0.01250000		504,518.75	258,401.41	6,306.48	264,707.89
8/1/2022 0:00		79	0.01265823		498,212.27	264,707.89	6,306.48	271,014.38
9/1/2022 0:00		78	0.01282051		491,905.78	271,014.38	6,306.48	277,320.86
10/1/2022 0:00		77	0.01298701		485,599.30	277,320.86	6,306.48	283,627.34
11/1/2022 0:00		76	0.01315789		479,292.82	283,627.34	6,306.48	289,933.83
12/1/2022 0:00		75	0.01333333		472,986.33	289,933.83	6,306.48	296,240.31
1/1/2023 0:00		74	0.01351351		466,679.85	296,240.31	6,306.48	302,546.80
2/1/2023 0:00		73	0.01369863		460,373.36	302,546.80	6,306.48	308,853.28
3/1/2023 0:00		72	0.01388889		454,066.88	308,853.28	6,306.48	315,159.77
4/1/2023 0:00		71	0.01408451		447,760.39	315,159.77	6,306.48	321,466.25
5/1/2023 0:00		70	0.01428571		441,453.91	321,466.25	6,306.48	327,772.74
6/1/2023 0:00		69	0.01449275		435,147.42	327,772.74	6,306.48	334,079.22
7/1/2023 0:00		68	0.01470588		428,840.94	334,079.22	6,306.48	340,385.70
8/1/2023 0:00		67	0.01492537		422,534.46	340,385.70	6,306.48	346,692.19
9/1/2023 0:00		66	0.01515152		416,227.97	346,692.19	6,306.48	352,998.67
10/1/2023 0:00		65	0.01538462		409,921.49	352,998.67	6,306.48	359,305.16
11/1/2023 0:00		64	0.01562500		403,615.00	359,305.16	6,306.48	365,611.64
12/1/2023 0:00		63	0.01587302		397,308.52	365,611.64	6,306.48	371,918.13
1/1/2024 0:00		62	0.01612903		391,002.03	371,918.13	6,306.48	378,224.61
2/1/2024 0:00		61	0.01639344		384,695.55	378,224.61	6,306.48	384,531.09
3/1/2024 0:00		60	0.01666667		378,389.07	384,531.09	6,306.48	390,837.58

A

Average of A = $352,999 1

Amortization Expense for DC POR Equipment

company	01 DC Washington Gas Light Company
asset_id	1112445058
depr_group	DC 303006-Intangible - DC- POR
utility_account	303006 - Intangible - DC POR
vintage	2019
ldg_work_order_number	W1000220

gl_posting_mo_yr	init_life	remaining_life	month_calc_rate	current_value	Adjustment to Base	depreciation_base	beginning_reserve	curr_depr_expense	ending_reserve
2/1/2019 0:00	120	120	14.285%	7,233.97		3,945.78	-	46.97	46.97
3/1/2019 0:00		119	14.285%			4,340.38	46.97	51.67	98.64
4/1/2019 0:00		118	14.285%		2,312.71	4,822.62	98.64	57.41	156.05
5/1/2019 0:00		117	10.256%			7,077.92	156.05	60.50	216.55
6/1/2019 0:00		116	10.345%			7,017.42	216.55	60.50	277.05
7/1/2019 0:00		115	10.435%			6,956.92	277.05	60.49	337.54
8/1/2019 0:00		114	9.677%			6,896.43	337.54	55.62	393.16
9/1/2019 0:00		113	9.757%			6,840.81	393.16	55.62	448.78
10/1/2019 0:00		112	9.837%			6,785.19	448.78	55.62	504.40
11/1/2019 0:00		111	9.918%			6,729.57	504.40	55.62	560.02
12/1/2019 0:00		110	10.001%			6,673.95	560.02	55.62	615.64
1/1/2020 0:00		109	10.085%			6,618.33	615.64	55.62	671.26
2/1/2020 0:00		108	10.170%			6,562.71	671.26	55.62	726.88
3/1/2020 0:00		107	10.257%			6,507.09	726.88	55.62	782.50
4/1/2020 0:00		106	11.285%			6,451.47	782.50	60.67	843.17
5/1/2020 0:00		105	11.392%			6,390.80	843.17	60.67	903.84
6/1/2020 0:00		104	11.501%			6,330.13	903.84	60.67	964.51
7/1/2020 0:00		103	11.612%			6,269.46	964.51	60.67	1,025.18
8/1/2020 0:00		102	11.726%			6,208.79	1,025.18	60.67	1,085.85
9/1/2020 0:00		101	11.842%			6,148.12	1,085.85	60.67	1,146.52
10/1/2020 0:00		100	11.960%			6,087.45	1,146.52	60.67	1,207.19
11/1/2020 0:00		99	12.080%			6,026.78	1,207.19	60.67	1,267.86
12/1/2020 0:00		98	12.203%			5,966.11	1,267.86	60.67	1,328.53
1/1/2021 0:00		97	12.328%			5,905.44	1,328.53	60.67	1,389.20
2/1/2021 0:00		96	12.456%			5,844.77	1,389.20	60.67	1,449.87
3/1/2021 0:00		95	12.587%			5,784.10	1,449.87	60.67	1,510.54
4/1/2021 0:00		94	12.720%			5,723.43	1,510.54	60.67	1,571.21
5/1/2021 0:00		93	12.857%			5,662.76	1,571.21	60.67	1,631.88
6/1/2021 0:00		92	12.996%			5,602.09	1,631.88	60.67	1,692.55
7/1/2021 0:00		91	13.138%			5,541.42	1,692.55	60.67	1,753.22
8/1/2021 0:00		90	13.284%			5,480.75	1,753.22	60.67	1,813.89
9/1/2021 0:00		89	13.432%			5,420.08	1,813.89	60.67	1,874.56
10/1/2021 0:00		88	13.584%			5,359.41	1,874.56	60.67	1,935.23
11/1/2021 0:00		87	13.740%			5,298.74	1,935.23	60.67	1,995.90
12/1/2021 0:00		86	13.899%			5,238.07	1,995.90	60.67	2,056.57
1/1/2022 0:00		85	14.062%			5,177.40	2,056.57	60.67	2,117.24
2/1/2022 0:00		84	14.229%			5,116.73	2,117.24	60.67	2,177.91
3/1/2022 0:00		83	14.399%			5,056.06	2,177.91	60.67	2,238.58
4/1/2022 0:00		82	14.574%			4,995.39	2,238.58	60.67	2,299.25
5/1/2022 0:00		81	14.753%			4,934.72	2,299.25	60.67	2,359.92
6/1/2022 0:00		80	14.937%			4,874.05	2,359.92	60.67	2,420.59
7/1/2022 0:00		79	15.125%			4,813.38	2,420.59	60.67	2,481.26
8/1/2022 0:00		78	15.318%			4,752.71	2,481.26	60.67	2,541.93
9/1/2022 0:00		77	15.516%			4,692.04	2,541.93	60.67	2,602.60
10/1/2022 0:00		76	15.720%			4,631.37	2,602.60	60.67	2,663.27
11/1/2022 0:00		75	15.928%			4,570.70	2,663.27	60.67	2,723.94
12/1/2022 0:00		74	16.143%			4,510.03	2,723.94	60.67	2,784.61
1/1/2023 0:00		73	16.363%			4,449.36	2,784.61	60.67	2,845.28
2/1/2023 0:00		72	16.589%			4,388.69	2,845.28	60.67	2,905.95
3/1/2023 0:00		71	16.822%			4,328.02	2,905.95	60.67	B 2,966.62
4/1/2023 0:00		70	17.061%			4,267.35	2,966.62	60.67	3,027.29
5/1/2023 0:00		69	17.307%			4,206.68	3,027.29	60.67	3,087.96
6/1/2023 0:00		68	17.560%			4,146.01	3,087.96	60.67	3,148.63
7/1/2023 0:00		67	17.821%			4,085.34	3,148.63	60.67	3,209.30
8/1/2023 0:00		66	18.089%			4,024.67	3,209.30	60.67	3,269.97
9/1/2023 0:00		65	18.366%			3,964.00	3,269.97	60.67	3,330.64
10/1/2023 0:00		64	18.652%			3,903.33	3,330.64	60.67	3,391.31
11/1/2023 0:00		63	18.946%			3,842.66	3,391.31	60.67	3,451.98
12/1/2023 0:00		62	19.250%			3,781.99	3,451.98	60.67	3,512.65
1/1/2024 0:00		61	19.564%			3,721.32	3,512.65	60.67	3,573.32
2/1/2024 0:00		60	19.888%			3,660.65	3,573.32	60.67	3,633.99
3/1/2024 0:00		59	20.223%			3,599.98	3,633.99	60.67	3,694.66

Average of B = $3,331
1

Revenues
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Allocator	WG	DC	MD	VA	FERC
	A	C	D	E	F	G	H
1	**Operating Revenues**						
2	Sales of Gas and Transportation to Customers						
3	Residential	Financial Stmt.	$ 917,499,221	$ 114,679,781	$ 387,260,842	$ 415,558,598	$ -
4	Commercial and Industrial other than Group Metered Apts	Financial Stmt.	185,406,991	45,038,920	68,772,040	71,596,030	-
5	Group Metered Apartments	Financial Stmt.	37,945,816	16,671,589	10,825,850	10,448,377	-
6	Commercial and Industrial - Interruptible	Financial Stmt.	2,467,672	1,970,320	414,562	82,789	-
7	Transportation Sales / Mountaineer	Financial Stmt.	313,468,665	78,440,325	136,629,702	95,065,801	3,332,837
8	WSSC Revenues		586,938		586,938		-
9	Total Heating/Cooling and Other Uses		$ 1,457,375,303	$ 256,800,936	$ 604,489,935	$ 592,751,595	$ 3,332,837
10	Rate Adjustment due Customers	Financial Stmt.	(1,841,180)	(268,728)	(805,138)	(767,313)	-
11	Unbilled Gas Accrual/Reversal	Financial Stmt.	(6,749,446)	(6,782,977)	446,100	(412,569)	-
12	Provision for Rate Refunds	Financial Stmt.	3,798,715	-	2,211,388	1,587,327	-
13	Total Gas Sales & Transportation Revenues		$ 1,452,583,392	$ 249,749,231	$ 606,342,285	$ 593,159,040	$ 3,332,837
14	Other Operating Revenues						
15	Forfeited Discounts (Non POR)	Financial Stmt.	11,349,728	3,245,453	4,328,263	3,776,011	-
16	Forfeited Discounts (POR)	Financial Stmt.	582,776	360,143 1	222,583	50	-
17	Rent from Gas Property	Annual Firm_ ACT	967,406	139,688	416,107.68	411,610.20	-
18	Miscellaneous Service Revenues						
19	Reconnect Revenues	Financial Stmt.	847,711	174,354	568,927	104,430	-
20	Reconnect Revenues - Premium	Financial Stmt.	(234)	-	(234)	-	-
21	Dishonored Check Charge	Financial Stmt.	647,108	44,740	303,282	299,086	-
22	Service Initiation Charge	Financial Stmt.	3,947,838	838,570	1,816,987	1,292,280	-
23	Field Collection Charge	Financial Stmt.	4,951	433	3,528	990	-
24	IRATE Non Compliance MTR. Charge	Financial Stmt.	-	-	-	-	-
25	Other Gas Revenues						
26	Watergate Revenues	Financial Stmt.	-	-	-	-	-
27	Third Party Balancing Charges	Financial Stmt.	50,236,702	6,609,061	25,841,472	17,786,168	-
28	CNG Sales for Natural Gas Vehicles	Financial Stmt.	1,934,788	847,959	606,779	480,050	-
29	Off System Sales Revenue Net of Gas Cost	EX:3:2	86,111,467	14,177,234	38,508,187	33,426,045	-
30	Miscellaneous						
31	Other Allocable Miscellaneous	Financial Stmt.	(2,331,859)	(133,354)	(1,653,845)	(544,660)	-
32	Oth Gas Rev - MD RM-35	Financial Stmt.	1,374,694	736,920 1	637,773	-	-
33	Third Party Billing	Financial Stmt.	459,364	114,447	-	344,917	-
34	Total Other Operating Revenues		$ 156,132,439	$ 27,155,649	$ 71,599,810	$ 57,376,979	$ -
35	Total Operating Revenues		$ 1,608,715,831	$ 276,904,880	$ 677,942,095	$ 650,536,019	$ 3,332,837

Washington Gas Light Company
Income Statement Summary -- Combined
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Allocator	WG	DC	MD	VA	FERC
	A	C	D	E	F	G	H
1	**Operating Revenues**		$ 1,608,715,831	$ 276,904,880	$ 677,942,095	$ 650,536,019	$ 3,332,837
2	Operating Expenses						
3	Gas Purchased		$ 454,828,378	$ 64,262,645	$ 200,704,535	$ 189,861,198	$ -
4	Operation - Other than Gas Purchased		322,051,962	61,031,214	137,950,468	122,960,170	110,110
5	Maintenance		114,413,313	25,568,839	46,799,501	41,961,616	83,356
6	Depreciation		135,410,640	23,907,431	41,034,291	70,456,187	12,731
7	Amortization of Capitalized Software	Financial Stmt.	21,433,284	3,757,163	8,810,769	8,785,972	79,380
			2,512,710	465,325	930,290	1,107,746	9,349
			18,822,562	3,193,858	7,880,446	7,678,226	70,031
			98,012	97,980 (1)	32	-	-
8	Amortization of Chalk Point / MD Post 1989 Inter	Financial Stmt.	94,718	-	94,718	-	-
9	Amortization of General Plant		14,127,280	1,878,281	5,415,781	6,833,217	-
10	Amortization of Unrecovered Plant Loss Chillum	Financial Stmt.	-	-	-	-	-
11	Interest on Customer Deposits		528,578	41,769	128,646	358,163	-
12	Interest on Supplier Refunds		73,600	11,533	31,581	30,486	-
13	General Taxes		171,665,153	58,992,535	88,254,140	24,335,027	83,452
14	Other Income Taxes	Financial Stmt.	13,182,317	756,509	5,234,557	7,027,005	164,246
15	Expenses Before Federal Income Taxes		$ 1,247,809,223	$ 240,207,920	$ 534,458,986	$ 472,609,042	$ 533,275
16	Federal Income Tax Expense		$ 50,043,363	$ 2,871,897	$ 19,871,685	$ 26,676,264	$ 623,518
17	ITC Adjustment		(305,994)	(90,913)	(108,018)	(107,064)	-
18	Loss- Disposition of Utility Plant	Financial Stmt.	451,758	100,274	351,484	-	-
19	Total Operating Expenses		$ 1,297,998,351	$ 243,089,178	$ 554,574,138	$ 499,178,242	$ 1,156,793
20	Net Operating Income		$ 310,717,480	$ 33,815,702	$ 123,367,957	$ 151,357,777	$ 2,176,044
21	Net Income Adjustments						
22	AFUDC	ADJ_CWIP	1,259,101	467,443	791,658	-	-
23	LCP Equity Accrual		-	-	-	-	-
24	Net Operating Income - Adjusted		$ 311,976,581	$ 34,283,145	$ 124,159,615	$ 151,357,777	$ 2,176,044
25	Net Rate Base		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952
26	Return Earned		7.28%	4.22%	7.83%	8.14%	7.84%

Washington Gas Light Company
Customer Accounts
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Allocator	WG	DC	MD	VA	FERC
	A	C	D	E	F	G	H
1	**Customer Accounts**						
2	General Supervision-Direct	Financial Stmt.	$ -	$ -	$ -	$ -	$ -
3	General Supervision-Allocable	Customer_Accts	-	-	-	-	-
4	Total General Supervision		$ -	$ -	$ -	$ -	$ -
5	Meter Reading-Direct	Financial Stmt.	$ -	$ -	$ -	$ -	$ -
6	Meter Reading-Allocable	Avg_Meters	5,504,551	762,664	2,174,130	2,567,758	-
7	Total Meter Reading		$ 5,504,551	$ 762,664	$ 2,174,130	$ 2,567,758	$ -
8	Dispatch Applications and Orders-Direct	Financial Stmt.	$ 2,171,311	$ 296,545	$ 1,132,179	$ 742,587	$ -
9	Dispatch Applications and Orders-Allocable	Avg_Meters	13,855,708	1,919,729	5,472,583	6,463,397	-
10	Total Dispatch Applications and Orders		$ 16,027,019	$ 2,216,274	$ 6,604,762	$ 7,205,984	$ -
11	Customer Collection Expenses						
12	Customer Credit and Appliance Service-Direct	Financial Stmt.	$ 8,268	$ -	$ (46,049)	$ 54,317	$ -
13	Customer Credit and Appliance Service-Allocable	Avg_AR	8,373,169	2,191,914	3,899,276	2,281,979	-
14	Other-Direct	Financial Stmt.	-	-	-	-	-
15	Other-Allocable	Avg_Meters	(1,669,693)	(231,338)	(659,478)	(778,877)	-
16	Credit and Debit Card Transactions	Credit_Debit_Card	3,520,829	478,381	1,594,599	1,447,850	
17	Total Customer Collection Expenses		$ 10,232,573	$ 2,438,956	$ 4,788,348	$ 3,005,269	$ -
18	Customer Billing and Accounting-Direct	Financial Stmt.	$ 108,799	$ 108,700	$ -	$ 99	$ -
19	Customer Billing and Acct-POR Collection Exp	Financial Stmt.	621,466	226,115 1	395,350	-	-
20	Customer Billing and Accounting-Allocable	Avg_Meters	4,295,147	595,099	1,696,452	2,003,596	-
21	Total Customer Billing and Accounting		$ 5,025,412	$ 929,915	$ 2,091,803	$ 2,003,695	$ -
22	Total Uncollectible Accounts		$ 15,334,992	$ 6,420,597	$ 3,901,686	$ 5,012,709	$ -
			10,027	(11,815)	(49,416)	71,257	-
			154,072	64,873	38,243	50,955	-
			-				
			14,787,223	6,226,265	3,670,461	4,890,497	-
			383,671	141,274 1	242,397	-	-
		Total_Weather_All_NW	-	-	-	-	-
23	Total Customer Accounts		$ 52,124,547	$ 12,768,405	$ 19,560,728	$ 19,795,414	$ -

Washington Gas Light Company
Interest Expense
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Allocator	WG	DC	MD	VA	FERC
	A	C	D	E	F	G	H
1	**Interest Expense**						
2	Interest on Long Term Debt	Net_Rate_Base	85,860,916	16,374,320	31,994,268	37,492,328	-
4	Interest on Commercial Paper	Net_Rate_Base	11,735,620	2,239,357	4,371,528	5,124,735	-
5	Interest on Credit Line Fees	Net_Rate_Base	48,962	9,343	18,238	21,381	-
6	Interest on Credit Line Fees	Net_Rate_Base	1,006,084	191,978	374,767	439,339	-
7	Interest On Bank Loans	Net_Rate_Base	-	-	-	-	-
8	Interest on Financing Leases	Net_Rate_Base	493,872	94,239	183,968	215,665	-
9	Interest on Short-Term Revolver	Net_Rate_Base	-	-	-	-	-
9	Amortization of Debt Discount/Expenses	Net_Rate_Base	753,779	149,466	267,345	336,969	-
10	Amort. Gain/Loss/Premium on Reacquired Debt	Net_Rate_Base	(365,099)	(64,061)	(149,669)	(151,368)	-
11	AFUDC	ADJ_CWIP	(1,259,101)	(467,443)	(791,658)	-	-
12	POR CWC Costs	Financial Stmt.	58,019	58,019 1	0	0	-
13	Interest on Supplier Refunds	Financial Stmt.	73,600	11,533	31,581	30,486	-
14	Interest on Customer Deposits	Financial Stmt.	528,578	41,769	128,646	358,163	-
15	Interest re LCP Expenses	Financial Stmt.	-	-	-	-	-
16	Int Exp re DC Carrying Costs	Financial Stmt.	-	-	-	-	-
17	Oth Int Costs VA Save Carrying Costs	Financial Stmt.	-	-	-	-	-
18	Interest re Maryland Demand Side Management Ex	Financial Stmt.	-	-	-	-	-
19	Other Interest Expense	Net_Rate_Base	470,794	89,836	175,371	205,587	-
20	Total Interest		$ 99,406,025	$ 18,728,355	$ 36,604,384	$ 44,073,285	$ -
	Adjusted to Remove:						
21	Interest on debt to Associated Company	Net_Rate_Base	$ -	$ -	$ -	$ -	$ -
22	Non-Utility Interest Charges	Net_Rate_Base	-	-	-	-	-
23	AFUDC	ADJ_CWIP	(1,259,101)	(467,443)	(791,658)	-	-
24	Interest on Supplier Refunds	Financial Stmt.	73,600	11,533	31,581	30,486	-
25	Int Exp re DC Carrying Costs	Financial Stmt.	-	-	-	-	-
26	Oth Int Costs VA Save Carrying Costs	Financial Stmt.	-	-	-	-	-
27	Oth Int Exp Customer Deposits	Financial Stmt.	528,578	41,769	128,646	358,163	-
28	Non-Utility Interest on Equity Investment in Comme	Net_Rate_Base	-	-	-	-	-
29	Non-Utility Interest on Equity Investment in Primary	Net_Rate_Base	-	-	-	-	-
30	Interest per Cost of Service		$ 100,062,947	$ 19,142,496	$ 37,235,816	$ 43,684,636	$ -

Adjustment No. 8D

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 8D & 29 - Interest on Debt (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	Distribution Amount D	Ratemaking Amount E
1	**Interest on Total Debt**				
2	Net Rate Base	Rate Base Stmt, Ln.23	$ 2/ 4,284,239,876	$ 3/ 796,176,491	$ 3/ 760,992,964
3	Weighted Average Cost of Debt	Cost of Capital, Ln. 1 + Ln. 2	4/ 2.36%	4/ 2.36%	4/ 2.36%
4	Interest on Debt	Ln. 2 * Ln. 3	$ 101,225,321	$ 18,811,557	$ 17,980,262
5	Per Books Interest Expense	Per Books	5/ 100,062,947	5/ 19,142,496	18,811,557
6	Adjustment to Interest Expense _1/	Ln. 4 - Ln. 5	$ 1,162,374	$ (330,939)	$ (831,295)

7 **Adjustment Description**: To synchronize interest expense used in determining the overall return requirement with the interest
8 expense used to calculate income taxes.

_1/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line 9:16.

Washington Gas Light Company
Rate Base Summary
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	—— Reference —— Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Gas Plant in Service	RB:3:17		$ 7,249,016,177	$1,317,182,832	$ 2,711,617,252	$ 3,190,657,625	$ 29,558,468
2	Gas Plant Held for Future Use	RB:4:13		-	-	-	-	-
3	Unrecovered Plant - Peaking Facility		Total_Weather_All_NW	-	-	-	-	-
4	Construction Work in Progress	RB:5:29		397,111,025	79,322,274	134,339,566	183,449,185	-
5	Materials & Supplies	RB:6:12		123,327,981	19,836,447	52,379,031	51,112,503	-
6	Non Plant - ADIT	RB:12:18	Financial Stmt.	(34,509,521)	(3,062,666)	(21,491,098)	(9,955,757)	0
7	FC 1027 - Rate Base CWIP (Reg Asset)			(0)	(0)			
8	Unamortized East Station Cost (Net of Deferred Taxes)		Financial Stmt.	1,075,846	1,075,846	-	-	-
9	Sub-Total	= 1>10		$ 7,736,021,508	$1,414,354,734	$ 2,876,844,750	$ 3,415,263,556	$ 29,558,468
10	Cash Working Capital	RB:7>9		$ 121,292,100	$ 39,219,091	$ 67,230,077	$ 14,826,433	$ 16,500
11	Total Rate Base Additions	= 9+10		$ 7,857,313,609	$1,453,573,825	$ 2,944,074,827	$ 3,430,089,989	$ 29,574,968
12	LESS:							
13	Reserve for Depreciation	RB:10:35		$ 2,370,279,045	$ 449,057,859	$ 864,931,885	$ 1,054,487,285	$ 1,802,016
14	Accumulated DIT re Depreciation	RB:11:21		1,298,608,831	212,149,665	532,439,389	554,019,777	0
15	Accumulated DIT re Gains/Losses On Reacquired Debt							
16	Federal	RB:11:9	Net_Rate_Base	175,290	29,300	70,009	75,981	-
17	State	RB:11:9	Net_Rate_Base	57,829	10,143	22,631	25,055	-
18	NOL Carryforward Federal		Net_Rate_Base	(78,173,336)	(14,916,809)	(29,119,631)	(34,136,895)	-
19	NOL Carryforward State		Net_Rate_Base	(68,626,785)	(13,095,164)	(25,563,533)	(29,968,088)	-
20	NOL Federal Benefit of State		Net_Rate_Base	14,411,625	2,749,985	5,368,342	6,293,298	-
21	Customer Advances for Construction		Financial Stmt.	2,698,381	305,769	244,862	2,147,750	-
22	Customer Deposits		Financial Stmt.	12,871,928	1,432,785	2,467,234	8,971,908	-
23	Supplier Refunds		Financial Stmt.	4,509,391	626,315	1,675,549	2,207,527	-
24	Deferred Tenant Allowance		Non_Genl_Plnt	16,261,534	3,017,287	6,000,718	7,243,529	-
25	Total Rate Base Deductions	= 13>24		$ 3,573,073,733	$ 641,367,135	$ 1,358,537,454	$ 1,571,367,128	$ 1,802,016
26	Net Rate Base	= 11 - 25		$ 4,284,239,876 1	$ 812,206,690 3	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952

Washington Gas Light Company
District of Columbia Jurisdiction

Average Rate Base Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Books Amount	Distribution Adjustments	Distribution Amount	Ratemaking Adjustments	Ratemaking Amount
	A	B	C	D	E = C + D	F	G = E + F
1	Gas Plant in Service		$ 1,317,182,832	$ (770,154)	$ 1,316,412,678	$ 27,107,163	$ 1,343,519,841
2	Construction Work in Progress		79,322,274	-	79,322,274	(72,437,698)	6,884,577
3	Materials & Supplies	Adj List Pg 2, Ln. 14	19,836,447	(16,895,300)	2,941,148	-	2,941,148
4	Non-Plant ADIT		(3,062,666)		(3,062,666)	(293,256)	(3,355,922)
5	FC 1027 - Rate Base CWIP (Reg Asset) _a/		(0)	-	(0)	-	(0)
6	Unamortized East Station _a/	Adj List Pg 2, Ln. 19	1,075,846	-	1,075,846	690,481	1,766,327
7	Sub-Total	Sum of Lns. 1 > 3	$ 1,414,354,734	$ (17,665,454)	$ 1,396,689,281	$ (44,933,310)	$ 1,351,755,971
8	Cash Working Capital	Adj List Pg 2, Ln. 17	39,219,091	652,610	39,871,701	954,625	40,826,325
9	Gross Rate Base	Ln. 7 + Ln. 8	$ 1,453,573,825	$ (17,012,844)	$ 1,436,560,981	$ (43,978,685)	$ 1,392,582,296
10	LESS:						
11	Reserve for Depreciation	Per Books	$ 449,057,859	$ (356,329)	$ 448,701,530	$ 7,495,833	$ 456,197,363
12	ADIT: M.A.C.R.S. Depreciation	Per Books	212,149,665	-	212,149,665	3,877,037	216,026,702
13	ADIT: Gains/Losses on Reaquired Debt (Federal)	Per Books	29,300	-	29,300	-	29,300
14	ADIT: Gains/Losses on Reaquired Debt (State)	Per Books	10,143	-	10,143	-	10,143
15	NOL Carryforward Federal	Per Books	(14,916,809)	-	(14,916,809)	(20,845,267)	(35,762,077)
16	NOL Carryforward State	Per Books	(13,095,164)	-	(13,095,164)	857,264	(12,237,900)
17	NOL Federal Benefit of State	Per Books	2,749,985	-	2,749,985	(180,026)	2,569,959
18	Customer Advances for Construction	Per Books	305,769	-	305,769	-	305,769
19	Customer Deposits	Per Books	1,432,785	-	1,432,785	-	1,432,785
20	Supplier Refunds	Adj List Pg 2, Ln. 25	626,315	(626,315)	-	-	-
21	Deferred Tenant Allowance	Per Books	3,017,287	-	3,017,287	-	3,017,287
22	Total Rate Base Deductions	Sum of Lns. 11 > 21	$ 641,367,135	$ (982,644)	$ 640,384,490	$ (8,795,158)	$ 631,589,332
23	Net Rate Base	Ln. 9 - Ln. 22	$ 2/ 812,206,690	$ (16,030,199)	$ 796,176,491 1	$ (35,183,527)	$ 760,992,964 1

a/ Net of deferred taxes

Washington Gas Light Company
District of Columbia Jurisdiction

Utility Cost of Capital

Twelve Months Ended March 31, 2024

Line No.	Description	Ratio	Cost	Weighted Cost	
	A	C	D	E = C x D	
1	Long-term Debt	42.88%	4.84%	A 2.08%	Sum of A = 2.36%
2	Short-term Debt	4.63%	6.20%	A 0.29%	(rounded down) 1
3	Common Equity	52.49%	10.50%	5.51%	
4	Total	100.00%		7.87%	

Washington Gas Light Company
Interest Expense
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
A	B	C	D	E	F	G	H
1 **Interest Expense**							
2 Interest on Long Term Debt	AL:3:6	Net_Rate_Base	85,860,916	16,374,320	31,994,268	37,492,328	-
4 Interest on Commercial Paper	AL:3:6	Net_Rate_Base	11,735,620	2,239,357	4,371,528	5,124,735	-
5 Interest on Credit Line Fees	AL:3:6	Net_Rate_Base	48,962	9,343	18,238	21,381	-
6 Interest on Credit Line Fees	AL:3:6	Net_Rate_Base	1,006,084	191,978	374,767	439,339	-
7 Interest On Bank Loans	AL:3:6	Net_Rate_Base	-	-	-	-	-
8 Interest on Financing Leases	AL:3:6	Net_Rate_Base	493,872	94,239	183,968	215,665	-
9 Interest on Short-Term Revolver	AL:3:6	Net_Rate_Base	-	-	-	-	-
9 Amortization of Debt Discount/Expenses	AL:3:6	Net_Rate_Base	753,779	149,466	267,345	336,969	-
10 Amort. Gain/Loss/Premium on Reacquired Debt	AL:3:6	Net_Rate_Base	(365,099)	(64,061)	(149,669)	(151,368)	-
11 AFUDC	AL:3:14	ADJ_CWIP	(1,259,101)	(467,443)	(791,658)	-	-
12 POR CWC Costs		Financial Stmt.	58,019	58,019	0	0	-
13 Interest on Supplier Refunds		Financial Stmt.	73,600	11,533	31,581	30,486	-
14 Interest on Customer Deposits		Financial Stmt.	528,578	41,769	128,646	358,163	-
15 Interest re LCP Expenses		Financial Stmt.	-	-	-	-	-
16 Int Exp re DC Carrying Costs		Financial Stmt.	-	-	-	-	-
17 Oth Int Costs VA Save Carrying Costs		Financial Stmt.	-	-	-	-	-
18 Interest re Maryland Demand Side Management Expenses		Financial Stmt.	-	-	-	-	-
19 Other Interest Expense	AL:3:6	Net_Rate_Base	470,794	89,836	175,371	205,587	-
20 Total Interest	=2>19		$ 99,406,025	$ 18,728,355	$ 36,604,384	$ 44,073,285	$ -
Adjusted to Remove:							
21 Interest on debt to Associated Company	AL:3:6	Net_Rate_Base	$ -	$ -	$ -	$ -	$ -
22 Non-Utility Interest Charges	AL:3:6	Net_Rate_Base	-	-	-	-	-
23 AFUDC	AL:3:14	ADJ_CWIP	(1,259,101)	(467,443)	(791,658)	-	-
24 Interest on Supplier Refunds		Financial Stmt.	73,600	11,533	31,581	30,486	-
25 Int Exp re DC Carrying Costs		Financial Stmt.	-	-	-	-	-
26 Oth Int Costs VA Save Carrying Costs		Financial Stmt.	-	-	-	-	-
27 Oth Int Exp Customer Deposits		Financial Stmt.	528,578	41,769	128,646	358,163	-
28 Non-Utility Interest on Equity Investment in Comme	AL:3:6	Net_Rate_Base	-	-	-	-	-
29 Non-Utility Interest on Equity Investment in Primary	AL:3:6	Net_Rate_Base	-	-	-	-	-
30 Interest per Cost of Service	=20-(21>29)		$ 100,062,947	$ 19,142,496	$ 37,235,816	$ 43,684,636	$ -

* Based on weighted average of Commercial Paper rates on average investment.

Adjustment No. 9D

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 9D - Cash Working Capital (Distribution)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Per Books C	DC Dist. Adjustment D	DC Dist. Amount E	DC Lag Days F	DC Dollar Days G = E x F
1	Composite Revenue Lag					9/ 89.00	
2	Gas Purchased	Per Books Adj 2D	$10/ 64,262,645	$4/ 1,806,227 A	$4/ 66,068,873 2	38.19	$ 2,523,164,162
3	Payroll	Per Books	10/ 25,573,530	-	25,573,530	11.71	299,504,692
4	Other Operations and Maintenance Expenses						
5	Employee Health Benefits	Per Books	4,793,783 B	-	4,793,783	30.37	145,571,833
6	Property and Public Liability Insurance	Per Books	3,677,954	-	3,677,954	(163.46)	(601,213,770)
7	Other O&M	Adj 8D WP 1 Adj 2D	3/ 52,683,423	(3,946,617) A	48,736,805	25.47	1,241,251,457
8	Less: Pension Benefit (Non Cash)	Per Books	10/ 42,494	-	42,494	25.47	1,082,247
9	Less: OPEB Benefit (Non Cash)	Per Books	6,584,462	-	6,584,462	25.47	167,696,128
10	Property Taxes	Per Books	2,013,868	-	2,013,868	71.02	143,032,994
11	Delivery Tax	Per Books	23,451,041	-	23,451,041	26.13	612,799,160
12	Rights-of-Way Fee	Per Books	12,518,268	-	12,518,268	(54.53)	(682,621,127)
13	FICA Taxes	Per Books	2,103,553	-	2,103,553	9.97	20,970,937
14	Unemployment Tax	Per Books	(6,961)	-	(6,961)	9.99	(69,562)
15	Environmental Tax	Per Books	-	-	-	-	-
16	Federal Excise Tax	Per Books	(21,714)	-	(21,714)	(17.51)	380,156
17	Sustainable Trust Fund	Per Books	16,761,017	-	16,761,017	26.13	437,982,135
18	Energy Assistance Fund	Per Books	2,156,914	-	2,156,914	26.13	56,362,323
19	Firm Storage Service	Per Books	29	-	29	308.86	8,840
20	Other Taxes - Direct Assignment	Per Books	16,520	-	16,520	79.00	1,305,080
21	Income Taxes (Current)	Per Books Adj 10D	(1,897,447)	8/ (3,089,477)	(4,986,924)	-	-
22	Subtotal	Sum of Lns. 2 > 21	214,713,379	(5,229,867)	209,483,512	20.85	$ 4,367,207,685
23	Lead Lag Requirement	Ln. 22, Col/ E / 365			$ 573,927	68.16	$ 39,116,900
24	Other Lead-Lag Items						
25	Imprest Funds	Per Books	-	-	-	-	-
26	Special Deposits	Per Books	-	-	-	-	-
27	Interest on Long-Term Debt	Adj 8D	-	7/ (330,939)	(330,939)	91.25	2,036
28	Economic Evaluation of Facility Extenstion (GSP 14)	Accts. 186.200 & 174.400	10/ 752,764	-	752,764	-	752,764
29	Cash Working Capital - Distribution						$ 39,871,701 2
30	Cash Working Capital - Per Books						10/ 39,219,091
31	Cash Working Capital Distribution Adjustment	RB:1:10					$ 652,610

5/
Sum of A = ($2,140,390)

10/
Sum of B = $61,155,160

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 30 - Cash Working Capital (Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Dist. Amount C	DC RM Adjustment D	DC RM Amount E	DC Lag Days F	DC Dollar Days G = E x F
1	Composite Revenue Lag					9/ 89.00	
2	Gas Purchased	Adj 1	1/ $ 66,068,873	$ 15/ 7,674,914	$ 73,743,787	38.19	$ 2,816,268,422
3	Payroll	Adj 5 & Adj 6	25,573,530	12/ (2,389,314)	23,184,216	11.71	271,522,214
4	Other Operations and Maintenance Expenses						
5	Employee Health Benefits	Adj 9	4,793,783	13/ 79,796	4,873,579	30.37	147,994,982
6	Property and Public Liability Insurance	Adj 18	3,677,954	14/ 347,779	4,025,733	(163.46)	(658,063,186)
7	Other O&M	Various	48,736,805	17/ (557,652)	48,179,153	25.47	1,227,048,919
8	Less: Pension Benefit (Non Cash)		42,494	-	42,494	25.47	1,082,247
9	Less: OPEB Benefit (Non Cash)		6,584,462	-	6,584,462	25.47	167,696,128
10	Property Taxes		2,013,868	-	2,013,868	71.02	143,032,994
11	Delivery Tax	Adj 1	23,451,041	34/ 2,241,912	25,692,953	26.13	671,382,563
12	Rights-of-Way Fee	Adj 1	12,518,268	34/ (2,608,388)	9,909,880	(54.53)	(540,385,729)
13	FICA Taxes	Adj 12	2,103,553	16/ 22,322	2,125,875	9.97	21,193,472
14	Unemployment Tax		(6,961)	-	(6,961)	9.99	(69,562)
15	Environmental Tax		-	-	-	-	-
16	Federal Excise Tax		(21,714)	-	(21,714)	(17.51)	380,156
17	Sustainable Trust Fund	Adj 1	16,761,017	34/ 4,577,879	21,338,896	26.13	557,606,691
18	Energy Assistance Fund	Adj 1	2,156,914	34/ 210,071	2,366,985	26.13	61,851,688
19	Firm Storage Service		29	-	29	308.86	8,840
20	Other Taxes - Direct Assignment		16,520	-	16,520	79.00	1,305,080
21	Income Taxes	Adj. 31	(4,986,924)	8/ 166,747	(4,820,177)	-	-
22	Subtotal	Sum of Lns. 2 > 21	$ 209,483,512	$ 9,766,066	$ 219,249,578	22.30	$ 4,889,855,917
23	Lead Lag Requirement	Ln. 22, Col. E / 365			$ 600,684	66.70	$ 40,066,410
24	Other Lead-Lag Items						
25	Interest on Long-Term Debt	Adj 29	7/ (330,939)	7/ (831,295)	(1,162,234)	91.25	7,152
26	Economic Evaluation of Facility Extenstion (GSP 14)	Accts. 186.200 & 174.400	10/ 752,764	-	752,764	-	752,764
27	Cash Working Capital - Ratemaking						$ 40,826,325
28	Cash Working Capital - Distribution Amount						1/ 39,871,701
29	Cash Working Capital Ratemaking Adjustment	RB:1:10					$ 954,625

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 9D Workpaper No. 1 - Other O&M Expenses (Per Book)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	DC Per Books
	A	B	C
1	Operation Expenses	DC Inc Stmt, Ln. 3	$ 125,293,859
2	Maintenance Expenses	DC Inc Stmt, Ln. 4	25,568,839
3	Total O&M Expenses	Ln. 1 + Ln. 2	$ 150,862,698
4	Deductions		
5	Gas Purchased	Per Books	$ 64,262,645
6	Payroll	Per Books	25,573,530
7	Employee Benefits	Per Books	4,793,783
8	Property and Public Liability Insurance	Per Books	3,677,954
9	Depreciation Elimination	Per Books	(128,636)
10	Total Deductions	Sum of Lns. 5 > 9	$ 98,179,276
11			
12	Total Other O&M Expenses	Ln. 3 - Ln. 10	$ 52,683,423 1

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1D - Purchased Gas Costs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		Amount C
1	*Purchased Gas Revenues*			
2	Fuel Revenues	RV:1:13	$	(59,477,160)
3	Third Party Balancing Charges	RV:1:27		(6,609,061)
4	Balancing Charges Reconciliation Factor	Analysis		-
5	Total Adjustment for Purchased Gas Revenues	Lines 2 > 4	$	(66,086,221)
6	*Purchased Gas Costs*			
7	Hampshire Exchange Service	EX:2:9	$	(40,957)
8	Storage - Allocable	EX:2:12		(1,765,271)
9	Gas Purchase Costs	EX:3:3		(66,068,873) 1
10	Propane Gasified	EX:3:4		1,806,227 1
11	Total Adjustment for Purchased Gas Costs	Lines 7 > 10 (EX:3:3)	$	(66,068,873)

Adjustment Description: To remove fuel revenues, purchased gas costs, and gas supplier revenues from distribution revenues and expenses.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 2D - GAC Revenues and Uncollectible Expense Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Gas Administration Charge Revenues		
2	Residential	Analysis	$ (1,074,697)
3	Commercial and Industrial Other Than Group Metered Apartments	Analysis	(507,259)
4	Group Metered Apartments	Analysis	(191,045)
5	Gas Administration Charge Revenues Elimination Amount	1/	(1,773,001)
6	Less: Gas Procurement Cost		
7	Residential	Analysis	47,400
8	Commercial and Industrial Other Than Group Metered Apartments	Analysis	22,294
9	Group Metered Apartments	Analysis	8,477
10	Gas Procurement Cost Total	Adj No. 3D	78,171 A
11	GAC Uncollectible Expense Elimination Amount 2/	Line 5 + Line 9	$ (1,694,830) B

12 **Adjustment Description:** To remove Gas Administration Charge uncollectible amounts.

1/ For Class Cost purposes, note that this adjustment relates to RV:1:14.
2/ For Class Cost purposes, note that this adjustment relates to EX:7:21.

6/
B - A = ($1,694,830) - $78,171 - $367,389 = ($2,140,390) 1

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 7D - Purchase of Receivables (POR) Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Book Amount C	Ratemaking Adjustment D
1	**Capitalized Software**			
2	Capitalized Software (POR)	303006 (RB:2:2)	$ 762,920	$ (762,920)
3	Computer Equipment (POR)	373106 (RB:2:35)	7,234	(7,234)
4	Total Plant in Service	Ln. 2 + Ln. 3	$ 770,154	$ (770,154)
5	**Reserve for Depreciation**			
6	DC POR Software	Property Analysis	$ 352,999	$ (352,999)
7	DC POR Equipment	Property Analysis	3,331	(3,331)
8	Total Depreciation Reserve	Ln. 6 + Ln. 7	$ 356,329	$ (356,329)
9	**Other Operating Revenues**			
10	Late Payment Charges (POR)	487107 (RV:1:16)	$ 360,143	$ (360,143)
11	Other Gas Revenues	495306 (RV:1:32)	736,920	(736,920)
12	Total Revenues	Ln. 10 + Ln. 11	$ 1,097,063	$ (1,097,063)
13	**Depreciation and Amortization**			
14	Amortization of Capitalized Software (POR)	404311 (SM:1:7)	$ 97,980	$ (97,980)
15	**Customer Accounts**			
16	Collection Expense (POR)	903307 (EX:7:19)	$ 226,115	$ (226,115)
17	Uncollectible Accounts (POR)	904107 (EX:7:22)	141,274	(141,274)
18	Total Customer Accounts	Ln. 16 + Ln. 17	$ 367,389	$ (367,389) 5
19	**Interest Expense**			
20	POR CWC Costs	431135 (EX:9:12)	$ 58,019	$ (58,019) a/

21 a/ Adjustment is reflected in the Interest on Debt Adjustment #8D.

22 **Adjustment Description:** To eliminate purchase of receivables costs incurred during the study period.
Note:

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 8D & 29 - Interest on Debt (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	Distribution Amount D	Ratemaking Amount E
1	**Interest on Total Debt**				
2	Net Rate Base	Rate Base Stmt, Ln.23	$ 4,284,239,876	$ 796,176,491	$ 760,992,964
3	Weighted Average Cost of Debt	Cost of Capital, Ln. 1 + Ln. 2	2.36%	2.36%	2.36%
4	Interest on Debt	Ln. 2 * Ln. 3	$ 101,225,321	$ 18,811,557	$ 17,980,262
5	Per Books Interest Expense	Per Books	100,062,947	19,142,496	18,811,557
6	Adjustment to Interest Expense _1/	Ln. 4 - Ln. 5	$ 1,162,374	$ (330,939) 1 2	$ (831,295) 2

7 **Adjustment Description**: To synchronize interest expense used in determining the overall return requirement with the interest
8 expense used to calculate income taxes.

_1/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line 9:16.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 10D & 31 - State and Federal Income Taxes (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Distribution Amount C	Ratemaking Amount D
1	**Net Operating Income - Adjusted**	**DC Inc Stmt, Ln. 18**	**$ 20,999,112**	**$ 27,756,328**
2	Add: Income Taxes	DC Inc Stmt, Ln. 12	448,015	614,762
3	Less: Interest Expense	Adj 8D / Adj 29, Ln. 4	(18,811,557)	(17,980,262)
4	Taxable Income	Ln. 1 + Ln. 2 + Ln. 3	2,635,571	10,390,828
5	Flow-Throughs and Permanent Items (Basis)			
6	AFUDC Equity	Per Book ETR / Analysis	70,134	18,597
7	Meals and Entertainment	Per Book ETR / Analysis	184,959	184,959
8	Compensation Limitation	Per Book ETR / Analysis	-	-
9	Parking	Per Book ETR / Analysis	96,216	96,216
10	R&D credit	Per Book ETR / Analysis	-	-
11	Return to Provision True Up	Per Book ETR / Analysis	(806,112)	-
12	Other Tax Adjustments	Per Book ETR / Analysis	(176,160)	-
13	NOL Flow-through	Adj. 32	-	-
14	Total Flow-Throughs and Permanent Items	Ln. 6 > Ln. 12	(630,964)	299,771
15	Taxable Income (Adjusted)	Ln. 4 + Ln. 14	2,004,607	10,690,600
16	Federal Income Tax	Ln. 15 * 21.00%	420,968	2,245,026
17	Add: Excess Deferred Tax (Protected)		-	5,397,883
18	Add: Excess Deferred Tax (Unprotected)		-	(7,908,370)
19	Add: Excess Deferred Tax on PLR NOL			(140,599)
20	Less: Remove EDIT amortization related to FC 1027 Write Off			343,555
21	Add: Capitalizated OPEB		(12,689)	-
22	Add: ITC		(90,913)	(90,913)
23	Add: Amortization of Prior Flow-Through Balance		-	71,421
24	Total Federal Income Taxes	Ln. 17 > Ln. 22	317,365	(81,998)
25	Per Book / Ratemaking Federal Income Taxes		2,780,984	317,365
26	Federal Income Tax Adjustment	Ln. 24 - Ln. 25	(2,463,619)	(399,363)
27	State Income Tax (Net of Federal Tax Benefit)	Ln. 15 * 6.52%	130,650	696,760
28	Per Book / Ratemaking State Income Taxes		756,509	130,650
29	State Income Tax Adjustment	Ln. 27 - Ln. 28	(625,859)	566,110
30	Income Tax Adjustment	Ln. 26 + Ln. 29	(3,089,477) 1	166,747 2

31 **Adjustment Description:** To adjust state and federal income tax to rate year amounts.

Washington Gas Light Company
District of Columbia Jurisdiction

Summary of Lead / Lag Studies

For 12 Months Ended March 31, 2024

Line No.	Description	Lead / Lag Days
1	Revenue Lag	89.00 ①
2	Gas Purchase Lag	38.19
3	Payroll Lead	11.71
4	Employee Health Benefits	30.37
5	Other O&M	25.47
6	FICA Taxes	9.97
7	Public Insurance Liability	(163.46)
8	Property Tax Lag	71.02
9	Federal Unemployment Tax Lag	9.99
10	Federal Excise Tax Lag	(17.51)
11	Other Tax Lag	308.86
12	Interest on Long-term Debt	91.25
13	Arena Fee (Other Taxes - Direct Assignment)	79.00
14	Delivery Tax	26.13
15	Rights-of-Way Fee	(54.53)

1/ Lead/Lags 1 and 2 are based on the Twelve Months Ended March 31, 2024.
2/ Lead/Lags 3 - 15 are base on the Twelve Months Ended December 31, 2020

Washington Gas Light Company
Cash Working Capital
District of Columbia
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Reference Sc-Pg-Ln	Allocator	Expenses	Adjustments		Adjusted Expenses		Lead/Lag Days	Cash Working Capital Requirement
	A	B	C	D	E		F		G	H
1	Composite Revenue Lag								89.00	
2	Gas Purchased	EX:3:5		$ 64,262,645	$ -		$ 64,262,645	1	38.19	$ 2,454,184,506
3	Payroll	WEX:6:30		25,573,530	-		25,573,530		11.71	299,504,692
4	Other Operations and Maintenance Expenses 1/			61,026,523	128,636	1/	61,155,159		25.47	1,557,527,820
5	Less: Pension Benefit 2/		Total_Labor	42,494	-		42,494		25.47	1,082,247
6	Less: OPEB Benefit 3/		Total_Labor	6,584,462	-		6,584,462		25.47	167,696,128
7	General Taxes									
8	Property Taxes	EX:8:2		2,013,868	-		2,013,868		71.02	143,032,994
9	Delivery Tax	EX:8:8		23,451,041	-		23,451,041		26.13	612,799,160
10	Rights-of-Way Fee	EX:8:9		12,518,268	-		12,518,268		(54.53)	(682,621,127)
11	FICA Taxes	EX:8:10>11		2,103,553	-		2,103,553		9.97	20,970,937
12	Unemployment Tax	EX:8:12		(6,961)	-		(6,961)		9.99	(69,562)
13	Federal Excise Tax	EX:8:17		(21,714)	-		(21,714)		(17.51)	380,156
14	Sustainable Trust Fund	EX:8:18		16,761,017	-		16,761,017		26.13	437,982,135
15	Energy Assistance Fund	EX:8:19		2,156,914	-		2,156,914		26.13	56,362,323
16	Firm Storage Service	EX:8:23		29	-		29		308.86	8,840
17	Other Taxes - Direct Assignment	EX:8:22		16,520	-		16,520		79.00	1,305,080
18	Federal Income Taxes	EX:10:2		(1,201,342)	-		A (1,201,342)		-	0
19	Other Income Taxes	EX:10:3		(696,105)	-		A (696,105)		-	0
20	Total Net Expenses	= 2 > 19		$ 214,584,743	$ 128,636		$ 214,713,379		23.61	$ 5,070,146,329
21	Subtotal						$ 588,256		65.39	$ 38,466,327
22	Other Lead-Lag Items:									
23	Imprest Funds	AL:4:30	O&M _X_ Gas	$ -						$ -
24	Economic Eval. of Facility Ext. (GSP 14)		Accts186200 & 174400	752,764	-		752,764	1 2		752,764
25	Interest on Long-Term Debt	EX:9:2		0			$ -		91.25	0
26	Preferred Dividends			812,206,690	0.00%		-		0.00	-
27	Total Cash Working Capital	= 21 > 26								$ 39,219,091 1

1/ Represents an adjustment to exclude depreciation expense for transportation and POE equipment from the calculation of cash working capital.(WEX13:10)
2/ To exclude Pension Benefit from Working Capital calculations, because it is a noncash item.
3/ To exclude OPEB Benefit from Working Capital calculations, because it is a noncash item.

Sum of A = ($1,897,447)
1

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 5 - Wages and Salaries Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		Frederick/Shen Unions C	Teamsters & Local 2 Unions D	Management E	Total F=C+D+E
1	**Annual Payroll (Gross) TME March 31, 2024**	Analysis		$ 5,108,819	$ 72,615,991	$ 106,452,220	$ 184,177,030
2	Pro Forma Increase - Test Year (Apr-2023 to Mar-2024)	Workpaper 2		50,086	320,862	3,138,466	3,509,414
3	Pro Forma Gross Payroll TME March 31, 2024	Ln. 1 + Ln. 2		$ 5,158,906	$ 72,936,853	$ 109,590,685	$ 187,686,444
4	Pro Forma Increase - (Apr-2024 to Mar-2025)	Workpaper 2		103,178	1,857,618	1,362,578	3,323,373
5	Pro Forma Gross Payroll in Rate Effective Period (Aug-2025 to Jul-2026)	Ln. 3 + Ln. 4		$ 5,262,084	$ 74,794,471	$ 110,953,263	$ 191,009,817
6	Pro Forma Payroll Increase	(Ln. 5 - Ln. 1)		$ 153,265	$ 2,178,480	$ 4,501,043	$ 6,832,788
7	Operations & Maintenance Allocation Factor	Analysis		75.53%	75.53%	75.53%	75.53%
8	Proforma Payroll Increase Allocable to Operations & Maintenance (System)	Ln. 6 * Ln. 7		$ 115,757	$ 1,645,354	$ 3,399,531	$ 5,160,643
9	District of Columbia Allocation Factor			19.36%	19.36%	19.36%	19.36%
10	Proforma Payroll Increase Allocable to Operations & Maintenance (District of Columbia)	Ln. 8 * Ln. 9		$ 22,411	$ 318,541	$ 658,149	$ 999,100
11	Adjust to reflect amortization of ratification bonus	Workpaper 3					$ 1,957
12	**Total Wages and Salaries Adjustment**	Ln. 10 + Ln. 11					**$ 1,001,057** 12
13	Wages & Salaries Expense Adjustment - Operations	Ln. 10 * 0.6434	_2/				$ 644,085
14	Wages & Salaries Expense Adjustment - Maintenance	Ln. 10 * 0.3566	_2/				$ 356,972

15 **Adjustment Description:** To reflect pro forma labor wage increases through the rate effective period.

1/ Per book Short-term incentive compensation and benefits expenses are excluded from the cost of service here rather than in 401(k) adjustment (#8).

2/ For class cost purposes, the full amount of this adjustment relates to COSA line EX 5:3.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 6 - LTI Expense Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	Factor Comp_A&G	DC Amount
	A	B	C	D	E = C * D
1	Long-Term Incentive - Performance Shares	Acct 920411 & 920412	$ (40,509)		
2	Long-Term Incentive - Performance Units	Acct 920421 & 920422	$ (17,309,695)		
3	**Total Expense Adjustment _1/**	Ln. 1 + Ln. 2	$ (17,350,204)	19.54%	$ (3,390,371) A

4 **Adjustment Description:** To remove 100% of per book long-term incentive expense.

_1/ For class cost purposes, the full amount of this adjustment relates to COSA line EX:5:3.

11/
(3,390,371) + $1,001,057 = $2,389,314 2

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 9 - Employee Benefits Expense 401(k)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Amount
	A	B	C
1	Per Book Test Year Contributions	Account 926207 (EX:5:14)	$ 10,900,486
2	Test Year Contribution Related to Organizational redesign	Analysis	$ (579,010)
3	Test Year Contributions Adjusted	Ln. 1 + Ln. 2	$ 10,321,475
4	Three Year Average Growth Factor	Workpaper 1	5.29%
5	Employee Savings Plans Expense Increase	Ln. 3 * Ln. 4	$ 545,669
6	Operations & Maintenance Allocation Factor	Analysis	75.53%
7	Expense Adjusment (System)	Ln. 5 * Ln.6	$ 412,131
8	District of Columbia Allocation Factor	Total_Labor	19.36%
9	Expense Adjusment (District of Columbia)	Ln. 7 * Ln. 8	$ 79,796 (2)

10 **Adjustment Description:** To adjust 401(k) employee benefits expense for current employees to a pro forma basis.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 18 - Insurance Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Incremental Insurance Premiums, Excluding Property Insurance		
2	Excess Public Liability	Insurance Analysis	$ 1,225,502
3	Director and Officer Liability	Insurance Analysis	40,201
4	General Liability	Insurance Analysis	38,759
5	Professional	Insurance Analysis	20,210
6	Commercial Crime/Cyber Liability	Insurance Analysis	90,071
7	Workers Compensation	Insurance Analysis	410,501
8	Service Fees	Insurance Analysis	(33,966)
9	Total Incremental Expense, Excluding Property Insurance	= Sum (Ln. 2 > Ln. 8)	$ 1,791,278
10	DC Factor (Total_Labor)	AL:4:10	19.3618%
11	DC Insurance Expense Adjustment Excluding Property	= Ln. 9 * Ln. 10	$ 346,824
12	Incremental Property Insurance	Insurance Analysis	$ 5,128
13	DC Factor (Net_GPIS)	AL:3:13	18.6176%
14	DC Property Insurance Expense Adjustment	= Ln. 12 * Ln. 13	$ 955
15	Adjustment Total 1/	= Ln. 11 + Ln. 14	$ 347,779 2

16 **Adjustment Description:** To reflect insurance premium increases.

1/ For class cost purposes, the full amount of the adjustment relates to COSA line EX:5:8.

Washington Gas Light Company
System

Jurisdictional Allocation of Purchased Gas Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Allocator C	System D=E+F+G	D.C. E	Maryland F	Virginia G
1	Commodity						
2	Allocable	Line 4 - Line 3	Sales Normal Weather Therms	$ 236,353,873	$ 31,673,000	$ 98,735,488	$ 105,945,385
3	Interruptible	Page 21, Line 7	Direct Assignment	-	-	-	-
4	Total Commodity	Page 20, Line 10		$ 236,353,873	$ 31,673,000	$ 98,735,488	$ 105,945,385
5	Firm Transportation Demand						
6	Base Gas	footnote 1/	Peak_Day_Base	$ 15,505,776	$ 2,192,298	$ 6,561,234	$ 6,752,244
7	Weather Gas	footnote 1/	Peak_Day_Weather	126,618,658	18,134,074	55,105,954	53,378,630
8	Total FT Demand	RM Demand Cost, Line 12		$ 142,124,434	$ 20,326,372	$ 61,667,188	$ 60,130,874
9	Storage Service Demand						
10	Demand	RM Demand Cost, Line 25	Peak_Day_Weather	$ 75,541,326	$ 10,818,879	$ 32,876,488	$ 31,845,959
11	Capacity	RM Demand Cost, Line 35	Wintr_Pipe_NW	38,219,634	6,416,808	16,527,132	15,275,694
12	Injection/Withdrawal	N/A	Wintr_Pipe_NW	-	-	-	-
13	Total Storage Service Demand	Sum of Lines 10 - 12		$ 113,760,961	$ 17,235,687	$ 49,403,621	$ 47,121,653
14	Peaking Service Demand	RM Demand Cost, Line 52	Firm Weather_NW	$ 18,381,178	$ 2,702,500	$ 7,900,081	$ 7,778,597
15	Total Ratemaking Pipeline Cost of Gas	Sum of Lines 4, 8, 13 & 14		$ 510,620,446	$ 71,937,559	$ 217,706,378	$ 220,976,509
16	Purchased Gas Cost Per Books	footnote 2/		454,828,378	64,262,645	200,704,535	189,861,198
17	Adjustment to Purchased Gas Cost 3/	Line 15 - Line 16		$ 55,792,068	$ 7,674,914	$ 17,001,843	$ 31,115,311
18	Adjustment Description: To adjust purchased gas costs to a Ratemaking basis.						

1/ 10.91% of Line 8 assigned to base gas and the balance assigned to Weather Gas.
2/ Excludes Other Gas Cost included in O&M Expenses (Hampshire Gas Company).
3/ For Class Cost purposes, note that this adjustment relates to EX:3:5.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 12 - FICA / Medicare Tax Expense

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	Labor Factor	DC Amount
	A	B	C	D	E
1	Incremental Payroll Expense	Adj. No. 5	$ 5,160,643		
2	Adjust to reflect 5 year amortization of ratification bonus	Adj. No. 5	1,957		
3	Labor Adjustment Change	Ln. 1 + Ln. 2	**$ 5,162,599**		
4	Factor - SSI Wages to Gross Wages	Analysis	91.23%		
5	Social Security Insurance (SSI) Base	Ln. 1 * Ln. 4	$ 4,709,839		
6	SSI Rate		6.20%		
7	SSI Tax	Ln. 5 * Ln. 6	292,010	19.36%	56,538
8	Base - Medicare (Payroll Increase)	Ln. 3	$ 5,162,599		
9	Base - Medicare (Long-Term Incentive Elimination)	Adj. No. 6	(17,350,204)		
10	Total Medicare Base	Ln. 8 + Ln. 9	(12,187,604)		
11	Medicare Rate		1.45%		
12	Medicare Tax - Medicare	Ln. 10 * Ln. 11	(176,720)	19.36%	(34,216)
13	Total Pro Forma Adjustment	Ln. 7 + Ln. 12	**$ 115,290**	19.36%	**$ 22,322** _1/ 2
14					

15 **Adjustment Description:** To reflect increase in employer's portion of FICA taxes to reflect proforma increase in salaries and wages.

_1/ For class cost purposes, $56,538 relates to EX:8:10 and -$34,216 relates to EX:8:11.

DC Uncoll Exp

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 Workpaper 9 - Ratemaking Adjustment to Uncollectible Accounts Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Ratemaking Sales and Delivery Revenues 1/	Adj 1 WP 7, Column C, Line 27	$ 205,930,738
2	Accrual Rate for Uncollectible Gas Accounts	Adj 1 WP 2	2.7046%
3	Ratemaking Uncollectible Gas Accounts Expense	Line 1 x Line 2	$ 5,569,603
4	Per Books Uncollectible Gas Accounts Expense	Per Books	6,226,265
5	Distribution Adjustment to Uncollectible Expense	Adjustment No. 2D	(1,694,830)
6	Distribution Only, Per Book Uncollectible Expense	Line 4 + Line 5 + Line 6	4,531,435
7	Ratemaking Adjustment to Uncollectible Gas Accounts 2/	Line 3 - Line 6	$ 1,038,168 A

8 **Adjustment Description:** To adjust per book uncollectible accounts expense to reflect adjusted non-gas ratemaking revenues.

A $1,038,168 -
18/ $630,366 -
19/ $565,665 -
20/ $39,094+
21/ $73,633+
22/ $278,465+
23/ $333,242+
24/ $1,043,643 -
25/ $97,796 -
26/ $125,884+
27/ $136,923 -
28/ $26,978+
29/ $195,423 -
30/ $1,978,270
31/ -$52,311
32/ -$411,796
33/ +$271,011
=($557,652) 2

1/ Less: Gas Cost.
2/ For Class Cost purposes, note that this adjustment relates to EX:7:22.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 7 - Postretirement Benefits Other Than Pensions (OPEB) Expense

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	DC Amount
	A	B	C	D = C * 19.36%
1	**Current Employees**			
2	Employer Service Cost	Actuarial Rpt	$ 4,010,336	
3	Washington % of Basic Pay (eliminates Hampshire)	Analysis	99.41%	
4	Washington Gas Portion of Expense	Ln. 2 * Ln. 3	$ 3,986,626	
5	O&M Factor (OPEB Service Costs)	Analysis	81.48%	
6	Total Employer Service Cost	Ln. 4 * Ln. 5	$ 3,248,198	$ 628,910
7	Other Components of Net Periodic Expense	Actuarial Rpt	$ (41,549,691)	
8	Washington % of Basic Pay (eliminates Hampshire)	Analysis	99.41%	
9	Washington Gas Portion of Expense	Ln. 7 * Ln. 8	$ (41,304,041)	
10	O&M Factor (OPEB Other Costs)	Analysis	98.08%	
11	Total Other Components of Net Periodic Expense	Ln. 9 * Ln. 10	$ (40,511,351)	$ (7,843,739)
12	Total Net Periodic Post-Retirement Benefit Expense	Ln. 6 + Ln. 11	$ (37,263,153)	$ (7,214,828)
13	District of Columbia OPEB Costs Per Book	EX:5:15		(6,584,462)
14	Adjustment to OPEB Cost	Ln. 12 - Ln. 13		$ (630,366) 17

15 **Adjustment Description:** To calculate OPEB expense on a pro forma basis.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 8 - Pension & SERP Expense

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	DC Amount
	A	B	C	D = C * 19.36%
1	Pro Forma Employer Service Cost	Workpaper 1	$ 6,934,286	
2	O&M Factor (Pension Service Cost)		81.17%	
3	PF Employer Service Cost	Ln. 1 * Ln. 2	$ 5,628,648	$ 1,089,809
4	Pro Forma Other Components of Net Periodic Expense	Workpaper 1	$ (8,881,587)	
5	O&M Factor (Pension Other Costs)		98.74%	
6	PF Other Components of Net Periodic Expense	Ln. 4 * Ln. 5	$ (8,769,665)	$ (1,697,967)
7	Total Pro Forma Pension Expense	Ln. 3 + Ln. 6	$ (3,141,017)	$ (608,158)
8	Per Book Qualified Pension Expense	EX:5:9	$ (1,529,287)	$ (295,849) a/
9	Per Book SERP/Restoration	EX:5:9	$ 1,309,631	$ 253,355 b/
10	Total Per Book Pension Expense	Ln. 8 + Ln. 9		$ (42,494)
11	Pro Forma Pension Adjustment	Ln. 7 - Ln. 10		$ (565,665) 17

12 **Adjustment Description:** To calculate pension expense on a pro forma basis.

a/ Qualified Pension Expense Accounts are: 926101, 926107, 926109, 926115, 926116, 926116

b/ SERP/Restoration Expense Accounts are: 926103, 926105, 926106, 926113, 926114, 926114

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 10 - Employee Benefits Expense (Fringe) Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	O&M Factor	DC Factor	DC Amount	_2/
	A	B	C	D	E	F=C*D*E	
1	Professional Services	Workpaper 2	$ (22,490)	100.00%	19.36%	$ (4,354)	_1/
2	Physicals	Workpaper 2	(7,150)	100.00%	19.36%	(1,384)	_1/
3	Parking	Workpaper 3	(71,760)	86.17%	19.36%	(11,972)	
4	Car Allowance	Workpaper 4	(110,439)	100.00%	19.36%	(21,383)	_1/
5	**Adjustment to Fringe Benefits (Current Employees)**	**Ln. 1 > Ln. 4**	**$ (211,838)**			**$ (39,094)**	17

6 **Adjustment Description:** To remove executive fringe benefits expense.

_1/ O&M factor not applicable because this amount already excludes affiliate transactions.
_2/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line EX:5:14.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 15 - Amortization of COVID Regulatory Asset

Twelve Months Ended March 31, 2024

Line	Description		Reference	Amount
1	Total Regulatory Asset Balance allowed in FC 1169		Order No. 21939	$ 368,163
2	Amortization Period (Years)		5 Years	5
3	Annual Amortization		Ln. 1 / Ln. 2	$ 73,633
4	Test Year Amortization Expense (Per Book)			-
5	**Total Adjustment to Amortization Expense**	_1/	**Ln. 3 - Ln. 4**	**$ 73,633** 17

6 Adjustment Description: To amortize the COVID regulatory asset over 5 years.

1/ For class cost purposes:
$73,633 relates to EX:5:5

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 17 - Environmental Costs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Actual Remediation Expenses as of March 31, 2024	Financial Statement	$ 37,232,664
2	Less: Expenses approved in Prior Cases	Order 21939	27,639,236
3	Total Environmental Expenses Incurred Subsequent to FC Case No. 1169	= Ln. 1 - Ln. 2	$ 9,593,428
4	District of Columbia Factor (Total_Weather_All_NW)	AL:1:19	0.164770
5	Environmental Expenses Applicable to DC	= Ln. 3 * Ln. 4	$ 1,580,712
6	Less: Amount over (under) collected since FC 1169 through July 2025	Financial Statement	(1,126,956)
7	Balance of expenditures incurred to be amortized over 5 years	= Ln. 5 - Ln. 6	2,707,668
8	Annual amortization for 5-year period	= Ln. 7 / 5	$ 541,534
9	Less: Per book annual amortization expense	EX: 5:21	263,068
10	**Total DC Amortization Expense adjustment**	Ln. 8 - Ln. 9	**278,465** 17
11	Rate Base:		
12	Deferred Balance of Environmental Cost, Net of Deferred Taxes	[Ln. 7 - (Ln. 8/2)] * 0.724825	$ 1,766,327
13	Less: Unamortized East Station Cost (Net of Deferred Taxes) March 31, 2024	RB:1:8	1,075,846
14	**Total DC Ratebase Adjustment**	**= Ln. 12 - Ln. 13**	**$ 690,481**

15 **Adjustment Description:** To reflect additional environmental cost incurred since Formal Case No. 1169.

1/ For class cost purposes the total adjustment relates to COSA line EX:5:21.

Washington Gas Light Company
District of Columbia Jurisidiction

Adjustment No. 20 - Commission-Mandated Audit Fees

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Regulatory Asset Balance as of July 31, 2025 (FC 1115 Pipes 1)	Analysis	$ 218,773
2	Regulatory Asset Balance as of July 31, 2025 (FC 1175 Pipes 2)	Analysis	$ 832,225
3	Total Annual Amortization (Rate Year)	(Ln. 1 + Ln. 2)/3	$ 350,333
4	Test Year Expense (System)	Analysis	$ 91,675
5	Three_Part_Factor	AL:5:30	18.64%
6	Per Book Expense (District of Columbia)	Ln. 4 * Ln. 5	$ 17,091
7	Adjustment	Ln. 3 - Ln. 6	$ 333,242 1/

8 **Adjustment Description:** To reflect the amortization of ProjectPipes audit fees at rate year amount.

1/ For Class Cost purposes, note that $333,242 of the adjustment relates to EX:5:6.

17

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 21 - Non-Labor Inflation

Twelve Months Ended March 31, 2024

Line No.	Description		Allocator	Non-Labor Expense	Calculated Increase
	A		B	C	D
1	Test Year Operations Expense	_1/	DC Inc Stmt, Ln. 3, Col. E	$ 57,084,597	
2	Test Year Maintenance Expense		DC Inc Stmt, Ln. 4, Col. E	25,568,839	
3	Labor Expense in Test Year O&M		Workpaper 1	(28,256,576)	
4	Test Year Non Labor O&M Expense		Sum (Ln. 1 > Ln. 3)	$ 54,396,860	
5	Non Labor Expense Adjustments to Cost of Service		Workpaper 2	(12,491,893)	
6	Test Year Non Labor O&M Expense (Adjusted)		Ln. 4 + Ln. 5	$ 41,904,967	
7	Inflation Rate (2024)		1 + (2.49% * 1)	102.49%	
8	Non Labor O&M Expense @ 12/31/2024		Ln. 6 * Ln. 7	$ 42,948,611	
9	Incremental Increase		Ln. 8 - Ln. 6		1,043,643
10	**Adjustment Total**		**Ln. 8**		**1,043,643** 17

1/ excludes Gas Purchased Expense

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 22 - Trade Dues, Business Memberships, and Community Affairs

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Allocator	System Amount	DC Factor	Ratemaking Adjustment
	A	B	C	D	E	F = C * D * E
1	Direct Charges - District of Columbia	Analysis	100% DC	$ 17,683	100%	$ (17,683)
2	Allocated Charges - Support Payments	Analysis	Comp_A&G	$ 409,981	19.54%	$ (80,114)
3	Direct Charges - Other Jurisdictions					
4	Maryland		100% MD	$ 275,283	0%	$ -
5	Virginia		100% VA	$ 318,274	0%	$ -
6	Total Other Jurisdictions	Ln. 4 + Ln. 5		$ 593,557		$ -
7	Total Company Memberships & Trade Dues	Ln. 1 + Ln. 2 + Ln. 7	1/	$ 1,021,220		$ (97,796)
8	Trade Dues & Business Associations					$ (48,991)
9	American Gas Association Dues					$ (59,768)
10	Community Affairs					$ 10,962
11	Total					$ (97,796) 17

12 **Adjustment Description:** To exclude Trade Dues, Business Memberships, and Community Affairs payments, as directed in prior
13 Commission Orders.

1/ For class cost purposes the total adjustment relates to COSA line EX:5:29

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 23 - General Advertising Expense Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Allocator	Reference	DC Amount
	A	B	C	D
1	Eliminate Advertising Expense Direct	Financial Statement	EX:5:19	$ -
2	Eliminate Advertising Expense Allocable	Comp A&G	EX:5:20	(125,884)
3	Total Adjustment		Ln. 1 + Ln. 2	$ (125,884) 17

4 **Adjustment Description:** To eliminate direct and indirect general advertising expenses (account 930100)
5 incurred during the study period.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 25 - Legal Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Legal Expenses (DC - Per Book Amount)	Financial Statements	$ 338,684
2	DC Corrected Per Book Amount	Analysis	475,607
3	Proforma Adjustment Amount	Line 2 - Line 1	$ 136,923 1/

17

4 **Adjustment Description:** To correct Legal expenses on a jurisdictional basis for
5 twelve months ended March 31, 2024.

1/ For Class Cost purposes, note that -$65.07 of the adjustment relates to EX:5:5, and $136,988.08 of the adjustment relates to EX:5:6.

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 26 - Prior Period Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Account B	DC Total C
1	Prior Period Items		
2	Short Term Incentive Reclass	920432 (EX:5:2)	$ (26,978)
3	Adjustment Total		$ (26,978) 17

4 **Adjustment Description:** To adjust test year expense to remove prior period adjustments.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 11 - Medical Plans Inflation

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	O&M Factor	Labor Factor	MD Amount
	A	B	C	D	E	F=C*D*E
1	Insurance Benefits Expense - Carefirst / BCBS	Account 926.274	$ 17,091,522			
2	Insurance Benefits Expense - Kaiser-Permanente	Account 926.264	$ 1,590,804			
3	Insurance Benefits Expense - Delta Dental	Account 926.215	$ 1,173,961			
4	Test Year Expense Related to Organizational redesign	Analysis	(765,460)			
5	Total Group Meidcal Expense (Test Year)	Ln. 1 + Ln. 2 + Ln. 3 + Ln. 4	19,090,827			
6	Inflation Rate	Analysis	7.00%			
7	**Total Expense Adjustment _1/**	Ln. 5 * Ln. 6	**$ 1,336,358**	75.53%	19.36%	**$ 195,423** 17

8 **Adjustment Description:** To adjust employee medical benefits expense for current employees to a pro forma basis.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 13 - Organizational Redesign Labor O&M Expense Reduction

Twelve Months Ended March 31, 2024

Line	Description	Reference		Amount
1	Reduction in salaries	Analysis	$	(7,233,986)
2	Reduction in short-term incentives	Analysis		(986,995)
3	Reduction in medical plans	Analysis		(730,291)
4	Reduction in 401(k)	Analysis		(556,223)
5	Reduction in payroll taxes	Analysis		(697,386)
6	Reduction in life insurance	Analysis		(12,492)
7	Reduction in rate year labor expenses (System)	Sum Lns. 1 to 6	$	(10,217,373)
8	DC Labor Factor	AL 4:11		19.36%
9	Reduction in rate year labor expense (DC)	Ln. 7 * Ln. 8	$	(1,978,270) 17

10 **Adjustment Description:** To reflect the reduction in salaries and other related expenses
11 related to the reduction in force as part of the organizational redesign.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 27 - Merger Transition Cost to Achieve Amortization Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Total Company B	Allocation Factor C	District of Columbia D = B * C
1	**Transition Cost Amortization**			
2	Account 921003 - Merger Transition Amortization Expense	$ 308,014	16.98%	$ 52,311
3	**Elimination of Merger Transition Amortization Expense**			**$ (52,311)** 17

4 **Adjustment Description:** To eliminate merger-related cost to achieve amortizaton for the period for twelve months
5 ending March 2024.

Note: The merger amortizations ended in July 2023

_1/ For class cost purposes, the full amount of this adjustment relates to COSA line EX 5:5.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 28 - Credit/Debit Card Transaction Fees Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference		MD Amount
	A	B		C
1	Credit/Debit Card Transaction Fees (Per Book)	EX:7:16	$	478,381
2	ACH Payment Increase	Analysis	$	66,585
3	Net Credit/Debit Card Fees	Ln. 1 - Ln. 2	$	411,796
4	Elimination of Credit/Debit Card Transaction Fees		$	(411,796) 17

5 **Adjustment Description:** To eliminate credit/debit card fees for twelve months ended March 31, 2024.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 14 - Involuntary Separation Program Cost to Implement Amortization

Twelve Months Ended March 31, 2024

Line	Description	Reference		System
1	Severance	Workpaper 1	$	4,479,772
2	COBRA Continuation Coverage	Adj 13		730,291
3	Short-Term Incentive	Workpaper 1		144,628
4	Paid Time Off	Workpaper 1		360,408
5	Outplacement Services	ledger		32,000
6	Additional Security Costs	ledger		35,112
7	Consultant Services for Organizational Redesign	Analysis		1,216,372
8	Cost to Implement Organizational Redesign	Lns. 1 to 7	$	6,998,583
9	Annual Amortization (System)	Ln. 8 / 5	$	1,399,717
10	DC Labor Factor	AL 4:11		19.36%
11	Annual Amortization (DC)	Ln. 9 * Ln. 10	$	271,011 17

12 **Adjustment Description:** To reflect the costs associated with implementing the April 2024
13 Involutary Separation Program amortized over 5 years.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 - Ratemaking Revenues and Related Expenses Summary

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Book Amount C	Distribution Adjustments D	Distribution-Only Amount E = C + D	Ratemaking Adjustments F	Ratemaking Amount _2/ G = E + F
1	**Operating Revenues**						
2	Base Revenues						
3	Base Rate Revenues (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	$ 127,731,965	$ -	$ 127,731,965	$ 18,877,467	$ 146,609,432
4	Distribution Charge & Plant Recovery Adjustments	Rev WP 1 + Adj 1 WP 7	(8,444,784)	-	(8,444,784)	8,444,784	-
5	Peak Usage Charge	Rev WP 1 + Adj 1 WP 7	4,254,611	-	4,254,611	229,056	4,483,667
6	Fuel Revenues _1/	Rev WP 1 + Adjs 1D, 2D, 4D	69,417,982	(69,417,982)	-	-	-
7	Revenue Taxes						
8	DC Right of Way Tax (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	12,367,741	-	12,367,741	(2,457,862)	9,909,879
9	Delivery Tax (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	19,243,088	-	19,243,088	1,978,792	21,221,880
10	Sustainable Energy Trust Fund (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	16,438,143	-	16,438,143	4,900,753	21,338,896
11	Energy Assistance Trust Fund (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	2,109,146	-	2,109,146	257,838	2,366,984
12	Non-District of Columbia Tariff Rates & Revenue Taxes	Rev WP 1 + Adj 1 WP 7	(50,138)	-	(50,138)	50,138	-
13	Off-System Sales Revenue (Asset Optimization)	Rev WP 1 + Adj 5D	14,177,234	(14,177,234)	-		-
14	PROJECTpipes	Rev WP 1 + Adj 1 WP 7	13,157,184	-	13,157,184	(13,157,184)	-
15	Sales of Gas to Customers (excl. CNG customers)	Sum Lns. 2 to 14	$ 270,402,172	$ (83,595,216)	$ 186,806,956	$ 19,123,782	$ 205,930,738
16	Late Payment Fees	Rev WP 1 + Adj 7D + Adj 1 WP 8	3,605,596	(360,143)	3,245,453	332,243	3,577,696
17	Other Operating Revenues	Adj No. 1, Page 2, Line 40	2,897,112	(736,920)	2,160,192	(41,088)	2,119,103
18	**Total Operating Revenues (RV 1:35)**	**Sum Lns. 15 to 17**	**$ 276,904,880**	**$ (84,692,279)**	**$ 192,212,601**	**$ 19,414,936**	**$ 211,627,537**
19	**Revenue Related Expenses**						
20	Uncollectible Accounts Expense	EX 7:19 + Adj 2D + Adj 1 WP 9	$ 6,226,265	$ (1,694,830)	$ 4,531,435	$ 1,038,168	$ 5,569,603
21	Delivery Tax Expense Expense (excl. PSC assessment)	EX 8:8 + Adj 1 WP 10	18,979,968	-	18,979,968	2,241,912 ②	21,221,880
22	Rights of Way Fee Expense	EX 8:9 + Adj 1 WP 11	12,518,268	-	12,518,268	(2,608,389)	9,909,879
23	Sustainable Energy Trust Fund	EX 8:17 + Adj 1 WP 12	16,761,017	-	16,761,017	4,577,879	21,338,896
24	Energy Assistance Trust Fund Fee	EX 8:17 + Adj 2 WP 13	2,156,914	-	2,156,914	210,070	2,366,984
25	**Total Revenue Related Expenses**	**Sum Lns. 20 to 24**	**$ 56,642,432**	**$ (1,694,830)**	**$ 54,947,602**	**$ 5,459,640**	**$ 60,407,242**

26 **Adjustment Description:** To adjust Operating Revenues to a Ratemaking basis.

Adjustment No. 10D

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 10D & 31 - State and Federal Income Taxes (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Distribution Amount C	Ratemaking Amount D	
1	**Net Operating Income - Adjusted**	**DC Inc Stmt, Ln. 18**	$ 2/ **20,999,112**	$ 2/ **27,756,328**	
2	Add: Income Taxes	DC Inc Stmt, Ln. 12	2/ 448,015	2/ 614,762	
3	Less: Interest Expense	Adj 8D / Adj 29, Ln. 4	3/ (18,811,557)	3/ (17,980,262)	
4	Taxable Income	Ln. 1 + Ln. 2 + Ln. 3	2,635,571	10,390,828	
5	Flow-Throughs and Permanent Items (Basis)				
6	AFUDC Equity	Per Book ETR / Analysis	5/ 70,134	5/ 18,597	
7	Meals and Entertainment	Per Book ETR / Analysis	184,959	184,959	
8	Compensation Limitation	Per Book ETR / Analysis	-	-	
9	Parking	Per Book ETR / Analysis	96,216	96,216	
10	R&D credit	Per Book ETR / Analysis	-	-	
11	Return to Provision True Up	Per Book ETR / Analysis	(806,112)	-	
12	Other Tax Adjustments	Per Book ETR / Analysis	(176,160)	-	
13	NOL Flow-through	Adj. 32	-	-	
14	Total Flow-Throughs and Permanent Items	Ln. 6 > Ln. 12	(630,964)	299,771	
15	Taxable Income (Adjusted)	Ln. 4 + Ln. 14	2,004,607	10,690,600	
16	Federal Income Tax	5/ Ln. 15 * 21.00%	420,968	2,245,026	5/ Sum of A = $5,257,284
17	Add: Excess Deferred Tax (Protected)		5/ -	5/ 5,397,883 A	
18	Add: Excess Deferred Tax (Unprotected)		-	(7,908,370)	
19	Add: Excess Deferred Tax on PLR NOL			(140,599) A	
20	Less: Remove EDIT amortization related to FC 1027 Write Off			343,555	
21	Add: Capitalizated OPEB		(12,689)	-	
22	Add: ITC		(90,913)	(90,913)	
23	Add: Amortization of Prior Flow-Through Balance		-	71,421	
24	Total Federal Income Taxes	Ln. 17 > Ln. 22	317,365	(81,998)	
25	Per Book / Ratemaking Federal Income Taxes		2,780,984 B	317,365 C	
26	Federal Income Tax Adjustment	Ln. 24 - Ln. 25	(2,463,619)	(399,363)	
27	State Income Tax (Net of Federal Tax Benefit)	5/ Ln. 15 * 6.52%	130,650	696,760	
28	Per Book / Ratemaking State Income Taxes		756,509 B	130,650 C	
29	State Income Tax Adjustment	Ln. 27 - Ln. 28	(625,859)	566,110	
30	Income Tax Adjustment	Ln. 26 + Ln. 29	(3,089,477) 2	166,747 2	

2/ Sum of B = $3,537,493

2/ Sum of C = $448,015

31 **Adjustment Description:** To adjust state and federal income tax to rate year amounts.

Washington Gas Light Company
District of Columbia Jurisdiction

Income Statement and Rate of Return Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Books	Distribution Adjustments	Distribution Amounts	Ratemaking Adjustments	Ratemaking Amounts	Revenue Deficiency	ROE Amounts
	A	B	C	D	E = C + D	F	G = E + F	H	I = G + H
1	Operating Revenues	Adj List Pg 1, Ln. 11	$ 276,904,880	$ (84,692,285)	$ 192,212,595	$ 19,414,936	$ 211,627,531	$ 45,572,411	$ 257,199,942
2	Operating Expenses								
3	Operation	Adj List Pg 1, Ln. 41	$ 125,293,859	$ (68,209,263)	$ 57,084,597	$ (267,932)	$ 56,816,665	$ 1,200,094	$ 58,016,759
4	Maintenance	Adj List Pg 1, Ln. 20	25,568,839	-	25,568,839	356,972	25,925,811	-	25,925,811
5	Depreciation	Adj List Pg 1, Ln. 44	23,907,431	-	23,907,431	7,922,823	31,830,254	-	31,830,254
6	Amortization of General Plant	Per Books	1,878,281	-	1,878,281	-	1,878,281	-	1,878,281
7	Amortization of Capitalized Software	Adj List Pg 1, Ln. 45	3,757,163	(97,980)	3,659,183	-	3,659,183	-	3,659,183
8	Amortization of Unrecovered Plant Loss	Per Books	100,274	-	100,274	-	100,274	-	100,274
9	Interest on Customer Deposits	Adj List Pg 1, Ln. 48	41,769	-	41,769	35,315	77,084	-	77,084
10	Interest on Supplier Refunds	Per Books	11,533	(11,533)	-	-	-	-	-
11	General Taxes	Adj List Pg 2, Ln. 7	58,992,535	-	58,992,535	4,443,796	63,436,331	-	63,436,331
12	Expenses Before Income Taxes	Sum of Lns. 3 > 11	$ 239,551,685	$ (68,318,776)	$ 171,232,910	$ 12,490,974	$ 183,723,884	$ 1,200,094	$ 184,923,978
13	Income Taxes	Adj List Pg 2, Ln. 10	5/ 3,537,493 1	1/ (3,089,477)	448,015 1	1/ 166,747	614,762 1	12,210,152	12,824,914
14	Total Operating Expenses	Sum of Lns. 12 + 13	$ 243,089,178	$ (71,408,253)	$ 171,680,925	$ 12,657,721	$ 184,338,646	$ 13,410,246	$ 197,748,892
15	Net Operating Income	Ln. 1 - Ln. 14	$ 33,815,702	$ (13,284,032)	$ 20,531,669	$ 6,757,215	$ 27,288,885	$ 32,162,165	$ 59,451,050
16	Net Income Adjustments								
17	AFUDC	Per Books	467,443	-	467,443	-	467,443	-	467,443
18	Net Operating Income - Adjusted	Sum of Ln.s 15 > 17	$ 34,283,145	$ (13,284,032)	$ 20,999,112 1	$ 6,757,215	$ 27,756,328 1	$ 32,162,165	$ 59,918,493
19	Net Rate Base	Rate Base Stmt, Ln.23	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (35,183,527)	$ 760,992,964	$ -	$ 760,992,964
20	Return Earned	Ln. 18 / Ln. 19	4.22%		2.64%		3.65%		7.87%
21	Return on Common Equity								
22	Interest Expense		$ 19,142,496	$ (330,939)	$ 18,811,557	$ (831,295)	$ 17,980,262		$ 17,980,262
23	Net Income Available for Common Equit	Ln. 18 - Ln. 22	$ 15,140,649		$ 2,187,555		$ 9,776,066		$ 41,938,231
24	Common Equity Ratio	Cost of Capital, Ln. 3	52.49%		52.49%		52.49%		52.49%
25	Common Equity Capital	Ln. 19 * Ln. 24	$ 426,291,579		$ 417,878,033		$ 399,411,746		$ 399,411,746
26	Return Earned on Common Equity	Ln. 23 / Ln. 25	3.55%		0.52%		2.45%		10.50%

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 8D & 29 - Interest on Debt (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	Distribution Amount D	Ratemaking Amount E
1	**Interest on Total Debt**				
2	Net Rate Base	Rate Base Stmt, Ln.23	$ 4,284,239,876	$ 796,176,491	$ 760,992,964
3	Weighted Average Cost of Debt	Cost of Capital, Ln. 1 + Ln. 2	2.36%	2.36%	2.36%
4	Interest on Debt	Ln. 2 * Ln. 3	$ 101,225,321	$ 18,811,557 1	$ 17,980,262 1
5	Per Books Interest Expense	Per Books	100,062,947	19,142,496	18,811,557
6	Adjustment to Interest Expense _1/	Ln. 4 - Ln. 5	$ 1,162,374	$ (330,939)	$ (831,295)

7 **Adjustment Description**: To synchronize interest expense used in determining the overall return requirement with the interest
8 expense used to calculate income taxes.

_1/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line 9:16.

CUBE tm1serv:ETR Cube
ETR Study# Study#292
ETR_Period Mar-2024

Washington Gas Light Company
ETR Calculation by Jurisdiction
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Ln.		System Basis	System Tax rate	System Taxes	DC Basis	DC Tax rate	DC Taxes	MD Basis	MD Tax rate	MD Taxes	VA Basis	VA Tax rate	VA Taxes	Ferc Basis	Ferc Tax rate	Ferc Taxes
		274,833,320			18,678,142	18,678,142		111,922,024	111,922,024		141,269,347	141,269,347		2,963,808	2,963,808	
					-			-			-			-		
1	Taxable Income Before Permanent Items	274,833,320	26.58%	73,049,193	18,678,142 5	26.58% 5	4,964,548 5	111,922,024	26.58%	29,748,262	141,269,347	26.58%	37,548,620	2,963,808	26.58%	787,764
2	Flow-Through, Permanent Items, and Other Tax Adjustments															
3	Depreciation	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
4	Cost of Removal	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
5	AFUDC Equity	-	0.02%	50,092	70,134	0.10%	18,608	118,666	0.03%	31,484	-	0.00%	-	-	0.00%	-
6	Excess Deferred	-	-2.73%	(7,509,698)	-	-5.41%	(1,010,925)	-	-3.17%	(3,551,810)	-	-2.09%	(2,946,963)	-	0.00%	-
7	Meals and Entertainment	-	0.09%	253,970	184,959	0.26%	49,073	410,911	0.10%	109,022	361,359	0.07%	95,875	-	0.00%	-
8	Medicare Part D	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
9	FAS 123 R - write off	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
10	Non-deductible executive compensation under 162(m) (Perm item, est.)	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
11	Return to Provision True-Up	-	-0.58%	(1,588,785)	(806,112)	-1.15%	(213,876)	(2,832,214)	-0.67%	(751,437)	(2,349,909)	-0.44%	(623,472)	-	0.00%	-
12	Capitalized OPEB	-	-0.02%	(60,597)	(46,113)	-0.07%	(12,235)	(182,281)	-0.04%	(48,362)	-	0.00%	-	-	0.00%	-
13	Unprotected EDIT Amortization	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
	Prior Period Flow through Income Tax															
14	Reg Asset- VA	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
15	Charitable Contributions	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
16	Parking	-	0.05%	132,115	96,216	0.14%	25,528	213,756	0.05%	56,713	187,979	0.04%	49,874	-	0.00%	-
16	R&D credits	-	-0.27%	(753,411)	-	-0.78%	(145,577)	-	-0.29%	(323,418)	-	-0.20%	(284,417)	-	0.00%	-
17	Other Tax Adjustments	-	-0.13%	(347,198)	(176,160)	-0.25%	(46,738)	(618,925)	-0.15%	(164,212)	(513,527)	-0.10%	(136,248)	-	0.00%	-
18	Total Flow-through, Permanent Items, and Other Tax Adjustments	-	-3.57%	(9,823,512)	(677,077)	-7.15%	(1,336,142)	(2,890,087)	-4.15%	(4,642,020)	(2,314,097)	-2.72%	(3,845,351)	-	0.00%	-
19	Investment Tax Credit (ITC)	-	-0.11%	(305,994)	-	-0.49%	(90,913)	-	-0.10%	(108,018)	-	-0.08%	(107,064)	-	0.00%	-
20	Total Tax & Effective tax Rate	274,833,320	22.89%	62,919,686	18,001,065	18.94%	3,537,492	109,031,937	22.34%	24,998,224	138,955,249	23.78%	33,596,205	2,963,808	26.58%	787,764

Washington Gas Light Company
District of Columbia Juris

Income Tax Proof

Twelve Months Ended March 31, 2024

Line No.	Description	Per Books Amount	Per Books Tax Rate	Per Books Taxes	Distribution Amount	Distribution Tax Rate	Distribution Taxes	Ratemaking Amount	Ratemaking Tax Rate	Ratemaking Taxes	After Required Increase Amount	After Required Increase Tax Rate	After Required Increase Taxes
	A	C	D	E	F	G	H	I	J	K	I	J	K
1	**Net Operating Income - Adjusted**	**$ 34,283,145**			**$ 20,999,112**			**$ 27,756,328**			**$ 59,918,493**		
2	Income Taxes	3,537,493			448,015			614,762			12,824,914		
3	Net Operating Income, Before Tax	37,820,638			21,447,128			28,371,090			72,743,407		
4	Less: Interest Expense	19,142,496			18,811,557			17,980,262			17,980,262		
5	**Taxable Income**	**18,678,142**			**2,635,571**			**10,390,828**			**54,763,145**		
6	Effective Tax Rate	18.94%			17.00%			5.92%			23.42%		
7	**Reconciliation of the Effective Tax Rate**												
8	Taxable Income Before Permanent Items	4/ 18,678,142	4/ 26.58%	4/ 4,964,548	2,635,571	27.52%	725,243	10,390,828	27.52%	2,859,296	54,763,145	27.52%	15,069,448
9	Flow-Through and Permanent Items												
10	AFUDC Equity	70,134	0.10%	18,608	70,134	0.73%	19,299	18,597	0.05%	5,117	18,597	0.01%	5,117
11	Meals and Entertainment	184,959	0.26%	49,073	184,959	1.93%	50,896	184,959	0.49%	50,896	184,959	0.09%	50,896
12	Compensation Limitation	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
13	Parking	96,216	0.14%	25,528	96,216	1.00%	26,476	96,216	0.25%	26,476	96,216	0.05%	26,476
14	R&D credits	-	-0.78%	(145,577)	-	0.00%	-	-	0.00%	-	-	0.00%	-
15	Amortization of Prior Flow-Through Bal (COF	-	0.00%	-	-	0.00%	-	259,549	0.69%	7/ 71,421	259,549	0.13%	71,421
16	Excess Deferred (Protected) _1/	-	-5.41%	(1,010,925)	-	0.00%	-	6/ 19,616,181	50.60%	5,257,284	19,616,181	9.60%	5,257,284
17	Excess Deferred (Unprotected) _1/	-	0.00%	-	-	0.00%	-	6/ (28,739,422)	-76.11%	(7,908,370)	(28,739,422)	-14.44%	(7,908,370)
18	Excess Deferred - FC 1027 Write Off		0.00%		-	0.00%	-	1,248,495	3.31%	8/ 343,555	1,248,495	0.63%	343,555
19	Capitalized OPEB	(46,113)	-0.07%	(12,235)	(46,113)	-0.48%	(12,689)		0.00%	-		0.00%	-
20	Return to Provision True-up	(806,112)	-1.15%	(213,876)	(806,112)	-8.42%	(221,822)		0.00%	-		0.00%	-
21	Other Tax Adjustments	(176,160)	-0.25%	(46,738)	(176,160)	-1.84%	(48,475)		0.00%	-		0.00%	-
22	Total Flow-through and Permanent Items	(677,077)	-7.15%	(1,336,142)	(677,077)	-7.07%	(186,315)	(7,315,425)	-20.73%	(2,153,621)	(7,315,425)	-3.93%	(2,153,621)
23	Investment Tax Credit (ITC)	(90,913)	-0.49%	(90,913)	(90,913)	-3.45%	(90,913)	(90,913)	-0.87%	(90,913)	(90,913)	-0.17%	(90,913)
24	Total	17,910,152	18.94%	3,537,492	1,867,581	17.00%	448,015	2,984,490	5.92%	614,762	47,356,807	23.42%	12,824,914
25	Tax Variance			-			-			-			-
26	Pre-tax Variance			-			-			-			-

Calculation of Combined Income Tax Rates	(a) Per Book		(b) Distribution		(c) Ratemaking		(d) Revenue Requirement	
Federal Income Tax Rate				21.00%		21.00%		21.00%
State Income Tax Rate			8.25%		8.25%		8.25%	
Federal Benefit of State Taxes			-1.73%		-1.73%		-1.73%	
State Income Tax Rate net of Federal Benefit				6.52%		6.52%		6.52%
Combined Tax Rate		26.58%		27.5175%		27.52%		27.52%

Notes
_1/ "Excess Deferred (Protected)" tax basis and tax amount includeds both the protected and unprotected amount for per book and distribution. Protected and unprocted excess deferred taxes are calcualted separately for ratemaking pu

Washington Gas Light Company
District of Columbia Jurisdiction

Estimate of Excess Deferred Income Taxes - Annual Revenue Requirement (Plant)

Line No.	Description	Reference	Protected Differences: Deferred Tax Liability - Plant Method/Life Differences	Protected Differences: Deferred Tax Asset - NOL	Unprotected Differences /5: Deferred Tax Liability - Plant Basis and State Differences	Unprotected Differences /5: Non-Plant ADIT	DC Amount	
	A	B	C _2/	D _3/		E _4/	F = E + D + C	
1	ADIT Balance Before Reduction in Federal Tax		(63,509,794)	7,249,611	(93,309,418)	1,088,207	(148,481,394)	
2	ADIT Balance After Reduction in Federal Tax Rate		(38,179,031)	4,349,767	(65,043,833)	652,924	(98,220,174)	
3	Change in ADIT Balance	Ln 1 - Ln 2	(25,330,763)	2,899,844	(28,265,584)	435,283	(50,261,220)	
4	Amortization Periods (Years)		_1/	15	15	15		
5	ARAM / Amortization Protected	Ln 3 / Ln 4	(5,204,560) _1/	(193,323)	7,937,389	(29,019)	2,510,488	(19,616,181) 5
7	Tax Gross Up Factor	_6/	39.10%	39.10%	39.10%	39.10%	39.10%	28,739,422 5
8	Gross Up Amount	Ln. 5 * Ln. 7	(2,035,035)	(75,591)	3,103,599	(11,347)	981,626	0
9	ARAM Currently in Rates	Tax Analysis	(169,545)				(169,545)	
10	Annual Revenue Requirement	Ln. 5 + Ln. 8 - Ln. 9	(7,070,049)	(268,914)	11,040,988	(40,366)	3,661,659	

Notes:
_1/ Representative level of amortization under the Average Rate Assumption Method (ARAM)
_2/ The balance of the deferred tax liability is estimated at 12/31/17
_3/ The balance of the deferred tax asset NOL at 09/30/17 allocated from the jurisdictional Per Book Cost of Service Study.
_4/ The balance of the non-plant ADIT at 09/30/17 allocated from the jurisdictional Per Book Cost of Service Study.
_5/ Unprotected plant difference amortized over 29 year average remianing service life of plant as the PSC adopted in Order No. 18712.
_6/ Tax Gross Up Factor Calculation:

A	New Statutory Rate	28.1100%
B = (1-A)		71.8900%
C	Gross Up Factor (Tax)	39.1010%

New Statutory Combined Rate

	Revised Rate Calc.
Statutory Rate - State	9.0000%
Statutory Rate - Federal	21.000%
Statutory Rate - Federal Benefit of State Tax	(0.0189)
Revised Statutory Tax Rate - Total	28.1100%

	DC FY17 End of Period Amount	
Balance of Flowthrough Taxes at 9/30/17	$	1,071,321
Average Remaining Service Life		15
Amortization	$	71,421 5
Tax Gross-up		71.890%
Amortization Revenue Requirement	$	99,348
Replace Existing Flowthroughs	$	124,715.25
Grossed-up To Revenue Requirement	$	173,480.67
Net Change for Going to Full Normalization	$	(74,132.51)

Washington Gas Light Company
District of Columbia
FC 1027 Impairment amortization write off

	EDIT @ 1/1/2018	W/O EDIT - 1027 Impairment	Amortization for the W/O
DC/CM EDIT at 1/1/2018 p/Jurisdictional Exhibits			15 years
Federal Unprotected	27,146,225.89	(4,860,918.03)	
VA Unprotected	(812,296.97)	50,696.31	
MD Unprotected	559,440.66	(106,728.52)	
DC Unprotected	1,597,905.54	(159,705.66)	
WV Unprotected	380,834.59	5,604.27	
PA Unprotected	(629,706.81)	(81,790.51)	
NY Unprotected	23,181.40	(478.00)	
Total Unprotected	28,265,584.29	(5,153,320.15)	(343,554.68) 5

Adjustment No. 1

District of Columbia Jurisdiction

Adjustment No. 1 - Ratemaking Revenues and Related Expenses Summary

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Book Amount C	Distribution Adjustments D	Distribution-Only Amount E = C + D	Ratemaking Adjustments F	Ratemaking Amount 2/ G = E + F
1	**Operating Revenues**						
2	Base Revenues						
3	Base Rate Revenues (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	3/ $ 127,731,965	$ -	$ 127,731,965	$ 18,877,467	5/ $ 146,609,432
4	Distribution Charge & Plant Recovery Adjustments	Rev WP 1 + Adj 1 WP 7	(8,444,784)	-	(8,444,784)	8,444,784	-
5	Peak Usage Charge	Rev WP 1 + Adj 1 WP 7	4,254,611	-	4,254,611	229,056	4,483,667
6	Fuel Revenues _1/	Rev WP 1 + Adjs 1D, 2D, 4D	69,417,982	A/ (69,417,982)	-	-	-
7	Revenue Taxes						
8	DC Right of Way Tax (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	12,367,741	-	12,367,741	(2,457,862)	9,909,879
9	Delivery Tax (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	19,243,088	-	19,243,088	1,978,792	21,221,880
10	Sustainable Energy Trust Fund (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	16,438,143	-	16,438,143	4,900,753	21,338,896
11	Energy Assistance Trust Fund (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	2,109,146	-	2,109,146	257,838	2,366,984
12	Non-District of Columbia Tariff Rates & Revenue Taxes	Rev WP 1 + Adj 1 WP 7	(50,138)	-	(50,138)	50,138	-
13	Off-System Sales Revenue (Asset Optimization)	Rev WP 1 + Adj 5D	14,177,234	B/ (14,177,234)	-		-
14	PROJECTpipes	Rev WP 1 + Adj 1 WP 7	13,157,184	-	13,157,184	(13,157,184)	-
15	Sales of Gas to Customers (excl. CNG customers)	Sum Lns. 2 to 14	$ 270,402,172	$ (83,595,216)	$ 186,806,956	$ 19,123,782	$ 205,930,738
16	Late Payment Fees	Rev WP 1 + Adj 7D + Adj 1 WP 8	3/ 3,605,596	C/ (360,143)	28/ 3,245,453	28/ 332,243	3,577,696
17	Other Operating Revenues	Adj No. 1, Page 2, Line 40	2/ 2,897,112	(736,920)	2,160,192	(41,088)	2,119,103
18	**Total Operating Revenues (RV 1:35)**	**Sum Lns. 15 to 17**	**$ 276,904,880**	**$ (84,692,279)**	**$ 192,212,601**	**$ 19,414,936**	**$ 211,627,537**
19	**Revenue Related Expenses**						
20	Uncollectible Accounts Expense	EX 7:19 + Adj 2D + Adj 1 WP 9	32/ $ 6,226,265	$ (1,694,830)	$ 4,531,435	$ 1,038,168	$ 5,569,603
21	Delivery Tax Expense Expense (excl. PSC assessment)	EX 8:8 + Adj 1 WP 10	34/ 18,979,968	-	18,979,968	2,241,912	21,221,880
22	Rights of Way Fee Expense	EX 8:9 + Adj 1 WP 11	36/ 12,518,268	-	12,518,268	(2,608,389)	9,909,879
23	Sustainable Energy Trust Fund	EX 8:17 + Adj 1 WP 12	37/ 16,761,017	-	16,761,017	4,577,879	21,338,896
24	Energy Assistance Trust Fund Fee	EX 8:17 + Adj 2 WP 13	38/ 2,156,914	-	2,156,914	210,070	2,366,984
25	**Total Revenue Related Expenses**	**Sum Lns. 20 to 24**	**$ 56,642,432**	**$ (1,694,830)**	**$ 54,947,602**	**$ 5,459,640**	**$ 60,407,242**

26 **Adjustment Description:** To adjust Operating Revenues to a Ratemaking basis.

1/ Includes purchased gas costs, storage gas, ACA carrying costs, and gas administrative charge.
2/ Special contracts are shown within amount shown. For further detail, see the Revenue by Class tab.

A/ See Exhibit WG (D)-5 Adustment 1D, 2D and 4D
B/ See Exhibit WG (D)-5 Adjustment 5D
C/ See Exhibit WG (D)-5 Adjustment 7D

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 - Other Operating Revenues Breakout

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Book Amount C	Distribution Adjustments D	Distribution-Only Amount E = C + D	Ratemaking Adjustments F	Ratemaking Amount _3/ G = E + F
27	**Other Operating Revenues**						
28	Miscellaneous Service Revenues						
29	Reconnect Revenues	RV 1:19	$ 4/ 174,354	$ -	$ 174,354	$ -	$ 174,354
30	Reconnect Revenue Premium	RV 1:20	-	-	-	-	-
31	Dishonored Check Charge	RV 1:21	44,740	-	44,740	-	44,740
32	Service Initiation Charge	RV 1:22	838,570	-	838,570	-	838,570
33	Field Collection Charge	RV 1:23	433	-	433	-	433
34	IRATE Non-Compliance Meter Charge	RV 1:24	-	-	-	-	-
35	Other Miscellaneous Revenues						
36	Rents	RV 1:17 + Adj 1 WP 5	$ 139,688	$ -	$ 139,688	$ 29/ (41,088)	$ 98,600
37	CNG Sales for Natural Gas Vehicles _3/	RV 1:28	847,959	-	847,959	-	847,959
38	Other Gas Revenues (POR)	RV 1:32 + Adj 7D	736,920	A/ (736,920)	-	-	-
39	Third Party Billing	RV 1:33	114,447	-	114,447	-	114,447
40	**Total Other Operating Revenues**	**Sum Lns. 29 to 38**	**$ 2,897,112**	**$ (736,920)**	**$ 2,160,192**	**$ (41,088)**	**$ 2,119,103**

3/ For purposes of this adjustment, all components of CNG revenues (distribution revenues plus revenue taxes) are reflected in the Other Operating Revenues line. There are no ratemaking adjustments for CNG revenues or related expense.

A/ see Exhibit WG (D)-5 Adjustment 7D

Washington Gas Light Company
System

Adjustment No. 1 Workpaper No. 1 (Per Books Operating Revenues Breakout)

For the Twelve Months Ending March 31, 2024

Sum of A: 2,897,112 1
4/ Sum of B: 256,224,938
Sum of C: 69,417,982 1
Sum of D: (8,444,784) 1

4/ Sum of E: 847,959

Line No.	Description	Total Company Per Books	District of Columbia Cost of Service	Maryland Cost of Service	Virginia Cost of Service	FERC Cost of Service
	A	B = C + D + E + F	C	D	E	F
1	Operating Revenues					
2	Base Rate Revenues	$ 788,759,276	B $ 127,731,965 1	$ 305,968,937	$ 355,058,374	$ -
3	Base Rate Revenues (CNG)	$ 238,504	$ E 238,504 A			
4	Fuel Revenues	467,182,919	B 66,086,221 C	205,996,308	195,100,390	-
5	ORB Fuel Revenues - GAC	6,377,116	1,772,997	2,073,512	2,530,607	
6	ORB Fuel Revenues - Storage Gas	9,106,816	1,311,889	3,886,024	3,908,903	
7	ORB Fuel Revenues - ACA Carrying Costs	88,313	246,874	-	(158,561)	
8	Delivery Tax	19,243,088	19,243,088 1	-	-	-
9	Delivery Tax (CNG)	247,305	E 247,305 A			
10	Distribution Charge Adjustment	(8,444,750)	B (8,444,750) D	-	-	-
11	PROJECT*pipes*	13,157,184	13,157,184 1	-	-	-
12	Plant Recovery Adjustment	(34)	(34) D	-	-	-
13	Energy Assistance Trust Fund	2,109,146	2,109,146 1	-	-	-
14	Energy Assistance Trust Fund (CNG)	26,508	E 26,508 A			
15	Sustainable Energy Trust Fund	16,438,143	B 16,438,143 1	-	-	-
16	Sustainable Energy Trust Fund (CNG)	185,126	E 185,126 A			
17	Residential Essential Credit	0	0	-	-	-
18	DC Right of Way Tax	12,367,741	B 12,367,741 1	-	-	-
19	DC Right of Way Tax (CNG)	150,517	E 150,517 A			
20	Peak Usage Charge	4,254,611	B 4,254,611 1	-	-	-
21	Miscellaneous Charges	-		-	-	-
22	PGC Fuel Tax	-	-	-	-	-
23	STRIDE Surcharge	13,920,336	-	13,920,336	-	-
24	PSC Assessment	803,250	-	803,250	-	-
25	Therms Delivered Tax	2,871,363	-	2,871,363	-	-
26	Montgomery County Fuel Energy Charge	43,690,244	-	43,690,244	-	-
27	Revenue Normalization Adjustment	38,482,173	-	38,482,173	-	-
28	EMPOWER Surcharge	15,056,515	-	15,056,515	-	-
29	Interruptible Rate Adjustment	(1,411,585)	-	(1,411,585)	-	-
30	Firm Credit Adjustment	(591,021)	-	(591,021)	-	-
31	SAVE - Current Portion	12,084,052	-	-	12,084,052	-
32	SAVE - Reconciliation	(622,986)	-	-	(622,986)	-
33	CARE - CRA	38,838,326	-	-	38,838,326	-
34	CARE - Care Cost Adjustment	4,364,473	-	-	4,364,473	-
35	Weather Normalization Adjustment	(222,979)	-	-	(222,979)	-
36	Non-District of Columbia Jurisdictional Tariff Rates & Revenue Taxes	(50,138)	B (50,138) 1	-	-	-
37	Non-Maryland Jurisdictional Tariff Rates & Revenue Taxes	(7,089)	-	(7,089)	-	-
38	Non-Virginia Jurisdictional Tariff Rates & Revenue Taxes	2	-	-	2	-
39	Off-System Sales Revenue (Asset Optimization)	86,111,467	4/ 14,177,234 1	38,508,187	33,426,045	-
40	Chalkpoint and Panda Brandywine Revenues	1,000,188	-	1,000,188	-	-
41	Watergate Revenues	-	-	-	-	-
42	Mountaineer Revenues	3,332,837	-	-	-	3,332,837
43	WSSC Demand Revenue	586,938	-	586,938	-	-
44	Late Payment Fees	11,932,504	4/ 3,605,596 1	4,550,847	3,776,061	-
45	Other Operating Revenues	7,059,435	4/ 2,049,153 A	2,556,969	2,453,314	-
46	Total Operating Revenues	$ 1,608,715,831	$ 276,904,880	$ 677,942,095	$ 650,536,019	$ 3,332,837

Exhibit WG (D)-5
Adjustment No. 1

Washington Gas Light Company
Revenues
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Reference Sc-Pg-Ln	Reference Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operating Revenues**							
2	Sales of Gas and Transportation to Customers							
3	Residential		Financial Stmt.	$ 917,499,221	B $ 114,679,781	$ 387,260,842	$ 415,558,598	$ -
4	Commercial and Industrial other than Group Metered Apts		Financial Stmt.	185,406,991	45,038,920	68,772,040	71,596,030	-
5	Group Metered Apartments		Financial Stmt.	37,945,816	16,671,589	10,825,850	10,448,377	-
6	Commercial and Industrial - Interruptible		Financial Stmt.	2,467,672	1,970,320	414,562	82,789	-
7	Transportation Sales / Mountaineer		Financial Stmt.	313,468,665	78,440,325	136,629,702	95,065,801	3,332,837
8	WSSC Revenues			586,938		586,938		-
9	Total Heating/Cooling and Other Uses	=3>7		$ 1,457,375,303	$ 256,800,936	$ 604,489,935	$ 592,751,595	$ 3,332,837
10	Rate Adjustment due Customers		Financial Stmt.	(1,841,180)	B (268,728)	(805,138)	(767,313)	-
11	Unbilled Gas Accrual/Reversal		Financial Stmt.	(6,749,446)	(6,782,977)	446,100	(412,569)	-
12	Provision for Rate Refunds		Financial Stmt.	3,798,715	-	2,211,388	1,587,327	-
13	Total Gas Sales & Transportation Revenues	=8 > 11		$ 1,452,583,392	$ 249,749,231	$ 606,342,285	$ 593,159,040	$ 3,332,837
14	Other Operating Revenues							
15	Forfeited Discounts (Non POR)		Financial Stmt.	11,349,728	A 3,245,453 28	4,328,263	3,776,011	-
16	Forfeited Discounts (POR)		Financial Stmt.	582,776	A 360,143	222,583	50	-
17	Rent from Gas Property		Annual Firm_ ACT	967,406	C 139,688 2	416,107.68	411,610.20	-
18	Miscellaneous Service Revenues							
19	Reconnect Revenues		Financial Stmt.	847,711	174,354 2	568,927	104,430	-
20	Reconnect Revenues - Premium		Financial Stmt.	(234)	-	(234)	-	-
21	Dishonored Check Charge		Financial Stmt.	647,108	44,740 2	303,282	299,086	-
22	Service Initiation Charge		Financial Stmt.	3,947,838	838,570	1,816,987	1,292,280	-
23	Field Collection Charge		Financial Stmt.	4,951	433	3,528	990	-
24	IRATE Non Compliance MTR. Charge		Financial Stmt.	-	-	-	-	-
25	Other Gas Revenues							
26	Watergate Revenues		Financial Stmt.	-	-	-	-	-
27	Third Party Balancing Charges		Financial Stmt.	50,236,702	B 6,609,061	25,841,472	17,786,168	-
28	CNG Sales for Natural Gas Vehicles		Financial Stmt.	1,934,788	847,959 2	3 606,779	480,050	-
29	Off System Sales Revenue Net of Gas Cost		EX:3:2	86,111,467	14,177,234 3	38,508,187	33,426,045	-
30	Miscellaneous							
31	Other Allocable Miscellaneous		Financial Stmt.	(2,331,859)	B (133,354)	(1,653,845)	(544,660)	-
32	Oth Gas Rev - MD RM-35		Financial Stmt.	1,374,694	C 736,920 2	637,773	-	-
33	Third Party Billing		Financial Stmt.	459,364	C 114,447	-	344,917	-
34	Total Other Operating Revenues	=14>32		$ 156,132,439	$ 27,155,649	$ 71,599,810	$ 57,376,979	$ -
35	Total Operating Revenues	=13+34		$ 1,608,715,831	$ 276,904,880 3	$ 677,942,095	$ 650,536,019	$ 3,332,837

Sum of A: 3,605,596 3
Sum of B: 256,224,938
Sum of C: 2,049,153

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment 1 Workpaper 7 - Ratemaking Revenues

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Total DC C=D...M	Residential Htg/Clg D	Residential Non-htg-IMA E	Residential Non-htg-Other F	Commercial & Industrial H/C < 3075 G	Commercial & Industrial H/C > 3075 H	Commercial & Industrial CHP I	Commercial & Industrial Non-htg J	Group Metered Apartments H/C < 3075 K	Group Metered Apartments H/C >3075 L	Group Metered Apartments Non-htg M	Non-Firm N	Special Contracts O
1	Normal Weather Therms	Norm Wthr 1/	6/ 283,950,711	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	999,179	29,674,103	3,929,848	39,648,220	7/ 38,220,735
2	Distribution Charge Revenues		16 36 37 38												
3	Distribution Charges	DC Tariff		$ 8/ 0.5638	$ 0.6610	$ 0.6390	$ 9/ 0.5821	$ 11/ 0.4796	$ 0.1033	$ 9/ 0.4811	$ 10/ 0.4930	$ 0.4863	$ 0.4841	$ -	4/
4	Distribution Charge Revenues	Line 1 x Line 3	A $ 110,323,147	$ 47,806,387	$ 447,907	$ 1,088,558	$ 3,106,166	$ 33,022,572	$ 217,037	$ 3,854,925	$ 492,595	$ 14,430,516	$ 1,902,440	$ -	$ 3,954,044
5	Customer Charge Revenues														
6	Customer Bills or Units	Analysis 3/	6/ 1,957,520	1,627,379	131,084	42,794	53,982	40,679	12	22,135	7,177	20,485	10,430	1,327	36
7	Customer Charges	DC Tariff		$ 8/ 16.55	$ 12.00	$ 13.55	$ 9/ 29.90	$ 70.05	$ 11/ 343.75	$ 9/ 28.50	$ 12/ 28.50	$ 70.05	$ 28.50	$ 14/ 121.00	$ 121.00
8	Customer Charge Revenues	Line 6 x Line 7	A $ 36,286,285	$ 26,933,122	$ 1,573,008	$ 579,859	$ 1,614,062	$ 2,849,564	$ 4,125	$ 630,848	$ 204,545	$ 1,434,974	$ 297,255	$ 160,567	$ 4,356
9	Peak Usage Charge Revenues														
10	Therms from Maximum Usage Month	Norm Wthr 1/	15/ 16,621,656	N/A	N/A	N/A	15/ 785,545	9,533,168	280,694	1,166,597	115,023	4,209,429	531,201	N/A	-
11	Peak Usage Charge per Therm	DC Tariff		$ -	$ -	$ -	$ 9/ 0.0519	$ 0.0421	$ 11/ 0.0904	$ 9/ 0.0423	$ 10/ 0.0431	$ 0.0422	$ 0.0423	$ -	$ -
12	November through April Charge	6 Months		-	-	-	6	6	12	6	6	6	6	-	6
13	Peak Usage Charge Revenues	Line 10 x Line 11 x Line 12	$ 4,483,667 1	$ -	$ -	$ -	$ 244,619	$ 2,408,078	$ 304,497	$ 296,082	$ 29,745	$ 1,065,827	$ 134,819	$ -	$ -
14	Total Base Rate Revenues	Sum of Lines 4, 8, and 13	$ 151,093,099	$ 74,739,509	$ 2,020,915	$ 1,668,417	$ 4,964,847	$ 38,280,214	$ 525,659	$ 4,781,855	$ 726,885	$ 16,931,317	$ 2,334,514	$ 160,567	$ 3,958,400
15	DC Rights of Way Fee Revenues														
16	DC Rights of Way Fee per Therm	Analysis		$ 16/ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349
17	DC Rights of Way Fee Revenues	Line 1 x Line 16	$ 9,909,879 1	$ 2,959,281	$ 23,649	$ 59,453	$ 186,231	$ 2,403,019	$ 73,326	$ 279,644	$ 34,871	$ 1,035,626	$ 137,152	$ 1,383,723	$ 1,333,904
18	Delivery Tax Revenues														
19	Delivery Tax Rate Per Therm			$ 18/ 0.07070	$ 0.07070	$ 0.07070	$ 0.07777	$ 0.07777	$ 0.07777	$ 0.07777	$ 0.07070	$ 0.07070	$ 0.07070	$ 0.07777	$ 0.07777
20	Delivery Tax Revenues	Line 1 x Line 19	$ 21,221,880 1	$ 5,994,877	$ 47,908	$ 120,440	$ 414,991	$ 5,354,807	$ 163,397	$ 623,150	$ 70,642	$ 2,097,959	$ 277,840	$ 3,083,442	$ 2,972,427
21	Sustainable Energy Trust Fund Revenues														
22	Sustainable Energy Trust Fund Rate Per Therm			$ 18/ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515
23	Sustainable Energy Trust Fund Revenues	Line 1 x Line 22	$ 21,338,896 1	$ 6,372,206	$ 50,923	$ 128,021	$ 401,011	$ 5,174,408	$ 157,893	$ 602,157	$ 75,088	$ 2,230,009	$ 295,328	$ 2,979,564	$ 2,872,288
24	Energy Assistance Trust Fund Revenues														
25	Energy Assistance Trust Fund Rate Per Therm			$ 18/ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834
26	Energy Assistance Trust Fund Revenues	Line 1 x Line 25	$ 2,366,984 1	$ 706,827	$ 5,649	$ 14,200	$ 44,482	$ 573,963	$ 17,514	$ 66,793	$ 8,329	$ 247,360	$ 32,759	$ 330,504	$ 318,604
27	Total Non-gas Revenues	Sum of Lines 14, 17, 20, 23, and 26	$ 205,930,738 1 28 32	$ 90,772,700	$ 2,149,044	$ 1,990,531	$ 6,011,562	$ 51,786,411	$ 937,789	$ 6,353,599	$ 915,815	$ 22,542,271	$ 3,077,593	$ 7,937,800	$ 11,455,623
28	Purchased Gas Charge Revenues	2/													
29	Purchased Gas Charge	Page 23, Line 12 DC Rev by Class,		$ 19/ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ -	$ 0.6018
30	Purchased Gas Charge Revenues	Line 20 x Line 29	$ 73,743,790	$ 44,727,004	$ 359,630	$ 888,042	$ 2,624,191	$ 15,630,650	$ -	$ 1,983,757	$ 404,664	$ 6,187,304	$ 938,548	$ -	$ -
31	Total Sales/Delivery of Gas Revenues	Line 27 + Line 30	$ 279,674,528	$ 135,499,704	$ 2,508,674	$ 2,878,573	$ 8,635,753	$ 67,417,061	$ 937,789	$ 8,337,356	$ 1,320,479	$ 28,729,575	$ 4,016,141	$ 7,937,800	$ 11,455,623

1/ Amounts referenced as "Norm Wthr" come from the Normal Weather Study.
2/ Purchased gas revenues are not carried forward for ratemaking purposes.
3/ Amounts referenced as "Norm Wthr" come from the Normal Weather Study and are the meter totals for the referenced period.
4/ Includes AOC distribution revenues only. GSA revenues are returned to customers through the DCA and are excluded from this calcualtion. See the revenue support workpaper #2 for further detail regarding contractual rates charged to special contract customers.

Sum of A: 149,609,432 1

Exhibit WG (D)-5
Adjustment No. 1
Page 5 of 46

Washington Gas Light Company
District of Columbia Jurisdiction

Summary of Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Class Of Service	Meters	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual a/	Therm Sales: Weather Gas: Normal Weather b/	Therm Sales: Weather Adjustment	Therm Sales: Base Gas c/	Therm Sales: Total
	A	B	C	D	E	F	G	H=G-F	I	J=H+I
1	Residential									
2	Heating and Cooling	1,627,379	3,187	3,729	0.1397740	60,453,429	70,729,615	10,276,186	14,063,551	84,793,166
3	Non Heating and Non Cooling - IMA's	131,084	3,187	3,729	0.0076190	264,394	309,352	44,958	368,268	677,620
4	Non Heating and Non Cooling	42,794	3,187	3,729	0.0965330	1,100,079	1,287,100	187,021	416,434	1,703,534
5	Total - Residential	1,801,257				61,817,902	72,326,067	10,508,165	14,848,253	B 87,174,320
6										
7	Commercial and Industrial									
8	Heating and Cooling									
9	Less than 3075	53,982	3,187	3,729	0.2397700	3,467,503	4,057,018	589,515	1,279,120	5,336,138
10	More than 3075	40,679	3,187	3,729	3.0813470	33,508,268	39,197,035	5,688,767	29,657,369	68,854,404
11	Non Heating and Non Cooling	22,135	3,187	3,729	0.3998460	2,346,071	2,745,262	399,191	5,267,470	8,012,732
12	CHP	12	3,187	3,729	302.4376000	963,870	1,127,791	163,921	973,241	2,101,032
13	Total - Commercial and Industrial	116,808				40,285,712	47,127,106	6,841,394	37,177,200	C 84,304,306
14										
15	Group Metered Apartments									
16	Heating and Cooling									
17	Less than 3075	7,177	3,187	3,729	0.2524320	484,154	566,702	82,548	432,477	999,179
18	More than 3075	20,485	3,187	3,729	3.2184570	17,517,359	20,493,631	2,976,272	9,180,472	29,674,103
19	Non Heating and Non Cooling	10,430	3,187	3,729	0.4780260	1,326,063	1,551,590	225,527	2,378,258	3,929,848
20	Total - Group Metered Apartments	38,092				19,327,576	22,611,923	3,284,347	11,991,207	D 34,603,130
21										
22	Total Firm	1,956,157				121,431,190	142,065,096	20,633,906	64,016,660	206,081,756
23	Interruptible	1,327	3,187	3,729	38.56989	13,597,776	15,911,005	2,313,229	23,916,786	A 39,827,791
24	Special Contracts	36	3,187	3,729	d/	9,297,721	10,878,939	1,581,218	27,341,796	38,220,735
25	Total Throughput	1,957,520				144,326,687	168,855,040	24,528,353	115,275,242	284,130,282
		163,127								

a/ Schedule 2B, Column F
b/ Schedule 2B, Column G
c/ Schedule 2B, Column I
d/ Schedule 2B for noted classes

A 39,827,791
39/ (179,571)
39,648,220 5

B 87,174,320
C 84,304,306
D 34,603,130
A 39,827,791
39/ (179,571)
7/ 38,220,735
283,950,711 5

District of Columbia Jurisdiction

Adjustment No. 1 - Workpaper No. 4 (Special Contract Revenues)

For the Twelve Months Ending March 31, 2024

Line No.	Period	Total Normal Weather Therms b/	Total Special Contract Revenues
	A	B	C
1	Mar-2024	4,128,107	$ 862,786
2	Feb-2024	4,644,485	968,112
3	Jan-2024	4,504,450	939,549
4	Dec-2023	3,888,881	813,991
5	Nov-2023	3,118,690	656,894
6	Oct-2023	2,415,600	513,484
7	Sep-2023	2,278,483	421,419
8	Aug-2023	2,278,483	421,419
9	Jul-2023	2,278,483	421,419
10	Jun-2023	2,380,592	439,282
11	May-2023	2,815,282	595,007
12	Apr-2023	3,489,199	732,467
13	Total	38,220,735	$ 7,785,830

5 6

a/ See supplemental schedules for Special Contracts 1 & 2
b/ Normal Weather Study, Schedule 1B, Column E for Special Cor
NOTE: All rates included within this workpaper are contractual.

WASHINGTON GAS LIGHT COMPANY
Residential Service
Rate Schedule No. 1

AVAILABILITY
This schedule is available in the District of Columbia portion of the Company's service area for firm gas service to any customers classified residential as defined in Section 1A. of the General Service Provisions, subject to the provision for Emergency or Stand-by Service included herein.

RATE FOR MONTHLY CONSUMPTION

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

Heating and/or Cooling
All billing months — $16.55 per customer S

Non-Heating and Non-Cooling
All billing months
(a) Individually Metered Apartment — $12.00 per customer S
(b) Other — $13.55 per customer S

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

Heating and/or Cooling
All gas delivered during the billing month — 56.38 ¢ per therm S

Non-Heating and Non-Cooling
All gas delivered during the billing month

(a) Individually Metered Apartment — 66.10 ¢ per therm S
(b) Other — 63.90 ¢ per therm S

Purchased Gas Charge
The "purchased gas charge" is the amount the Company charges for each therm of gas consumed by the customer. Such charge is a measure of the costs of the Company to purchase gas to be distributed to the customer for use at the customer's premises.

The gas consumed under this schedule shall be billed an amount per therm representing the average unit cost of purchased gas in accordance with Section 16 of the General Service Provisions.

DISTRIBUTION CHARGE ADJUSTMENT
The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

GAS SUPPLY REALIGNMENT ADJUSTMENT
The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Firm Commercial and Industrial Delivery Service
Rate Schedule No. 2A (continued)

Heating and/or Cooling
All billing months

(a) Normal Weather Annual Usage less than 3,075 therms — $29.90 per customer 5

(b) Normal Weather Annual Usage 3,075 therms or more — $70.05 per customer 5

Non-Heating and Non-Cooling — $28.50 per customer 5
All billing months/all customers

Peak Usage Charge
"Peak usage" is a measure of the amount of gas delivered to the customer for which the Company must incur substantial costs for investment, operation and maintenance of gas distribution facilities, and additional distribution facilities to accommodate customers' increased gas deliveries. Increased usage or decreased usage by a customer has a corresponding increase or decrease on the Company's costs and therefore on the level of the "peak usage charge" the Company must bill a customer.

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced during the current November – April billing period. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. The rate is:

Billing Months of November - April inclusive:

(a) Normal Weather Annual Usage Less than 3,075 therms — 5.19 ¢ per therm of maximum months usage 5

(b) Normal Weather Annual Usage 3,075 therms of more — 4.21 ¢ per therm of maximum months usage 5

(c) Non-Heating and Non-Cooling — 4.23 ¢ per therm of maximum months usage 5

Distribution Charge
The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

All gas delivered during the billing month
Heating and/or Cooling

(a) Normal Weather Annual Usage Less than 3,075 therms — 58.21¢ per therm 5

(b) Normal Weather Annual Usage 3,075 therms or more — 47.96¢ per therm 5

Non-Heating and Non-Cooling — 48.11¢ per therm 5

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Firm Group Metered Apartment Sales Service - Rate Schedule No. 3
(continued)

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced during the current November - April billing period. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. During the initial application of the Peak Usage Charge, November 1994 through April 1995, customers shall be deemed to have commenced service subsequent to April 1994 for purposes of establishing the maximum billing month's usage. The rate is:

Billing Months of November - April inclusive:

(a) Normal Weather Annual Usage Less than 3,075 therms	4.31 ¢ per therm of maximum months usage 5
(b) Normal Weather Annual Usage 3,075 therms of more	4.22 ¢ per therm of maximum months usage 5
(c) Non-Heating and Non-Cooling	4.23 ¢ per therm of maximum months usage 5

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

All gas delivered during the billing month

Heating and/or Cooling

(a) Normal Weather Annual Usage less than 3,075 therms	49.30¢ per therm 5
(b) Normal Weather Annual Usage 3,075 therms or more	A 48.63¢ per therm 5
Non-Heating and Non-Cooling	48.41¢ per therm 5

Purchased Gas Charge

The "purchased gas charge" is the amount the Company charges for each therm of gas consumed by the customer. Such charge is a measure of the costs of the Company to purchase gas to be distributed to the customer for use at the customer's premises.

The gas consumed under this schedule shall be billed an amount per therm representing the average unit cost of purchased gas in accordance with Section 16 of the General Service Provisions.

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Delivery Service For Combined Heat and Power/Distributed Generation Facilities
Rate Schedule No. 7 (continued)

RATE FOR MONTHLY DELIVERIES

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

All billing months/all customers $343.75 per customer ⑤

Peak Usage Charge

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced as of the current billing month. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. The rate is:

All billing months/all customers 9.04¢ per therm of maximum months usage ⑤

Volumetric Charge

All gas delivered during the billing month 10.33¢ per therm ⑤

The rates discussed above shall be in addition to the following:

Transitional Cost Charge

A charge per therm shall be billed for all therms delivered during the billing month to recover Company supplier transitional costs which shall be equal to the amount per therm included in the calculation of the current months' Purchased Gas Charge as set forth in General Service Provision No. 16.

TERMS AND CONDITIONS

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

DELIVERY TAX CHARGE

All customer gas consumption under this rate schedule shall also be billed an amount per therm for District of Columbia Delivery Tax in accordance with the applicable sections of the District of Columbia Official Code.

WASHINGTON GAS LIGHT COMPANY

Firm Commercial and Industrial Sales Service

Rate Schedule No. 2

AVAILABILITY

This schedule is available in the District of Columbia portion of the Company's service area for firm gas service to any customer classified as Commercial and Industrial as defined in Section 1A of the General Service Provisions, subject to the provision for Emergency or Stand-by Service included herein.

RATE FOR MONTHLY CONSUMPTION

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

Heating and/or Cooling

All billing months:

(a)	Normal Weather Annual Usage less than 3,075 therms	$29.90 per customer 5
(b)	Normal Weather Annual Usage 3,075 therms or more	$70.05 per customer 5

Applicability of (a) or (b) shall be determined each year in accordance with Section 1A. of the General Service Provisions.

Non-Heating and Non-Cooling

All billing months/all customers $28.50 per customer 5

Peak Usage Charge

"Peak usage" is a measure of the amount of gas delivered to the customer for which the Company must incur substantial costs for investment, operation and maintenance of gas distribution facilities, and additional distribution facilities to accommodate customers' increased gas deliveries. Increased usage or decreased usage by a customer has a corresponding increase or decrease on the Company's costs and therefore on the level of the "peak usage charge" the Company must bill a customer.

Delivery Service For Combined Heat and Power/Distributed Generation Facilities
Rate Schedule No. 7 (continued)

RATE FOR MONTHLY DELIVERIES

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

All billing months/all customers — $343.75 per customer 5

Peak Usage Charge

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced as of the current billing month. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. The rate is:

All billing months/all customers — 9.04¢ per therm of maximum months usage

Volumetric Charge

All gas delivered during the billing month — 10.33¢ per therm

The rates discussed above shall be in addition to the following:

Transitional Cost Charge

A charge per therm shall be billed for all therms delivered during the billing month to recover Company supplier transitional costs which shall be equal to the amount per therm included in the calculation of the current months' Purchased Gas Charge as set forth in General Service Provision No. 16.

TERMS AND CONDITIONS

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

DELIVERY TAX CHARGE

All customer gas consumption under this rate schedule shall also be billed an amount per therm for District of Columbia Delivery Tax in accordance with the applicable sections of the District of Columbia Official Code.

Interruptible Delivery Service - Rate Schedule No. 6
(continued)

RATE FOR MONTHLY USAGE

Customer Charge

(All billing months)	$121.00 per customer 5

Delivery Charge (Per therm)

All gas delivered during the billing month:

First 75,000 therms	20.94¢
Over 75,000 therms	19.32¢

Large volume customers with existing contracts are excluded from these rates.

Transitional Cost Surcharge

A surcharge of $.0025 per therm for all therms delivered shall be billed in addition to the above charges for monthly deliveries. However, in no event shall such charge exceed the average cost per therm included in the Purchased Gas Charge (PGC) factor.

POSTING

Customers taking service under this rate schedule may have access to the Company's Electronic Bulletin Board (see Information Services). The charge for access is included in the Customer Charge.

Monthly rates (Delivery Charge) for service shall be posted via the Electronic Bulletin Board the day before the earliest nomination deadline of the Company's interstate pipelines each calendar month.

MINIMUM MONTHLY BILL

The minimum monthly bill shall be the Customer Charge, the applicable Transitional Cost Surcharge plus the following as applicable:

Customers with annual usage greater than 250,000 therms:	$2,200
All others:	$ 225

DELIVERY TAX CHARGE

For bills rendered on and after December 2, 2005, all customer gas consumption under this rate schedule shall also be billed an amount per therm for District of Columbia Delivery Tax in accordance with the applicable sections of the District of Columbia Official Code. This charge replaces the Gross Receipts Tax Charge that was based on the effective tax rate along with the billing of revenues to which it applied.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 - Workpaper No. 1 (Peak Usage Therms Billed)

As Billed in November 2023

Line No.	Rate Category	System Level	Total Peak Usage Therms	Average Peak Usage Therms
1	C&I - Heating/Cooling	1	785,545 5	168
2	C&I - Heating/Cooling	2	9,533,168	2,818
3	C&I - CHP	1	280,694	280,694
4	C&I - Non-H/C		1,166,597	605
5	GMA - Heating/Cooling	1	115,023	185
6	GMA - Heating/Cooling	2	4,209,429	2,595
7	GMA - Non-H/C		531,201	603
8	**Grand Total**		**16,621,656**	**1,267**

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 - Workpaper No. 3 (Rights of Way Revenue Charge)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	DC Rights of Way Payment (Q2 CY 2024)	Analysis	$ 17/ 2,474,375
2	Annualized ROW Payment	Line 1 * 4	$ 9,897,499.84
3	Normal Weather Therms (Mar-2024 T12)	Revenue Study (Adj 1 WP 7, Column C, Line 1)	5/ 283,950,711
4	Calculated DC Rights of Way Revenue Charge	Line 2 / Line 3	$ 0.0349 5

NOTE: DC ROW Revenue Charge has been rounded to four decimal points for billing purposes. As a result, the annualized ROW payment (line 2) line will vary slightly from the Revenue Study due to rounding. This rounding differential will be caught up in future rates.

\\spwsvfil001\Finance\Regulatory Accounting\01. COS Production Environment\Quarterly Updates\District of Columbia\2024-03 Mar\[DC Adj 1 WP 3 - DC Rights of Way Fee Calculation Mar-2024.xlsx]Payment Due 1-30-24

Washington Gas Light Company

Public Right of Way Rental Fees
For Quarter Beginnning April 1, 2024

	Linear Feet	Annual Tax Rate	Tax Rate for 2nd Qtr 2024	Period Covered	Total Due 4-2-2024
Per WGL	**9,337,264**	1.06	0.265	04/01/2024 - 06/30/2024	**2,474,374.96** 16

Description		Rates
District of Columbia		
Delivery Tax - Residential (Per Therm) e/	$	0.07070 5
Delivery Tax - Non-Residential (Per Therm) e/		
Group Metered Apartments	$	0.07070
Other Than Group Metered Apartments	$	0.07777
Rights-of-Way Fee (Per Therm) f/	$	0.0394 5 36
Sustainable Energy Trust Fund (Per Therm) g/ i/	$	0.07515 5 37
Energy Assistance Trust Fund (Per Therm) g/ k/	$	0.0083359 5 38
Maryland		
Gross Receipts Tax (GRT)		2.00%
Public Service Commission Assessment Fee j/		0.2325%
GRT/PSC Assessment Fee Surcharge factor j/		0.0391%
Franchise Tax (Per Therm) b/	$	0.0041
Montgomery County Fuel-Energy Tax - Residential (Per Therm) c/ h/	$	0.0973227
Montgomery County Fuel-Energy Tax - Non-Residential (Per Therm) c/ h/	$	0.1741479
Prince George's County Energy Tax (Per Therm) j/	$	0.086519
Virginia (including Shenandoah)		
State Consumption Tax (Per ccf - 500 ccf max) d/	$	0.0197
VA Sales & Use Tax Surcharge (Per Therm) a/	$	-

a/ Effective April 2007
b/ Effective July 2009, adjusted for GRT/PSC Assessment Tax
c/ Includes adjustment for MD GRT and PSC Assessment Fee
d/ Effective July 2021
e/ Effective for meter readings on and after September 29, 2006
f/ Effective April 2024 billing (March 2024 interruptible usage)
g/ Excludes Residential Essential Service (RES) participants
h/ Effective for service rendered on and after July 1, 2022
i/ Effective October 1, 2023.
j/ Effective for bills rendered on and after July 1, 2022
k/ Effective October 1, 2017

Washington Gas Light Company
System

Ratemaking Purchased Gas Charge Calculation

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Allocator C	System Amount D=E+F+G	D.C. E	Maryland F	Virginia G
1	Pipeline Cost of Gas						
2	Total Ratemaking Pipeline Cost	Page 19, Line 15		$ 510,620,446	$ 71,937,559	$ 217,706,378	$ 220,976,509 22
3	Less: Interruptible Sales Cost	Page 21, Line 7		-	-	-	-
4	Firm Pipeline Cost	Line 2 - Line 3		$ 510,620,446	$ 71,937,559	$ 217,706,378	$ 220,976,509
5	Other Cost of Gas						
6	Hampshire Gas Company	Per Books	Firm Weather_NW	26/ $ 12,006,572	$ 1,765,271	$ 5,160,327	$ 5,080,974
7	Propane Gasified	Ratemaking	Firm Weather_NW	-	-	-	-
8	Hampshire X-39 Exchange Service	Per Books	Firm Weather_NW	278,568	40,957	119,726	117,885
9	Total Other Cost of Gas	Sum of Lines 6 - 8		$ 12,285,140	$ 1,806,228	$ 5,280,053	$ 5,198,859
10	Total Ratemaking Cost to Firm Customers	Line 4 + Line 9		$ 522,905,586	$ 73,743,787	$ 222,986,431	$ 226,175,368
11	Ratemaking Firm Therm Sales	DC Rev by Class, Line 1			20/ 122,542,753	382,007,337	409,902,410
12	Ratemaking Purchased Gas Charge	Line 10 / Line 11			$ 0.6018 5	$ 0.5837	$ 0.5518

Washington Gas Light Company
System

Normal Weather Sales Sendout and Commodity Cost of Gas

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C
1	Normal Weather Sales Sendout		
2	District of Columbia	Normal Weather Study	21/ 122,542,753 19
3	Maryland	Normal Weather Study	382,007,337
4	Virginia	Normal Weather Study	409,902,410
5	Company Use Gas	Analysis	2,606,526
6	Total Normal Weather Wet Therms	Sum of Lines 2 - 5	917,059,026
7	Adjusted for Unaccounted-for Gas of 3.69% 40/	Line 6 / (1 - 0.0369)	952,206,518
8	Wet Therm to Dry Dth Conversion	Line 7 x 0.10177	96,906,057
9	Weighted Average Commodity Cost of Gas per Dry Dth		$ 41/ 2.4390
10	Commodity Cost of Gas for Sales Service	Line 8 x Line 9	$ 236,353,873 22

Washington Gas Light Company
Allocation Factors Based on Normal Weather Study

Twelve Months Ended March 2024 - AVG

Description	------ Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Firm Annual Weather Gas**									
2 TOTAL FIRM WEATHER GAS - NW	NW Study	Firm_Weather_NW	966,262,395	142,065,096	415,291,747	408,905,552	0.147025	0.429792	0.423183
3 TOTAL FIRM THERM SALES - NW	NW Study	Annual_ Firm_NW	1,418,556,506	206,081,756	605,693,246	606,781,504	0.145276	0.426979	0.427746
4 TOTAL FIRM THERM SALES - NW(sales only)		Annual_ Firm_Sales_NW	914,452,500	122,542,753	382,007,337	409,902,410	0.134007	0.417744	0.448249
5 **Non-Firm Annual Weather Gas**									
6 June Sales	Financial Stmt.		19,106,249	4,878,086	10,601,572	3,626,591			
7 July Sales	Financial Stmt.		16,385,284	4,144,577	9,130,761	3,109,946			
8 Aug. Sales	Financial Stmt.		15,994,187	4,074,410	9,020,913	2,898,865			
9 Total Summer Usage	=+6+7+8		51,485,720	13,097,073	28,753,246	9,635,401			
10 Annualization Factor	Constant		4	4	4	4			
11 Annualized Summer Usage	=9*10		205,942,881	52,388,293	115,012,983	38,541,605			
12 Watergate Usage	Financial Stmt.		-	-	-	-			
13 Calculated Base Usage	=11+12		205,942,881	52,388,293	115,012,983	38,541,605			
14 Actual Usage	NW Study		239,874,935	73,882,136	116,925,204	49,067,596			
15 Weather Usage	=14-13		33,932,054	21,493,843	1,912,220	10,525,990			
16 Total Interruptible Therm Sales - NW			263,839,380	77,868,955	133,858,923	52,111,502			
17 Weather Gas Interruptible - NW			57,843,990	26,677,272	19,855,837	11,310,880			
18 TOTAL FIRM THERM SALES - NW(Delivery only)		Annual_ Firm_Delivery_NW	509,207,172	81,663,741	227,864,492	199,678,939	0.160374	0.447489	0.392137
19 TOTAL ALL WEATHER GAS	=2+18	Total_Weather_All_NW	1,024,106,385	168,742,368	435,147,584	420,216,432	0.164770	0.424905	0.410325
20 TOTAL ANNUAL THERM SALES	=4+17	Annual_Total_NW	1,682,395,886	283,950,710.85	739,552,169	658,893,006	0.168778	0.439583	0.391640
25 ANNUAL THERMS ADJUSTED	=20-24	Pipeline_NW	1,682,395,886	283,950,711	739,552,169	658,893,006	0.1688	0.4396	0.3916
26 FIRM ANNUAL PIPELINE	=3-24	Firm_Pipe_ Ann_ Adj	1,418,556,506	206,081,756	605,693,246	606,781,504	0.145276	0.426979	0.427746
27 FIRM ANNUAL PIPELINE(Sales only)	=4-24	Firm_Pipe_ Ann_Sales_ Adj	914,452,500	122,542,753 42	382,007,337	409,902,410 20	0.134007	0.417744	0.448249
28 **Peak Day Therm Sales- Normal Weather**									
29 Weather Gas	NW Study	Peak_Day _Weather	15,991,500	2,290,271	6,959,692	6,741,537	0.143218	0.435212	0.421570
30 Base Gas	NW Study	Peak_Day_Base	1,218,969	172,345	515,804	530,820	0.141386	0.423148	0.435466
31 Total Peak Day Therms	=29+30	Peak_Day_Total	17,210,469	2,462,616	7,475,496	7,272,357	0.143088	0.434357	0.422554
32 PEAK DAY AND ANNUAL SALES	=(20+31)/2	Comp_Peak_ Ann_NW					0.155933	0.436970	0.407097
33 TOTAL WINTER THERMS (NOV-APR)	NW Study	Wintr_Pipe_NW	1,277,081,957	214,413,097	552,242,395	510,426,464	0.167893	0.432425	0.399682

Washington Gas Light Company
System

Jurisdictional Allocation of Purchased Gas Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Allocator C		System D=E+F+G	D.C. E	Maryland F	Virginia G
1	Commodity							
2	Allocable	Line 4 - Line 3	Sales Normal Weather Therms		20/ $ 236,353,873	23/ $ 31,673,000	$ 98,735,488	$ 105,945,385
3	Interruptible	Page 21, Line 7	Direct Assignment		-	-	-	-
4	Total Commodity	Page 20, Line 10			$ 236,353,873	$ 31,673,000	$ 98,735,488	$ 105,945,385
5	Firm Transportation Demand							
6	Base Gas	footnote 1/	Peak_Day_Base		$ 15,505,776	$ 23/ 2,192,298	$ 6,561,234	$ 6,752,244
7	Weather Gas	footnote 1/	Peak_Day_Weather		126,618,658	18,134,074	55,105,954	53,378,630
8	Total FT Demand	RM Demand Cost, Line 12		24/	$ 142,124,434	$ 20,326,372	$ 61,667,188	$ 60,130,874
9	Storage Service Demand							
10	Demand	RM Demand Cost, Line 25	Peak_Day_Weather	24/	$ 75,541,326	23/ $ 10,818,879	$ 32,876,488	$ 31,845,959
11	Capacity	RM Demand Cost, Line 35	Wintr_Pipe_NW		38,219,634	6,416,808	16,527,132	15,275,694
12	Injection/Withdrawal	N/A	Wintr_Pipe_NW		-	-	-	-
13	Total Storage Service Demand	Sum of Lines 10 - 12			$ 113,760,961	$ 17,235,687	$ 49,403,621	$ 47,121,653
14	Peaking Service Demand	RM Demand Cost, Line 52	Firm Weather_NW		$ 24/ 18,381,178	$ 23/ 2,702,500	$ 7,900,081	$ 7,778,597
15	Total Ratemaking Pipeline Cost of Gas	Sum of Lines 4, 8, 13 & 14		19/	$ 510,620,446	$ 71,937,559	$ 217,706,378	$ 220,976,509
16	Purchased Gas Cost Per Books	footnote 2/		27/	454,828,378	64,262,645	200,704,535	189,861,198
17	Adjustment to Purchased Gas Cost 3/	Line 15 - Line 16			$ 55,792,068	$ 7,674,914	$ 17,001,843	$ 31,115,311

18 Adjustment Description: To adjust purchased gas costs to a Ratemaking basis.

1/ 10.91% of Line 8 assigned to base gas and the balance assigned to Weather Gas.
2/ Excludes Other Gas Cost included in O&M Expenses (Hampshire Gas Company).
3/ For Class Cost purposes, note that this adjustment relates to EX:3:5.

DC Rev by Class

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment 1 Workpaper 7 - Class Cost Allocation of Ratemaking Pipeline Gas Cost

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Total DC	Residential			Commercial & Industrial				Group Metered Apartments			Non-Firm	Special Contracts
				Htg/Clg	Non-htg-IMA	Non-htg-Other	H/C < 3075	H/C > 3075		Non-htg	H/C < 3075	H/C >3075	Non-htg		
	A	B	C=D...M	D	E	F	G	H		I	J	K	L	M	N
1	Commodity														
2	Allocable - Firm	Page 19, Line 2	31,673,000 22	19,210,276	154,469	381,406	1,127,084	6,713,377	-	852,035	173,790	2,657,460	403,102	-	-
3	Non-Firm	Page 19, Line 3	-											-	-
4	Total Commodity	Line 2 + Line 3	31,673,000	19,210,276	154,469	381,406	1,127,084	6,713,377	-	852,035	173,790	2,657,460	403,102	-	-
5	Firm Transportation Demand:														
6	Base Gas	Page 19, Line 6	2,192,298 22	(470,372)	12,555	14,322	44,113	1,036,573	33,277	176,763	14,756	314,639	80,736	-	934,936
7	Weather Gas	Page 19, Line 7	18,134,074	8,377,287	36,613	152,780	480,100	4,661,817	133,485	324,002	66,516	2,430,365	183,553	-	1,287,556
8	Total Firm Transportation Demand	Line 6 + Line 7	20,326,372	7,906,915	49,168	167,102	524,213	5,698,390	166,762	500,765	81,272	2,745,004	264,289	-	2,222,492
9	Storage Service Demand														
10	Demand	Page 19, Line 10	10,818,879 22	4,997,932	21,843	91,149	286,430	2,781,263	79,638	193,301	39,684	1,449,968	109,509	-	768,162
11	Capacity	Page 19, Line 11	6,416,808	780,004	14,078	41,998	132,064	1,538,487	45,887	154,202	22,228	706,568	78,510	801,272	2,101,530
12	Injection/Withdrawal	Page 19, Line 12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Total Storage Service Demand	Sum of Lines 10 - 12	17,235,687	5,777,936	35,921	133,147	418,494	4,319,750	125,505	347,503	61,912	2,156,536	188,019	801,272	2,869,692
14	Peaking Service Demand	Page 19, Line 14	2,702,500 22	1,249,783	5,467	22,742	71,687	692,608	19,928	48,507	10,013	362,119	27,417	-	192,229
15	Total Ratemaking Pipeline Cost	Sum of Lines 4, 8, 13 & 14	71,937,559	34,144,910	245,025	704,397	2,141,478	17,424,125	312,195	1,748,810	326,987	7,921,119	882,827	801,272	5,284,413

Exhibit WG (D)-5
Adjustment No. 1
Page 23 of 46

Washington Gas Light Company
System

Ratemaking Purchased Gas Charge - Determination of Annual Demand Cost of Gas

Twelve Months Ended March 31, 2024

Line No.	Description	Billing Determinants Monthly	Billing Determinants Annual	Cost Rate	System Cost	
	A	B	C	D	E=CxD	
1	Firm Transportation					
2	Columbia - FTS Reservation Charge >50% LF	327,943	3,935,316	$ 9.5920	$ 37,747,551	
3	WB Express	75,000	900,000	$ 21.5918	$ 19,432,620	
4	Columbia Gulf - FTS-1 Res. Charge	70,316	843,792	$ 5.0490	$ 4,260,306	
5	Transco - FTS Reservation Charge	362,288	4,347,456	$ 11.8938	$ 51,707,772	
6	DTI - East Tennessee	80,000	960,000	$ 7.6300	$ 7,324,800	
7	DTI - FTNN Reservation Charge	60,224	722,688	$ 4.1553	$ 3,002,985	
8	DTI - FTNN Reservation Charge-MA	25,000	300,000	$ 9.9401	$ 2,982,030	
9	DTI - FTNN GSS Res. Charge	N/A	233,880	$ 4.1553	$ 971,842	
10	DTI - FTNN GSS Res. Charge-MA	40,000	480,000	$ 9.9401	$ 4,771,248	
11	DTI - FTNN GSS Res. Charge-Allegheny	100,000	1,200,000	$ 8.2694	$ 9,923,280	
12	Total Firm Transportation				$ 142,124,434	22
13	Storage Demand					
14	Columbia - SST Reservation Charge	N/A	3,596,544	$ 9.4730	$ 34,070,061	
15	Columbia - SST Reservation Charge-EME	N/A	425,000	$ 17.2138	$ 7,315,872	
16	Columbia - SST Reservation Charge-Ohio	N/A	510,000	$ 7.9790	$ 4,069,290	
17	Columbia - FSS Reservation Charge	423,122	5,077,464	$ 2.4810	$ 12,597,188	
18	Columbia - FSS Reservation Charge -EME	50,000	600,000	$ 3.9235	$ 2,354,100	
19	Columbia - FSS Reservation Charge -Ohio	-	-	$ -	$ -	
20	Columbia - Hardy Demand Charge	81,793	981,516	$ 5.0590	$ 4,965,489	
21	Transco - GSS Demand Charge	53,303	639,636	$ 3.2665	$ 2,089,358	
22	DTI - GSS Demend Charge-MA	40,000	480,000	$ 1.8655	$ 895,440	
23	DTI - GSS Demand Charge	46,776	561,312	$ 1.8655	$ 1,047,128	
24	DTI - GSS Demand Charge-Allegheny	100,000	1,200,000	$ 5.1145	$ 6,137,400	
25	Total Storage Demand				$ 75,541,326	22
26	Storage Capacity					
27	Columbia - FSS Capacity Charge	26,339,686	316,076,232	$ 0.0447	$ 14,128,608	
28	Columbia - FSS Capacity Charge-EME	3,016,500	36,198,000	$ 0.0646	$ 2,338,391	
29	Columbia - FSS Capacity Charge-Ohio	4,020,000	48,240,000	$ 0.1875	$ 9,045,000	
30	Columbia - Hardy Capacity Charge	5,754,528	69,054,336	$ 0.0720	$ 4,973,984	
31	Transco - GSS Capacity Charge	2,543,831	30,525,972	$ 0.0195	$ 596,172	
32	DTI - GSS Capacity Charge-MA	2,800,000	33,600,000	$ 0.0145	$ 487,200	
33	DTI - GSS Capacity Charge	3,420,000	41,040,000	$ 0.0145	$ 595,080	
34	DTI - GSS Capacity Charge-Allegheny	6,000,000	72,000,000	$ 0.0841	$ 6,055,200	
35	Total Storage Capacity				$ 38,219,634	22
36	Peaking Demand Costs					
37	LNG - Cove Point					
38	FPS-2 Reservation Charge	50,000	600,000	$ 2.3293	$ 1,397,580	
39	FPS-2 FT Reservation Charge	50,000	600,000	$ 0.5631	337,860	
40	FPS-3 Reservation Charge	50,000	600,000	$ 1.9432	1,165,920	
41	FPS-3 FYT Reservation Charge	50,000	600,000	$ 0.5631	337,860	
42	FTS Reservation Charge	350,000	4,200,000	$ 1.1453	4,810,260	
43	FTS0019 Reservation Charge	150,000	1,800,000	$ 3.6377	6,547,860	
44	Total Columbia LNG				$ 14,597,340	
45	Pine Needle LNG	19,777	237,324		601,238	
46	Twin Eagle Energy	20,000	80,000		242,000	
47	EQT	-	-		-	
48	Pesco Energy	-	-		-	
49	Pacific Summit	20,000	80,000		492,000	
50	Saltville Peaking	71,073	852,876		2,448,600	
51	Total Other Peaking				$ 3,783,838	
52	Total Peaking Demand				$ 18,381,178	22
53	Total Annual Demand Cost of Gas				$ 274,266,573	
54	FT Volumes for Base Gas Percentage					
55	Columbia		25 5,679,108			
56	Transco		4,347,456			
57	DTI		3,896,568			
58	Total		13,923,132			

Washington Gas Light Company
System

Jurisdictional Allocation of Purchased Gas Expense - Determination of Firm Transportation Demand Base Gas Percentage

Twelve Months Ended March 31, 2024

Line No.	Description A	Amount B	
1	Base Gas percentage determined as follows with balance assigned to Weather Gas:		
2	Peak Day Base Gas Requirement (Normal Weather Study)	1,218,969	Wet Therms
3	Demand Billing Determinants:		
4	Customers base gas requirements adjusted for company use and unaccounted-for gas:		
5	Monthly Base Gas (Peak Day Bas Gas Requirement / 10)	121,897	Dry Dth
6	Complement of the 3.69% unaccounted-for factor	0.9631	
7	Monthly Base Gas Requirements (monthly base gas adjusted for unaccounted-for gas)	126,567	Dry Dth
8	Annual Base Gas Requirements (monthly base gas requirements x 12 months)	1,518,804	Dry Dth
9	Annual Demand Volumes:		
10	Columbia Firm Transportation	5,679,108	Dry Dth 24
11	Transco Firm Transportation	4,347,456	Dry Dth
12	Consolidated Firm Transportation	3,896,568	Dry Dth
13	Total Annual Demand Volumes	13,923,132	Dry Dth
14	Base Gas Percentage (annual base gas requirements divided by annual demand volumes)	10.91%	

Washington Gas Light Company
Operations Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	---- Reference ---- Sc-Pg-Ln	Allocator			WG	DC	MD	VA	FERC
	A	B	C			D	E	F	G	H
1	Operation Expenses									
2	Gas Purchased	EX:3:5				$ 454,828,378	$ 64,262,645	$ 200,704,535	$ 189,861,198	$ -
3	Purchased Gas Expenses		Financial Stmt.	807500	Purch Gas Exp-Oth Purch Gs Exp	896,834	151,366	394,233	351,236	-
4	Purchased Gas Expenses		Financial Stmt.	807500	Purch Gas Exp-Oth Purch Gs Exp	54,868	596	17,799	36,473	-
5	Purchased Gas Expenses - Hexane		Financial Stmt.	807505	Hexane Additive (O&M Portion)	3,460,797	-	-	3,460,797	-
6	Purchased Gas Expenses- Chalk Point		Financial Stmt.	807510	Oth Purch Gas Exp-Chalk Point	32,044	-	32,044	-	-
7	Propane Holding	AL:1:2	Firm_Weather_NW	Sub Total		-	-	-	-	-
8	Watergate		Financial Stmt.	Sub Total		102,248	102,248	-	-	-
9	Hampshire Exchange Service	AL:1:2	Firm_Weather_NW	Sub Total		278,568 19	40,957	119,726	117,885	-
10	Property Modifications - Chalk Point		Financial Stmt.			-	-	-	-	-
11	Storage - Direct		Financial Stmt.	Sub Total		245	-	105	140	-
12	Storage - Allocable	AL:1:2	Firm_Weather_NW	Sub Total		16,757,838	2,463,828	7,202,383	7,091,628	-
				814000	Op Superv & Eng-Undrgrnd Strge	39				
				815000	Maps And Records	-				
				816000	Well Expenses	-				
				817000	Lines Expenses	-				
				818000	Compressor Station Expenses	1,588				
				820000	Meas & Regulating Sta Expenses	-				
				821000	Purification Expenses	-				
				824000	Other Expenses	-				
				825000	Storage Well Royalties	-				
				826000	Rents	622,037				
				826201	Rents-Hampshire Strge Facilties	12,006,572 19				
				826202	Rnt-Gs Used-Hamp Gs Co Str Fac	-				
				840000	Operation Supervision & Eng	333,268				
				841000	Operation Labor And Expenses	3,794,334				
13	Transmission	AL:2:8	Transmission_Plnt	Sub Total		3,214,585	474,160	1,246,238	1,410,951	83,237
14	Transmission - Chalk Point		Financial Stmt.	857101	Meas & Reg Sta Exp-Chalk Point	24,972	-	24,972	-	-
15	Transmission - Panda		Financial Stmt.	857104	Oper-Trans Meas&Reg Stat-Panda	8,960	-	8,960	-	-
16	Distribution									
17	Supervision and Engineering -									
18	Distribution	AL:5:17	Dist_X_Admin	Sub Total		955,435	218,452	389,587	347,396	-
19	Appliance Service - Direct		Financial Stmt.	870002	Appliance Service Department	-	-	-	-	-
20	Appliance Service - Allocable	AL:5:6	Appl_Svc_X_Admin	870002	Appliance Service Department	-	-	-	-	-
21	Other	AL:2:22	Tot_Dist_Plnt	870003	Oth Than T&D Or App Service	5,208,625	1,004,253	1,886,834	2,317,538	-
22	Load Dispatching	AL:1:32	Comp_Peak_Ann_NW	871000	Distribution Load Dispatching	2,154,642	335,980	941,514	877,148	-
23	Load Dispatching - Chalk Point		Financial Stmt.	871001	Distr Load Disptch-Chalk Point	-	-	-	-	-
24	Compressor Station Equipment	AL:1:32	Comp_Peak_Ann_NW	872000	Compressor Sta Labor & Exp	-	-	-	-	-
25	Mains	AL:2:16	Dist_Mains_Plnt	874000	Mains And Service Expenses	1,368,210	291,861	471,936	604,413	-
26	Mains - Chalk Point		Financial Stmt.	856001	Mains Expenses-Chalk Point	-	-	-	-	-
27	Removing/Setting Meters - Direct		Financial Stmt.	878000	Meter & House Reg Expenses	1,689,348	121,682	1,105,374	462,292	-
28	Removing/Setting Meters - Allocable	AL:5:2	Direct_Meter_Exp	878000	Meter & House Reg Expenses	-	-	-	-	-
29	Measuring and Regulating Station Equipment	AL:2:17	Dist_Meas_Reg_Plnt	875000	Meas & Reg Station Exp-General	509,583	303,237	123,239	83,107	-
30	Measuring and Reg Station Equip - Chalk Point		Financial Stmt.	875001	Inactive-See Legacy FRS System	-	-	-	-	-
31	Services On Customer Premises-Direct		Financial Stmt.	Sub Total		44,751	1,533	8,132	35,086	-
32	Services On Customer Premises-Allocable	AL:5:4	Direct_SOCP	Sub Total		0	0	0	0	-
33	Office Expenses -					-				-
34	Distribution	AL:5:17	Dist_X_Admin	Sub Total		12,555,986	2,870,823	5,119,808	4,565,354	-
35	Appliance Service - Direct		Financial Stmt.	880002	Other Expenses - App Service	-	-	-	-	-
36	Appliance Service - Allocable	AL:5:6	Appl_Svc_X_Admin	880002	Other Expenses - App Service	-	-	-	-	-
37	Other	AL:2:16	Dist_Mains_Plnt	880003	Oth Exp-Oth Thn T&D Or App Srv	245,147	52,294	84,559	108,295	-
38	Rents		Financial Stmt.	881000	Rents	14,652	-	298	14,355	-
39	Customer Accounts	EX:7:23				52,124,547	12,768,405	19,560,728	19,795,414	-
40	Customer Service and Information Exp - Allocable	AL:4:12	Avg_Meters	Sub Total		3,156,065	437,277	1,246,549	1,472,238	-
41	Information Exp - Direct		Financial Stmt.	909000	Info & Instruct Advert Exp	240,680	75,837	150,863	13,981	-
42	Sales Expense	AL:4:12	Avg_Meters	Sub Total		602,426	83,467	237,940	281,019	-
43	Advertising Exp - Direct	AL:4:12	Financial Stmt.	913000	Advertising Expenses	1,770	-	1,770	-	-
44	Administrative and General	EX:5:31				215,854,266	39,138,720	97,390,911	79,297,762	26,873
45	Interest on Financing Leases	AL:3:6	Net_Rate_Base	427420		$ 493,872	$ 94,239	$ 183,968	$ 215,665	$ -
46	Total Operation Expenses	=2>44				$ 776,880,340	$ 125,293,859	$ 338,655,003	$ 312,821,368	$ 110,110

Washington Gas Light Company
Development of Gas Purchased Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	—— Reference —— Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Gas Purchase Costs		Financial Stmt.	$ 381,002,051	$ 51,891,638	$ 167,476,401	$ 161,634,012	$ -
2	Less: Off System Sales Cost of Gas Recovered			$ (86,111,467)	$ (14,177,234)	$ (38,508,187)	$ (33,426,045)	$ -
3	PGC Recovered - DC/MD/VA	=1-2		$ 467,113,518	$ 66,068,873	$ 205,984,588	$ 195,060,057	$ -
4	Propane Gasified		Financial Stmt.	$ (12,285,140)	$ (1,806,227)	$ (5,280,054)	$ (5,198,859)	$ -
5	Total Gas Purchased & Propane Gasified	=3+4	Financial Stmt.	$ 454,828,378	$ 64,262,645	$ 200,704,535	$ 189,861,198	$ 22 -

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 Workpaper 8 - Ratemaking Adjustment to Late Payment Charges

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C	
1	Actual Late Payment Charges	RV 1:15	$ 4/ 3,245,453	1
2	Sales of Gas Revenues	Adj 1 Page 1, Column E, Line 15	$ 1/ 186,806,956	
3	Per Books Late Payment Charge Percentage	Analysis	1.7373%	
4	Ratemaking Total Sales of Gas	Adj 1 WP 7, Column C, Line 27	$ 5/ 205,930,738	
5	Ratemaking Late Payment Charges	Line 3 x Line 4	$ 3,577,696	1
6	Ratemaking Adjustment	Line 5 - Line 1	$ 332,243	1

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 - Workpaper No. 5 (East Station Revenue Sharing)

Twelve Months Ended Mar 31, 2024

Line No.	Description	Reference		Amount
	A	B		C
1	Maritime Plaza I	Per Financials; Allocable	$ 30/	317,091
2	Maritime Plaza II	Per Financials; Allocable		252,018
3	Total Maritime Rent		$	569,109
4	Actual firm Therm sales	AL:4:24	31/	14.4395%
5				
6	Total Allocable Maritime Rent to District of Columbia	Line 3 x Line 4	$	82,176
7				
8	Sum of Maritime Plaza @ 50%	Line 6 x 50%		41,088
9				
10	Total Amount to Remove from Ratemaking Revenues		$	(41,088) 2

11 **Workpaper Description:** To eliminate from revenues the 50/50 allocations for the twelve months
12 ended March 31, 2024 per Formal Case No. 989 (Opinion No. 14104).

Unit	01

Row Labels	Sum of Amount	
At&T Network Real Estate Admin	(22,560)	
Maritime Plaza - I	(317,091)	29
Maritime Plaza - II	(252,018)	29
Redi Call Communications	(6,125)	
Sprint/Nextel Property SVC-Frederick	(25,555)	
W.G.L. Federal Credit Union	(11,778)	
Federal Bureau of Investigation	(49,106)	
NPL Construction Company	(53,820)	
T-Mobile Northeast LLC	(9,042)	
Sunland Construction	(33,655)	
Sprint/Nextel Property Svcs-Centreville	(12,563)	
Cellco Partnership,	(11,146)	
Dish Wireless LLC	(46,550)	
AT&T - Network Real Estate Admin.	(25,827)	
T-Moble NorthEast LLC	(27,941)	
Cellco Partnership (Verizon Wireless)	(22,961)	
Sprint / Nextel	(25,879)	
AT & T - Network Real Estate	(6,576)	
Redi- Call Communications	(2,366)	
Dish Wireless LLC NW	(3,200)	
Dish Wireless LLC NW	(1,648)	
Grand Total	**(967,406)**	

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	—— Reference —— Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395 29	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M_X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses - 25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding 42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 Workpaper 9 - Ratemaking Adjustment to Uncollectible Accounts Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Ratemaking Sales and Delivery Revenues 1/	Adj 1 WP 7, Column C, Line 27	$ 5/ 205,930,738
2	Accrual Rate for Uncollectible Gas Accounts	Adj 1 WP 2	33/ 2.7046%
3	Ratemaking Uncollectible Gas Accounts Expense	Line 1 x Line 2	$ 5,569,603
4	Per Books Uncollectible Gas Accounts Expense	Per Books	6,226,265 1
5	Distribution Adjustment to Uncollectible Expense	Adjustment No. 2D	(1,694,830)
6	Distribution Only, Per Book Uncollectible Expense	Line 4 + Line 5 + Line 6	4,531,435
7	Ratemaking Adjustment to Uncollectible Gas Accounts 2/	Line 3 - Line 6	$ 1,038,168 1
8			

Adjustment Description: To adjust per book uncollectible accounts expense to reflect adjusted non-gas ratemaking revenues.

1/ Less: Gas Cost.
2/ For Class Cost purposes, note that this adjustment relates to EX:7:22.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 - Workpaper No. 2 (Uncollectible Rate)

5 TME Periods through March 2024

Period	Net Charge-Offs	Revenues from Gas Sales	Charge-off Ratio
TME March 2020	$ 15,393,492	$ 213,194,978	
TME March 2021	2,093,575	219,989,955	
TME March 2022	2,444,653	256,116,979	
TME March 2023	7,356,265	280,502,194	
TME March 2024	5,864,418	255,978,896	
Total	$ 33,152,402	$ 1,225,783,002	
5 Year Avg.	$ 6,630,480	$ 245,156,600	2.7046% 32

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 Workpaper 10 - Ratemaking Adjustment to Delivery Tax Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Amount C
1	Ratemaking Delivery Tax Expense	Adj 1 WP 7, Column C, Line 20	$ 5/ 21,221,880
2	Delivery Tax in PBCOSA		35/ 23,451,041
3	Less: PSC Assessment Fees included in PBCOSA		4,471,073
4	Per Books Delivery Tax Expense	Per Books	18,979,968 1
5	Adjustment to Delivery Tax Expense 1/	Line 1 - Line 2	$ 2,241,912 1

6 **Adjustment Description:** To adjust per books Delivery Tax to reflect normal weather therms.

1/ For Class Cost purposes, note that this adjustment relates to EX:8:8.

Washington Gas Light Company
General Tax Expense
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description A	---- Reference ---- Sc-Pg-Ln B				WG D	DC E		MD F	VA G	FERC H
1	**General Taxes**										
2	Property Taxes		Analysis	Sub Total		$ 50,009,514	$ 2,013,868		$ 27,934,055	$ 19,988,883	$ 72,707
3	Property Taxes - Chalk Point										
4	Maryland State & Prince George's County		Financial Stmt.	Sub Total		135,764	-		135,764	-	-
5	Property Taxes - Panda										
6	Maryland State & Prince George's County		Financial Stmt.	Sub Total		-	-		-	-	-
7	Total Property Taxes	=2>6				$ 50,145,278	$ 2,013,868	34	$ 28,069,820	$ 19,988,883	$ 72,707
8	Gross Receipts Taxes		Financial Stmt.	Sub Total		$ 36,271,509	$ 23,451,041		$ 12,820,467	$ -	$ -
				408331	DC Gross Receipts Tax	18,979,971	18,979,971		-	-	-
				408332	Gross Receipt Tx-DC Reimb Fee	4,471,073	4,471,073		-	-	-
				408333	MD Gross Receipts Tax	11,098,340	(2)		11,098,342	-	-
				408334	Gross Receipt Tax-MD-PSC Fund	1,722,125	-		1,722,125	-	
				408335	VA Gross Receipts Tax-Current	-	-		-	-	
				408336	Gross Receipt Tax-VA VAlu Fund	-	-		-	-	
				408337	Grt-VA-Ann Bus Lc-Cnty,Cty,Twn	-	-		-	-	
				408399	Revenue Taxes - Gross Receipts	-	-		-	-	-
9	DC Rights-of-Way Fee		Financial Stmt.	408348	DC ROW Fee	12,518,268	12,518,268	36	-	-	-
10	F.I.C.A. Taxes	AL:4:11	Total_Labor	Sub Total		8,469,616	1638232.747		3,639,262	3,183,652	8,470
11	Medicare Taxes	AL:4:11	Total_Labor	Sub Total		2,405,694	465,321		1033689.079	904,279	2,406
12	Unemployment Taxes	AL:4:11	Total_Labor	Sub Total		(35,988)	(6,961)		(15,463)	(13,527)	(36)
13	Montgomery County Fuel Energy Tax		Financial Stmt.	408374	Misc-Mont County Fuel Enrgy Tx	42,701,928	-		42,701,928	-	-
14	St Mary's County Fuel Energy Tax		Financial Stmt.	408347	Grss Rcelpt Tx-St Mry Frch Fee	27,577	-		27,577	-	-
15	PG County Maintenance Fees		Financial Stmt.	408349	PG County Maintenance Fees	-	-		-	-	-
16	Environmental Tax	AL:1:20	Annual_Total_NW	408389	Environmental Tax	-	-		-	-	-
17	Federal Excise Tax	AL:4:11	Total_Labor	408390	Misc-Fed Excise Tax-Ace Ltd	(112,245)	(21,714)		(48,238)	(42,199)	(94)
18	DC Sustainable Energy Trust Fund		Financial Stmt.	408384	DC Sustainable Energy Trust Fund	16,761,017	16,761,017	37	-	-	-
19	DC Energy Assistance Trust Fund		Financial Stmt.	408385	DC Energy Assistance Trust Fund	2,156,914	2,156,914	38	-	-	-
20	DC Natural Gas Trust Fund		Financial Stmt.	408378	DC Natural Gas Trust Fund	-	-		-	-	-
21	Virginia save Program		Financial Stmt.	408395	Virginia Save Program	-	-		-	-	-
22	Miscellaneous Other Taxes - Direct Assignment		Financial Stmt.	Sub Total		355,436	16,520		25,043	313,873	-
23	Miscellaneous Other Taxes - Allocated	AL:3:6	Net_Rate_Base	Sub Total		150	29		56	66	-
24	Total General Taxes	=7+ (8>23)				$ 171,665,153	$ 58,992,535		$ 88,254,140	$ 24,335,027	$ 83,452

DC ROW

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 Workpaper 11 - Ratemaking Adjustment to Rights of Way Fee

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		DC Amount C
1	Total Normal Weather Therms	Adj 1 WP 7, Column C, Line 1	5/	283,950,711
2	Rights of Way Fee Surcharge	Adj 1 WP 3	$ 18/	0.0349
3	Ratemaking Rights of Way Fee	Line 1 x Line 2	$	9,909,880 ①
4	Per Books Rights of Way Fee	Per Books	35/	12,518,268
5	Adjustment to Rights of Way Fee 1/	Line 3 - Line 4	$	(2,608,388)

6 **Adjustment Description:** To adjust the Rights of Way Fee to a Ratemaking basis.

1/ For Class Cost purposes, note that this adjustment relates to EX:8:9.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 Workpaper 12 - Ratemaking Adjustment to Sustainable Energy Trust Fund

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		DC Amount C
1	Total Normal Weather Therms	Adj 1 WP 7, Column C, Line 1	5/	283,950,711
2	SETF Fee Surcharge	Current Filed Rate	$ 18/	0.07515
3	Ratemaking SETF Fee	Line 1 x Line 2	$	21,338,896 1
4	Per Books SETF Fee	Per Books	35/	16,761,017
5	Adjustment to SETF Fee 1/	Line 3 - Line 4	$	4,577,879

6 **Adjustment Description:** To adjust the Sustainable Energy Trust Fund Fee to a Ratemaking
7 basis.

1/ For Class Cost purposes, note that this adjustment relates to EX:8:18.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 Workpaper 13 - Ratemaking Adjustment to Energy Assistance Trust Fund Fee

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Amount C
1	Total Normal Weather Therms	Adj 1 WP 7, Column C, Line 1	5/ 283,950,711
2	EATF Surcharge	Current Filed Rate	$ 18/ 0.0083359
3	Ratemaking EATF Fee	Line 1 x Line 2	$ 2,366,985 1
4	Per Books EATF Fee	Per Books	35/ 2,156,914
5	Adjustment to EATF Fee 1/	Line 3 - Line 4	$ 210,071

6 **Adjustment Description:** To adjust the Energy Assistance Trust Fund Fee to a Ratemaking basis.

1/ For Class Cost purposes, note that this adjustment relates to EX:8:19.

Washington Gas Light Company
System

Interruptible Curtailment Calculation

Based on 12 Months Ending Mar 2024

		Base Gas					Weather Gas									
		Base Gas Therms b/					Heating HDD's									Total
Line No.	Interruptible Customers	Jan-2024	Feb-2024	Total	Curtailment Days /a	Curtailment Therms	Jan-2024	Feb-2024	Total	Curtailment Days	Curtailment HDDs	Avg number Customers	Variation per HDD	Curtailment Therms	Curtailment Therms
	A	B	C	D=B+C	E	F= (E / 59) x D	G	H	I=G+H	J /a	K= (I / 59) x J	L	M	N=KxLxM	O=F+N
1	District of Columbia	1,982,552	1,964,529	3,947,081	1	66,900	763	811	1,574	1	26.6779661	109.50	38.5698900	112,672	**179,571** 6
2	Maryland	8,156,991	8,193,741	16,350,732	1	277,131	757	812	1,569	1	26.5932203	134.00	40.7933900	145,367	**422,498**
3	Virginia	2,537,942	2,545,671	5,083,614	1	86,163	757	812	1,569	1	26.5932203	108.00	28.4013200	81,571	**167,733**

/a : Curtailment days based on a Ten Year average
/b : Average of usage for July and August used for Shenandoah

Washington Gas Light Company
System

Revenue - Workpaper No. 2 (Lost and Unaccounted For Gas Amounts)

3 TME Periods through August 2023

Line No.	Period	Lost and Unaccounted For Percentage
	A	B
1	TME August 2021	3.6182%
2	TME August 2022	4.3452%
3	TME August 2023	3.1100%
4	THREE YEAR AVERAGE	3.6912% 20

Washington Gas Light Company

Monthly Projected Commodity Cost of Gas

For The Twelve Months Commencing September 2023

Line No.	Month/Year	Futures	Transport	Delivered Price	Average Storage	Percent Storage	Blended Dry Dth Rate	Wet Therm Rate (WACOG)	Line No.
	A	B a/	C b/	D=B+C	E c/	F	G	H d/	
1	SEPTEMBER 2023	$ 2.5580	$ 0.1060	$ 2.6640	$ 2.7018	2.1%	$ 2.6648	$ 0.2818	1
2	OCTOBER	$ 2.6860	$ 0.1060	$ 2.7920	$ 2.7018	8.2%	$ 2.7846	$ 0.2945	2
3	NOVEMBER	$ 3.1290	$ 0.1060	$ 3.2350	$ 2.7018	14.2%	$ 3.1591	$ 0.3341	3
4	DECEMBER	$ 2.7850	$ 0.1060	$ 2.8910	$ 2.7018	23.4%	$ 2.8467	$ 0.3010	4
5	JANUARY 2024	$ 2.5730	$ 0.1060	$ 2.6790	$ 2.7018	0.0%	$ 2.6790	$ 0.2833	5
6	FEBRUARY	$ 2.5910	$ 0.1060	$ 2.6970	$ 2.7018	82.1%	$ 2.7009	$ 0.2856	6
7	MARCH	$ 1.6090	$ 0.1060	$ 1.7150	$ 2.7018	40.2%	$ 2.1120	$ 0.2233	7
8	APRIL	$ 1.6650	$ 0.1060	$ 1.7710	$ 2.7018	0.0%	$ 1.7710	$ 0.1872	8
9	MAY	$ 1.7760	$ 0.1060	$ 1.8820	$ 2.7018	0.0%	$ 1.8820	$ 0.1990	9
10	JUNE	$ 1.9580	$ 0.1060	$ 2.0640	$ 2.7018	0.0%	$ 2.0640	$ 0.2183	10
11	JULY	$ 2.1560	$ 0.1060	$ 2.2620	$ 2.7018	0.0%	$ 2.2620	$ 0.2392	11
12	AUGUST	$ 2.2360	$ 0.1060	$ 2.3420	$ 2.7018	0.0%	$ 2.3420	$ 0.2476	12
13	Average						$ 2.4390	$ 0.2579	13

20

a/ NYMEX contracts @ COB 01/22/2024.

b/ Analysis of above index costs to city gate.

c/ Estimated average rate @ October 31, 2023.

d/ Converted to wet therm sold basis (Dry dth / comp. u-for / 10 x 1.0177)
Unaccounted-for @ 3.76%

Supplemental Schedule 1
Sales

	Total NW Therms	Total MB
Sales	122,542,753	1,718,412
Delivery	81,663,741	237,709

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales - For Allocation Purposes Only

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Therm Sales: Weather Gas: Normal Weather	Therm Sales: Weather Adjustment	Therm Sales: Base Gas b/	Therm Sales: Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I
1	*DC Res Sales Htg / HC*									
2	Mar-2024	121,494	516	634	0.1365690	8,561,634	10,519,527	1,957,893	986,155	11,505,682
3	Feb-2024	121,682	699	811	0.1365690	11,615,974	13,477,189	1,861,215	996,848	14,474,037
4	Jan-2024	121,736	655	763	0.1365690	10,889,613	12,685,153	1,795,540	1,006,461	13,691,614
5	Dec-2023	121,865	536	552	0.1365690	8,920,638	9,186,926	266,288	1,016,709	10,203,635
6	Nov-2023	121,880	223	288	0.1365690	3,711,842	4,793,769	1,081,927	1,026,016	5,819,785
7	Oct-2023	121,552	39	47	0.1365690	647,409	780,211	132,802	1,032,412	1,812,623
8	Sep-2023	121,075	1	-	0.1365690	16,535	-	(16,535)	1,037,482	1,037,482
9	Aug-2023	120,936	-	-	0.1365690	-	-	-	1,045,402	1,045,402
10	Jul-2023	120,628	-	-	0.1365690	-	-	-	1,051,827	1,051,827
11	Jun-2023	120,599	21	35	0.1365690	345,872	576,453	230,581	1,060,660	1,637,113
12	May-2023	120,658	130	184	0.1365690	2,142,159	3,031,978	889,819	1,070,269	4,102,247
13	Apr-2023	121,043	367	415	0.1365690	6,066,775	6,860,249	793,474	1,082,803	7,943,052
14	Total	1,455,148	3,187	3,729		52,918,451	61,911,455	8,993,004	12,413,045	74,324,500 A
15										
16	*DC Res Sales Non Htg - IMA*									
17	Mar-2024	10,083	516	634	0.0070800	36,836	45,260	8,424	27,125	72,385
18	Feb-2024	10,127	699	811	0.0070800	50,118	58,148	8,030	27,243	85,391
19	Jan-2024	10,169	655	763	0.0070800	47,158	54,933	7,775	27,356	82,289
20	Dec-2023	10,189	536	552	0.0070800	38,666	39,820	1,154	27,410	67,230
21	Nov-2023	10,238	223	288	0.0070800	16,164	20,876	4,712	27,542	48,418
22	Oct-2023	10,227	39	47	0.0070800	2,824	3,403	579	27,512	30,915
23	Sep-2023	10,242	1	-	0.0070800	73	-	(73)	27,553	27,553
24	Aug-2023	10,253	-	-	0.0070800	-	-	-	27,582	27,582
25	Jul-2023	10,253	-	-	0.0070800	-	-	-	27,582	27,582
26	Jun-2023	10,222	21	35	0.0070800	1,520	2,533	1,013	27,499	30,032
27	May-2023	10,199	130	184	0.0070800	9,387	13,286	3,899	27,437	40,723
28	Apr-2023	10,218	367	415	0.0070800	26,550	30,023	3,473	27,488	57,511
29	Total	122,420	3,187	3,729		229,296	268,282	38,986	329,328	597,610 A

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

A: 74,324,500
597,610
43/ 5,836,405
44/29,270,504
45/ 10,954,114
46/ 1,559,619
21/ 122,542,753

Supplemental Schedule 1
Sales

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales - For Allocation Purposes Only

Based on 12 Months Ending Mar 2024

						<	Therm Sales			>
						<---	Weather Gas	--->		
Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Actual	Normal Weather	Weather Adjustment	Base Gas b/	Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I
1	*DC Res Sales Non Htg - OTH*									
2	Mar-2024	3,041	516	634	0.0995640	156,231	191,959	35,728	29,378	221,337
3	Feb-2024	3,034	699	811	0.0995640	211,152	244,985	33,833	29,310	274,295
4	Jan-2024	3,041	655	763	0.0995640	198,317	231,017	32,700	29,378	260,395
5	Dec-2023	3,042	536	552	0.0995640	162,340	167,186	4,846	29,388	196,574
6	Nov-2023	3,049	223	288	0.0995640	67,696	87,428	19,732	29,455	116,883
7	Oct-2023	3,047	39	47	0.0995640	11,831	14,258	2,427	29,436	43,694
8	Sep-2023	3,022	1	-	0.0995640	301	-	(301)	29,195	29,195
9	Aug-2023	3,003	-	-	0.0995640	-	-	-	29,011	29,011
10	Jul-2023	3,000	-	-	0.0995640	-	-	-	28,982	28,982
11	Jun-2023	3,001	21	35	0.0995640	6,275	10,458	4,183	28,992	39,450
12	May-2023	3,006	130	184	0.0995640	38,908	55,069	16,161	29,040	84,109
13	Apr-2023	2,977	367	415	0.0995640	108,780	123,007	14,227	28,760	151,767
14	Total	36,263	3,187	3,729		961,831	1,125,367	163,536	350,325	1,475,692 A
15										
16	*DC C&I Sales Htg / HC < 3075*									
17	Mar-2024	3,818	516	634	0.2340740	461,146	566,602	105,456	89,663	656,265
18	Feb-2024	3,814	699	811	0.2340740	624,038	724,027	99,989	89,569	813,596
19	Jan-2024	3,773	655	763	0.2340740	578,471	673,852	95,381	88,606	762,458
20	Dec-2023	3,760	536	552	0.2340740	471,743	485,825	14,082	88,301	574,126
21	Nov-2023	3,750	223	288	0.2340740	195,744	252,800	57,056	88,066	340,866
22	Oct-2023	3,748	39	47	0.2340740	34,215	41,234	7,019	88,019	129,253
23	Sep-2023	3,722	1	-	0.2340740	871	-	(871)	87,408	87,408
24	Aug-2023	3,761	-	-	0.2340740	-	-	-	88,324	88,324
25	Jul-2023	3,749	-	-	0.2340740	-	-	-	88,042	88,042
26	Jun-2023	3,744	21	35	0.2340740	18,404	30,673	12,269	87,925	118,598
27	May-2023	3,766	130	184	0.2340740	114,598	162,200	47,602	88,442	250,642
28	Apr-2023	3,740	367	415	0.2340740	321,285	363,306	42,021	87,831	451,137
29	Total	45,145	3,187	3,729		2,820,515	3,300,519	480,004	1,060,195	4,360,714 A

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Sum of A: 5,836,405 42

Supplemental Schedule 1
Sales

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales - For Allocation Purposes Only

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Therm Sales: Weather Gas: Normal Weather	Therm Sales: Weather Gas: Weather Adjustment	Therm Sales: Base Gas b/	Therm Sales: Total	
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	
1	*DC C&I Sales Htg / HC > 3075*										
2	Mar-2024	1,995	516	634	2.1813760	2,245,552	2,759,070	513,518	817,396	3,576,466	
3	Feb-2024	1,992	699	811	2.1813760	3,037,365	3,524,039	486,674	816,167	4,340,206	
4	Jan-2024	1,992	655	763	2.1813760	2,846,172	3,315,465	469,293	816,167	4,131,632	
5	Dec-2023	2,001	536	552	2.1813760	2,339,604	2,409,443	69,839	819,854	3,229,297	
6	Nov-2023	1,983	223	288	2.1813760	964,624	1,245,793	281,169	812,479	2,058,272	
7	Oct-2023	1,977	39	47	2.1813760	168,191	202,691	34,500	810,021	1,012,712	
8	Sep-2023	1,991	1	-	2.1813760	4,343	-	(4,343)	815,757	815,757	
9	Aug-2023	1,959	-	-	2.1813760	-	-	-	802,646	802,646	
10	Jul-2023	1,974	-	-	2.1813760	-	-	-	808,792	808,792	
11	Jun-2023	1,975	21	35	2.1813760	90,473	150,788	60,315	809,202	959,990	
12	May-2023	1,965	130	184	2.1813760	557,232	788,698	231,466	805,104	1,593,802	
13	Apr-2023	2,011	367	415	2.1813760	1,609,936	1,820,500	210,564	823,952	2,644,452	
14	Total	23,815	3,187	3,729		13,863,492	16,216,487	2,352,995	9,757,537	25,974,024	A
15											
16	*DC C&I Sales Non Htg*										
17	Mar-2024	1,216	516	634	0.2485950	155,982	191,653	35,671	173,715	365,368	
18	Feb-2024	1,217	699	811	0.2485950	211,476	245,360	33,884	174,689	420,049	
19	Jan-2024	1,212	655	763	0.2485950	197,350	229,890	32,540	174,799	404,689	
20	Dec-2023	1,216	536	552	0.2485950	162,028	166,865	4,837	176,207	343,072	
21	Nov-2023	1,221	223	288	0.2485950	67,688	87,418	19,730	177,765	265,183	
22	Oct-2023	1,224	39	47	0.2485950	11,867	14,301	2,434	179,038	193,339	
23	Sep-2023	1,228	1	-	0.2485950	305	-	(305)	180,462	180,462	
24	Aug-2023	1,225	-	-	0.2485950	-	-	-	180,858	180,858	
25	Jul-2023	1,226	-	-	0.2485950	-	-	-	181,843	181,843	
26	Jun-2023	1,248	21	35	0.2485950	6,515	10,859	4,344	185,958	196,817	
27	May-2023	1,258	130	184	0.2485950	40,655	57,543	16,888	188,308	245,851	
28	Apr-2023	1,258	367	415	0.2485950	114,773	129,784	15,011	189,167	318,951	
29	Total	14,749	3,187	3,729		968,639	1,133,673	165,034	2,162,808	3,296,481	A

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Sum of A: 29,270,504 42

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales - For Allocation Purposes Only

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Normal Weather	Weather Adjustment	Base Gas b/	Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I
1	*DC GMA Sales Htg / HC < 3075*									
2	Mar-2024	463	516	634	0.2072500	49,514	60,837	11,323	25,732	86,569
3	Feb-2024	475	699	811	0.2072500	68,812	79,838	11,026	26,399	106,237
4	Jan-2024	460	655	763	0.2072500	62,444	72,741	10,297	25,566	98,307
5	Dec-2023	455	536	552	0.2072500	50,544	52,053	1,509	25,288	77,341
6	Nov-2023	467	223	288	0.2072500	21,583	27,874	6,291	25,955	53,829
7	Oct-2023	456	39	47	0.2072500	3,686	4,442	756	25,343	29,785
8	Sep-2023	458	1	-	0.2072500	95	-	(95)	25,454	25,454
9	Aug-2023	467	-	-	0.2072500	-	-	-	25,955	25,955
10	Jul-2023	466	-	-	0.2072500	-	-	-	25,899	25,899
11	Jun-2023	478	21	35	0.2072500	2,080	3,467	1,387	26,566	30,033
12	May-2023	481	130	184	0.2072500	12,959	18,342	5,383	26,733	45,075
13	Apr-2023	480	367	415	0.2072500	36,509	41,284	4,775	26,677	67,961
14	Total	5,606	3,187	3,729		308,226	360,878	52,652	311,567	672,445 A
15										
16	*DC GMA Sales Htg / HC > 3075*									
17	Mar-2024	765	516	634	2.4521040	967,944	1,189,295	221,351	269,155	1,458,450
18	Feb-2024	749	699	811	2.4521040	1,283,802	1,489,504	205,702	263,525	1,753,029
19	Jan-2024	757	655	763	2.4521040	1,215,839	1,416,313	200,474	266,340	1,682,653
20	Dec-2023	765	536	552	2.4521040	1,005,461	1,035,474	30,013	269,155	1,304,629
21	Nov-2023	753	223	288	2.4521040	411,755	531,773	120,018	264,933	796,706
22	Oct-2023	763	39	47	2.4521040	72,967	87,935	14,968	268,451	356,386
23	Sep-2023	771	1	-	2.4521040	1,891	-	(1,891)	271,266	271,266
24	Aug-2023	775	-	-	2.4521040	-	-	-	272,673	272,673
25	Jul-2023	780	-	-	2.4521040	-	-	-	274,432	274,432
26	Jun-2023	804	21	35	2.4521040	41,401	69,002	27,601	282,876	351,878
27	May-2023	803	130	184	2.4521040	255,975	362,303	106,328	282,525	644,828
28	Apr-2023	814	367	415	2.4521040	732,537	828,345	95,808	286,395	1,114,740
29	Total	9,299	3,187	3,729		5,989,572	7,009,944	1,020,372	3,271,726	10,281,670 A

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Sum of A: 10,954,114 42

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales - For Allocation Purposes Only

Based on 12 Months Ending Mar 2024

						< Therm Sales				
						<Weather Gas>				
Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Actual	Normal Weather	Weather Adjustment	Base Gas b/	Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I
1	*DC GMA Sales Non Htg*									
2	Mar-2024	496	516	634	0.3286500	84,113	103,349	19,236	77,424	180,773
3	Feb-2024	497	699	811	0.3286500	114,174	132,468	18,294	77,888	210,356
4	Jan-2024	491	655	763	0.3286500	105,695	123,123	17,428	77,252	200,375
5	Dec-2023	492	536	552	0.3286500	86,669	89,256	2,587	77,714	166,970
6	Nov-2023	491	223	288	0.3286500	35,985	46,474	10,489	77,861	124,335
7	Oct-2023	491	39	47	0.3286500	6,293	7,584	1,291	78,165	85,749
8	Sep-2023	492	1	-	0.3286500	162	-	(162)	78,629	78,629
9	Aug-2023	500	-	-	0.3286500	-	-	-	80,218	80,218
10	Jul-2023	501	-	-	0.3286500	-	-	-	80,688	80,688
11	Jun-2023	504	21	35	0.3286500	3,478	5,797	2,319	81,484	87,281
12	May-2023	505	130	184	0.3286500	21,576	30,538	8,962	81,959	112,497
13	Apr-2023	507	367	415	0.3286500	61,152	69,150	7,998	82,597	151,747
14	Total	5,967	3,187	3,729		519,297	607,739	88,442	951,880	1,559,619 42

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Adjustment No. 2

Washington Gas Company
District of Columbia Jurisdiction

Adjustment No. 2 - CWIP Elimination

Test Period Twelve Months Ended March 31, 2024

Line No.	Description	Reference	DC Amount
	A	B	C
1	Construction Work in Progess (CWIP)	RB 5:29	$ 2/ 79,322,274
2	Less: Projectpipes CWIP	Adj. 3	$ 3/ 13,108,574
3	Total Non-Project*pipes* CWIP per book	Ln. 1 - Ln. 2	$ 66,213,700
4	**Total Ratemaking Adjustment**		**$ (66,213,700)**

5 **Adjustment Description:** To eliminate non-PROJECT*pipes* Construction Work in Progress (CWIP) from test year ratebase.

Washington Gas Light Company
Construction Work In Progress
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	——Reference—— Allocator	WG	DC	MD	VA	FERC
	A	C	D	E	F	G	H
1	**Construction Work In Progress**						
2	Intangible	Non_Genl_Plnt	$ 9,544,190	$ 1,770,901	$ 3,521,930	$ 4,251,359	$ -
3	Intangible Situs	Financial Stmt.	259,636	-	259,636	-	$ -
4	Total Intangible		$ 9,803,825	$ 1,770,901	$ 3,781,566	$ 4,251,359	$ -
5	Storage	Total_Weather_All_NW	$ 2,055,950	$ 338,760	$ 873,583	$ 843,608	$ -
6	Storage - Chalk Point	Financial Stmt.	0	-	0	-	
7	Storage - VA Gas Reserves	Financial Stmt.					
8	Total Storage		$ 2,055,950	$ 338,760	$ 873,583	$ 843,608	
9	Transmission						
10	Spurlines and Related Regulating						
11	Equipment and Structures	Financial Stmt.	20,718,087	157,674	2,754,916	17,805,496	
12	WSSC		(1,532)		(1,532)		
13	Panda	Financial Stmt.	-	-	-	-	
14	Other	Comp_Peak_ Ann_NW	31,910,231	$ 4,975,856	$ 13,943,817	$ 12,990,559	$ -
15	Total Transmission		$ 52,626,786	$ 5,133,530	$ 16,697,201	$ 30,796,055	$ -
16	Distribution						
17	Compressor Station Equipment	Total_Weather_All_NW	-	$ -	$ -	$ -	$ -
18	Other	Financial Stmt.	302,781,574	66,743,485	102,356,539	133,681,550	
19	Mains		-	-	-	-	
20	Services		-	-	-	-	
21	Total Distribution		$ 302,781,574	$ 66,743,485	$ 102,356,539	$ 133,681,550	$ -
22	General Alloc	Non_Genl_Plnt	28,662,461	$ 5,318,248	$ 10,576,821	$ 12,767,392	$ -
23	General - Situs	Financial Stmt.	1,180,429	17,351	53,856	1,109,222	
24	General - Panda	Financial Stmt.	-	-	-	-	
25	General - Chalk Point	Financial Stmt.	-	-	-	-	
26	Total General		29,842,890	5,335,599	10,630,677	13,876,613	
27	AFUDC	Financial Stmt.	$ -	$ -	$ -	$ -	$ -
28	CNG Equipment	Financial Stmt.	$ -	$ -	$ -	$ -	
29	Total Construction Work in Progress		$ 397,111,025	$ 79,322,274 1	$ 134,339,566	$ 183,449,185	$ -

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 3 - PROJECT*pipes* Average to End of Period

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Test Year Average Amount C	Test Year EOP Amount D	Ratemaking Adjustment E = D - C
1	**Expense (12 Months)**				
2	Depreciation	EX:6:22	$ 2,719,002	$ 2,950,160	$ 231,158
3	**Net GPIS (13 Month Average)**				
4	Gas Plant in Service	RB:3:17	$ 80,506,896	$ 107,614,058	$ 27,107,163
5	Construction Work in Progress	RB:5:29	$ 13,108,574 1	$ 6,884,577	$ (6,223,998)
6	Depreciation Reserve	RB:10:35	$ 5,674,931	$ 7,264,766	$ 1,589,836
7	Cost of Removal	RB:10:35	$ (10,419,702)	$ (8,327,576)	$ 2,092,125
8	Accumulated Deferred Income Tax	RB:11:21	$ 25,914,685	$ 33,949,905	$ 8,035,220
9	Net Rate Base Change	+ Ln. 4 + Ln. 5 - Ln. 6 - Ln. 7 - Ln.8	$ 72,445,556	$ 81,611,539	$ 9,165,984

10 **Adjustment Description:** To adjust test year PROJECT*pipes* expense and rate base to end of period amounts.

Adjustment No. 3

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 3 - PROJECT*pipes* Average to End of Period

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Test Year Average Amount	Test Year EOP Amount	Ratemaking Adjustment
	A	B	C	D	E = D - C
1	**Expense (12 Months)**				
2	Depreciation	EX:6:22	$ 2/ 2,719,002	$ 2/ 2,950,160	$ 231,158
3	**Net GPIS (13 Month Average)**				
4	Gas Plant in Service	RB:3:17	$ 80,506,896	$ 107,614,058	$ 27,107,163
5	Construction Work in Progress	RB:5:29	$ 13,108,574	$ 6,884,577	$ (6,223,998)
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7	Cost of Removal	RB:10:35	$ (10,419,702)	$ (8,327,576)	$ 2,092,125
8	Accumulated Deferred Income Tax	RB:11:21	$ 25,914,685	$ 33,949,905	$ 8,035,220
9	Net Rate Base Change	+ Ln. 4 + Ln. 5 - Ln. 6 - Ln. 7 - Ln.8	$ 72,445,556	$ 81,611,539	$ 9,165,984

10 **Adjustment Description:** To adjust test year PROJECT*pipes* expense and rate base to end of period amounts.

Rate Case Roll-in	Apr-2021	Dec-2023	CAPEX/COR fix
CAPEX	(87,158,382)	(48,192,719)	12,586,515
COR	(12,345,787)	(5,605,982)	
Net Plant Additions	(82,265,209)	(48,192,719)	
Accumulated Depreciation	(3,439,343)	(1,027,471)	
ADIT	26,434,638	13,318,862	
Depreciation Exp		74,776	

ADIT Fix		
Oct 2019 (for Aug'22 - Jun'23)	670,282	(1,340,563)
Dec 2021 (revised in Mar 2024)	(909,671)	

	a	b	c	d = a - c	e = b	f = c	g = e + f				
		Cumulative	Cumulative							Net Rate Base	Depreciation
	CAPEX	COR	Additions	CWIP	COR	GPIS	COR+GPIS	Accum Depr	Accum ADIT	calc	Expense
Mar-23	78,169,502	7,119,139	69,704,737	8,464,765	7,119,139	69,704,737	76,823,876	4,257,105	(19,188,605)	61,842,931	193,402
Apr-23	79,680,922	7,400,682	73,063,216	6,617,706	7,400,682	73,063,216	80,463,898	4,473,306	(20,130,755)	62,477,543	201,230
May-23	86,251,892	8,165,019	76,860,667	9,391,225	8,165,019	76,860,667	85,025,686	4,696,051	(21,324,751)	68,396,108	208,403
Jun-23	94,233,310	9,123,050	79,833,936	14,399,374	9,123,050	79,833,936	88,956,986	4,924,067	(22,343,803)	76,088,490	215,090
Jul-23	97,996,288	9,476,232	82,221,895	15,774,394	9,476,232	82,221,895	91,698,127	5,156,200	(23,034,219)	79,282,102	221,022
Aug-23	102,103,620	9,852,370	81,858,244	20,245,377	9,852,370	81,858,244	91,710,614	5,388,300	(22,973,787)	83,593,904	225,158
Sep-23	107,115,835	10,407,683	85,276,357	21,839,478	10,407,683	85,276,357	95,684,040	5,626,239	(24,001,699)	87,895,579	229,316
Oct-23	112,512,633	11,263,817	89,293,535	23,219,098	11,263,817	89,293,535	100,557,352	5,862,543	(25,277,688)	92,636,219	231,835
Nov-23	119,953,395	12,622,825	105,862,049	14,091,347	12,622,825	105,862,049	118,484,874	6,148,416	(30,132,229)	96,295,575	246,268
Dec-23	125,952,572	13,721,218	111,426,231	14,526,340	13,721,218	111,426,231	125,147,449	6,422,844	(31,890,087)	101,360,858	256,480
Jan-24	128,410,818	14,436,458	116,792,759	11,618,059	14,436,458	116,792,759	131,229,217	6,585,997	(28,905,425)	107,355,855	141,688
Feb-24	121,159,870	13,540,052	117,820,143	3,339,726	13,540,052	117,820,143	131,360,196	6,968,265	(33,737,953)	93,993,704	267,910
Mar-24	127,085,150	8,327,576	120,200,574	6,884,577	8,327,576	120,200,574	128,528,150	7,264,766	(33,949,905)	94,198,055	274,601
13 mo average	106,201,985	10,419,702	93,093,411	13,108,574	10,419,702	93,093,411	103,513,113	5,674,931	(25,914,685)	85,032,071	
12 mo sum											2,719,002
									0.002284522		0.029207241
									107614058.3		0.027414259

CAPEX Correction (to remove disallowed CAPEX spending from cummulative additions)

	EOP	AVG			Accum Depr	Accum ADIT	Depreciation Expense
					274,601	245,847	274,601
CAPEX	120,200,574	93,093,411			12	12	(28,754.17)
Disallowed	(12,586,515)	(12,586,515)	(28,754.17)	345,049.99	3,295,210	2,950,160	
Revised Total	107,614,058	80,506,896			120,200,574	107,614,058	245,846.64
					0.03	0.03	2,950,159.65

	EOP	AVG
Net Rate Base	94,198,055	85,032,071
Disallowed	(12,586,515)	(12,586,515)
Revised Total	81,611,539	72,445,556

Exhibit WG (D)-5
Adjustment No. 3
Page 2 of 2

Adjustment No. 4

Washington Gas Light Company
District of Columbia Jurisdiction
Adjustment No. 4 - New Depreciation Rates
Twelve Months Ended Mar 31, 2024

Line No.	Description	Reference	Depreciable Property	PROJECT*pipes* Adjustment	Depreciation Rates	Amount
	A	B	C	D	E	F = C × E or D × E
1	**Property Other Than PROJECTpipes**					
2	Intangible - Capitalized Software	SM 1:7				$ 3,757,163
3	Storage	RB 2:3	2/ 12,565,793		4/ 1.90%	238,986
4	Transmission					
5	Spurlines & Related Regulating					
6	Equipment and Structures	RB 2:8	2/ 56,197,740		4/ 1.37%	$ 767,826
7	Other	RB 2:12	2/ 108,628,696		4/ 2.42%	2,631,286
8	Total Transmission	Ln. 6 + Ln. 7				$ 3,399,112
9	Distribution					
10	Compressor Station Equipment	RB 2:18	2/ 450,802		5/ 3.71%	$ 16,745
11	Other	Sum of RB 2:1-28 Less ARO	2/ 1,030,846,267		5/ 2.60%	26,829,544
12	Total Distribution	Ln. 10 + Ln. 11				$ 26,846,289
13	General					
14	Enscan	Analysis	3/ 11,557,700		5/ 5.93%	$ 685,372
15	Other - Direct	Analysis	3/ 7,234		8/ 4.52%	327
16	Other - Allocable	Sum of RB 2:35-36 - Ln. 14	2/ 52,462,958		8/ 4.52%	2,371,212
17	Total General	Ln. 15 + Ln. 16				$ 3,056,911
18	Ratemaking Depreciation Expense - Safety Plant	Sum of Lns. 2,3,8,12,17				$ 37,298,461
19	Less: Per Book Depreciation Expense	Sum of SM1:6+7+9				29,542,876
20	**Tatal Adjustment Other Than PROJECTpipes**	Ln. 18 - Ln. 19				$ 7,755,586
21	**PROJECTpipes**					
22	PROJECTpipes Net Rate Base (EOP)	Adjustment No. 3, Ln. 9		9/ 107,614,058	7/ 2.68%	$ 2,886,239
23	PROJECTpipes Depreciation Expense (EOP)	Adjustment No. 3, Ln. 2				2,950,160
24	**Total PROJECT*pipes* Depreciation Expense Adjustment**	Ln. 22 - Ln. 23				$ (63,921)
25	**Total Depreciation Expense Adjustment**	Ln. 20 + Ln. 22				$ 7,691,665
26	**Reserve for Depreciation**					
27	Reserve for Depreciation adjustment based on Other than PROJECTpipes	Analysis	7,755,586	One Half Year		$ 3,877,793
28	Reserve for Depreciation adjustment based on Adjusted Gas Plant in Service - PROJECTpipes	Adjustment No. 3, Ln. 6	(63,921)	EOP		$ (63,921)
29	**Total Reserve for Depreciation Adjustment**	Ln. 27 + Ln. 28				$ 3,813,872
30	**ADIT**					
31	Reserve Adjsutmentn Other than project pies	Ln. 20				$ 3,877,793
32	Composite Tax Rate	Composite Tax Rate Calc				10/ 27.52%
33	ADIT Adjustment - Other that project pipes	Ln. 31 * Ln. 32				$ 1,067,072
34	Deferred Tax Basis - PROJECTpipes	Ln. 24				$ (63,921)
35	Composite Tax Rate	Composite Tax Rate Calc				10/ 27.52%
36	ADIT Adjustment - PROJECTpipes	Ln. 34 * Ln. 35				$ (17,589)
37	**Total ADIT Adjustment**	Ln. 33 + Ln. 36				$ 1,049,482

38 **Adjustment Description:** To reflect the depreciation expense based on the 2024 Depreciation Rate Study, on 13 months average depreciable gas plant in service as of March
39 31, 2024. Also including expense related to Pro Forma safety related projects through Mar 2024. Also to synchronize depreciation reserve with the depreciation expense
40 Deferred Income Taxes for Safety and PROJECTpipes Plant.

NOTES: General Other includes amortized plant (Office Furn, & Equip., Stores, Comm. Equip, etc.) and depreciable plant (Stuctures and Improv.).

Exhibit WG (D)-5
Adjustment No. 4
Page 2 of 10

Washington Gas Light Company
Depreciable Gas Plant In Service
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description A	—— Reference —— Sc-Pg-Ln B	Allocator C	WG D	DC E	MD F	VA G	FERC H
1	**Depreciable Gas Plant In Service**							
2	Capitalized Software	AL:2:23	Non_Genl_Plnt	$ 168,881,787	$ 31,956,957	$ 62,038,051	$ 74,886,780	$ -
3	Storage	AL:1:19	Total_Weather_All_NW	76,262,465	$ 12,565,793	$ 32,404,277	$ 31,292,394	$ -
4	Storage - AFUDC		Financial Stmt.	(511,776)	-	-	(511,776)	0
5	Total Storage	= 3 + 4		$ 75,750,689	$ 12,565,793 (1)	$ 32,404,277	$ 30,780,618	$ -
6	Transmission							
7	Spurlines and Related Regulating							
8	Equipment and Structures		Financial Stmt.	$ 414,164,974	$ 56,197,740 (1)	$ 120,198,620	$ 209,444,575	$ 28,324,039
9	WSSC			5,547	-	5,547	-	-
10	ChalkPoint		Financial Stmt.	13,995,741	-	13,995,741	-	-
11	Panda		Financial Stmt.	2,034,808	-	2,034,808	-	-
12	Other	AL:1:32	Comp_Peak_Ann_NW	696,637,349	108,628,696 (1)	304,409,695	283,598,957	-
13	Transmission Mains - ARO			6,956,762	2,515	3,954,742	2,999,506	-
14	Post 1989 MD Interruptible Customers		Financial Stmt.	2,477,416	-	2,477,416	-	-
15	AFUDC		Financial Stmt.	(5,268,645)	-	-	(5,268,645)	0
16	Total Transmission	= 8 > 15		$ 1,131,003,953	$ 164,828,951	$ 447,076,569	$ 490,774,393	$ 28,324,039
17	Distribution							
18	Compressor Station Equipment	AL:1:19	Total_Weather_All_NW	$ 2,735,941	$ 450,802 (1)	$ 1,162,514	$ 1,122,625	$ -
19	Mains		Financial Stmt.	2,573,799,925	A. 549,032,913	887,779,494	1,136,987,518	-
20	Distribution Mains - ARO			61,255,520	1,086,978	34,552,539	25,616,002	-
21	Measuring and Regulator Station Equipment		Financial Stmt.	17,875,325	A. 10,637,047	4,323,013	2,915,266	-
22	Services		Financial Stmt.	2,297,650,823	A. 399,729,625	873,174,680	1,024,746,517	-
23	Distribution Services - ARO			61,635,355	967,723	35,467,125	25,200,508	-
24	Meters		Financial Stmt.	138,243,994	A. 26,892,685	53,287,464	58,063,846	-
25	Meter Installations		Financial Stmt.	252,239,013	35,970,717	91,047,414	125,220,882	-
26	House Regulators		Financial Stmt.	43,226,309	4,731,358	15,452,640	23,042,310	-
27	House Regulator Installations		Financial Stmt.	15,195,671	3,744,785	6,522,287	4,928,599	-
28	Gas Light Services		Financial Stmt.	5,022,656	107,137	1,977,956	2,937,563	-
29	Post 1989 MD Interruptible Customers		Financial Stmt.	2,917,888	-	2,917,888	-	-
30	AFUDC		Financial Stmt.	(17,294)	-	-	(17,294)	-
31	Total Distribution	= 18 > 30		$ 5,471,781,126	$ 1,033,351,770	$ 2,007,665,014	$ 2,430,764,342	$ -
32	General							
33	Transportation	AL:2:23	Non_Genl_Plnt	$ 42,991,069	$ 7,947,207	$ 15,805,240	$ 19,078,670	$ 159,953
34	POE	AL:2:23	Non_Genl_Plnt	4,988,314	922,126	1,833,904	2,213,725	18,560
35	Other - Direct		Financial Stmt.	65,528,429	11,564,934 (3)	36,619,764	17,343,732	-
36	Other - Allocable	AL:2:23	Non_Genl_Plnt	283,802,687	52,462,958 (1)	104,337,239	125,946,573	1,055,916
37	AFUDC		Financial Stmt.	(5,105,363)	-	-	(5,105,363)	-
38	Total General	= 33 > 37		$ 392,205,136	$ 72,897,224	$ 158,596,147	$ 159,477,337	$ 1,234,428
39	CNG Equipment		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
40	CIAC - GPIS		Financial Stmt.	-	-	-	-	
41	CIAC - Liability		Financial Stmt.	-	-	-	-	
42	Total Depreciable Gas Plant in Service	sum of (2,5,16,31,38,39,40,41)		$ 7,239,622,691	$ 1,315,600,695	$ 2,707,780,058	$ 3,186,683,470	$ 29,558,468

sum of A. = 1,030,846,267 (1)

Washington Gas
Maryland

Depreciation Expense Workpaper
General Plant - Enscan

CUBE:	tm1serv:PP & GPIS Cube_Version
tm1serv:PP_GPIS_Company	01 DC Washington Gas Light Company
tm1serv:PP_GPIS_gl_account	101000 Gas Plant In Service
	101000 Gas Plant Non-Unitized
GL Version	Actual

General Plant - Enscan

	General - Comm Equip Enscan		Gen. - Comm Equip TAMRD		Total	
Mar-2023	$	11,314,494	$	-	$	11,314,494
Apr-2023	$	11,331,478	$	-	$	11,331,478
May-2023	$	11,370,592	$	-	$	11,370,592
Jun-2023	$	11,370,592	$	-	$	11,370,592
Jul-2023	$	11,455,900	$	-	$	11,455,900
Aug-2023	$	11,521,876	$	-	$	11,521,876
Sep-2023	$	11,630,355	$	-	$	11,630,355
Oct-2023	$	11,717,418	$	-	$	11,717,418
Nov-2023	$	11,746,111	$	-	$	11,746,111
Dec-2023	$	11,521,899	$	-	$	11,521,899
Jan-2024	$	11,521,899	$	-	$	11,521,899
Feb-2024	$	11,853,420	$	-	$	11,853,420
Mar-2024	$	11,894,061	$	-	$	11,894,061
13 Month Total	$	150,250,097	$	-	$	150,250,097
		13		13		13
13 Month Average	$	11,557,700	$	-	$	A. 11,557,700 ①

2/ A.

$\boxed{11{,}564{,}934 - 11{,}557{,}700 = 7{,}234}$ ①

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA

Statement A

Comparison of Current and SFAS 143 Accrual Rates
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.35 Percent

	Account Description	Current Investment	Current Net Salvage	Current Total	SFAS 143 Investment	SFAS 143 Net Salvage	SFAS 143 Total	Difference
	A	B	C	D=B+C	E	F	G=E+F	H=G-D
STORAGE AND PROCESSING PLANT								
Allocated Property								
361.00	Structures and Improvements							
0.00	Maryland (Rockville)	2.39%	0.76%	3.15%	2.06%	0.44%	2.50%	0.76%
0.00	Virginia (Ravensworth)	2.47%	0.50%	2.97%	2.11%	0.42%	2.53%	0.50%
	Total Account 361.00	2.43%	0.64%	3.06%	2.08%	0.43%	2.51%	0.00%
362.00	Gas Holders							
0.00	Maryland (Rockville)	1.69%	0.57%	2.26%	1.11%	0.27%	1.38%	0.57%
0.00	Virginia (Ravensworth)	1.79%	0.34%	2.13%	1.51%	0.29%	1.80%	0.34%
	Total Account 362.00	1.74%	0.47%	2.20%	1.29%	0.28%	1.57%	0.00%
363.50	Other Equipment							
0.00	Maryland (Rockville)	5.37%	0.11%	5.48%	2.24%	0.05%	2.29%	0.11%
0.00	Virginia (Ravensworth)	1.97%	1.54%	3.51%	2.90%	0.42%	3.32%	1.54%
	Total Account 363.50	3.93%	0.72%	4.64%	2.52%	0.21%	2.73%	0.00%
Total Allocated Property		2.14%	0.53%	2.67%	1.60%	0.30%	1.90%	0.00%
Total Storage and Processing Plant		2.14%	0.53%	2.67%	1.60%	0.30%	1.90% 1	0.00%
TRANSMISSION PLANT								
Assigned Property								
365.20	Rights of Way	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
366.00	Meas. and Reg. Station Structures	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
367.10	Mains - Steel	0.50%	0.10%	0.60%	1.09%	0.14%	1.23%	0.10%
369.00	Measuring and Regulating Equipment	1.09%	0.20%	1.29%	1.18%	0.26%	1.44%	0.20%
Total Assigned Property		0.88%	0.16%	1.05%	1.15%	0.22%	1.37% 1	0.00%
Allocated Property								
365.20	Rights of Way							
0.00	District	0.33%	0.00%	0.33%	-4.47%	0.00%	-4.47%	0.00%
0.00	Maryland	1.60%	0.00%	1.60%	1.40%	0.00%	1.40%	0.00%
0.00	Virginia	1.15%	0.00%	1.15%	0.73%	0.00%	0.73%	0.00%
	Total Account 365.20	1.45%	0.00%	1.45%	1.17%	0.00%	1.17%	0.00%
366.00	Meas. and Reg. Station Structures							
0.00	Maryland	0.33%	1.24%	1.57%	2.13%	1.01%	3.14%	1.24%
0.00	Virginia	1.33%	0.02%	1.35%	2.06%	0.21%	2.27%	0.02%
	Total Account 366.00	1.19%	0.19%	1.38%	2.00%	0.39%	2.39%	0.00%
367.10	Mains - Steel							
0.00	District	1.05%	0.10%	1.15%	1.66%	0.14%	1.80%	0.10%
0.00	Maryland	1.44%	-0.03%	1.41%	1.67%	-0.11%	1.56%	-0.03%
0.00	Virginia	1.47%	0.10%	1.57%	1.67%	0.08%	1.75%	0.10%
	Total Account 367.10	1.43%	0.05%	1.48%	1.67%	0.01%	1.68%	0.00%
369.00	Measuring and Regulating Equipment							
0.00	District	-0.18%	0.20%	0.02%	-1.06%	0.26%	-0.80%	0.20%
0.00	Maryland	0.29%	2.40%	2.69%	-0.70%	7.49%	6.79%	2.40%
0.00	Virginia	0.55%	0.00%	0.55%	-0.92%	-4.95%	-5.87%	0.00%
	Total Account 369.00	0.33%	1.79%	2.13%	-0.76%	4.49%	3.73%	0.00%
Total Allocated Property		1.04%	0.66%	1.69%	0.85%	1.57%	2.42% 1	0.00%
Total Transmission Plant		1.01%	0.56%	1.57%	0.91%	1.32%	2.22%	0.00%
DISTRIBUTION PLANT								
Assigned Property								
375.00	Structures and Improvements	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
376.10	Mains - Steel	0.87%	0.39%	1.26%	1.22%	0.62%	1.84%	0.39%
376.20	Mains - Plastic	1.53%	0.57%	2.10%	1.80%	0.86%	2.66% 7	0.57%
376.30	Mains - Cast Iron	-1.78%	1.14%	-0.64%	0.86%	1.88%	2.74%	1.14%
378.00	Measuring and Regulating Equipment	1.08%	0.11%	1.19%	2.00%	0.24%	2.24%	0.11%
380.10	Services - Steel	1.18%	0.91%	2.09%	1.63%	0.69%	2.32%	0.91%
380.20	Services - Plastic	1.42%	0.73%	2.15%	1.79%	0.92%	2.71% 7	0.73%
380.30	Services - Copper	-1.86%	1.46%	-0.40%	1.34%	1.39%	2.73%	1.46%
381.20	Meters - Hard Case	3.13%	0.00%	3.13%	3.80%	0.00%	3.80%	0.00%

Statement A

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
Comparison of Current and SFAS 143 Accrual Rates
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.35 Percent

	Current			SFAS 143			
Account Description	Investment	Net Salvage	Total	Investment	Net Salvage	Total	Difference
A	B	C	D=B+C	E	F	G=E+F	H=G-D
381.30 Meters - Electronic Devices	2.39%	0.00%	2.39%	4.99%	0.00%	4.99%	0.00%
381.50 Meters - Electronic Demand Recorders	-0.33%	0.00%	-0.33%	2.18%	0.00%	2.18%	0.00%
382.00 Meter Installations	1.42%	0.12%	1.54%	2.09%	0.16%	2.25%	0.12%
383.00 House Regulators	1.76%	1.52%	3.28%	2.59%	1.87%	4.46%	1.52%
384.00 House Regulator Installations	1.51%	0.00%	1.51%	1.75%	0.12%	1.87%	0.00%
386.20 Gas Lights	-0.10%	2.49%	2.39%	1.92%	2.74%	4.66%	2.49%
Total Assigned Property	1.41%	0.60%	2.01%	1.80%	0.81%	2.60%	0.00%
Allocated Property							
375.00 Structures and Improvements							
0.00 District	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.00 Maryland	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.00 Virginia	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Account 375.00							
377.00 Compressor Station Equipment							
0.00 District	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.00 Maryland	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.00 Virginia	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Account 377.00			0.00%	0.00%	0.00%	0.00%	0.00%
378.00 Measuring and Regulating Equipment							
0.00 District	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
0.00 Maryland	3.85%	-0.10%	3.75%	3.37%	0.35%	3.72%	-0.10%
0.00 Virginia	5.21%	0.55%	5.76%	3.35%	0.33%	3.68%	0.55%
Total Account 378.00	4.04%	-0.01%	4.03%	3.37%	0.35%	3.71%	0.00%
Total Allocated Property	4.04%	-0.01%	4.03%	3.37%	0.35%	3.71% 1	0.00%
Total Distribution Plant	1.41%	0.60%	2.01%	1.80%	0.81%	2.60% 1	0.00%
GENERAL PLANT							
Allocated Property (Depreciable)							
390.00 Structures and Improvements							
0.00 District	2.14%	0.21%	2.35%	2.06%	0.14%	2.20%	0.21%
0.00 Maryland	2.27%	0.14%	2.41%	1.99%	0.23%	2.22%	0.14%
0.00 Virginia	1.96%	0.20%	2.16%	1.99%	0.20%	2.19%	0.20%
Total Account 390.00	2.03%	0.19%	2.22%	1.99%	0.20%	2.20%	0.00%
Total Allocated Property (Depreciable)	2.03%	0.19%	2.22%	1.99%	0.20%	2.20%	0.00%
Assigned Property (Amortizable)							
303.05 Software - 5 year	20.00%	0.00%	20.00%	← 5 Year Amortization →		20.00%	0.00%
303.06 Software (DC POR) - 10 year	10.00%	0.00%	10.00%	← 10 Year Amortization →		10.00%	0.00%
303.10 Software - 10 year	10.00%	0.00%	10.00%	← 10 Year Amortization →		10.00%	0.00%
391.10 Office Furniture and Equipment (DC POR)	5.00%	0.00%	5.00%	← 20 Year Amortization →		5.00%	0.00%
391.11 Office Furniture and Equipment	5.00%	0.00%	5.00%	← 20 Year Amortization →		5.00%	0.00%
391.21 Computer Equipment	14.29%	0.00%	14.29%	← 7 Year Amortization →		14.29%	0.00%
393.00 Stores Equipment	5.00%	0.00%	5.00%	← 20 Year Amortization →		5.00%	0.00%
394.00 Tools, Shop & Garage Equipment	5.00%	0.00%	5.00%	← 20 Year Amortization →		5.00%	0.00%
395.00 Laboratory Equipment	5.00%	0.00%	5.00%	← 15 Year Amortization →		5.00%	0.00%
397.10 Communication Equipment - Telephones	0.00%	0.00%	0.00%			0.00%	0.00%
397.20 ENSCAN Equipment	5.93%	0.00%	5.93%	← 18 Year Amortization →		5.93% 1	0.00%
397.30 TRACE - AMR Devices	0.00%	0.00%	0.00%			0.00%	0.00%
398.00 Miscellaneous Equipment	6.67%	0.00%	6.67%	← 15 Year Amortization →		6.67%	0.00%
Total Assigned Property (Amortizable)	7.49%	0.00%	7.49%	7.49%	0.00%	7.49%	0.00%
Total General Plant	5.50%	0.07%	5.57%	5.49%	0.07%	5.56%	0.00%
TOTAL JURISDICTION	1.64%	0.56%	2.21%	1.97%	0.79%	2.75%	0.00%

Exhibit WG (D)-5
Adjustment No. 4
Page 6 of 10

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA — Statement B

Comparison of Current and SFAS 143 Accruals
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.35 Percent

	Account Description	12/31/23 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Investment	SFAS 143 Net Salvage	SFAS 143 Total	Difference
	A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STORAGE AND PROCESSING PLANT									
Allocated Property									
361.00	Structures and Improvements								
0.00	Maryland (Rockville)	$ 1,311,110	$ 31,336	$ 9,965	$ 41,301	$ 27,009	$ 5,769	$ 32,778	$ (8,523)
0.00	Virginia (Ravensworth)	1,183,946	29,243	5,919	35,162	24,981	4,973	29,954	(5,208)
	Total Account 361.00	$ 2,495,056	$ 60,579	$ 15,884	$ 76,463	$ 51,990	$ 10,742	$ 62,732	$ (13,731)
362.00	Gas Holders								
0.00	Maryland (Rockville)	$ 4,460,885	$ 75,389	$ 25,427	$ 100,816	$ 49,516	$ 12,044	$ 61,560	$ (39,256)
0.00	Virginia (Ravensworth)	3,676,243	65,805	12,500	78,305	55,511	10,661	66,172	(12,133)
	Total Account 362.00	$ 8,137,128	$ 141,194	$ 37,927	$ 179,121	$ 105,027	$ 22,705	$ 127,732	$ (51,389)
363.50	Other Equipment								
0.00	Maryland (Rockville)	$ 818,973	$ 43,979	$ 900	$ 44,879	$ 18,345	$ 409	$ 18,754	$ (26,125)
0.00	Virginia (Ravensworth)	604,207	11,903	9,305	21,208	17,522	2,538	20,060	(1,148)
	Total Account 363.50	$ 1,423,180	$ 55,882	$ 10,205	$ 66,087	$ 35,867	$ 2,947	$ 38,814	$ (27,273)
	Total Allocated Property	$ 12,055,364	$ 257,655	$ 64,016	$ 321,671	$ 192,884	$ 36,394	$ 229,278	$ (92,393)
	Total Storage and Processing Plant	$ 12,055,364	$ 257,655	$ 64,016	$ 321,671	$ 192,884	$ 36,394	$ 229,278	$ (92,393)
TRANSMISSION PLANT									
Assigned Property									
365.20	Rights of Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
366.00	Meas. and Reg. Station Structures	0	0	0	0	0	0	0	0
367.10	Mains - Steel	4,258,093	21,290	4,258	25,548	46,413	5,961	52,374	26,826
369.00	Measuring and Regulating Equipment	7,874,665	85,834	15,749	101,583	92,921	20,474	113,395	11,812
	Total Assigned Property	$ 12,132,758	$ 107,124	$ 20,007	$ 127,131	$ 139,334	$ 26,435	$ 165,769	$ 38,638
Allocated Property									
365.20	Rights of Way								
0.00	District	$ 470	$ 2	$ -	$ 2	$ (21)	$ -	$ (21)	$ (23)
0.00	Maryland	803,227	12,852	0	12,852	11,245	0	11,245	(1,607)
0.00	Virginia	401,040	4,612	0	4,612	2,928	0	2,928	(1,684)
	Total Account 365.20	$ 1,204,737	$ 17,466	$ -	$ 17,466	$ 14,152	$ -	$ 14,152	$ (3,314)
366.00	Meas. and Reg. Station Structures								
0.00	Maryland	$ 499,988	$ 1,650	$ 6,200	$ 7,850	$ 10,650	$ 5,050	$ 15,700	$ 7,850
0.00	Virginia	3,153,657	41,944	631	42,575	64,965	6,623	71,588	29,013
	Total Account 366.00	$ 3,653,645	$ 43,594	$ 6,831	$ 50,425	$ 75,615	$ 11,673	$ 87,288	$ 36,863
367.10	Mains - Steel								
0.00	District	$ 1,833,775	$ 19,255	$ 1,834	$ 21,089	$ 30,441	$ 2,567	$ 33,008	$ 11,919
0.00	Maryland	11,899,374	171,351	(3,570)	167,781	198,720	(13,089)	185,631	17,850
0.00	Virginia	15,473,955	227,467	15,473	242,940	258,415	12,379	270,794	27,854
	Total Account 367.10	$ 29,207,104	$ 418,073	$ 13,737	$ 431,810	$ 487,576	$ 1,857	$ 489,433	$ 57,623
369.00	Measuring and Regulating Equipment								
0.00	District	$ 599,848	$ (1,080)	$ 1,200	$ 120	$ (6,358)	$ 1,560	$ (4,798)	$ (4,918)
0.00	Maryland	13,331,810	38,662	319,963	358,625	(93,323)	998,553	905,230	546,605
0.00	Virginia	3,963,721	21,800	0	21,800	(36,466)	(196,204)	(232,670)	(254,470)
	Total Account 369.00	$ 17,895,379	$ 59,382	$ 321,163	$ 380,545	$ (136,147)	$ 803,909	$ 667,762	$ 287,217

A. B.
454,106,167 + 357,615,007 = 811,721,174

454,106,167/811,721,174 = 0.56
357,615, 007/811,721,174 = 0.44

4/
0.56*2.660% = 1.488%
0.44*2.710% = 1.194%
4/

1.488% + 1.194% = 2.682% 1

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
Comparison of Current and SFAS 143 Accruals
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.35 Percent

Statement B

	Account Description	12/31/23 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Investment	SFAS 143 Net Salvage	SFAS 143 Total	Difference
	A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
	Total Allocated Property	$ 51,960,865	$ 538,515	$ 341,731	$ 880,246	$ 441,196	$ 817,439	$ 1,258,635	$ 378,389
	Total Transmission Plant	$ 64,093,623	$ 645,639	$ 361,738	$ 1,007,377	$ 580,530	$ 843,874	$ 1,424,404	$ 417,027
	DISTRIBUTION PLANT								
	Assigned Property								
375.00	Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
376.10	Mains - Steel	96,886,105	842,909	377,856	1,220,765	1,182,010	600,694	1,782,704	561,939
376.20	Mains - Plastic	454,106,167 A.	6,947,824	2,588,405	9,536,229	8,173,911	3,905,313	12,079,224	2,542,995
376.30	Mains - Cast Iron	6,002,962	(106,853)	68,434	(38,419)	51,625	112,856	164,481	202,900
378.00	Measuring and Regulating Equipment	11,225,235	121,233	12,348	133,581	224,505	26,941	251,446	117,865
380.10	Services - Steel	53,992,928	637,117	491,336	1,128,453	880,085	372,551	1,252,636	124,183
380.20	Services - Plastic	357,615,007 B.	5,078,133	2,610,590	7,688,723	6,401,309	3,290,058	9,691,367	2,002,644
380.30	Services - Copper	3,030,970	(56,376)	44,252	(12,124)	40,615	42,130	82,745	94,869
381.20	Meters - Hard Case	23,438,610	733,628	0	733,628	890,667	0	890,667	157,039
381.30	Meters - Electronic Devices	2,491,253	59,541	0	59,541	124,314	0	124,314	64,773
381.50	Meters - Electronic Demand Recorders	852,990	(2,815)	0	(2,815)	18,595	0	18,595	21,410
382.00	Meter Installations	35,599,234	505,509	42,719	548,228	744,024	56,959	800,983	252,755
383.00	House Regulators	4,735,146	83,339	71,974	155,313	122,640	88,547	211,187	55,874
384.00	House Regulator Installations	3,728,682	56,303	0	56,303	65,252	4,474	69,726	13,423
386.20	Gas Lights	107,165	(107)	2,668	2,561	2,058	2,936	4,994	2,433
	Total Assigned Property	$ 1,053,812,454	$ 14,899,385	$ 6,310,582	$ 21,209,967	$ 18,921,610	$ 8,503,459	$ 27,425,069	$ 6,215,102
	Allocated Property								
375.00	Structures and Improvements								
0.00	District	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
0.00	Maryland	0	0	0	0	0	0	0	0
0.00	Virginia	0	0	0	0	0	0	0	0
	Total Account 375.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
377.00	Compressor Station Equipment								
0.00	District	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
0.00	Maryland	0	0	0	0	0	0	0	0
0.00	Virginia	0	0	0	0	0	0	0	0
	Total Account 377.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
378.00	Measuring and Regulating Equipment								
0.00	District	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
0.00	Maryland	170,682	6,571	(171)	6,400	5,752	597	6,349	(51)
0.00	Virginia	28,078	1,463	154	1,617	941	93	1,034	(583)
	Total Account 378.00	$ 198,760	$ 8,034	$ (17)	$ 8,017	$ 6,693	$ 690	$ 7,383	$ (634)
	Total Allocated Property	$ 198,760	$ 8,034	$ (17)	$ 8,017	$ 6,693	$ 690	$ 7,383	$ (634)
	Total Distribution Plant	$ 1,054,011,214	$ 14,907,419	$ 6,310,565	$ 21,217,984	$ 18,928,303	$ 8,504,149	$ 27,432,452	$ 6,214,468
	GENERAL PLANT								
	Allocated Property (Depreciable)								
390.00	Structures and Improvements	0							
0.00	District	$ 607,056	$ 12,991	$ 1,275	$ 14,266	$ 12,505	$ 850	$ 13,355	$ (911)
0.00	Maryland	5,474,473	124,271	7,664	131,935	108,942	12,591	121,533	(10,402)
0.00	Virginia	20,131,767	394,583	40,264	434,847	400,622	40,264	440,886	6,039

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA Statement B

Comparison of Current and SFAS 143 Accruals
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.35 Percent

Account Description	12/31/23 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Investment	SFAS 143 Net Salvage	SFAS 143 Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Total Account 390.00	$ 26,213,296	$ 531,845	$ 49,203	$ 581,048	$ 522,069	$ 53,705	$ 575,774	$ (5,274)
Total Allocated Property (Depreciable)	$ 26,213,296	$ 531,845	$ 49,203	$ 581,048	$ 522,069	$ 53,705	$ 575,774	$ (5,274)
Assigned Property (Amortizable)							0	
303.05 Software - 5 year	$ 3,181,844 B.	$ 636,369	$ -	$ 636,369	636,369 G	$ -	$ 636,369	$ -
303.06 Software (DC POR) - 10 year	762,920 C.	76,292	0	76,292	76,292 H.	0	76,292	0
303.10 Software - 10 year	14,210,276	1,421,028	0	1,421,028	1,421,028	0	1,421,028	0
391.10 Office Furniture and Equipment (DC POR)	7,234	362	0	362	362	0	362	0
391.11 Office Furniture and Equipment	3,831,631	191,582	0	191,582	191,582	0	191,582	0
391.21 Computer Equipment	1,902,016	271,798	0	271,798	271,798	0	271,798	0
393.00 Stores Equipment	31,298	1,565	0	1,565	1,565	0	1,565	0
394.00 Tools, Shop & Garage Equipment	2,286,711	114,336	0	114,336	114,336	0	114,336	0
395.00 Laboratory Equipment	18,011	901	0	901	901	0	901	0
397.10 Communication Equipment - Telephones	7,532,335	0	0	0	0	0	0	0
397.20 ENSCAN Equipment	11,521,899 D.	683,249	0	683,249	683,249 F.	0	683,249	0
397.30 TRACE - AMR Devices	0	0	0	0	0	0	0	0
398.00 Miscellaneous Equipment	414,859	27,671	0	27,671	27,671	0	27,671	0
Total Assigned Property (Amortizable)	$ 45,701,034	$ 3,425,153	$ -	$ 3,425,153	$ 3,425,153	$ -	$ 3,425,153	$ -
Total General Plant	$ 71,914,330 A.	$ 3,956,998	$ 49,203	$ 4,006,201	$ 3,947,222 E.	$ 53,705	$ 4,000,927	$ (5,274)
TOTAL JURISDICTION	$ 1,202,074,531	$ 19,767,711	$ 6,785,522	$ 26,553,233	$ 23,648,939	$ 9,438,122	$ 33,087,061	$ 6,533,828

0.00
0.00

RA calculation:

General Plant Other Depreciation Rate Calculation

Total Genetal Plant	$ A. 71,914,330	$ E. 3,947,222
Less:		
software - 5 yr	$ B. 3,181,844	$ F. 636,369
software - 10 yr	$ C. 762,920	$ G. 76,292
Enscan	$ D. 11,521,899	$ H. 683,249
	$ 56,447,667	$ 2,551,312

General Plant Other Depreciation Rate 4.52% 1

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 3 - PROJECT*pipes* Average to End of Period

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Test Year Average Amount C	Test Year EOP Amount D	Ratemaking Adjustment E = D - C
1	**Expense (12 Months)**				
2	Depreciation	EX:6:22	$ 2,719,002	$ 2,950,160	$ 231,158
3	**Net GPIS (13 Month Average)**				
4	Gas Plant in Service	RB:3:17	$ 80,506,896	$ 107,614,058 1	$ 27,107,163
5	Construction Work in Progress	RB:5:29	$ 13,108,574	$ 6,884,577	$ (6,223,998)
6	Depreciation Reserve	RB:10:35	$ 5,674,931	$ 7,264,766	$ 1,589,836
7	Cost of Removal	RB:10:35	$ (10,419,702)	$ (8,327,576)	$ 2,092,125
8	Accumulated Deferred Income Tax	RB:11:21	$ 25,914,685	$ 33,949,905	$ 8,035,220
9	Net Rate Base Change	+ Ln. 4 + Ln. 5 - Ln. 6 - Ln. 7 - Ln.8	$ 72,445,556	$ 81,611,539	$ 9,165,984

10 **Adjustment Description:** To adjust test year PROJECT*pipes* expense and rate base to end of period amounts.

Calculation of Composite tax rate

State Income Taxes	8.25%
Federal Income Taxes (.21% * (1-(8.25%))	19.27%
Composite Tax Rate	27.52% 1

Adjustment No. 5

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 5 - Wages and Salaries Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Frederick/Shen Unions C	Teamsters & Local 2 Unions D	Management E	Total F=C+D+E
1	**Annual Payroll (Gross) TME March 31, 2024**	Analysis	$ 3/ 5,108,819 A	$ 72,615,991 A	$ 106,452,220 2	$ 184,177,030
2	Pro Forma Increase - Test Year (Apr-2023 to Mar-2024)	Workpaper 2	50,086 B	320,862 B	3,138,466 2	3,509,414
3	Pro Forma Gross Payroll TME March 31, 2024	Ln. 1 + Ln. 2	$ 5,158,906	$ 72,936,853	$ 109,590,685	$ 187,686,444
4	Pro Forma Increase - (Apr-2024 to Mar-2025)	Workpaper 2	3/ 103,178 C	1,857,618 C	1,362,578 2	3,323,373
5	Pro Forma Gross Payroll in Rate Effective Period (Aug-2025 to Jul-2026)	Ln. 3 + Ln. 4	$ 5,262,084	$ 74,794,471	$ 110,953,263	$ 191,009,817
6	Pro Forma Payroll Increase	(Ln. 5 - Ln. 1)	$ 153,265	$ 2,178,480	$ 4,501,043	$ 6,832,788
7	Operations & Maintenance Allocation Factor	Analysis	6/ 75.53%	75.53%	75.53%	75.53% 2
8	Proforma Payroll Increase Allocable to Operations & Maintenance (System)	Ln. 6 * Ln. 7	$ 115,757	$ 1,645,354	$ 3,399,531	$ 5,160,643
9	District of Columbia Allocation Factor		7/ 19.36%	19.36%	19.36%	19.36% 2
10	Proforma Payroll Increase Allocable to Operations & Maintenance (District of Columbia)	Ln. 8 * Ln. 9	$ 22,411	$ 318,541	$ 658,149	$ 999,100
11	Adjust to reflect amortization of ratification bonus	Workpaper 3				$ 5/ 1,957
12	**Total Wages and Salaries Adjustment**	Ln. 10 + Ln. 11				**$ 1,001,057** 2
13	Wages & Salaries Expense Adjustment - Operations	Ln. 10 * 0.6434	_2/			$ 644,085
14	Wages & Salaries Expense Adjustment - Maintenance	Ln. 10 * 0.3566	_2/			$ 356,972

15 **Adjustment Description:** To reflect pro forma labor wage increases through the rate effective period.

1/ Per book Short-term incentive compensation and benefits expenses are excluded from the cost of service here rather than in 401(k) adjustment (#8).

2/ For class cost purposes, the full amount of this adjustment relates to COSA line EX 5:3.

Sum of A = 77,724,810 2
Sum of B = 370,948
Sum of C = 1,960,796

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 5 Workpaper 1 - Increase to Labor Expense

Test Year: April 1, 2023 - March 31, 2024
Interim Year: April 1,2024 - July 31, 2025
Rate Year: August 1, 2025 - July 31, 2026

Line	Description	Reference	Test year Labor	Test Year Pay Increase Annualization	Pay Increase post 12 months Test Period	Total Rate Year Labor	Adjustment
	A	B	C	D	E	F	G
1	Unions	Page 1	$ 1/ 77,724,810	$ 370,948	$ 1,960,796	$ 80,056,555	$ 2,331,744
2	Management	Page 1	106,452,220	3,138,466	1,362,578	110,953,263	4,501,043
3	Total Company	Ln. 1 + Ln. 2	$ 184,177,030	$ 3,509,414	$ 3,323,373	$ 191,009,817	$ 6,832,787
4	Adjustment Request Factor		100%	100%	100%		
5	Total Company Requested	Ln. 3 * Ln. 4	$ 184,177,030	$ 3,509,414	$ 3,323,373	$ 191,009,817	$ 6,832,787
6	O&M Factor	Page 1	1/ 75.53%	75.53%	75.53%	75.53%	75.53%
7	District of Columbia Labor Factor	Page 1	19.36%	19.36%	19.36%	19.36%	19.36%
8	DC Jurisdictional O&M Amount	Ln. 3 * Ln. 6 * Ln. 7	$ 26,930,640	$ 513,152	$ 485,949	$ 27,929,740	$ 999,100
9	Adjust to reflect amortization of ratification bonus						$ 1/ 1,957
10	**Total Wages and Salaries Adjustment**						$ 1,001,057

Exhibit WG (D)-5
Adjustment No. 5
Page 3 of 15

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 5 Workpaper 2 - Increase to Labor Expense

Test Year: April 1, 2023 - March 31, 2024
Interim Year: April 1,2024 - July 31, 2025
Rate Year: August 1, 2025 - July 31, 2026

Line No.	Description	Effective Date	Gross Payroll / Basis _3		Actual Test Year Increase _1/		Increase %	Months Applicable	Annualized Increase _2/	Increase Amount		New Gross Payroll
	A	B	C	D	E	F	G	H	I	J	K	L
1	**Frederick**											
2	Pro Forma Increase (Test Year)	4/ 8/1/2023	$ 2,135,565	A	$ 42,711	A	4/ 3.00%	4	1.00%	$ 21,356	D	$ 2,199,632
3	Pro Forma Increase (Rate Year)	8/1/2024	$ 2,199,632		n/a		3.00%	8	2.00%	$ 43,993	G	$ 2,243,625
4	**Shenandoah**											
5	Pro Forma Increase (Test Year)	8/1/2023	$ 2,873,081	A	$ 57,462	A	3.00%	4	1.00%	$ 28,731	D	$ 2,959,274
6	Pro Forma Increase (Rate Year)	8/1/2024	$ 2,959,274		n/a		3.00%	8	2.00%	$ 59,185	G	$ 3,018,459
7	**Teamsters**											
8	Pro Forma Increase (Test Year)	6/1/2023	$ 64,172,384	B	$ 1,604,310	B	3.00%	2	0.50%	$ 320,862	E	$ 66,097,556
9	Pro Forma Increase (Rate Year)	6/1/2024	$ 66,097,556		n/a		3.00%	10	2.50%	$ 1,652,439	H	$ 67,749,994
10	**Local 2**											
11	Pro Forma Increase (Test Year)	4/1/2023	$ 6,640,094	B	$ 199,203	B	3.00%	-	0.00%	$ -	E	$ 6,839,297
12	Pro Forma Increase (Rate Year)	4/1/2024	$ 6,839,297		n/a		3.00%	12	3.00%	$ 205,179	H	$ 7,044,476
13	**Management**											
14	Pro Forma Increase (Test Year)	1/1/2024	$ 105,406,064	C	$ 1,046,155	C	3.97%	9	2.98%	$ 3,138,466	F	$ 109,590,685
15	Pro Forma Increase (Rate Year)	1/1/2025	$ 109,590,685		n/a		4.97%	3	1.24%	$ 1,362,578	I	$ 110,953,263
16	Test Year Gross Payroll (Frederick & Shenandoah)									14/ $ 5,108,819 1		= sum As
17	Test Year Gross Payroll (Teamsters & Local 2)									$ 72,615,991		= sum Bs
18	Test Year Gross Payroll (Management)									$ 106,452,220		= sum Cs
19	Total Gross Payroll Test Year: April 1, 2023 - March 31, 2024									$ 184,177,030		
20	Test Year Increase (Frederick & Shenandoah)									$ 50,086		= sum Ds
21	Test Year Increase (Teamsters & Local 2)									$ 320,862		= sum Es
22	Test Year Increase (Management)									$ 3,138,466		= sum Fs
23	Total Test Year Increase									$ 3,509,414		
24	Rate Year (Frederick & Shenandoah)									$ 103,178		= sum Gs
25	Rate Year (Teamsters & Local 2)									$ 1,857,618		= sum Hs
26	Rate Year (Management)									$ 1,362,578		= sum Is
27	Total Interim Period & Partial Rate Year									$ 3,323,373		
28	Pro Forma Gross Payroll Twelve Months Ended July 31, 2026									$\boxed{\$\ 191,009,817}$		

Notes:
1/ Test year increase is the total of the wage increase from effective date (column B) to the end of the test year.
2/ For the test year only, the annualized increase is the incremental amount of wages that would have been paid if the wage increase was applicable for the full twelve months of the test year.
3/ Excludes 100% of long-term incentive compensation.

Adjustment No. 5 - Wage Increase Schedule

		DC	DC
Updated	Beginning of Test Year	**4/1/2023**	Apr-2023
Updated	End of Test Year	**3/31/2024**	Mar-2024
Updated	**Filing Date**	**8/1/2024**	Aug-2024
Updated	Beginning of Rate Effective Period	8/1/2025	Aug-2025
Updated	**End of Rate Effective Period**	**7/31/2026**	Jul-2026

Wage Increases by Labor Group

	Pay Group	Effective Date		Increase	a/	
Updated	Frederick Production & Maintenance/Clerical	8/1/2023	3	9/ 3.00%	3 b/	IBEW Local 1900 - 8/1/21 through 7/31/26
Updated	Frederick Production & Maintenance/Clerical	8/1/2024		10/ 3.00%	b/	IBEW Local 1900 - 8/1/21 through 7/31/26
Updated	Local 2	4/1/2023		11/ 3.00%	c/	Local 2- 4/1/2022 through 3/31/2027
Updated	Local 2	4/1/2024		3.00%	c/	Local 2- 4/1/2022 through 3/31/2027
Updated	Teamsters	6/1/2023		12/ 3.00%	d/	Teamsters Local 96 (Washington) 6/1/21 through 5/31/26
Updated	Teamsters	6/1/2024		3.00%	d/	Teamsters Local 96 (Washington) 6/1/21 through 5/31/26
Updated	Shenandoah	8/1/2023		13/ 3.00%	e/	Teamsters Local 96 (Shenandoah) - 8/1/2021 through 7/31/2026
Updated	Shenandoah	8/1/2024		3.00%	e/	Teamsters Local 96 (Shenandoah) - 8/1/2021 through 7/31/2026
Updated	Management	1/1/2024		3.97%		
Updated	Management	1/1/2025		4.97%	f/	

a/ Union wage increases per most recent contract.

b/ Per 2021 contract renewal.

b/ Per 2022 contract renewal.

d/ Per 2021 contract renewal

e/ Per 2021 contract renewal.

f/ Three year average of management increases.

1/1/2022 average increase	5.22%
1/1/2023 average increase	5.73%
1/1/2024 average increase	3.97%
3 year average	4.97%

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 5 Workpaper 3 - Contract Ratification Bonus Expense

Test Year: April 1, 2023 - March 31, 2024
Interim Year: April 1,2024 - July 31, 2025
Rate Year: August 1, 2025 - July 31, 2026

Line	Description	Reference	Test Year Expense
	A	B	C
1	Local 2 Contract Ratification Bonus Expense	Analysis	$ 8/ 50,536
2	Annual Amortization	Ln. 1 * 1/5	$ 10,107
3	District of Columbia Allocation Factor	Total Labor	7/ 19.36%
4	Adjust to reflect amortization of ratification bonus	Ln. 2 * Ln. 3	$ 1,957 1

NOTE: Test year ratification bonus reflects the operations & maintenance ("O&M") portion only and excludes any amounts that were capitalized or distributed to affliates.

Washington Gas Light Company
All Jurisdictions

Operations & Maintenance (O&M) Factor Calculation & Classification of Payroll

Twelve Months ending March 31, 2024

Utility Labor (Direct)

Res Type	(All)
Source	TLI

Sum of Sum Amount		Unit / Year / Period													Payroll Classification			
		01	01	01	01	01	01	01	01	01	01	01	01	Grand Total				
		23	23	23	23	23	23	23	23	23	24	24	24					
Exp Type	Account	4	5	6	7	8	9	10	11	12	1	2	3		O&M	Capital	Other	Affiliates
Capital		494,874	460,058	563,786	390,981	946,926	627,555	658,202	791,793	619,873	566,559	610,149	629,162	7,359,918	-	7,359,918	-	-
Non-Utility		8,310	6,289	6,886	4,867	7,027	5,360	6,219	6,893	64,101	10,779	5,479	5,446	137,654	-	-	137,654	-
O&M		8,943,411	8,779,237	8,495,575	7,887,392	12,973,264	8,478,117	9,078,234	8,815,747	7,933,074	11,962,271	10,143,655	9,375,791	112,865,769	112,865,769	-	-	-
Other		356,400	302,277	321,010	270,147	436,100	292,814	273,777	272,411	286,860	411,167	338,185	346,413	3,907,561	-	-	3,907,561	-
Pool	163101	43,017	48,440	46,887	43,844	69,450	36,989	53,857	59,608	47,987	50,103	49,849	36,883	586,915	1,138	585,750	27	-
Pool	184105	10,751	15,696	14,772	14,473	21,356	14,447	16,759	15,819	15,182	19,389	15,687	16,345	190,677	164,301	-	4,864	21,511
Pool	184107	69,874	69,473	62,167	59,199	103,586	60,807	56,654	42,387	40,997	52,112	47,446	47,908	712,610	689,915	-	16,844	5,852
Pool	184122	21,736	22,861	21,365	17,794	31,511	20,245	27,153	29,189	20,974	30,488	38,026	59,007	340,350	308,730	28,715	2,905	-
Pool	184123	161,892	142,303	139,355	141,771	257,861	164,189	184,696	183,973	156,633	206,063	167,626	136,168	2,042,530	1,827,923	194,892	19,714	-
Pool	184131	591	589	599	570	893	590	623	339	226	485	81	235	5,822	4,632	1,070	120	-
Pool	184181	-	-	-	101	-	-	-	-	-	58	10,869	12,962	23,990	21,640	1,210	695	445
Pool	184201	86,113	82,332	74,296	51,128	77,365	54,546	48,188	43,690	(132,024)	59,636	45,777	47,540	538,587	-	538,587	-	-
Pool	184211	45,918	45,385	47,791	38,442	67,430	45,792	38,772	34,064	52,655	45,330	34,633	34,050	530,260	-	530,260	-	-
Pool	184212	46,818	46,659	46,797	42,876	84,409	53,666	52,793	51,927	92,674	64,826	60,119	56,840	700,403	-	700,403	-	-
Pool	184213	57,967	67,264	57,048	53,880	102,241	64,049	62,769	58,307	100,087	82,498	63,307	52,367	821,784	-	821,784	-	-
Pool	184215	423,233	459,306	416,710	409,500	686,383	443,389	464,710	453,934	410,668	566,352	494,985	436,864	5,666,032	-	5,666,032	-	-
Pool	184218	129,795	133,572	122,241	109,661	188,078	130,233	177,783	158,983	137,683	204,199	186,557	175,614	1,854,397	114,380	1,740,018	-	-
Pool	184227	33,872	36,160	34,963	32,873	61,184	38,652	42,119	38,148	35,545	49,777	42,791	40,136	486,219	-	486,219	-	-
Pool	184231	1,043,026	1,081,760	1,024,816	921,533	1,560,366	1,005,191	1,012,066	1,022,455	947,651	1,272,489	1,088,950	1,066,574	13,046,876	-	13,046,876	-	-
Grand Total		11,977,597	11,799,659	11,497,063	10,491,034	17,675,429	11,536,631	12,255,372	12,079,664	10,830,845	15,654,582	13,444,173	12,576,305	151,818,352	115,998,427	31,701,735	4,090,382	27,808

Affiliate Labor (Direct)

Res Type	(All)
Source	TLI

Sum of Sum Amount		Year / Period																
		23	23	23	23	23	23	23	23	23	24	24	24	Grand Total				
Exp Type	Unit	4	5	6	7	8	9	10	11	12	1	2	3					
Non-Utility	00	12,580	14,193	13,656	13,358	20,138	13,816	14,405	13,304	11,458	17,986	15,553	14,075	174,523	-	-	-	174,523
Non-Utility	01	6,120	5,730	6,886	4,787	6,579	5,360	6,021	5,112	62,558	7,019	5,479	5,205	126,857	-	-	-	126,857
Non-Utility	07	1,122	240	-	-	83	401	-	-	-	-	-	56	1,902	-	-	-	1,902
Non-Utility	15	89,325	103,119	71,214	97,122	136,906	86,914	89,669	83,821	69,701	103,994	85,071	83,867	1,100,723	-	-	-	1,100,723
Non-Utility	20	14,954	16,410	4,824	3,684	2,650	1,438	1,353	4,673	842	634	4,525	2,108	58,095	-	-	-	58,095
Non-Utility	24	4,500	4,203	3,179	3,862	4,877	3,877	4,059	4,269	3,636	5,664	4,652	4,183	50,960	-	-	-	50,960
Non-Utility	28	3	60	3	2	985	2	3	2	2	2	655	251	1,971	-	-	-	1,971
Non-Utility	300	240	13,473	25,370	19,185	37,680	24,639	26,670	24,724	72,612	25,551	27,096	(46,644)	250,596	-	-	-	250,596
Non-Utility	312	-	-	-	116	-	-	-	-	-	-	-	-	116	-	-	-	116
Grand Total		128,844	157,429	125,131	142,117	209,898	136,447	142,180	135,906	220,809	160,850	143,032	63,101	1,765,744	-	-	-	1,765,744
Total		12,106,440	11,957,088	11,622,194	10,633,150	17,885,326	11,673,079	12,397,552	12,215,570	11,051,654	15,815,432	13,587,205	12,639,406	153,584,096	115,998,427	31,701,735	4,090,382	1,793,552
Percentage															75.53% 1	20.64%	2.66%	1.17%

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618 1 5	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses -									
25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding									
42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Row Labels	Sum of Sum_Dollars	O&M % as of 03/31/2022	O&M amount		
184105	1,000	0.81874	818.74		
184107	2,000	0.98356	1,967.12		
184211	3,400	-	-		
184212	2,250	-	-		
184213	3,000	-	-		
184215	10,980	-	-		
184218	6,400	0.20000	1,280.00		
184231	11,500	-	-		
184241	1,000	-	-		
880001	10,920	1.00000	10,920.00		
885001	5,950	1.00000	5,950.00		
887000	500	1.00000	500.00		
892300	500	1.00000	500.00		
902000	3,000	1.00000	3,000.00		
903100	8,000	1.00000	8,000.00		
903210	1,000	1.00000	1,000.00		
912000	600	1.00000	600.00		
920000	16,000	1.00000	16,000.00		
Grand Total	88,000		50,535.86	5	57.43%

ANNEX B
Pay Classification & Wage Rate Schedule
Office Unit

During the term of the Contract, pay classifications and wage rates (rounded to nearest cent – for reference only) shall be:

General Wage Increase 2.00%
August 1, 2021
Wage Grade

Grade	Hire	6 Month	1 Year	2 Year	3 Year	4 Year
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

General Wage Increase 3.00%
August 1, 2022
Wage Grade

Grade	Hire	6 Month	1 Year	2 Year	3 Year	4 Year
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

General Wage Increase 3.00% 4
August 1, 2023
Wage Grade

Grade	Hire	6 Month	1 Year	2 Year	3 Year	4 Year
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

ANNEX B (Cont'd)
Pay Classification & Wage Rate Schedule
Office Unit

During the term of the Contract, pay classifications and wage rates (rounded to nearest cent – for reference only) shall be:

General Wage Increase 3.00% 4
August 1, 2024
Wage Grade

Grade	Hire	6 Month	1 Year	2 Year	3 Year	4 Year
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

General Wage Increase 3.00%
August 1, 2025
Wage Grade

Grade	Hire	6 Month	1 Year	2 Year	3 Year	4 Year
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NEW L2 GWI Effective: April 1, 2022						
GWI 2.00%	Step					
Grade	1	2	3	4	5	6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4

NEW L2 GWI Effective: April 1, 2023						
GWI 3.00%	Step					
Grade	1	2	3	4	5	6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4

NEW L2 GWI Effective: April 1, 2024						
GWI 3.00%	Step					
Grade	1	2	3	4	5	6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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NEW L2 GWI Effective: April 1, 2025						
GWI 3.00%	Step					
Grade	1	2	3	4	5	6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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NEW L2 GWI Effective: April 1, 2026						
GWI 3.00%	Step					
Grade	1	2	3	4	5	6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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ANNEX W
Wage Grades and Rates
4 3.00% Increase in Rates Effective June 1, 2023
(rounded to the nearest cent – for reference only)

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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ANNEX W
Wage Grades and Rates
4 3.00% Increase in Rates Effective June 1, 2024
(rounded to the nearest cent – for reference only)

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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ANNEX W
Wage Grades and Rates
④ 3.00% Increase in Rates Effective August 1, 2023
(rounded to the nearest cent – for reference only)

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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ANNEX W
Wage Grades and Rates
④3.00% Increase in Rates Effective August 1, 2024
(rounded to the nearest cent – for reference only)

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

GROSS PAYROLL DOLLARS (Washington Gas - Excludes Hampshire) DC

CUBE:	tm1serv:Labor Paycheck Data													
Labor_BU	01													
Labor_Group	See Below													
Labor_Type	Total Gross Pay - Include													
Labor_Period	See Below													
	Apr-2023	May-2023	Jun-2023	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024	TME	
Executive Compensation (WD)	430,130	430,130	645,194	430,130	430,130	430,130	454,901	453,208	670,898	436,643	439,045	2,813,302	8,063,840	
Non Executive Management (WD)	7,336,587	7,294,965	11,053,896	7,405,463	7,409,334	7,411,431	7,424,563	7,447,139	11,093,306	7,563,582	7,607,771	19,286,224	108,334,263	
Non Executive Management (WD) - Excluded 15/	(632,958)	(633,319)	(960,985)	(652,690)	(679,232)	(686,787)	(691,040)	(686,220)	(1,022,844)	(691,121)	(698,700)	(1,909,986)	(9,945,883)	106,452,220 3
Frederick Union Clerical (WD)	38,405	38,405	57,660	42,469	41,997	43,526	43,267	43,243	64,980	49,999	43,474	58,911	566,334	
Frederick Union Prod/Maint (WD)	127,484	118,256	182,453	106,764	113,340	119,877	113,476	128,067	174,243	127,968	139,972	160,043	1,611,943	
Shenandoah Union (WD)	216,771	215,748	322,074	216,818	212,572	215,354	220,389	226,930	330,634	230,170	221,915	301,168	2,930,543	5,108,819
IBT Eligible Employees (WD)	4,665,832	4,447,616	7,148,792	4,601,657	4,650,493	4,819,765	4,913,234	5,061,181	7,727,333	5,411,780	5,693,007	6,636,003	65,776,694	
Local 2 Eligible Employees (WD)	490,794	492,544	777,711	506,139	506,726	500,161	493,130	518,616	783,400	570,701	522,914	676,460	6,839,297	72,615,991
Total	12,673,045	12,404,344	19,226,797	12,656,750	12,685,358	12,853,458	12,971,920	13,192,164	19,821,951	13,699,721	13,969,398	28,022,124	184,177,030	184,177,030

Paycheck Details related to Organization Redesign

Sum of Current Period Result		TM1 Period												
Include?	TM1 Labor Type	Apr-2023	May-2023	Jun-2023	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024	Grand Total
N	134 - Educational Refund - No Tax	1,298	-	-	-	2,429	-	-	-	-	3,462	-	-	7,189
N	137 - Mileage - Non Taxable	2,381	2,310	4,111	1,892	2,749	2,687	2,727	1,764	3,121	1,350	2,100	2,216	29,408
N	138 - Misc. Reimbursement	345	296	735	407	231	746	291	527	1,274	269	19	263	5,403
N	224 - Vehicle Allowance	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	16,800
N	56B - Perf Unit	-	-	-	-	-	-	-	-	-	827,805	-	1,407,269	2,235,074
N	56E - Signing Bonus	-	-	5,000	-	-	-	-	-	-	-	-	-	5,000
N	GIFT - Gift Card / Financial Services	-	-	-	-	-	1,950	-	-	1,075	-	-	-	3,025
N	GRSUP - Gross-Up	-	869	-	58	851	-	-	2,632	32	-	-	-	4,441
N	GTL - Group Term Life	2,055	2,067	3,102	2,101	2,109	2,124	2,124	2,121	3,175	2,289	2,290	2,291	27,847
N	SRP - Executive SERP	2,900	2,900	4,350	2,900	2,900	2,900	2,900	2,900	4,350	2,940	2,954	2,954	37,848
N	VMI - VR Plan Mileage	-	-	-	35	-	24	24	-	24	-	-	24	131
N	VRP - Vehicle Reimbursement Plan	400	400	400	400	400	400	400	400	400	400	400	400	4,800
N	Eq Tr - Eq Tran	-	-	-	-	-	-	-	-	-	-	150	168	318
N Total		10,779	10,242	19,098	9,193	13,069	12,230	9,866	11,744	14,851	839,915	9,313	1,416,986	2,377,285
Y	1 - Regular Hours	535,942	560,088	794,057	539,881	608,142	589,701	620,672	581,795	757,186	463,745	656,641	618,853	7,326,702
Y	12 - Holiday Hours Worked	-	-	-	-	-	-	-	-	-	-	-	89	89
Y	208 - Illness 100%	22,840	13,906	3,476	-	-	-	-	-	-	-	-	-	40,222
Y	210 - Illness 50%	-	-	812	-	-	-	-	-	-	-	-	-	812
Y	228 - Illness 80%	1,641	4,923	11,487	1,641	6,564	-	-	-	-	-	-	-	26,255
Y	31 - Paid Time Off	63,037	48,662	70,477	69,257	56,170	50,241	49,976	62,262	176,276	112,913	31,591	39,079	829,941
Y	31B - PTO Accrual	3,311	1,493	7,262	5,560	1,616	5,303	9,393	4,174	13,476	7,261	2,745	1,204	62,798
Y	32 - Jury Duty	-	-	-	-	-	-	-	-	-	-	313	-	313
Y	37 - Holiday	-	-	62,370	32,332	-	33,916	-	34,223	68,147	101,606	-	34,840	367,434
Y	4 - Overtime	-	39	601	302	1,590	1,029	3,709	439	343	276	350	-	8,678
Y	49 - Excused - Administrative	-	-	1,391	-	-	-	-	-	-	-	-	-	1,391
Y	4X - Premium Overtime	-	20	992	151	795	514	1,854	219	171	138	175	45	5,074
Y	56G - Executive Incentive	-	-	-	-	-	-	-	-	-	-	-	330,223	330,223
Y	56K - Short Term Incentive	-	-	-	-	-	-	-	-	-	-	-	878,968	878,968
Y	7 - Change of Schedule	-	-	1,382	-	-	-	-	-	-	-	-	-	1,382
Y	BRV - Bereavement	-	-	-	-	-	-	-	-	-	-	-	991	991
Y	FLSAB - FLSA Bonus	-	-	-	-	-	-	-	-	-	-	-	609	609
Y	ONC - WG Management On-Call	6,186	4,189	6,678	3,566	4,356	6,083	5,436	3,107	7,246	5,182	6,886	5,085	63,999
Y Total		632,958	633,319	960,985	652,690	679,232	686,787	691,040	686,220	1,022,844	691,121	698,700	1,909,986	9,945,883
Grand Total		643,737	643,561	980,083	661,882	692,301	699,017	700,907	697,964	1,037,695	1,531,036	708,013	3,326,972	12,323,169

14

Adjustment No. 6

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 6 - LTI Expense Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	Factor Comp_A&G D	DC Amount E = C * D
1	Long-Term Incentive - Performance Shares	Acct 920411 & 920412	$ 2/ (40,509)		
2	Long-Term Incentive - Performance Units	Acct 920421 & 920422	$ (17,309,695)		
3	**Total Expense Adjustment _1/**	Ln. 1 + Ln. 2	$ (17,350,204)	3/19.54%	$ (3,390,371)

4 **Adjustment Description:** To remove 100% of per book long-term incentive expense.

_1/ For class cost purposes, the full amount of this adjustment relates to COSA line EX:5:3.

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Description A	—Reference— Sc-Pg-Ln B	Allocator C			WG D	DC E	MD F	VA G	FERC H
1 **Administrative & General Expenses**									
2 Administrative & General Salaries-Direct		Financial Stmt.	Sub Total		$ 4,032,355	$ 930,862	$ 1,648,492	$ 1,449,739	$ 3,262
3 Administrative & General Salaries-Allocable	AL:4:23	Comp_A&G	Sub Total		100,516,479	19,641,740	43,423,120	37,451,620	-
			920000	Admin & General Salaries	55,145,308				-
			920000_adj	Admin & General Salaries	-				
			920188	Admin & Gen Sal Distr-Finance	16,058,651				-
			920190	Admin & Gen Sal Distr	(339,411)				-
			920194	Adm & Gen Sal Distr-Inv Rel	-				-
			920196	Admin & Gen Sal Distr - Commun	-				-
			920197	Admin & Gen Sal Distr-Gen Ldgr	-				-
			920198	Admin & Gen Sal Distr - Tax	-				-
			920199	Admin & Gen Sal Distr - Strtgy	-				-
			920401	Exec IncentiveProgram-Gross	-				
			920402	Exec Incentive Progr-Distr	-				
			920411	ExecPerforShare(99Progr)-Gross	41,348 A				
			920412	ExecPerfShares(99Prog)-Distr	(839) B				
			920421	Exec&MgtPerformanceUnit-Gross	17,490,643 C				
			920422	Exec&Mgt PerformanceUnit Distr	(180,948) D				
			920431	Employee Incentive - ROE Gross	11,612,309				
			920441		3,373,243				
			920432	Empl Incentive-ROE Distr	(2,683,825)				
4 Office Supplies & Expenses-Direct		Financial Stmt.	Sub Total		3,942,404	1,103,503	1,731,733	1,104,963	2,204
5 Office Supplies & Expenses-Allocable	AL:4:23	Comp_A&G	Sub Total		33,046,634	6,457,582	14,276,146	12,312,906	-
6 Outside Services	AL:5:30		Sub Total	Outside Services Employed	37,435,574	7,053,669	15,176,292	15,205,613	-
7 Property Insurance	AL:3:13	Net_GPIS	Manual Data		-	-	-	-	-
8 Injuries & Damages	AL:4:11	Total_Labor	Sub Total		18,995,900	3,677,954	8,170,412	7,147,535	-
9 Pension Expense	AL:4:11	Total_Labor	Sub Total		(219,656)	(42,494)	(94,398)	(82,580)	(185)
10 DC Regulatory					-				
11 Pension Expense		Financial Stmt.	926104	Appl-Def Pen Cost-DC Ord 9146	-	-	-	-	-
12 Amortization of Rate Case Expenses		Financial Stmt.	928001	Rg Com Exp-Amrt DC Rte Cse Exp	475,776	475,776	-	-	-
13 Least Cost Planning Expenses		Financial Stmt.	930201	Amrtz LCP Exp Recov Curr Rate	-	-	-	-	-
14 Employee Health Benefits			Sub Total		24,779,774	4,793,783	10,649,176	9,315,976	20,840
15 OPEB	Labor factor	Financial Stmt.	Sub Total		(34,007,440)	(6,584,462)	(14,627,092)	(12,795,885)	-
16 Rate Case Expenses-Direct		Financial Stmt.	928000	Regulatory Commission Expenses	1,526,109	206,553	1,049,073	269,875.64	607
17 Rate Case Expenses-Allocable	AL:4:23	Comp_A&G	928000	Regulatory Commission Expenses	9,523	1,861	4,114	3,548	-
18 DC PSC Assessment Expense		Financial Stmt.	928002	DC PSC Assessment Expense	-	-	-	-	-
19 General Advertising Expenses - Direct		Financial Stmt.	930100	General Advertising Expenses	1,269	-	984	285	-
20 General Advertising Expenses - Allocable	AL:4:23	Comp_A&G	930100	General Advertising Expenses	644,209	125,884	278,298	240,027	-
21 Environmental Expense - Regulatory Amortization		Financial Stmt.	930210_T	Amrt Env Exp Rcvr-Cur Rates	686,319	263,068	423,250	-	-
22 Environmental Reserve - Regulatory Adjustment		Financial Stmt.	930211	Environmental Reserve Adjustme	1,738,655	-	-	1,738,655	-
23 Rents		Financial Stmt.	931000	Rents	263,877	-	-	263,877	-
24 MD Demand Side Management Expenses		Comp_A&G	930202	MD Dmd Sd Mgt Cst-Rcvr-Cur Rte	1,041,022	203,424	449,721	387,876	-
25 VA Care Expenses		Financial Stmt.	930206	MiscGenExp-Va Care Effic Prog	4,294,347	-	-	4,294,347	-
26 MD EmPOWER MD Expenses		Financial Stmt.	930207	MiscGenExp – EmPOWER MD Prog	13,710,995	-	13,710,995	-	-
27 Multi-Family Unit Contribution Amortization Expense		Financial Stmt.	930220	MultifamUnitContriAmortExp	199,129	17,451	140,914	40,764	-
28 Multi-Family Unit Contribution Amortization Expense - Allocable			930220		-	-	-	-	-
29 Miscellaneous General Expenses-Direct		Financial Stmt.	930200_Total	Misc General Expenses	367,847	348,831	(45,528)	64,398	145
30 Miscellaneous General Expenses-Allocable	AL:4:23	Comp_A&G	930200_total	Misc General Expenses	2,373,165	463,736	1,025,207	884,222	-
31 Total Administrative & General Expenses	= 2 >30				$ 215,854,266	$ 39,138,720	$ 97,390,911	$ 79,297,762	$ 26,873

A + B = 40,509 1
C + D = 17,309,695 ↓

Exhibit WG (D)-5
Adjustment No. 6
Page 2 of 3

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954 1	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses -									
25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding									
42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Adjustment No. 7

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 7 - Postretirement Benefits Other Than Pensions (OPEB) Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	DC Amount D = C * 19.36%
1	**Current Employees**			
2	Employer Service Cost	Actuarial Rpt	$ [redacted]	
3	Washington % of Basic Pay (eliminates Hampshire)	Analysis	[redacted]	
4	Washington Gas Portion of Expense	Ln. 2 * Ln. 3	$ [redacted]	
5	O&M Factor (OPEB Service Costs)	Analysis	[redacted]	
6	Total Employer Service Cost	Ln. 4 * Ln. 5	$ [redacted]	$ [redacted]
7	Other Components of Net Periodic Expense	Actuarial Rpt	$ [redacted]	
8	Washington % of Basic Pay (eliminates Hampshire)	Analysis	[redacted]	
9	Washington Gas Portion of Expense	Ln. 7 * Ln. 8	$ [redacted]	
10	O&M Factor (OPEB Other Costs)	Analysis	[redacted]	
11	Total Other Components of Net Periodic Expense	Ln. 9 * Ln. 10	$ [redacted]	$ [redacted]
12	Total Net Periodic Post-Retirement Benefit Expense	Ln. 6 + Ln. 11	$ [redacted]	$ [redacted]
13	District of Columbia OPEB Costs Per Book	EX:5:15		[redacted]
14	Adjustment to OPEB Cost	Ln. 12 - Ln. 13		$ (630,366)

15 **Adjustment Description:** To calculate OPEB expense on a pro forma basis.

[redacted]

	Qualified	SERP	Restoration	PRW	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Washington Gas Light Company
All Jurisdictions

Utility Operations & Maintenance (O&M) Factors Other Than Wages & Salaries

Twelve Months ending March 31, 2024

Account	Classification	Account Description	Mar-2024 TME
OPEB (Service Costs)			
		OPEB Gross	3,712,747
		OPEB Distribution	(687,699)
		OPEB % Distributed	-18.52%
		OPEB O&M Factor	**81.48%**
OPEB (Other Periodic Costs)			
		OPEB Gross	(37,757,107)
		OPEB Distribution	724,620
		OPEB % Distributed	-1.92%
		OPEB O&M Factor	**98.08%**

Washington Gas Light Company
System

Hampshire Basic Payroll Percentage Calculation

Twelve Months ending March 31, 2024

Period	Washington	Hampshire	Total
Apr-2023	$ 13,071,145	$ 78,253	$ 13,149,398
May-2023	$ 13,256,214	$ 78,253	$ 13,334,467
Jun-2023	$ 13,330,067	$ 78,253	$ 13,408,320
Jul-2023	$ 13,333,887	$ 78,253	$ 13,412,139
Aug-2023	$ 13,282,784	$ 78,253	$ 13,361,036
Sep-2023	$ 13,312,865	$ 78,539	$ 13,391,403
Oct-2023	$ 13,397,593	$ 79,114	$ 13,476,708
Nov-2023	$ 13,338,351	$ 79,114	$ 13,417,465
Dec-2023	$ 13,331,180	$ 79,114	$ 13,410,294
Jan-2024	$ 13,524,106	$ 81,607	$ 13,605,713
Feb-2024	$ 13,485,559	$ 81,607	$ 13,567,166
Mar-2024	$ 13,451,481	$ 81,903	$ 13,533,384
Total	$ 160,115,231	$ 952,261	$ 161,067,493
	99.41%	0.59%	100.00%

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
A	B	C	D	E	F	G	H
1 **Administrative & General Expenses**							
2 Administrative & General Salaries-Direct		Financial Stmt.	$ 4,032,355	$ 930,862	$ 1,648,492	$ 1,449,739	$ 3,262
3 Administrative & General Salaries-Allocable	AL:4:23	Comp_A&G	100,516,479	19,641,740	43,423,120	37,451,620	-
4 Office Supplies & Expenses-Direct		Financial Stmt.	3,942,404	1,103,503	1,731,733	1,104,963	2,204
5 Office Supplies & Expenses-Allocable	AL:4:23	Comp_A&G	33,046,634	6,457,582	14,276,146	12,312,906	-
6 Outside Services	AL:5:30		37,435,574	7,053,669	15,176,292	15,205,613	-
7 Property Insurance	AL:3:13	Net_GPIS	-	-	-	-	-
8 Injuries & Damages	AL:4:11	Total_Labor	18,995,900	3,677,954	8,170,412	7,147,535	-
9 Pension Expense	AL:4:11	Total_Labor	(219,656)	(42,494)	(94,398)	(82,580)	(185)
10 DC Regulatory			-				
11 Pension Expense		Financial Stmt.	-	-	-	-	-
12 Amortization of Rate Case Expenses		Financial Stmt.	475,776	475,776	-	-	-
13 Least Cost Planning Expenses		Financial Stmt.	-	-	-	-	-
14 Employee Health Benefits			24,779,774	4,793,783	10,649,176	9,315,976	20,840
15 OPEB	Labor factor	Financial Stmt.	(34,007,440)	(6,584,462)	(14,627,092)	(12,795,885)	-
16 Rate Case Expenses-Direct		Financial Stmt.	1,526,109	206,553	1,049,073	269,875.64	607
17 Rate Case Expenses-Allocable	AL:4:23	Comp_A&G	9,523	1,861	4,114	3,548	-
18 DC PSC Assessment Expense		Financial Stmt.	-	-	-	-	-
19 General Advertising Expenses - Direct		Financial Stmt.	1,269	-	984	285	-
20 General Advertising Expenses - Allocable	AL:4:23	Comp_A&G	644,209	125,884	278,298	240,027	-
21 Environmental Expense - Regulatory Amortization		Financial Stmt.	686,319	263,068	423,250	-	-
22 Environmental Reserve - Regulatory Adjustment		Financial Stmt.	1,738,655	-	-	1,738,655	-
23 Rents		Financial Stmt.	263,877	-	-	263,877	-
24 MD Demand Side Management Expenses	AL:4:23	Comp_A&G	1,041,022	203,424	449,721	387,876	-
25 VA Care Expenses		Financial Stmt.	4,294,347	-	-	4,294,347	-
26 MD EmPOWER MD Expenses		Financial Stmt.	13,710,995	-	13,710,995	-	-
27 Multi-Family Unit Contribution Amortization Expense		Financial Stmt.	199,129	17,451	140,914	40,764	-
28 Multi-Family Unit Contribution Amortization Expense - Allocable			-	-	-	-	-
29 Miscellaneous General Expenses-Direct		Financial Stmt.	367,847	348,831	(45,528)	64,398	145
30 Miscellaneous General Expenses-Allocable	AL:4:23	Comp_A&G	2,373,165	463,736	1,025,207	884,222	-
31 Total Administrative & General Expenses	=2>30		$ 215,854,266	$ 39,138,720	$ 97,390,911	$ 79,297,762	$ 26,873

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	Reference — Sc-Pg-Ln	Reference — Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses - 25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding 42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Adjustment No. 8

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 8 - Pension & SERP Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	DC Amount D = C * [redacted]	
1	Pro Forma Employer Service Cost	Workpaper 1	$ [redacted]		
2	O&M Factor (Pension Service Cost)		[redacted]		
3	PF Employer Service Cost	Ln. 1 * Ln. 2	$ [redacted]	$ [redacted]	
4	Pro Forma Other Components of Net Periodic Expense	Workpaper 1	$ [redacted]		
5	O&M Factor (Pension Other Costs)		[redacted]		
6	PF Other Components of Net Periodic Expense	Ln. 4 * Ln. 5	$ [redacted]	$ [redacted]	
7	Total Pro Forma Pension Expense	Ln. 3 + Ln. 6	$ [redacted]	$ [redacted]	
8	Per Book Qualified Pension Expense	EX:5:9	$ [redacted]	$ [redacted]	a/
9	Per Book SERP/Restoration	EX:5:9	$ [redacted]	$ [redacted]	b/
10	Total Per Book Pension Expense	Ln. 8 + Ln. 9		$ [redacted])	
11	Pro Forma Pension Adjustment	Ln. 7 - Ln. 10		$ (565,665)	

12 **Adjustment Description:** To calculate pension expense on a pro forma basis.

a/ Qualified Pension Expense Accounts are: 926101, 926107, 926109, 926115, 926116, 926116
b/ SERP/Restoration Expense Accounts are: 926103, 926105, 926106, 926113, 926114, 926114

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 8 - Pension Expense Workpaper 1

Twelve Months Ended March 31, 2024

Line No.	Description A	Amount B	Factor C	DC Amount D = B * C	
1	**Actuarial Report Data**				
2	**Employer Service Costs**				
3	Pension	[redacted]	99.41%	[redacted]	a/
4	Supplemental Executive Retirement Plan (SERP)	[redacted]	0.00%	-	b/
5	Defined Benefit Restoration	[redacted]	0.00%	-	b/
6	Total Employer Services Costs	[redacted]		[redacted]	
7	**Other Components of Net Periodic Expense**				
8	Pension	[redacted]	99.41%	[redacted]	a/
9	Supplemental Executive Retirement Plan (SERP)	[redacted]	0.00%	-	b/
10	Defined Benefit Restoration	[redacted]	0.00%	-	b/
11	Total Other Components of Net Periodic Expense	[redacted]		[redacted]	

a/ Pension expense related to Hamphsire expense eliminated based on Hampshire percentage of payroll.
b/ Per Order No. 18712 in FC 1137, SERP and restoration expenses are excluded from the cost of service.

2.5 Summary and comparison of benefit cost and cash flows

All monetary amounts shown in US Dollars

Fiscal Year Ending	12/31/2024	12/31/2023
[redacted]		
[redacted]	A [redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]		
[redacted]	B [redacted]	[redacted]
	B - A = (8,934,409)	
[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Appendix C : Supplemental Executive Retirement Plan

Benefit Cost and Net Balance Sheet Position Under ASC-715

All monetary amounts shown in US Dollars

Fiscal Year Beginning	1/1/2024	1/1/2023
[redacted]	C [redacted]	[redacted]
[redacted]	D [redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Appendix D : Defined Benefit Restoration Plan

Benefit Cost and Net Balance Sheet Position Under ASC – 715

All monetary amounts shown in US Dollars

Fiscal Year Beginning	1/1/2024	1/1/2023
[redacted]	[redacted]	[redacted]

Washington Gas Light Company
System

Hampshire Basic Payroll Percentage Calculation

Twelve Months ending March 31, 2024

Period	Washington	Hampshire	Total
Apr-2023	$ 13,071,145	$ 78,253	$ 13,149,398
May-2023	$ 13,256,214	$ 78,253	$ 13,334,467
Jun-2023	$ 13,330,067	$ 78,253	$ 13,408,320
Jul-2023	$ 13,333,887	$ 78,253	$ 13,412,139
Aug-2023	$ 13,282,784	$ 78,253	$ 13,361,036
Sep-2023	$ 13,312,865	$ 78,539	$ 13,391,403
Oct-2023	$ 13,397,593	$ 79,114	$ 13,476,708
Nov-2023	$ 13,338,351	$ 79,114	$ 13,417,465
Dec-2023	$ 13,331,180	$ 79,114	$ 13,410,294
Jan-2024	$ 13,524,106	$ 81,607	$ 13,605,713
Feb-2024	$ 13,485,559	$ 81,607	$ 13,567,166
Mar-2024	$ 13,451,481	$ 81,903	$ 13,533,384
Total	$ 160,115,231	$ 952,261	$ 161,067,493
	99.41%	0.59%	100.00%

Washington Gas Light Company
All Jurisdictions

Utility Operations & Maintenance (O&M) Factors Other Than Wages & Salaries

Twelve Months ending March 31, 2024

Account	Classification	Account Description	Mar-2024 TME
Pension (Service Costs)			
		Pension Gross	6,763,148
		Pension Distribution	(1,273,415)
		Pension % Distributed	-18.83%
		Pension O&M Factor	**81.17%**
Pension (Other Periodic Costs)			
		Pension Gross	(7,108,600)
		Pension Distribution	89,580
		Pension % Distributed	-1.26%
		Pension O&M Factor	**98.74%**
SERP			
		Pension Gross	1,325,722
		Pension Distribution	(16,090)
		Pension % Distributed	-1.21%
		Pension O&M Factor	**98.79%**

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Administrative & General Expenses**							
2	Administrative & General Salaries-Direct		Financial Stmt.	$ 4,032,355	$ 930,862	$ 1,648,492	$ 1,449,739	$ 3,262
3	Administrative & General Salaries-Allocable	AL:4:23	Comp_A&G	100,516,479	19,641,740	43,423,120	37,451,620	-
4	Office Supplies & Expenses-Direct		Financial Stmt.	3,942,404	1,103,503	1,731,733	1,104,963	2,204
5	Office Supplies & Expenses-Allocable	AL:4:23	Comp_A&G	33,046,634	6,457,582	14,276,146	12,312,906	-
6	Outside Services	AL:5:30		37,435,574	7,053,669	15,176,292	15,205,613	-
7	Property Insurance	AL:3:13	Net_GPIS	-	-	-	-	-
8	Injuries & Damages	AL:4:11	Total_Labor	18,995,900	3,677,954	8,170,412	7,147,535	-
9	Pension Expense	AL:4:11	Total_Labor	(219,656)	(42,494)	(94,398)	(82,580)	(185)
10	DC Regulatory			-				
11	Pension Expense		Financial Stmt.	-	-	-	-	-
12	Amortization of Rate Case Expenses		Financial Stmt.	475,776	475,776	-	-	-
13	Least Cost Planning Expenses		Financial Stmt.	-	-	-	-	-
14	Employee Health Benefits			24,779,774	4,793,783	10,649,176	9,315,976	20,840
15	OPEB	Labor factor	Financial Stmt.	(34,007,440)	(6,584,462)	(14,627,092)	(12,795,885)	-
16	Rate Case Expenses-Direct		Financial Stmt.	1,526,109	206,553	1,049,073	269,875.64	607
17	Rate Case Expenses-Allocable	AL:4:23	Comp_A&G	9,523	1,861	4,114	3,548	-
18	DC PSC Assessment Expense		Financial Stmt.	-	-	-	-	-
19	General Advertising Expenses - Direct		Financial Stmt.	1,269	-	984	285	-
20	General Advertising Expenses - Allocable	AL:4:23	Comp_A&G	644,209	125,884	278,298	240,027	-
21	Environmental Expense - Regulatory Amortization		Financial Stmt.	686,319	263,068	423,250	-	-
22	Environmental Reserve - Regulatory Adjustment		Financial Stmt.	1,738,655	-	-	1,738,655	-
23	Rents		Financial Stmt.	263,877	-	-	263,877	-
24	MD Demand Side Management Expenses	AL:4:23	Comp_A&G	1,041,022	203,424	449,721	387,876	-
25	VA Care Expenses		Financial Stmt.	4,294,347	-	-	4,294,347	-
26	MD EmPOWER MD Expenses		Financial Stmt.	13,710,995	-	13,710,995	-	-
27	Multi-Family Unit Contribution Amortization Expense		Financial Stmt.	199,129	17,451	140,914	40,764	-
28	Multi-Family Unit Contribution Amortization Expense - Allocable			-	-	-	-	-
29	Miscellaneous General Expenses-Direct		Financial Stmt.	367,847	348,831	(45,528)	64,398	145
30	Miscellaneous General Expenses-Allocable	AL:4:23	Comp_A&G	2,373,165	463,736	1,025,207	884,222	-
31	Total Administrative & General Expenses	=2>30		$ 215,854,266	$ 39,138,720	$ 97,390,911	$ 79,297,762	$ 26,873

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses -									
25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding									
42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Adjustment No. 9

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 9 - Employee Benefits Expense 401(k)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Amount
	A	B	C
1	Per Book Test Year Contributions	Account 926207 (EX:5:14)	$ 3/10,900,486
2	Test Year Contribution Related to Organizational redesign	Analysis	$ 6/(579,010)
3	Test Year Contributions Adjusted	Ln. 1 + Ln. 2	$ 10,321,475
4	Three Year Average Growth Factor	Workpaper 1	2/ 5.29%
5	Employee Savings Plans Expense Increase	Ln. 3 * Ln. 4	$ 545,669
6	Operations & Maintenance Allocation Factor	Analysis	4/ 75.53%
7	Expense Adjusment (System)	Ln. 5 * Ln.6	$ 412,131
8	District of Columbia Allocation Factor	Total_Labor	5/19.36%
9	Expense Adjusment (District of Columbia)	Ln. 7 * Ln. 8	$ 79,796

10 **Adjustment Description:** To adjust 401(k) employee benefits expense for current employees to a pro forma basis.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 9 Workpaper 1 - 401(k) Contribution Rate Worksheet

Twelve Months Ended March 31, 2024

Line No.	Description	Reference		Amount	Annual Growth
1	March 31, 2021	Account 926207 (EX:5:14)	$	8,850,465	
2	March 31, 2022	Account 926207 (EX:5:14)	$	9,215,160	4.12%
3	March 31, 2023	Account 926207 (EX:5:14)	$	10,014,647	8.68%
4	March 31, 2024	Account 926207 (EX:5:14)	$	3/ 10,900,486	
5	Test Year Contribution Related to Organizational redesign	Analysis	$	6/ (579,010)	
6	Test Year Contributions Adjusted	Ln. 4 + Ln. 5	$	10,321,475	3.06%
7	3 Year Average			Average Ln. 2 > 6	5.29% 1

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Description	—Reference— Sc-Pg-Ln	Allocator			WG	DC	MD	VA	FERC
A	B	C			D	E	F	G	H
1 **Administrative & General Expenses**									
2 Administrative & General Salaries-Direct		Financial Stmt.	Sub Total		$ 4,032,355	$ 930,862	$ 1,648,492	$ 1,449,739	$ 3,262
3 Administrative & General Salaries-Allocable	AL 4:23	Comp_A&G	Sub Total		100,516,479	19,641,740	43,423,120	37,451,620	-
4 Office Supplies & Expenses-Direct		Financial Stmt.	Sub Total		3,942,404	1,103,503	1,731,733	1,104,963	2,204
5 Office Supplies & Expenses-Allocable	AL 4:23	Comp_A&G	Sub Total		33,046,634	6,457,582	14,276,146	12,312,906	-
6 Outside Services	AL 5:30		Sub Total	Outside Services Employed	37,435,574	7,053,669	15,176,292	15,205,613	-
7 Property Insurance	AL 3:13	Net_GPIS	Manual Data		-	-	-	-	-
8 Injuries & Damages	AL 4:11	Total_Labor	Sub Total		18,995,900	3,677,954	8,170,412	7,147,535	-
9 Pension Expense	AL 4:11	Total_Labor	Sub Total		(219,656)	(42,494)	(94,398)	(82,580)	(185)
10 DC Regulatory					-				
11 Pension Expense		Financial Stmt.	926104	Appl-Def Pen Cost-DC Ord 9146	-	-	-	-	-
12 Amortization of Rate Case Expenses		Financial Stmt.	928001	Rg Com Exp-Amrt DC Rte Cse Exp	475,776	475,776	-	-	-
13 Least Cost Planning Expenses		Financial Stmt.	930201	Amrtz LCP Exp Recov Curr Rate	-	-	-	-	-
14 Employee Health Benefits			Sub Total		24,779,774	4,793,783	10,649,176	9,315,976	20,840
14 Employee Health Benefits MD Write-Off		Financial Stmt.	926202_write-off		-	-	-	-	-
14 Employee Health Benefits less Write-Off	AL 4:11	Total_Labor	Sub Total		24,779,774	4,793,783	10,649,176	9,315,976	20,840
			X_926202_less_write-off		217,451				183
			926203	Budgets-Empl Benefits Medicare	-				-
			926204	Emp Ben-Med Exp-Osha Reqs	-				-
			926205	Educational Refunds	771				1
			926207	Emp Benefit-Thrift Saving Plan	10,900,486 (1)				9,167
			926208	Emp Benefits	310,259				261
			926209	Employee Benefits Distributed	(5,106,949)				(4,295)
			926210	Grp Ins Prem Paid To Hmo'S	-				-
			926211	Cost Of Presc Drug Program	-				-
			926212	Grp Ins Prem App To Life Insur	(21,266)				(18)
			926213	Self-Funded Group Medical Plan	-				-
			926215	Self-Funded Grp Dental Care	1,173,961				987
			926216	Self-Funded Grp Med Plan-Opt	-				-
			926217	Self-Fund Nonocc Sick/Inj Prog	-				-
			926250	Emp Ben - Flex Plan Credits	-				-
			926251	Emp Benefits - Cobra Credits	-				-
			926252_T	EMPLOYEE BENEFITS - LT Care	-				-
			926260	Basic Life Insur-CIGNA-Mgt	180,039				151
			926261	Basic Life Insur Union-CIGNA	-				-
			926262	Added Basic Life-CIGNA-Union	-				-
			926263_T	Long Term Disability-UNUM-Mgt	680,756				573
			926264	Kaiser HMO - Mgt/Union	1,590,804				1,338
			926265	Emplr Non Taxbl HAS Plan Contr	160,242				135
			926266	NYLCare HMO - Mgt/Union	-				-
			926268	MDIPA HMO - Mgt/Union	-				-
			926270	Emp Group Med Plan-Mgt & Union	-				-
			926272	Emp Comp Med Plan-Mgt & Union	-				-
			926274	Blue Cross/Blue Shield Pln	17,091,522				14,374
			926276	Consumer Dental Plan - Mgt	-				-
			926277	LTD-Union	74,645				63
			926309	Thrift Savings Distributed	(2,472,945)				(2,080)
			926430	Emp Beneft-Blue Cross Med Plan	-				-
15 OPEB	Labor factor	Financial Stmt.	Sub Total		(34,007,440)	(6,584,462)	(14,627,092)	(12,795,885)	-
16 Rate Case Expenses-Direct		Financial Stmt.	928000	Regulatory Commission Expenses	1,526,109	206,553	1,049,073	269,875.64	607
17 Rate Case Expenses-Allocable	AL 4:23	Comp_A&G	928000	Regulatory Commission Expenses	9,523	1,861	4,114	3,548	-
18 DC PSC Assessment Expense		Financial Stmt.	928002	DC PSC Assessment Expense	-	-	-	-	-
19 General Advertising Expenses - Direct		Financial Stmt.	930100	General Advertising Expenses	1,269	-	984	285	-
20 General Advertising Expenses - Allocable	AL 4:23	Comp_A&G	930100	General Advertising Expenses	644,209	125,884	278,298	240,027	-
21 Environmental Expense - Regulatory Amortization		Financial Stmt.	930210_T	Amrt Env Exp Rcvr-Cur Rates	686,319	263,068	423,250	-	-
22 Environmental Reserve - Regulatory Adjustment		Financial Stmt.	930211	Environmental Reserve Adjustme	1,738,655	-	-	1,738,655	-
23 Rents		Financial Stmt.	931000	Rents	263,877	-	-	263,877	-
24 MD Demand Side Management Expenses		Comp_A&G	930202	MD Dmd Sd Mgt Cst-Rcvr-Cur Rte	1,041,022	203,424	449,721	387,876	-
25 VA Care Expenses		Financial Stmt.	930206	MiscGenExp-Va Care Effic Prog	4,294,347	-	-	4,294,347	-
26 MD EmPOWER MD Expenses		Financial Stmt.	930207	MiscGenExp – EmPOWER MD Prog	13,710,995	-	13,710,995	-	-
27 Multi-Family Unit Contribution Amortization Expense		Financial Stmt.	930220	MultifamUnitContrlAmortExp	199,129	17,451	140,914	40,764	-
28 Multi-Family Unit Contribution Amortization Expense - Allocable			930220		-	-	-	-	-
29 Miscellaneous General Expenses-Direct		Financial Stmt.	930200_Total	Misc General Expenses	367,847	348,831	(45,528)	64,398	145
30 Miscellaneous General Expenses-Allocable	AL 4:23	Comp_A&G	930200_total	Misc General Expenses	2,373,165	463,736	1,025,207	884,222	-
31 Total Administrative & General Expenses	= 2 >30				$ 215,854,266	$ 39,138,720	$ 97,390,911	$ 79,297,762	$ 26,873

Washington Gas Light Company
All Jurisdictions

Operations & Maintenance (O&M) Factor Calculation & Classification of Payroll

Twelve Months ending March 31, 2024

Utility Labor (Direct)

Res Type	(All)
Source	TLI

Sum of Sum Amount		Unit / Year / Period 01 / 23 / 4	01 / 23 / 5	01 / 23 / 6	01 / 23 / 7	01 / 23 / 8	01 / 23 / 9	01 / 23 / 10	01 / 23 / 11	01 / 23 / 12	01 / 24 / 1	01 / 24 / 2	01 / 24 / 3	Grand Total	Payroll Classification O&M	Capital	Other	Affiliates
Exp Type	Account																	
Capital		494,874	460,058	563,786	390,981	946,926	627,555	658,202	791,793	619,873	566,559	610,149	629,162	7,359,918	-	7,359,918	-	-
Non-Utility		8,310	6,289	6,886	4,867	7,027	5,360	6,219	6,893	64,101	10,779	5,479	5,446	137,654	-	-	137,654	-
O&M		8,943,411	8,779,237	8,495,575	7,887,392	12,973,264	8,478,117	9,078,234	8,815,747	7,933,074	11,962,271	10,143,655	9,375,791	112,865,769	112,865,769	-	-	-
Other		356,400	302,277	321,010	270,147	436,100	292,814	273,777	272,411	286,860	411,167	338,185	346,413	3,907,561	-	-	3,907,561	-
Pool	163101	43,017	48,440	46,887	43,844	69,450	36,989	53,857	59,608	47,987	50,103	49,849	36,883	586,915	1,138	585,750	27	-
Pool	184105	10,751	15,696	14,772	14,473	21,356	14,447	16,759	15,819	15,182	19,389	15,687	16,345	190,677	164,301	-	4,864	21,511
Pool	184107	69,874	69,473	62,167	59,199	103,586	60,807	56,654	42,387	40,997	52,112	47,446	47,908	712,610	689,915	-	16,844	5,852
Pool	184122	21,736	22,861	21,365	17,794	31,511	20,245	27,153	29,189	20,974	30,488	38,026	59,007	340,350	308,730	28,715	2,905	-
Pool	184123	161,892	142,303	139,355	141,771	257,861	164,189	184,696	183,973	156,633	206,063	167,626	136,168	2,042,530	1,827,923	194,892	19,714	-
Pool	184131	591	589	599	570	893	590	623	339	226	485	81	235	5,822	4,632	1,070	120	-
Pool	184181	-	-	-	101	-	-	-	-	-	58	10,869	12,962	23,990	21,640	1,210	695	445
Pool	184201	86,113	82,332	74,296	51,128	77,365	54,546	48,188	43,690	(132,024)	59,636	45,777	47,540	538,587	-	538,587	-	-
Pool	184211	45,918	45,385	47,791	38,442	67,430	45,792	38,772	34,064	52,655	45,330	34,633	34,050	530,260	-	530,260	-	-
Pool	184212	46,818	46,659	46,797	42,876	84,409	53,666	52,793	51,927	92,674	64,826	60,119	56,840	700,403	-	700,403	-	-
Pool	184213	57,967	67,264	57,048	53,880	102,241	64,049	62,769	58,307	100,087	82,498	63,307	52,367	821,784	-	821,784	-	-
Pool	184215	423,233	459,306	416,710	409,500	686,383	443,389	464,710	453,934	410,668	566,352	494,985	436,864	5,666,032	-	5,666,032	-	-
Pool	184218	129,795	133,572	122,241	109,661	188,078	130,233	177,783	158,983	137,683	204,199	186,557	175,614	1,854,397	114,380	1,740,018	-	-
Pool	184227	33,872	36,160	34,963	32,873	61,184	38,652	42,119	38,148	35,545	49,777	42,791	40,136	486,219	-	486,219	-	-
Pool	184231	1,043,026	1,081,760	1,024,816	921,533	1,560,366	1,005,191	1,012,066	1,022,455	947,651	1,272,489	1,088,950	1,066,574	13,046,876	-	13,046,876	-	-
Grand Total		11,977,597	11,799,659	11,497,063	10,491,034	17,675,429	11,536,631	12,255,372	12,079,664	10,830,845	15,654,582	13,444,173	12,576,305	151,818,352	115,998,427	31,701,735	4,090,382	27,808

Affiliate Labor (Direct)

Res Type	(All)
Source	TLI

Sum of Sum Amount		Year / Period 23 / 4	23 / 5	23 / 6	23 / 7	23 / 8	23 / 9	23 / 10	23 / 11	23 / 12	24 / 1	24 / 2	24 / 3	Grand Total	O&M	Capital	Other	Affiliates
Exp Type	Unit																	
Non-Utility	00	12,580	14,193	13,656	13,358	20,138	13,816	14,405	13,304	11,458	17,986	15,553	14,075	174,523	-	-	-	174,523
Non-Utility	01	6,120	5,730	6,886	4,787	6,579	5,360	6,021	5,112	62,558	7,019	5,479	5,205	126,857	-	-	-	126,857
Non-Utility	07	1,122	240	-	-	83	401	-	-	-	-	-	56	1,902	-	-	-	1,902
Non-Utility	15	89,325	103,119	71,214	97,122	136,906	86,914	89,669	83,821	69,701	103,994	85,071	83,867	1,100,723	-	-	-	1,100,723
Non-Utility	20	14,954	16,410	4,824	3,684	2,650	1,438	1,353	4,673	842	634	4,525	2,108	58,095	-	-	-	58,095
Non-Utility	24	4,500	4,203	3,179	3,862	4,877	3,877	4,059	4,269	3,636	5,664	4,652	4,183	50,960	-	-	-	50,960
Non-Utility	28	3	60	3	2	985	2	3	2	2	2	655	251	1,971	-	-	-	1,971
Non-Utility	300	240	13,473	25,370	19,185	37,680	24,639	26,670	24,724	72,612	25,551	27,096	(46,644)	250,596	-	-	-	250,596
Non-Utility	312	-	-	-	116	-	-	-	-	-	-	-	-	116	-	-	-	116
Grand Total		128,844	157,429	125,131	142,117	209,898	136,447	142,180	135,906	220,809	160,850	143,032	63,101	1,765,744	-	-	-	1,765,744
Total		12,106,440	11,957,088	11,622,194	10,633,150	17,885,326	11,673,079	12,397,552	12,215,570	11,051,654	15,815,432	13,587,205	12,639,406	153,584,096	115,998,427	31,701,735	4,090,382	1,793,552
Percentage															75.53% 1	20.64%	2.66%	1.17%

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618 1	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses -									
25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding									
42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Exhibit WG (D)-5
Adjustment No. 9
Page 5 of 6

Employer paid benefits related to organization redesign (TME March 2024)

Company	Washington Gas Light Company

Deduction Code	Deduction	Sum of MTD Amount	
401K Match	401K Match	343,136.33	401(k)
BSBSN	Blue Cross/Shield Medical Employer	630,901.96	medical
BSLFMN	Basic Life Insurance ER	12,911.96	life insurance
DNTALN	Dental Employer	57,452.57	medical
HSA ER	Health Savings Account Employer	10,776.88	medical
KPDHMN	Kaiser Medical Employer	66,328.27	medical
SPWEB	Saving Plan w/Enhanced Benefit	235,873.87	401(k)
W_FUI	FUI (ER)	3,238.62	payroll tax
W_MEDER	Medicare (ER)	179,144.40	payroll tax
W_OASER	OASDI (ER)	531,709.57	payroll tax
W_SUIER	SUI (ER)	5,691.34	payroll tax
Grand Total		2,077,165.77	

medical	765,459.68	
401(k)	579,010.20	① ②
life insurance	12,911.96	
payroll tax	719,783.93	
Total	2,077,165.77	
check	-	

Adjustment No. 10

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 10 - Employee Benefits Expense (Fringe) Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	O&M Factor	DC Factor	DC Amount _2/	
	A	B	C	D	E	F=C*D*E	
1	Professional Services	Workpaper 2	$ 3/(22,490)	100.00%	7/ 19.36%	$ (4,354)	_1/
2	Physicals	Workpaper 2	(7,150)	100.00%	19.36%	(1,384)	_1/
3	Parking	Workpaper 3	4/ (71,760)	6/ 86.17%	19.36%	(11,972)	
4	Car Allowance	Workpaper 4	5/ (110,439)	100.00%	19.36%	(21,383)	_1/
5	**Adjustment to Fringe Benefits (Current Employees)**	**Ln. 1 > Ln. 4**	**$ (211,838)**			**$ (39,094)**	

6 **Adjustment Description:** To remove executive fringe benefits expense.

_1/ O&M factor not applicable because this amount already excludes affiliate transactions.
_2/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line EX:5:14.

Washington Gas Light Company
System

Adjustment No. 10 Workpaper 1 - General Ledger Query by Source

Twelve Months Ended March 31, 2024

$	564,462	AP sourced items per GL query
$	564,462	AP query total
$	-	Difference (SHOULD BE ZERO)

Unit	01

Sum of Source		Year	Period											
		23	23	23	23	23	23	23	23	23	24	24	24	Grand Tota
Account	Source	4	5	6	7	8	9	10	11	12	1	2	3	
926202	ALO	-	195	(118)	-	-	491	344	(387)	188	93	148	434	1,387
926202	**AP**	**86,758**	**33,855**	**210**	**2,150**	**56,642**	**20,578**	**6,373**	**-**	**12,692**	**105**	**11,268**	**23,574**	**254,203**
926202	EXL	(1,562)	407	(352)	16,972	(17,097)	79	2,546	9,926	(10,365)	(50,383)	(28,167)	37,518	(40,477)
926202	TLI	-	255	-	-	-	394	595	90	192	170	177	546	2,420
926202 Total		85,196	34,712	(260)	19,122	39,545	21,542	9,858	9,630	2,707	(50,016)	(16,575)	62,072	217,533
926208	**AP**	**47,281**	**44,127**	**-**	**80,945**	**-**	**11,154**	**12,874**	**27,624**	**26,538**	**-**	**-**	**59,717**	**310,259**
926208	EXL	-	-	-	-	-	-	-	-	-	-	98	(98)	-
926208 Total		47,281	44,127	-	80,945	-	11,154	12,874	27,624	26,538	-	98	59,619	310,259
Grand Total		132,477	78,838	(260)	100,066	39,545	32,696	22,732	37,253	29,245	(50,016)	(16,478)	121,691	527,792

NOTE: Accounts 926202 and 926208 are included in the total of EX Page 5, Line 14 in the per book jurisdictional cost of service study.

Washington Gas Light Company
All Jurisdictions

Adjustment No. 10 Workpaper 2 - Professional Services and Executive Physicals Expense

Twelve Months Ended March 31, 2024

Prof Services	$	22,490	1	Product 05431
Exec Phys	$	7,150		

LABOR_EXEC_FRINGE_AP 137

GL Unit	Supplier	Year	Period	Descr	Sum Amount	Product	Dept	Process	Account	Voucher	Group	Oper Unit	Expense Type
01		23	11		5,000.00	05431	038		926208	01065404		10	Prof Services
01	ERNST & YOUNG LLP	23	5	Professional Services	2,575.00	05431	038		926208	01042572		10	Prof Services
01	ERNST & YOUNG LLP	23	12		3,605.00	05431	038		926208	01069601		10	Prof Services
01		23	12		3,264.75	05431	038		926208	01069112		10	Prof Services
01		23	12	Paying for reimbursement	3,300.00	05431	038		926208	01066808		10	Prof Services
01	JHU DEPARTMENT OF MEDICINE	23	7	JOHNS HOPKINS EXECUTIVE HEALTH	2,149.50		039	56201	926202	01050877		10	Exec Phys
01		23	7	Expense Distribution	1,500.00	05431	038		926208	01050580		10	Prof Services
01		23	8	Expense Distribution	(1,500.00)	05431	038		926208	01050580		10	Prof Services
01		23	8	VP Executive Tax Reimbursement	1,500.00	05431	038		926208	01050580		10	Prof Services
01		24	3	Expense Distribution	3,245.00	05431	038		926208	01079349		10	Prof Services
01	JHU DEPARTMENT OF MEDICINE	24	2	JOHNS HOPKINS EXECUTIVE HEALTH	2,500.00		039	56201	926202	01072743		10	Exec Phys
01	JHU DEPARTMENT OF MEDICINE	24	2	JOHNS HOPKINS EXECUTIVE HEALTH	2,500.00		039	56201	926202	01073227		10	Exec Phys

Washington Gas Light Company
All Jurisdictions

Adjustment No. 10 Workpaper 3 - Executive Parking Expense Twelve

Months Ended March 31, 2024

GL Unit	01

Sum of Breakout		Year	Period											
		23	23	23	23	23	23	23	23	23	24	24	24	Grand Total
Account	Charge Type	4	5	6	7	8	9	10	11	12	1	2	3	
184110	Common Area	186,016	103,900	115,004	115,004	115,004	115,004	115,004	115,004	115,004	126,196	126,196	126,196	1,473,535
184110	**Parking (Executive)**	**3,600**	**3,600**	**3,600**	**3,600**	**3,600**	**3,600**	**3,600**	**3,600**	**3,600**	**3,600**	**3,600**	**3,600**	**43,200** A
184110	**Parking (Tandem Exec)**	**2,380**	**2,380**	**2,380**	**2,380**	**2,380**	**2,380**	**2,380**	**2,380**	**2,380**	**2,380**	**2,380**	**2,380**	**28,560** B
184110	Parking (Tandem OGC)	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	12,240
184110	Storage	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	16,000
Grand Total		194,350	112,233	123,338	123,338	123,338	123,338	123,338	123,338	123,338	134,529	134,529	134,529	1,573,534

A + B = 71,760 1

NOTE: Account number 184110 is the building services allocation pool account for the Wharf, where the Company pays for parking for selected employees. Portions of the expense are allocated to utility O&M, capital, non-utility, and affiliates based on how employees who work at the Wharf charge their time.

Washington Gas Light Company
All Jurisdictions

Adjustment No. 10 Workpaper 4 - Executive Car Allowance Expense Twelve

Months Ended March 31, 2024

Unit	01

Sum of Activity	Year	Period											
	23								24			Grand Total
Account	4	5	6	7	8	9	10	11	12	1	2	3	
921000	9,445	9,445	9,445	9,445	9,445	9,470	9,774	9,774	9,074	8,374	8,374	8,374	110,439
Grand Total	9,445	9,445	9,445	9,445	9,445	9,470	9,774	9,774	9,074	8,374	8,374	8,374	110,439 1

Process	Building Services 101

Sum of Sum Amount

Utility?	Type	Account	Journal ID	Res Type	Grand Total	
Yes	Pool	184105	BS10100001	3130	(322,364)	
Yes	Pool	184110	BS10100001	3130	(4,652,556)	
Grand Total					(4,974,920)	-

Utility O&M Percentage	**0.8617** 1
Utility Capital Percentage	**-**
Utility Other & NonUtility Percentage	**0.0255**
Charged to Affiliates Percentage	**0.1128**
	1.0000

Process	Building Services 101

Sum of Sum Amount

Utility?	Type	Account	Journal ID	Res Type	Grand Total	
No	Intercompany	146000	BS10100001	3130	(561,252)	(0.1128)
No	Non-Utility	417465	BS10100001	3505	136,810	0.0275
No	Non-Utility	417904	BS10100001	3505	218,718	0.0440
No	Non-Utility	417956	BS10100001	3505	197,402	0.0397
No	O&M	920000	BS10100001	3505	8,322	0.0017
Yes	Intercompany	146000	BS10100001	3130	561,252	0.1128
Yes	Non-Utility	417465	BS10100001	3505	3,665	0.0007
Yes	Non-Utility	417904	BS10100001	3505	20,706	0.0042
Yes	Non-Utility	417464	BS10100001	3505	21	0.0000
Yes	O&M	920000	BS10100001	3505	4,136,058	0.8314
Yes	O&M	923000	BS10100001	3505	740	0.0001
Yes	O&M	928000	BS10100001	3505	149,950	0.0301
Yes	Other	143105	BS10100001	3505	21,708	0.0044
Yes	Other	146516	BS10100001	3505	17,201	0.0035
Yes	Other	426410	BS10100001	3505	16,300	0.0033
Yes	Other	426412	BS10100001	3505	45,966	0.0092
Yes	Other	421021	BS10100001	3505	1,064	0.0002
Yes	Other	426100	BS10100001	3505	287	0.0001
Grand Total					4,974,920	1.0000

-
-

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

	Description	—— Reference —— Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
	A	B	C	D	E	F	G	H	I	J
1	**Customer Accounts**									
2	General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3	Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4	Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5	Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6	Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7	Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8	Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9	Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10	Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11	**Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618 1	0.430114	0.376267
12	**Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13	**Expenses allocated on**									
14	**Composite A&G Factor**									
15	Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16	Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17	Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18	Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19	Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20	Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21	Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22	Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23	Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24	**Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25	**Operations & Maintenance**									
26	**Expenses - Adjusted**									
27	Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28	Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29	Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30	Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31	Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32	Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33	Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34	Operations & Maintenance Expenses -									
25	Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36	**Operations Expense Excluding**									
37	**Purchased Gas & Uncollectibles**									
38	Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39	Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40	Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41	Operations Expense Excluding									
42	Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43	Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Adjustment No. 11

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 11 - Medical Plans Inflation

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	O&M Factor D	Labor Factor E	MD Amount F=C*D*E
1	Insurance Benefits Expense - Carefirst / BCBS	Account 926.274	2/ $ 17,091,522			
2	Insurance Benefits Expense - Kaiser-Permanente	Account 926.264	$ 1,590,804			
3	Insurance Benefits Expense - Delta Dental	Account 926.215	$ 1,173,961			
4	Test Year Expense Related to Involuntary Sep. Prog.	Analysis	3/ (765,460)			
5	Total Group Meidcal Expense (Test Year)	Ln. 1 + Ln. 2 + Ln. 3 + Ln. 4	19,090,827			
6	Inflation Rate	Analysis	4/ 7.00%			
7	**Total Expense Adjustment _1/**	Ln. 5 * Ln. 6	**$ 1,336,358**	5/ 75.53%	6/ 19.36%	**$ 195,423**

8 **Adjustment Description:** To adjust employee medical benefits expense for current employees to a pro forma basis.

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----Reference---- Sc-Pg-Ln	Allocator			WG	DC	MD	VA	FERC
	A	B	C			D	E	F	G	H
1	**Administrative & General Expenses**									
2	Administrative & General Salaries-Direct		Financial Stmt	Sub Total		$ 4,032,355	$ 930,862	$ 1,648,492	$ 1,449,739	$ 3,262
3	Administrative & General Salaries-Allocable	AL 4 23	Comp_A&G	Sub Total		100,516,479	19,641,740	43,423,120	37,451,620	-
4	Office Supplies & Expenses-Direct		Financial Stmt	Sub Total		3,942,404	1,103,503	1,731,733	1,104,963	2,204
5	Office Supplies & Expenses-Allocable	AL 4 23	Comp_A&G	Sub Total		33,046,634	6,457,582	14,276,146	12,312,906	-
6	Outside Services	AL 5 30		Sub Total	Outside Services Employed	37,435,574	7,053,669	15,176,292	15,205,613	-
7	Property Insurance	AL 3 13	Net_GPIS	Manual Data		-	-	-	-	-
8	Injuries & Damages	AL 4 11	Total_Labor	Sub Total		18,995,900	3,677,954	8,170,412	7,147,535	-
9	Pension Expense	AL 4 11	Total_Labor	Sub Total		(219,656)	(42,494)	(94,398)	(82,580)	(185)
10	DC Regulatory					-				
11	Pension Expense		Financial Stmt	926104	Appl-Def Pen Cost-DC Ord 9146	-	-	-	-	-
12	Amortization of Rate Case Expenses		Financial Stmt	928001	Rg Com Exp-Amrt DC Rte Cse Exp	475,776	475,776	-	-	-
13	Least Cost Planning Expenses		Financial Stmt	930201	Amrtz LCP Exp Recov Curr Rate	-	-	-	-	-
14	Employee Health Benefits			Sub Total		24,779,774	4,793,783	10,649,176	9,315,976	20,840
14	Employee Health Benefits MD Write-Off		Financial Stmt	926202_write-off		-	-	-	-	-
14	Employee Health Benefits less Write-Off	AL 4 11	Total_Labor	Sub Total		24,779,774	4,793,783	10,649,176	9,315,976	20,840
				X_926202_less_write-off		217,451				183
				926203	Budgets-Empl Benefits Medicare	-				-
				926204	Emp Ben-Med Exp-Osha Reqs	-				-
				926205	Educational Refunds	771				1
				926207	Emp Benefit-Thrift Saving Plan	10,900,486				9,167
				926208	Emp Benefits	310,259				261
				926209	Employee Benefits Distributed	(5,106,949)				(4,295)
				926210	Grp Ins Prem Paid To Hmo'S	-				-
				926211	Cost Of Presc Drug Program	-				-
				926212	Grp Ins Prem App To Life Insur	(21,268)				(18)
				926213	Self-Funded Group Medical Plan	-				-
				926215	Self-Funded Grp Dental Care	1,173,961 1				987
				926216	Self-Funded Grp Med Plan-Opt	-				-
				926217	Self-Fund Nonocc Sicklnj Prog	-				-
				926250	Emp Ben - Flex Plan Credits	-				-
				926251	Emp Benefits - Cobra Credits	-				-
				926252_T	EMPLOYEE BENEFITS - LT Care	-				-
				926260	Basic Life Insur-CIGNA-Mgt	180,039				151
				926261	Basic Life Insur Union-CIGNA	-				-
				926262	Added Basic Life-CIGNA-Union	-				-
				926263_T	Long Term Disability-UNUM-Mgt	680,756				573
				926264	Kaiser HMO - Mgt/Union	1,590,804 1				1,338
				926265	Emplr Non Taxbl HAS Plan Contr	160,242				135
				926266	NYLCare HMO - Mgt/Union	-				-
				926268	MDIPA HMO - Mgt/Union	-				-
				926270	Emp Group Med Plan-Mgt & Union	-				-
				926272	Emp Comp Med Plan-Mgt & Union	-				-
				926274	Blue Cross/Blue Shield Pln	17,091,522 1				14,374
				926276	Consumer Dental Plan - Mgt	-				-
				926277	LTD-Union	74,645				63
				926309	Thrift Savings Distributed	(2,472,945)				(2,060)
				926430	Emp Benefit-Blue Cross Med Plan	-				-
15	OPEB	Labor factor	Financial Stmt	Sub Total		(34,007,440)	(6,584,462)	(14,627,092)	(12,795,885)	-
16	Rate Case Expenses-Direct		Financial Stmt	928000	Regulatory Commission Expenses	1,526,109	206,553	1,049,073	269,875 64	607
17	Rate Case Expenses-Allocable	AL 4 23	Comp_A&G	928000	Regulatory Commission Expenses	9,523	1,861	4,114	3,548	-
18	DC PSC Assessment Expense		Financial Stmt	928002	DC PSC Assessment Expense	-	-	-	-	-
19	General Advertising Expenses - Direct		Financial Stmt	930100	General Advertising Expenses	1,269	-	984	285	-
20	General Advertising Expenses - Allocable	AL 4 23	Comp_A&G	930100	General Advertising Expenses	644,209	125,884	278,298	240,027	-
21	Environmental Expense - Regulatory Amortization		Financial Stmt	930210_T	Amrt Env Exp Rcvr-Cur Rates	686,319	263,068	423,250	-	-
22	Environmental Reserve - Regulatory Adjustment		Financial Stmt	930211	Environmental Reserve Adjustme	1,738,655	-	-	1,738,655	-
23	Rents		Financial Stmt	931000	Rents	263,877	-	-	263,877	-
24	MD Demand Side Management Expenses		Comp_A&G	930202	MD Dmd Sd Mgt Cst-Rcvr-Cur Rte	1,041,022	203,424	449,721	387,876	-
25	VA Care Expenses		Financial Stmt	930206	MiscGenExp-Va Care Effic Prog	4,294,347	-	-	4,294,347	-
26	MD EmPOWER MD Expenses		Financial Stmt	930207	MiscGenExp – EmPOWER MD Prog	13,710,995	-	13,710,995	-	-
27	Multi-Family Unit Contribution Amortization Expense		Financial Stmt	930220	MultifamUnitContrAmortExp	199,129	17,451	140,914	40,764	-
28	Multi-Family Unit Contribution Amortization Expense - Allocable			930220		-	-	-	-	-
29	Miscellaneous General Expenses-Direct		Financial Stmt	930200_Total	Misc General Expenses	367,847	348,831	(45,528)	64,398	145
30	Miscellaneous General Expenses-Allocable	AL 4 23	Comp_A&G	930200_total	Misc General Expenses	2,373,165	463,736	1,025,207	884,222	-
31	Total Administrative & General Expenses	= 2 >30				$ 215,854,266	$ 39,138,720	$ 97,390,911	$ 79,297,762	$ 26,873

Employer paid benefits related to organization redesign (TME March 2024)

Company	Washington Gas Light Company

Deduction Code	Deduction	Sum of MTD Amount	
401K Match	401K Match	343,136.33	401(k)
BSBSN	Blue Cross/Shield Medical Employer	630,901.96	medical
BSLFMN	Basic Life Insurance ER	12,911.96	life insurance
DNTALN	Dental Employer	57,452.57	medical
HSA ER	Health Savings Account Employer	10,776.88	medical
KPDHMN	Kaiser Medical Employer	66,328.27	medical
SPWEB	Saving Plan w/Enhanced Benefit	235,873.87	401(k)
W_FUI	FUI (ER)	3,238.62	payroll tax
W_MEDER	Medicare (ER)	179,144.40	payroll tax
W_OASER	OASDI (ER)	531,709.57	payroll tax
W_SUIER	SUI (ER)	5,691.34	payroll tax
Grand Total		2,077,165.77	

medical	765,459.68 1
401(k)	579,010.20
life insurance	12,911.96
payroll tax	719,783.93
Total	2,077,165.77
check	-

WTW's healthcare actuarial practice anticipates market average trend may reasonably range from 6.0% to 11.0% for 2024 and 2025. We would recommend AltaGas utilize a 7-8% trend assumption for 2024 as it tends to capture most of the brokerage surveys that are publicly available (more detail included below). It should also be noted that AltaGas's fully insured premiums with Kaiser increased by 12% for 2024 (most employers saw double digit increases with Kaiser this year as Kaiser lost money in 2022 as a result of the COVID-19 pandemic; anecdotally Kaiser anticipates a return to more normal increases for 2025).

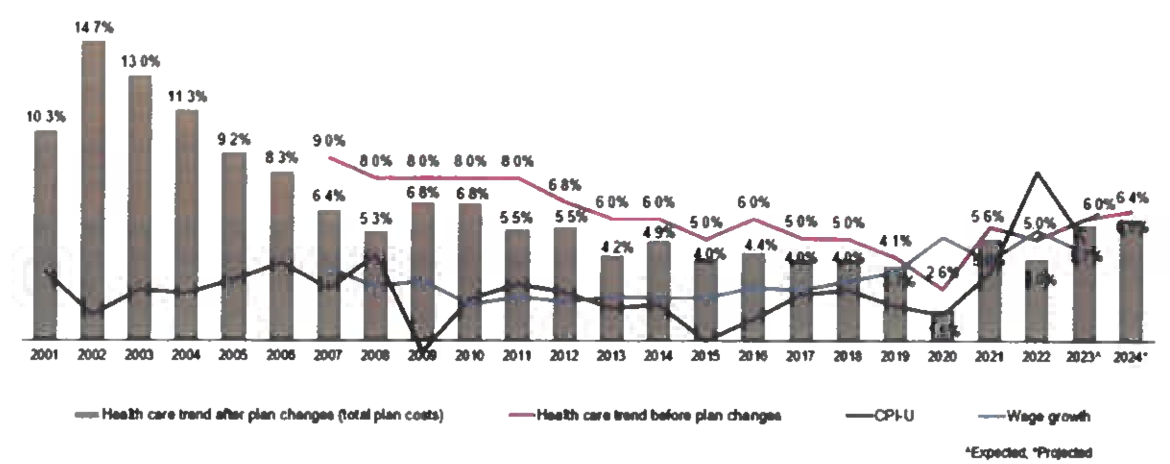
Health care cost growth tends to outpace the rate of general economic inflation as it is comprised of both price inflation as well as increases in health care utilization / service mix as well as technological advancements. We expect health care cost growth to continue to outpace general economic inflation over the near term (i.e. next 5 years). Factors influencing this growth include, but are not limited to:

- Contentious multiyear contract negotiations between insurance companies and health systems as the health systems look to recoup losses sustained during the COVID-19 pandemic
- Industry consolidation including hospitals, pharmacy benefit managers and insurance carriers
- Continued clinical workforce shortages
- Continued medical progress and technological advances
- Increased healthcare utilization due to provider practices (e.g. over-prescribing services)
- Increasing prevalence of GLP-1 agonists for weight loss

WTW's healthcare actuarial practice anticipates market average trend may reasonably range from 6.0% to 11.0% for 2024 and 2025. We recommend AltaGas utilize a trend assumption of 7-8% as this is aligned with market averages at this point in time. Additional broker and consulting house survey sources indicate the following:

- WTW's Best Practices in Healthcare Survey (a survey of employer plan sponsors) anticipates average healthcare trend of 6.4% for 2024:

Healthcare cost increases rising but with uncertainty and variability



Note: Percentages of healthcare trend are median numbers
Sample: Companies with at least 1,000 employees
Source: WTW 2023 Best Practices in Healthcare Survey, Bureau of Labor Statistics: CPI-U, CES

- WTW's Global Medical Trend Survey (a survey of insurance carriers) expects a gross trend of 8.94%. Insurance carriers tend to be more conservative in their trend estimates than brokers/consultants:

Washington Gas Light Company
All Jurisdictions

Operations & Maintenance (O&M) Factor Calculation & Classification of Payroll

Twelve Months ending March 31, 2024

Utility Labor (Direct)

Res Type	(All)
Source	TLI

Sum of Sum Amount		Unit / Year / Period													Payroll Classification			
		01	01	01	01	01	01	01	01	01	01	01	01	Grand Total				
		23	23	23	23	23	23	23	23	23	24	24	24					
Exp Type	Account	4	5	6	7	8	9	10	11	12	1	2	3		O&M	Capital	Other	Affiliates
Capital		494,874	460,058	563,786	390,981	946,926	627,555	658,202	791,793	619,873	566,559	610,149	629,162	7,359,918	-	7,359,918	-	-
Non-Utility		8,310	6,289	6,886	4,867	7,027	5,360	6,219	6,893	64,101	10,779	5,479	5,446	137,654	-	-	137,654	-
O&M		8,943,411	8,779,237	8,495,575	7,887,392	12,973,264	8,478,117	9,078,234	8,815,747	7,933,074	11,962,271	10,143,655	9,375,791	112,865,769	112,865,769	-	-	-
Other		356,400	302,277	321,010	270,147	436,100	292,814	273,777	272,411	286,860	411,167	338,185	346,413	3,907,561	-	-	3,907,561	-
Pool	163101	43,017	48,440	46,887	43,844	69,450	36,989	53,657	59,608	47,987	50,103	49,849	36,883	586,915	1,138	585,750	27	-
Pool	184105	10,751	15,696	14,772	14,473	21,356	14,447	16,759	15,819	15,182	19,389	15,687	16,345	190,677	164,301	-	4,864	21,511
Pool	184107	69,874	69,473	62,167	59,199	103,586	60,807	56,654	42,387	40,997	52,112	47,446	47,908	712,810	689,915	-	16,844	5,852
Pool	184122	21,736	22,861	21,365	17,794	31,511	20,245	27,153	29,189	20,974	30,488	38,026	59,007	340,350	308,730	28,715	2,905	-
Pool	184123	161,892	142,303	139,355	141,771	257,861	164,189	184,696	183,973	156,633	206,063	167,626	136,168	2,042,530	1,827,923	194,892	19,714	-
Pool	184131	591	589	599	570	893	590	623	339	226	485	81	235	5,822	4,632	1,070	120	-
Pool	184181	-	-	-	101	-	-	-	-	-	58	10,869	12,962	23,990	21,640	1,210	695	445
Pool	184201	86,113	82,332	74,296	51,128	77,365	54,546	48,188	43,690	(132,024)	59,636	45,777	47,540	538,587	-	538,587	-	-
Pool	184211	45,918	45,385	47,791	38,442	67,430	45,792	38,772	34,064	52,655	45,330	34,633	34,050	530,260	-	530,260	-	-
Pool	184212	46,818	46,659	46,797	42,876	84,409	53,666	52,793	51,927	92,674	64,826	60,119	56,840	700,403	-	700,403	-	-
Pool	184213	57,967	67,264	57,048	53,880	102,241	64,049	62,769	58,307	100,087	82,498	63,307	52,367	821,784	-	821,784	-	-
Pool	184215	423,233	459,308	416,710	409,500	686,383	443,389	464,710	453,934	410,668	566,352	494,985	436,864	5,666,032	-	5,666,032	-	-
Pool	184218	129,795	133,572	122,241	109,661	188,078	130,233	177,783	158,963	137,683	204,199	186,557	175,614	1,854,397	114,380	1,740,018	-	-
Pool	184227	33,872	36,160	34,963	32,873	61,184	38,652	42,119	38,148	35,545	49,777	42,791	40,136	486,219	-	486,219	-	-
Pool	184231	1,043,026	1,081,760	1,024,816	921,533	1,560,368	1,005,191	1,012,066	1,022,455	947,651	1,272,489	1,088,950	1,066,574	13,046,876	-	13,046,876	-	-
Grand Total		11,977,597	11,799,659	11,497,063	10,491,034	17,675,429	11,536,631	12,255,372	12,079,664	10,830,845	15,654,582	13,444,173	12,576,305	151,818,352	115,998,427	31,701,735	4,090,382	27,808

Affiliate Labor (Direct)

Res Type	(All)
Source	TLI

Sum of Sum Amount		Year / Period																
		23	23	23	23	23	23	23	23	23	24	24	24	Grand Total				
Exp Type	Unit	4	5	6	7	8	9	10	11	12	1	2	3					
Non-Utility	00	12,580	14,193	13,656	13,358	20,138	13,816	14,405	13,304	11,458	17,986	15,553	14,075	174,523	-	-	-	174,523
Non-Utility	01	6,120	5,730	6,886	4,787	6,579	5,360	6,021	5,112	62,558	7,019	5,479	5,205	126,857	-	-	-	126,857
Non-Utility	07	1,122	240	-	-	83	401	-	-	-	-	-	56	1,902	-	-	-	1,902
Non-Utility	15	89,325	103,119	71,214	97,122	136,906	86,914	89,669	83,821	69,701	103,994	85,071	83,867	1,100,723	-	-	-	1,100,723
Non-Utility	20	14,954	16,410	4,824	3,684	2,650	1,438	1,353	4,673	842	634	4,525	2,108	58,095	-	-	-	58,095
Non-Utility	24	4,500	4,203	3,179	3,862	4,877	3,877	4,059	4,269	3,636	5,664	4,652	4,183	50,960	-	-	-	50,960
Non-Utility	28	3	60	3	2	985	2	3	2	2	2	655	251	1,971	-	-	-	1,971
Non-Utility	300	240	13,473	25,370	19,185	37,680	24,639	26,670	24,724	72,612	25,551	27,096	(46,844)	250,596	-	-	-	250,596
Non-Utility	312	-	-	-	116	-	-	-	-	-	-	-	-	116	-	-	-	116
Grand Total		128,844	157,429	125,131	142,117	209,898	136,447	142,180	135,906	220,809	160,850	143,032	63,101	1,765,744	-	-	-	1,765,744
Total		12,106,440	11,957,088	11,622,194	10,633,150	17,885,326	11,673,079	12,397,552	12,215,570	11,051,654	15,815,432	13,587,205	12,639,406	153,584,096	115,998,427	31,701,735	4,090,382	1,793,552
Percentage															75.53% 1	20.64%	2.66%	1.17%

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618 1	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses -									
25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding									
42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Adjustment No. 12

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 12 - FICA / Medicare Tax Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	Labor Factor D	DC Amount E
1	Incremental Payroll Expense	Adj. No. 5	$ 2/ 5,160,643		
2	Adjust to reflect 5 year amortization of ratification bonus	Adj. No. 5	3/ 1,957		
3	Labor Adjustment Change	Ln. 1 + Ln. 2	**$ 5,162,599**		
4	Factor - SSI Wages to Gross Wages	Analysis	4/ 91.23%		
5	Social Security Insurance (SSI) Base	Ln. 1 * Ln. 4	$ 4,709,839		
6	SSI Rate		5/ 6.20%		
7	SSI Tax	Ln. 5 * Ln. 6	292,010	6/19.36%	56,538
8	Base - Medicare (Payroll Increase)	Ln. 3	$ 5,162,599		
9	Base - Medicare (Long-Term Incentive Elimination)	Adj. No. 6	7/ (17,350,204)		
10	Total Medicare Base	Ln. 8 + Ln. 9	(12,187,604)		
11	Medicare Rate		5/ 1.45%		
12	Medicare Tax - Medicare	Ln. 10 * Ln. 11	(176,720)	6/ 19.36%	(34,216)
13	Total Pro Forma Adjustment	Ln. 7 + Ln. 12	**$ 115,290**	6/ 19.36%	**$ 22,322** _1/

14 **Adjustment Description:** To reflect increase in employer's portion of FICA taxes to reflect proforma increase in salaries and wages.

_1/ For class cost purposes, $56,538 relates to EX:8:10 and -$34,216 relates to EX:8:11.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 5 - Wages and Salaries Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		Frederick/Shen Unions C	Teamsters & Local 2 Unions D	Management E	Total F=C+D+E
1	**Annual Payroll (Gross) TME March 31, 2024**	Analysis		$ 5,108,819	$ 72,615,991	$ 106,452,220	$ 184,177,030
2	Pro Forma Increase - Test Year (Apr-2023 to Mar-2024)	Workpaper 2		50,086	320,862	3,138,466	3,509,414
3	Pro Forma Gross Payroll TME March 31, 2024	Ln. 1 + Ln. 2		$ 5,158,906	$ 72,936,853	$ 109,590,685	$ 187,686,444
4	Pro Forma Increase - (Apr-2024 to Mar-2025)	Workpaper 2		103,178	1,857,618	1,362,578	3,323,373
5	Pro Forma Gross Payroll in Rate Effective Period (Aug-2025 to Jul-2026)	Ln. 3 + Ln. 4		$ 5,262,084	$ 74,794,471	$ 110,953,263	$ 191,009,817
6	Pro Forma Payroll Increase	(Ln. 5 - Ln. 1)		$ 153,265	$ 2,178,480	$ 4,501,043	$ 6,832,788
7	Operations & Maintenance Allocation Factor	Analysis		75.53%	75.53%	75.53%	75.53%
8	Proforma Payroll Increase Allocable to Operations & Maintenance (System)	Ln. 6 * Ln. 7		$ 115,757	$ 1,645,354	$ 3,399,531	$ 5,160,643 1
9	District of Columbia Allocation Factor			19.36%	19.36%	19.36%	19.36%
10	Proforma Payroll Increase Allocable to Operations & Maintenance (District of Columbia)	Ln. 8 * Ln. 9		$ 22,411	$ 318,541	$ 658,149	$ 999,100
11	Adjust to reflect amortization of ratification bonus	Workpaper 3					$ 1,957
12	**Total Wages and Salaries Adjustment**	Ln. 10 + Ln. 11					**$ 1,001,057**
13	Wages & Salaries Expense Adjustment - Operations	Ln. 10 * 0.6434	_2/				$ 644,085
14	Wages & Salaries Expense Adjustment - Maintenance	Ln. 10 * 0.3566	_2/				$ 356,972

15 **Adjustment Description:** To reflect pro forma labor wage increases through the rate effective period.

1/ Per book Short-term incentive compensation and benefits expenses are excluded from the cost of service here rather than in 401(k) adjustment (#8).

2/ For class cost purposes, the full amount of this adjustment relates to COSA line EX 5:3.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 5 Workpaper 3 - Contract Ratification Bonus Expense

Test Year: April 1, 2023 - March 31, 2024
Interim Year: April 1,2024 - July 31, 2025
Rate Year: August 1, 2025 - July 31, 2026

Line	Description	Reference	Test Year Expense
	A	B	C
1	Local 2 Contract Ratification Bonus Expense	Analysis	$ 50,536
2	Annual Amortization	Ln. 1 * 1/5	$ 10,107
3	District of Columbia Allocation Factor	Total Labor	19.36%
4	Adjust to reflect amortization of ratification bonus	Ln. 2 * Ln. 3	$ 1,957 1

NOTE: Test year ratification bonus reflects the operations & maintenance ("O&M") portion only and excludes any amounts that were capitalized or distributed to affliates.

Include?	Y
Company	Washington Gas Light Company
TM1 Period	(All)

CF DC Job Levels	Sum of Current Period Result	
Grand Total	192,404,096	**0.00**

Box 3 (2023 W2)	175,527,135
SSI-Gross Earnings Ratio	**91.23%** 1

General Information

OASDI & HI Contributions

A + B = 5.3 +0.9 = 6.2 1

Tax rates, 2023 (in percent)

Program	Employee	Employer	Self-employed
Total	7.65	7.65	15.30
OASI	5.30	5.30 A	10.60
DI	0.90	0.90 B	1.80
HI	[a] 1.45	1.45 1	[a] 2.90

a. Earned income exceeding $200,000 for individual filers and $250,000 for married couples filing jointly is subject to an additional HI tax of 0.90 percent.

Taxes payable, 2023 (in dollars)

Type of earner	OASI	DI	HI
Average	3,371	572	922
Maximum	8,491	1,442	No limit
Self-employed maximum	16,981	2,884	No limit

Maximum earnings subject to Social Security taxes, 2023 (in dollars)

Program	Amount
OASDI	160,200
HI	No limit

Earnings required for work credits, 2023: $1,640 for one work credit (one quarter of coverage)

NOTE: A worker may earn a maximum of four credits a year. Doing so in 2023, therefore, requires $6,560 in earnings.

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618 1	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
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21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses - 25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding 42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 6 - LTI Expense Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	Factor Comp_A&G	DC Amount
	A	B	C	D	E = C * D
1	Long-Term Incentive - Performance Shares	Acct 920411 & 920412	$ (40,509)		
2	Long-Term Incentive - Performance Units	Acct 920421 & 920422	$ (17,309,695)		
3	**Total Expense Adjustment _1/**	Ln. 1 + Ln. 2	$ (17,350,204) 1	19.54%	$ (3,390,371)

4 **Adjustment Description:** To remove 100% of per book long-term incentive expense.

_1/ For class cost purposes, the full amount of this adjustment relates to COSA line EX:5:3.

Adjustment No. 13

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 13 - Involuntary Separation Program Labor O&M Expense Reduction

Twelve Months Ended March 31, 2024

Line	Description	Reference		Amount
1	Reduction in salaries	Workpaper 1	$	2/ (7,233,986)
2	Reduction in short-term incentives	Workpaper 1		2/ (986,995)
3	Reduction in medical plans	Workpaper 2		3/ (730,291)
4	Reduction in 401(k)	Workpaper 2		(556,223)
5	Reduction in payroll taxes	Workpaper 2		(697,386)
6	Reduction in life insurance	Workpaper 2		(12,492)
7	Reduction in rate year labor expenses (System)	Sum Lns. 1 to 6	$	(10,217,373)
8	DC Labor Factor	AL 4:11		4/ 19.36%
9	**Reduction in rate year labor expense (DC)**	**Ln. 7 * Ln. 8**	**$**	**(1,978,270)**

10 **Adjustment Description:** To reflect the reduction in salaries and other related expenses
11 related to the Involuntary Separation Program in April 2024.

Washington Gas Light Company
System

Adjustment No. 13 Workpaper No. 1 - Exclusion from Test Year Per Book Expense

Twelve Months Ended March 31, 2024

CO	WG

BU	Exp Type	Account	Account Desc	Sum of Sum_Dollars	Pool Account Factors O&M	Pool Account Factors Capital	Pool Account Factors Other	Pool Account Factors Affiliate	Payroll Classification O&M	Payroll Classification Capital	Payroll Classification Other	Payroll Classification Affiliates
00	Non-Utility	417904	Services Provided by Reg Util	114,387.80	-	-	-	1.00	-	-	-	114,387.80
01	Capital	107100	Gas Plant	54,326.91	-	1.00	-	-	-	54,326.91	-	-
01	Pool	232312	AP-Emp Rel-Bonus Accruals (STI)	1,203,762.44	0.8199	0.0836	0.0294	0.0672	A 986,995.27 1	100,597.50	35,330.49	80,839.18
01	Pool	232321	AP-IncentivePln-PerformnceUnit (LTI)	2,235,073.79	-	-	-	-	-	-	-	-
01	Non-Utility	417904	Services Provided by Reg Util	59,152.00	-	-	1.00	-	-	-	59,152.00	-
01	O&M	700000	Ops Superv & Eng-Watergate Prj	12,624.85	1.00	-	-	-	12,624.85	-	-	-
01	O&M	870003	Oth Than T&D Or App Service	604.16	1.00	-	-	-	604.16	-	-	-
01	O&M	885001	Transmission & Distr Dept	550,020.23	1.00	-	-	-	550,020.23	-	-	-
01	O&M	887000	Maintenance Of Mains	60,136.04	1.00	-	-	-	60,136.04	-	-	-
01	O&M	903100	Cust Applications & Orders	79,562.44	1.00	-	-	-	79,562.44	-	-	-
01	O&M	908000	Customer Assist Expenses	186,865.51	1.00	-	-	-	186,865.51	-	-	-
01	O&M	912000	Demonstrating & Selling Exp	10,421.23	1.00	-	-	-	10,421.23	-	-	-
01	O&M	920000	Admin & General Salaries	4,823,702.50	1.00	-	-	-	4,823,702.50	-	-	-
01	O&M	921000	Office Supplies And Expenses	24,064.07	1.00	-	-	-	24,064.07	-	-	-
01	O&M	923000	Outside Services Employed	1,412.80	1.00	-	-	-	1,412.80	-	-	-
01	O&M	928000	Regulatory Commission Expenses	147,631.75	1.00	-	-	-	147,631.75	-	-	-
01	Other	143105	Miscellaneous Receivable-ALA	10,370.88	-	-	1.00	-	-	-	10,370.88	-
01	Other	146516	SEMCO-ENSTAR	26,322.52	-	-	1.00	-	-	-	26,322.52	-
01	Other	165002	Prepayments - EPM Oracle	1,652.70	-	-	1.00	-	-	-	1,652.70	-
01	Other	184241	A&G Overheads	120,014.01	-	-	1.00	-	-	-	120,014.01	-
01	Pool	184107	Bldg Serv-Springfield Station	116,764.44	0.97	-	0.02	0.01	113,045.68	-	2,759.94	958.82
01	Pool	184122	Transportation-Indirect Costs	21,127.10	0.91	0.08	0.01	-	19,164.33	1,782.46	180.30	-
01	Pool	184181	Nonproductive Labor Costs	1,329,167.28	0.90	0.05	0.03	0.02	1,198,945.33	67,049.45	38,495.43	24,677.07
01	Pool	184201	Clear-Inspect-Contractor Work	308,567.77	-	1.00	-	-	-	308,567.77	-	-
01	Pool	184212	Development And Design-MD	17,163.27	-	1.00	-	-	-	17,163.27	-	-
01	Pool	184218	D&D-Pre-approved Re WMIS	93,791.11	0.06	0.94	-	-	5,785.06	88,006.05	-	-
01	Pool	184231	Constr Supv - Outside Plant	200,413.47	-	1.00	-	-	-	200,413.47	-	-
07	O&M	920000	Admin & General Salaries	5,552.23	-	-	-	1.00	-	-	-	5,552.23
07	O&M	921000	Office Supplies And Expenses	6.39	-	-	-	1.00	-	-	-	6.39
15	Non-Utility	232312	AP-Emp Rel-Bonus Accruals	6,038.00	-	-	-	1.00	-	-	-	6,038.00
15	Non-Utility	417904	Services Provided by Reg Util	240,447.95	-	-	-	1.00	-	-	-	240,447.95
15	Non-Utility	107200	Nonutitlity Property	1,161.12	-	-	-	1.00	-	-	-	1,161.12
20	Non-Utility	417904	Services Provided by Reg Util	20,761.15	-	-	-	1.00	-	-	-	20,761.15
28	Non-Utility	417904	Services Provided by Reg Util	14.14	-	-	-	1.00	-	-	-	14.14
300	Non-Utility	417465	Salaries Related	76,466.28	-	-	-	1.00	-	-	-	76,466.28
300	Non-Utility	417904	Services Provided by Reg Util	95,809.92	-	-	-	1.00	-	-	-	95,809.92
302	Non-Utility	417465	Salaries Related	119.93	-	-	-	1.00	-	-	-	119.93
305	Non-Utility	417465	Salaries Related	403.84	-	-	-	1.00	-	-	-	403.84
312	Non-Utility	417465	Salaries Related	3,413.49	-	-	-	1.00	-	-	-	3,413.49
326	Non-Utility	417465	Salaries Related	2,276.62	-	-	-	1.00	-	-	-	2,276.62
Grand Total				12,261,574.13					B 8,220,981.26	837,906.88	294,278.27	673,333.93
			O&M Factor excluding STI & LTI						81.99%	8.36%	2.94%	6.72%

B - A = $7,233,986 1

Washington Gas Light Company
System

Adjustment No. 13 Workpaper No. 2 - Benefits and Taxes (Employer Portion) for Positions Eliminated

Twelve Months Ended March 31, 2024

Company	Washington Gas Light Company

Sum of MTD Amount			
		Grand Total	
Deduction Code	Deduction		
401K Match	401K Match	329,699	401(k)
BSBSN	Blue Cross/Shield Medical Employer	600,789	medical
BSLFMN	Basic Life Insurance ER	12,492	life insurance
DNTALN	Dental Employer	55,499	medical
HSA ER	Health Savings Account Employer	10,777	medical
KPDHMN	Kaiser Medical Employer	63,225	medical
SPWEB	Saving Plan w/Enhanced Benefit	226,524	401(k)
W_FUI	FUI (ER)	3,235	payroll tax
W_MEDER	Medicare (ER)	174,149	payroll tax
W_OASER	OASDI (ER)	514,323	payroll tax
W_SUIER	SUI (ER)	5,680	payroll tax
Grand Total		1,996,392	

medical	730,291	1
401(k)	556,223	
life insurance	12,492	
payroll tax	697,386	
Total (check)	1,996,392	

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:21		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	= 2 > 9	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618 1	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	= 15 > 22	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	= 27+28-29	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:22		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses -									
25 Adjusted	= 30-(31>33)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:22		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding									
42 Purchased Gas & Uncollectibles	= 38-39-40	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Adjustment No. 14

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 14 - Involuntary Separation Program Cost to Implement Amortization

Twelve Months Ended March 31, 2024

Line	Description	Reference		System
1	Severance	Workpaper 1	$	2/ 4,479,772
2	COBRA Continuation Coverage	Adj 13		3/ 730,291
3	Short-Term Incentive	Workpaper 1		2/ 144,628
4	Paid Time Off	Workpaper 1		2/ 360,408
5	Outplacement Services	ledger		4/ 32,000
6	Additional Security Costs	ledger		4/ 35,112
7	Consultant Services	Analysis		1,216,372
8	Cost to Implement	Lns. 1 to 7	$	6,998,583
9	Annual Amortization (System)	Ln. 8 / 5	$	1,399,717
10	DC Labor Factor	AL 4:11		5/ 19.36%
11	Annual Amortization (DC)	Ln. 9 * Ln. 10	$	271,011

12 **Adjustment Description:** To reflect the costs associated with implementing the April 2024
13 Involutary Separation Program amortized over 5 years.

Washington Gas Light Company
System

Adjustment No. 14 Workpaper No. 1 - Severance-related Payouts for Involuntary Separation Program in April 2024

Twelve Months Ended March 31, 2024

CO	WG

					Months			
					Dollars Paid			Total
					May	Jun	Jul (est)	
TRC	TRC Description	BU	Account	Account Desc				
VLPO	LPO - Leave Pay Out	01	184181	Nonproductive Labor Costs	360,408	-	-	360,408 1
SEPAL	21 - Separation Pay Allowance	01	920000	Admin & General Salaries	1,689,324	1,597,242	1,193,206	4,479,772 1
BONUB	56B - Perf Unit	01	920000	Admin & General Salaries	472,634	-	-	472,634
BONUB	56B - Perf Unit	01	232321	AP-IncentivePln-PerformnceUnit	-	-	-	-
BONUK	56K - Short Term Incentive	01	920000	Admin & General Salaries	24,617	-	-	A 24,617
BONUK	56K - Short Term Incentive	01	232312	AP-Emp Rel-Bonus Accruals	13,197	16,270	90,544	A 120,011
Grand Total					2,560,180	1,613,512	1,283,750	5,457,442

sum A = $144,628 1

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 13 - Involuntary Separation Program Labor O&M Expense Reduction

Twelve Months Ended March 31, 2024

Line	Description	Reference		Amount
1	Reduction in salaries	Workpaper 1	$	(7,233,986)
2	Reduction in short-term incentives	Workpaper 1		(986,995)
3	Reduction in medical plans	Workpaper 2		(730,291) 1
4	Reduction in 401(k)	Workpaper 2		(556,223)
5	Reduction in payroll taxes	Workpaper 2		(697,386)
6	Reduction in life insurance	Workpaper 2		(12,492)
7	Reduction in rate year labor expenses (System)	Sum Lns. 1 to 6	$	(10,217,373)
8	DC Labor Factor	AL 4:11		19.36%
9	**Reduction in rate year labor expense (DC)**	**Ln. 7 * Ln. 8**	**$**	**(1,978,270)**

10 **Adjustment Description:** To reflect the reduction in salaries and other related expenses
11 related to the Involuntary Separation Program in April 2024.

Washington Gas Light Company
System

Adjustment No. 14 Workpaper No. 2 - External Costs for Involuntary Separation Program in April 2024

Twelve Months Ended March 31, 2024

			Year / Period 24 / 5	24 / 6	Grand Total	
Supplier	Supplier Name	Descr				
0000124725	LEE HECHT HARRISON LLC	Professional Placement Service	$ 6,000	$ -	$ 6,000	
0000124725	LEE HECHT HARRISON LLC	Professional Services - 1 Mont	$ 1,500	$ -	$ 1,500	
0000124725	LEE HECHT HARRISON LLC	Professional Services 1 Month	$ -	$ 7,500	$ 7,500	
0000124725	LEE HECHT HARRISON LLC	Professional Services 2 Month	$ 2,500	$ -	$ 2,500	
0000124725	LEE HECHT HARRISON LLC	Professional Services 3 Month	$ 3,500	$ 3,500	$ 7,000	
0000124725	LEE HECHT HARRISON LLC	Professional Services 6 Month	$ -	$ 7,500	$ 7,500	
0000124725 Total			**$ 13,500**	**$ 18,500**	**$ 32,000**	1
0000133967	SUNSTATES SECURITY LLC	Volta -Security Special Detail	$ 5,877	$ 29,235	$ 35,112	
0000133967 Total			**$ 5,877**	**$ 29,235**	**$ 35,112**	1

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:21		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	= 2 > 9	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618 1	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	= 15 > 22	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	= 27+28-29	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:22		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses -									
25 Adjusted	= 30-(31>33)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:22		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding									
42 Purchased Gas & Uncollectibles	= 38-39-40	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.27253

Adjustment No. 15

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 15 - Amortization of COVID Regulatory Asset

Twelve Months Ended March 31, 2024

Line	Description		Reference	Amount
1	Total Regulatory Asset Balance allowed in FC 1169		Order No. 21939	$ 2/ 368,163
2	Amortization Period (Years)		5 Years	2/ 5
3	Annual Amortization		Ln. 1 / Ln. 2	$ 73,633
4	Test Year Amortization Expense (Per Book)			-
5	**Total Adjustment to Amortization Expense**	_1/	**Ln. 3 - Ln. 4**	**$ 73,633**

6 Adjustment Description: To amortize the COVID regulatory asset over 5 years.

1/ For class cost purposes:
$73,633 relates to EX:5:5

amortization in RMA 14. The amount remaining in the regulatory asset account of $368,163 for PPE and cleaning is amortized over a five-year period.

E. INTEREST ON CUSTOMER DEPOSITS

RMA 18 Interest on Customer Deposits

256. **WGL.** The Company's initial RMA 18 encompassed a $1,335 adjustment to interest credited to customer deposit balances.[466] WGL subsequently proffered a revised RMA 18. increasing interest expense credited to customer deposit balances by $52,514[467] to reflect the results of the Commission's Order No. 21556 in *Formal Case No. 712*, increasing the interest rate credited to customer deposit balances for CY 2023.[468]

257. **OPC.** OPC asserts that it did not object to WGL's original RMA 18. OPC notes that WGL revised its interest expense. While OPC does not oppose this modification, OPC argues that WGL did not provide a reason for the revision. Thus, OPC does not include the revision in its final calculations.[469]

Decision

258. The Commission finds that the Company did not explain the impact of its revised RMA 18 on net rate base. Accordingly, the Commission denies WGL's revision, including the 2023 interest rate. The Commission approves WGL's initial RMA 18 $1,335 Adjustment as just and reasonable.

F. NON-LABOR INFLATION ADJUSTMENT

RMA 20 – Non-labor Inflation Adjustment
BCO 6 - Remove Non-Labor Inflation Adjustment

259. **WGL.** WGL proposes a Non-Labor Inflation Adjustment, which applies an inflation factor to test-year non-labor expenses, resulting in a $2,824,811 increase in operating expenses. WGL argues that this adjustment is needed to take into account the effect of post-test-year inflation on WGL's expenses.[470] In WGL's view, this adjustment would permit WGL to

466 WGL (D) at 95:9-20; Exhibit WGL (D)-3 Adjustment 18 of 30 at 35 (Tuoriniemi Direct).

467 WGL (3D) 9:6-10:3, Exhibit WGL (3D)-1 at 1 (Tuoriniemi Rebuttal) .

468 *Formal Case No. 712, In the Matter of the Investigation into the Public Service Commission's Rules of Practice and Procedure*, Order No. 21556, ¶ 17, rel. December 14, 2022.

469 OPC Brief at 83.

470 WGL Initial Brief at 18.

Adjustment No. 16

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 16 - Regulatory Commission Expenses

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Calculation C	Calculation D	Amount to be Collected from Customers E
1	Costs from Prior Rate Cases @ 03/31/2024				$ 2/ 4,640,510
2	Prior Rate Case Costs from 4/1/2024 - 7/31/2025				(1,366,724)
3	Ratemaking Expenses For Current Case				
4	Estimated OPC Assessment				
5	Ratemaking Ratebase - Case No. 1169	Order No. 21939	5/ $580,402,431		
6	OPC Rate		0.25%		
7	Estimated OPC Adjustment	= Ln. 5 * Ln. 6	1,451,006	1,451,006	
8	Estimated PSC Assessment				
9	Ratemaking Ratebase - Case No. 1169	Order No. 21939	5/ $580,402,431		
10	PSC Rate		0.25%		
11	Estimated PSC Assessment	= Ln. 9 * Ln. 10	1,451,006	1,451,006	
12	Company Consultants:				
13	External Counsel		6/ 175,000		
14	Tax		50,000		
15	Return on Equity		155,000		
16	Depreciation Study		50,000		
17	Affiliate Costs		70,000		
18	Normal Weather		211,000	6/ 711,000	
19	Estimated Cost of Current Case	Σ 7 > 18			$ 3,613,012
20	Balance Due From Customers	= 1 + 2 + 19			$ 6,886,798
21	Amortization of Regulatory Commission Expenses	Ln. 20 / 3 years			$ 2,295,599
22	Ratemaking Adjustment to Regulatory Expense	= Ln. 21			$ 2,295,599
23	Carrying Costs on Unamortized Balance	Analysis			3/ 788,608
24	Removal of book amortization expense	GL Account No: 928001			4/ (475,776)
25	Total Ratemaking Expense Adjustment	= Ln. 22 > Ln. 24			$ 2,608,431

26 **Adjustment Description:** To amortize both the collection of prior regulatory commission expenses and the regulatory commission
27 expenses that are expected to be incurred during the current rate case. To include the annual carrying costs on the unamortized balance
28 of regulatory commission expenses.

1/ For Class Cost purposes, note that $2,608,431 relates to EX:5:16.

Washington Gas Light Company
District of Columbia Division- Pro Forma

Adjustment No. 16 - Regulatory Commission Expenses
Revised for the Effect of Formal Case No. 989

sum of A. = 1,366,724 1

net carrying costs collected and accrued through the start of the rate effective period = sum of B. = 656,002

unrecovered carrying costs at March 31, 2024 = C. = 268,732

B. + C. = 924,733 3/

								Carrying Cost at Authorized Pre-tax Rate of Return				Balance to Compound Carrying Costs			
Month	Year	Regulatory Commission Expense Incurred	Gross Expense Amount Allowed in DC Rates	FC 989 Amount Allowed in Rates	Amortization of Tracker Balance [A/C 229222]	Tracker Balance	Tracker Balance Plus Carrying Costs	Carrying Cost at Authorized Pre-tax Rate of Return (Debt)	Carrying Cost at Authorized Pre-tax Rate of Return (ROE) [A/C 253020]	Ratemaking Adjustment to Amortize Carrying Costs [A/C 229222]	Carrying Costs Balance	Monthly FC 1016 Carrying Costs Balance Change	Cumulative FC 1016 Carrying Costs Balance Change	Balance to Compute Compound Carrying Costs	Cumulative ROE
A	B	C	D	E	F	G= Prev+C-D-E-F	H = N	I= H x 2.45% / 12 (A) I= H x 2.23% / 12 (B) I= H x 2.09% / 12 (C) I= H x 2.363% / 12 (D)	I= H x 7.24% / 12 (A) I= H x 6.65% / 12 (B) I= H x 6.92% / 12 (C) I= H x 7.603% / 12 (D)	J	K= Prev + I + J	L = I + J	M = Prev + L	N = G + M	
March	2023	87,829	-	-	39,648	3,745,977	4,415,866	8,206	24,471	26,535	111,831	8,142	724,211	4,470,188	1,819,342
April	2023	36,533			39,648	3,742,861	4,470,188	8,307	24,772	26,535	118,375	6,544	730,755	4,473,617	1,844,115
May	2023	169,312			39,648	3,892,525	4,473,617	8,313	24,791	26,535	124,945	6,569	737,325	4,629,850	1,868,906
June	2023	251,897			39,648	4,104,774	4,629,850	8,604	25,657	26,535	132,670	7,726	745,050	4,849,825	1,894,563
July	2023	110,979			39,648	4,176,105	4,849,825	9,013	26,876	26,535	142,024	9,353	754,404	4,930,508	1,921,439
August	2023	605,871			39,648	4,742,328	4,930,508	9,163	27,323	26,535	151,974	9,950	764,354	5,506,682	1,948,762
September	2023	14,458			39,648	4,717,137	5,506,682	10,233	30,516	26,535	166,188	14,214	778,569	5,495,706	1,979,279
October	2023	159,566			39,648	4,837,055	5,495,706	10,213	30,455	26,535	180,321	14,133	792,701	5,629,757	2,009,734
November	2023	46,395			39,648	4,843,802	5,629,757	10,462	31,198	26,535	195,446	15,125	807,826	5,651,628	2,040,932
December	2023	50,862			39,648	4,855,016	5,651,628	10,503	31,319	26,535	210,733	15,287	823,113	5,678,129	2,072,252
January	2024	39,984			85,420	4,809,559	5,678,129	9,889	32,744	23,345	230,021	19,288	842,401	5,651,981	2,104,996
February	2024	136,566			85,420	4,860,705	5,651,981	9,844	32,593	23,345	249,113	19,092	861,493	5,722,198	2,137,589
March	2024	(134,775)			85,420	4,640,510 1	5,722,198	9,966	32,998	23,345	C 268,732	19,619	881,112	5,521,622	2,170,587
April	2024	3,613,012			85,420	8,168,102	5,521,622	9,617	31,841	23,345	286,845	18,113	899,225	9,087,327	2,202,428
May	2024				85,420	8,082,682	9,087,327	15,792	52,288	23,345	331,580	44,735	943,961	9,026,642	2,254,716
June	2024				85,420	7,997,261	9,026,642	15,721	52,054	23,345	376,010	44,430	988,390	8,985,652	2,306,770
July	2024				85,420	7,911,841	8,985,652	15,650	51,817	23,345	420,132	44,122	1,032,513	8,944,354	2,358,587
August	2024				85,420	7,826,421	8,944,354	15,578	51,579	23,345	463,945	43,812	1,076,325	8,902,745	2,410,166
September	2024				85,420	7,741,001	8,902,745	15,506	51,339	23,345	507,444	43,500	1,119,824	8,860,825	2,461,505
October	2024				85,420	7,655,580	8,860,825	15,433	51,097	23,345	550,629	43,185	1,163,009	8,818,589	2,512,603
November	2024				A. 85,420	7,570,160	8,818,589	15,359	50,854	23,345	593,497	B. 42,868	1,205,877	8,776,037	2,563,457
December	2024				85,420	7,484,740	8,776,037	15,285	50,608	23,345	636,045	42,548	1,248,425	8,733,165	2,614,065
January	2025				85,420	7,399,320	8,733,165	15,210	50,361	23,345	678,272	42,226	1,290,652	8,689,971	2,664,426
February	2025				85,420	7,313,899	8,689,971	15,135	50,112	23,345	720,174	41,902	1,332,554	8,646,453	2,714,539
March	2025				85,420	7,228,479	8,646,453	15,059	49,861	23,345	761,749	41,575	1,374,129	8,602,608	2,764,400
April	2025				85,420	7,143,059	8,602,608	14,983	49,608	23,345	802,995	41,246	1,415,375	8,558,434	2,814,008
May	2025				85,420	7,057,639	8,558,434	14,906	49,354	23,345	843,910	40,914	1,456,290	8,513,928	2,863,362
June	2025				85,420	6,972,218	8,513,928	14,828	49,097	23,345	884,490	40,580	1,496,870	8,469,088	2,912,459
July	2025				85,420	6,886,798	8,469,088	14,750	48,838	23,345	924,733	40,244	1,537,114	8,423,912	2,961,297
August	2025				191,300	6,695,498	8,423,912	16,568	53,373	65,717	928,977	4,243	1,541,357	8,236,855	3,014,670
September	2025				191,300	6,504,198	8,236,855	16,220	52,187	65,717	931,666	2,690	1,544,047	8,048,245	3,066,857
October	2025				191,300	6,312,898	8,048,245	15,848	50,992	65,717	932,790	1,123	1,545,170	7,858,068	3,117,849
November	2025				191,300	6,121,598	7,858,068	15,474	49,787	65,717	932,334	(456)	1,544,714	7,666,312	3,167,637
December	**2025**				191,300	**5,930,298**	**7,666,312**	**15,096**	**48,572**	**65,717**	**930,285**	**(2,049)**	**1,542,665**	**7,472,963**	**3,216,209**
January	2026				191,300	5,738,998	7,472,963	14,716	47,347	65,717	926,631	(3,654)	1,539,011	7,278,009	3,263,557
February	2026				191,300	5,547,698	7,278,009	14,332	46,112	65,717	921,357	(5,273)	1,533,737	7,081,436	3,309,669
March	2026				191,300	5,356,398	7,081,436	13,945	44,867	65,717	914,451	(6,906)	1,526,831	6,883,230	3,354,536
April	2026				191,300	5,165,099	6,883,230	13,554	43,611	65,717	905,899	(8,552)	1,518,279	6,683,378	3,398,147
May	2026				191,300	4,973,799	6,683,378	13,161	42,345	65,717	895,687	(10,212)	1,508,067	6,481,866	3,440,491
June	2026				191,300	4,782,499	6,481,866	12,764	41,068	65,717	883,802	(11,885)	1,496,182	6,278,680	3,481,560
July	2026				191,300	4,591,199	6,278,680	12,364	39,781	65,717	870,229	(13,573)	1,482,609	6,073,808	3,521,340
August	2026				191,300	4,399,899	6,073,808	11,960	38,483	65,717	854,954	(15,274)	1,467,335	5,867,233	3,559,823
September	2026				191,300	4,208,599	5,867,233	11,554	37,174	65,717	837,964	(16,990)	1,450,345	5,658,943	3,596,997
October	2026				191,300	4,017,299	5,658,943	11,143	35,854	65,717	819,245	(18,720)	1,431,625	5,448,924	3,632,851
November	2026				191,300	3,825,999	5,448,924	10,730	34,523	65,717	798,781	(20,464)	1,411,161	5,237,160	3,667,374
December	**2026**				191,300	**3,634,699**	**5,237,160**	**10,313**	**33,182**	**65,717**	**776,558**	**(22,223)**	**1,388,938**	**5,023,637**	**3,700,556**
January	2027				191,300	3,443,399	5,023,637	9,892	31,829	65,717	752,562	(23,996)	1,364,942	4,808,341	3,732,385
February	2027				191,300	3,252,099	4,808,341	9,468	30,465	65,717	726,778	(25,784)	1,339,158	4,591,257	3,762,850
March	2027				191,300	3,060,799	4,591,257	9,041	29,089	65,717	699,191	(27,587)	1,311,571	4,372,370	3,791,939
April	2027				191,300	2,869,499	4,372,370	8,610	27,703	65,717	669,786	(29,405)	1,282,166	4,151,665	3,819,642
May	2027				191,300	2,678,199	4,151,665	8,175	26,304	65,717	638,548	(31,238)	1,250,928	3,929,128	3,845,946
June	2027				191,300	2,486,899	3,929,128	7,737	24,894	65,717	605,462	(33,086)	1,217,842	3,704,742	3,870,840
July	2027				191,300	2,295,599	3,704,742	7,295	23,473	65,717	570,513	(34,949)	1,182,893	3,478,492	3,894,313
August	2027				191,300	2,104,299	3,478,492	6,850	22,039	65,717	533,684	(36,828)	1,146,084	3,250,364	3,916,352
September	2027				191,300	1,912,999	3,250,364	6,401	20,594	65,717	494,961	(38,723)	1,107,341	3,020,341	3,936,946
October	2027				191,300	1,721,700	3,020,341	5,948	19,136	65,717	454,328	(40,633)	1,066,708	2,788,407	3,956,082
November	2027				191,300	1,530,400	2,788,407	5,491	17,667	65,717	411,768	(42,560)	1,024,148	2,554,546	3,973,749

Washington Gas Light Company
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Adjustment No 16 - Regulatory Commission Expenses
Revised for the Effect of Formal Case No. 989

								Carrying Cost at Authorized Pre-tax Rate of Return				Balance to Compound Carrying Costs		
Month	Year	Regulatory Commission Expense Incurred	Gross Expense Amount Allowed in DC Rates	FC 989 Amount Allowed in Rates	Amortization of Tracker Balance [A/C 229222]	Tracker Balance	Tracker Balance Plus Carrying Costs	Carrying Cost at Authorized Pre-tax Rate of Return (Debt)	Carrying Cost at Authorized Pre-tax Rate of Return (ROE) [A/C 253020]	Ratemaking Adjustment to Amortize Carrying Costs [A/C 229222]	Carrying Costs Balance	Monthly FC 1016 Carrying Costs Balance Change	Cumulative FC 1016 Carrying Costs Balance Change	Balance to Compute Compound Carrying Costs	Cumulative ROE
A	B	C	D	E	F	G= Prev+C-D-E-F	H = N	I= H x 2.45% / 12 (A)	I= H x 7.24% / 12 (A)	J	K= Prev + I + J	L = I + J	M = Prev + L	N = G + M	
December	2027				191,300	1,339,100	2,554,548	5,030	16,185	65,717	387,266	(44,502)	979,647	2,318,746	3,989,934
January	2028				191,300	1,147,800	2,318,746	4,566	14,691	65,717	320,806	(46,460)	933,186	2,080,986	4,004,626
February	2028				191,300	956,500	2,080,986	4,096	13,185	65,717	272,372	(48,435)	884,752	1,841,251	4,017,810
March	2028				191,300	765,200	1,841,251	3,626	11,666	65,717	221,946	(50,426)	834,326	1,599,526	4,029,476
April	2028				191,300	573,900	1,599,526	3,150	10,134	65,717	169,512	(52,433)	781,893	1,355,792	4,039,611
May	2028				191,300	382,600	1,355,792	2,670	8,590	65,717	115,055	(54,457)	727,435	1,110,035	4,048,201
June	2028				191,300	191,300	1,110,035	2,186	7,033	65,717	58,556	(56,499)	670,937	862,237	4,055,234
July	2028				191,300	0	862,237	1,698	5,463	65,717	(0)	(58,556)	612,380	612,380	4,060,697
								341,692	1,099,399						

(A) The pretax rate of return for debt and equity reflects the period of Jan 2019 - Mar 2021
(B) The pretax rate of return for debt and equity reflects the period of Apr 2021 - Dec 2023 (FC 1162 stipulated cost of capital)
(C) The pretax rate of return for debt and equity reflects the period of Jan 2024 - Dec 2026 (FC 1169 capital structure)
(D) The pretax rate of return for debt and equity reflects the period from Aug 2025 and forward (proposed in 2024 DC rate case)

Under Recovered Carrying Costs:		
Total Carrying Costs over the 3-Year period	Analysis	1,441,091
Carrying Cost from Prior Unrecovered Bals	Analysis	924,733 2
		2,365,824
Refund/Recovery Period- 3 Years		3
Annual Carrying Cost Amortization		788,608 1
Monthly Carrying Cost Amortization		65,717

1JOURNALQUERY 12

Unit	Journal ID	Period	Account	Process	Product	Project	Dept	Sum Amount	Res Type	Long Descr	Source	Posted	Ref No	Oper Unit	Fund Proj	DateTime	Descr	Date	Year	Ledger Grp
01	GL00000038	4	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - April 2023	ONL	5/2/2023	AC10730	01		5/2/2023 16:56	To record amortization of DC r	4/30/2023	23	ACTUALS
01	GL00000038	5	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - May 2023	ONL	6/2/2023	AC10730	01		6/2/2023 16:30	To record amortization of DC r	5/31/2023	23	ACTUALS
01	GL00000038	6	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - June 2023	ONL	6/29/2023	AC10730	01		6/29/2023 20:23	To record amortization of DC r	6/30/2023	23	ACTUALS
01	GL00000038	7	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - July 2023	ONL	8/2/2023	AC10730	01		8/2/2023 20:46	To record amortization of DC r	7/31/2023	23	ACTUALS
01	GL00000038	8	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - August 2023	ONL	9/5/2023	AC10730	01		9/5/2023 11:25	To record amortization of DC r	8/31/2023	23	ACTUALS
01	GL00000038	9	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - September 2023	ONL	10/2/2023	AC10730	01		10/2/2023 20:24	To record amortization of DC r	9/30/2023	23	ACTUALS
01	GL00000038	10	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - October 2023	ONL	11/1/2023	AC10730	01		11/1/2023 19:09	To record amortization of DC r	10/31/2023	23	ACTUALS
01	GL00000038	11	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - November 2023	ONL	11/29/2023	AC10730	01		11/29/2023 18:09	To record amortization of DC r	11/30/2023	23	ACTUALS
01	GL00000038	12	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - December 2023	ONL	12/29/2023	AC10730	01		12/29/2023 19:53	To record amortization of DC r	12/31/2023	23	ACTUALS
01	GL00000038	1	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - January 2024	ONL	2/2/2024	AC10730	01		2/2/2024 8:12	To record amortization of DC r	1/30/2024	24	ACTUALS
01	GL00000038	2	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - February 2024	ONL	3/4/2024	AC10730	01		3/4/2024 13:12	To record amortization of DC r	2/29/2024	24	ACTUALS
01	GL00000038	3	928001		R70163			39,648	5100	To record amortization of DC rate to reg. liability - March 2024	ONL	4/2/2024	AC10730	01		4/2/2024 17:57	To record amortization of DC r	3/31/2024	24	ACTUALS
								475,776	1											

study has materially changed for the Commission to direct the Company to reduce the number of revenue lag days used in its CWC computation. Additionally, the Commission did not find that the Company's request for recovery of incremental bad debt expense is duplicated in the Company's CWC computation. Furthermore, as discussed in other sections of this Order, the Commission denies $8,787,212 of the Company's $9,155,375 COVID-19 regulatory asset and adjusts the CWC with related amortization accordingly. The Commission also denies AOBA's additional CWC adjustment related to services provided to the affiliates from WGL, since the majority of these services comprise the routine reimbursement of allowable consolidated customer billing program transactions for an affiliate, and the remaining balance of services rendered to the affiliates appear to have an immaterial impact on WGL's overall CWC.

150. Finally, the Commission denies OPC's BCO-12 adjustment that reduces the Company's CWC by $2,791,972. Some of the rate adjustments that OPC makes to update the Company's lead-lag study revenues and costs are not consistent with the ratemaking adjustments that the Commission is approving in this rate case. Having considered the information in the record, the Commission approves CWC of $37,981,478.

151. The Commission approves the following Rate Base of $580,402,431. 1

Reconciliation of WGL's Rate Base (From FC 1162 to FC 1169)		
Item No.	**Description**	**Approx. Rate Base ($Millions)**
1	**Rate Base at conclusion of FC 1162**	**$461.0**[291]
2	Transfer of PROJECTpipes Net rate base	$39.5
4	Post FC 1162 increases in Rate Base from December 31, 2019, to December 31, 2021 (24 months)	$79.9
5	**Rate Base approved in FC 1169**	**$580.4**

152. The approved rate base of $580.4 million excludes WGL's request to add forecasted post-test period additions.

VIII. <u>TEST YEAR REVENUES</u>

[291] Because there was a settlement in *Formal Case No. 1162*, there was no determination of rate base by the Commission. The Commission reviewed *Formal Case No. 1162*, WGL Supplemental Direct Testimony of Witness Tuoriniemi, Exhibit WG (2D-1) at 2, filed May 15, 2020. Exhibit WG (2D-1) shows WGL's Average Rate Base Summary Twelve Months Ended December 31, 2019, of $542.6 million. Following its precedent to exclude Construction Work in Progress from the rate base, the Commission subtracts $81.7 million from the Net Rate Base of $542.6 million, resulting in a rate base of $460.9 million.

Project External Costs for 2024 DC Rate Case

Contractor or Entity	Role	Witness		Cost Estimate
Outside Counsel	Witness Prep			$ 175,000
Miller and Chevalier	PLR Tax Assistance	Chuck Mannix?		$ 50,000
Scott Madden	ROE - Witness	Dylan D'Ascendis		$ 155,000
Foster	Depreciation	Dr. Ron White		$ 50,000
Pat Baryenbruch	Affiliate Costs	Pat Baryenbruch		$ 70,000
Energy Tools	Normal Weather	Paul Raab		$ 211,000
			Total	$ 711,000

1

WASHINGTON GAS LIGHT COMPANY
Recommended Cost of Capital
($ in '000s)

	A	B	C		D	E	F
		Ratio	Cost		Return	Taxes	Pretax Return
	Debt						
1	Long-Term Debt	42.879%	4.850%	a/	2.079%		
2	Short-Term Debt	5.121%	6.203%	b/	0.318%		
3	Total Debt	48.000%			2.397%	100.000%	2.397% (2)
4	Common Equity	52.000%	9.650%	c/	5.018%	72.483%	6.923% (2)
5	TOTAL	100.000%			7.415%		

Totals may not add due to rounding.

a/ From Schedule EXHIBIT WG (B)-5
b/ From Schedule EXHIBIT WG (B)-4
c/ Developed by Company Witness Dylan D'Ascendis, Exhibit WG (C) Page 6.

Adjustment No. 17

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 17 - Environmental Costs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Actual Remediation Expenses as of March 31, 2024	Financial Statement	2/ $ 37,232,664
2	Less: Expenses approved in Prior Cases	Order 21939	3/ 27,639,236
3	Total Environmental Expenses Incurred Subsequent to FC Case No. 1169	= Ln. 1 - Ln. 2	$ 9,593,428
4	District of Columbia Factor (Total_Weather_All_NW)	AL:1:19	4/ 0.164770
5	Environmental Expenses Applicable to DC	= Ln. 3 * Ln. 4	$ 1,580,712
6	Less: Amount over (under) collected since FC 1169 through July 2025	Financial Statement	5/ (1,126,956)
7	Balance of expenditures incurred to be amortized over 5 years	= Ln. 5 - Ln. 6	2,707,668
8	Annual amortization for 5-year period	= Ln. 7 / 5	$ 541,534
9	Less: Per book annual amortization expense	EX: 5:21	6/ 263,068
10	**Total DC Amortization Expense adjustment**	Ln. 8 - Ln. 9	**278,465**
11	Rate Base:		
12	Deferred Balance of Environmental Cost, Net of Deferred Taxes	7/ [Ln. 7 - (Ln. 8/2)] * 0.724825	$ 1,766,327
13	Less: Unamortized East Station Cost (Net of Deferred Taxes) March 31, 2024	RB:1:8	8/ 1,075,846
14	**Total DC Ratebase Adjustment**	**= Ln. 12 - Ln. 13**	**$ 690,481**

15 **Adjustment Description:** To reflect additional environmental cost incurred since Formal Case No. 1169.

1/ For class cost purposes the total adjustment relates to COSA line EX:5:21.

Washington Gas
Environmental Activities Schedule
March 31, 2024
Balance - MAR-24

	Liability			Other Regulatory Assets							
	242140	253206		Total Cash Expenditures	Remaining Expenditures	Amortization	Total		Jurisdictional Breakout 182324		
	Current	Long-Term	Total Liability	A	B	C	D= A+B-C	DC	MD	10 - Non-Jurisdictional	Total
Chillum (81501)	397,527	495,000	892,527	A. 942,473	133,541		1,076,015	294,117	781,897		1,076,015
East Station (81601-81602),(81609-81612)	402,107	875,000	1,277,107	A. 35,268,615	(15,445,595)	13,756,790	6,066,231	1,368,019	5,240,311	(542,210)	6,066,120
West Station (81502)	372,072	-	372,072	A 327,928	78,794	-	406,722	106,633	300,089	-	406,722
Hyattsville (81701- 81703)	1,049	115,000	116,049	6,505,540	89,335	6,594,875	-	-	-		-
East Church Street/Frederick (81801-81803)	93,088	80,000	173,088	195,478	(105,478)		90,000	-	-	90,000	90,000
Martinsburg (81901-81904)	249,453	115,000	364,453	-	-	-	-	-	-		-
Anacostia Study (81613)	2,735,135	2,970,588	5,705,723	A. 693,648	3,154,023	-	3,847,671	1,135,175	2,712,496		3,847,671
Total	4,250,430	4,650,588	8,901,018	43,933,682	(12,095,379)	20,351,665	11,486,638	2,609,827	8,252,896	(452,210)	11,486,638

$\boxed{\text{sum of A. = 37,232,664}}$ 1

FC 1169 Order 21939

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 16 - Environmental Costs

Twelve Months Ended December 31, 2021

Line Line	Description A	Reference B	Amount C
1	Actual Remediation Expenses as of December 31, 2021	Financial Statement	$ 27,639,236 1
2	Less: Actual Expenses in Prior Cases	Analysis	$ 23,521,923
3	Total Environmental Expenses Incurred Subsequent to FC Case No. 1162	= Ln. 1 - Ln. 2	$ 4,117,314
4	District of Columbia Factor (Total_Weather_All_NW)	AL:1:19	0.159380
5	Environmental Expenses Applicable to DC	= Ln. 4 * Ln. 5	$ 656,219
6	Less: Amount over (under) collected since FC 1162 through March 2023	Financial Statement	(992,985)
7	Balance of expenditures incurred to be amortized over 5 years	= Ln. 6 - Ln. 7	$ 1,649,204 5
8	Annual amortization for 5-year period	= Ln. 7 / 5	$ 329,841
9	Less: Per book annual amortization expense	EX: 5:21	240,811
10	**Total DC Amortization Expense adjustment**	Ln. 8 - Ln. 9	**$ 89,030**
11	Rate Base:		
12	Deferred Balance of Environmental Cost, Net of Deferred Taxes	[Ln. 7 - (Ln. 8/2)] * 0.724825	$ 1,075,846
13	Less: Unamortized East Station Cost (Net of Deferred Taxes) December 31, 2021	RB:1:8	352,283
14	**Total DC Ratebase Adjustment**	**= Ln. 10 - Ln. 11**	**$ 723,563**

15 **Adjustment Description:** To reflect additional environmental cost incurred since Formal Case No. 1137.

1/ For class cost purposes the total adjustment relates to COSA line EX:5:21.

Washington Gas Light Company
Allocation Factors Based on Normal Weather Study

Twelve Months Ended March 2024 - AVG

Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Firm Annual Weather Gas**									
2 TOTAL FIRM WEATHER GAS - NW	NW Study	Firm_Weather_NW	966,262,395	142,065,096	415,291,747	408,905,552	0.147025	0.429792	0.423183
3 TOTAL FIRM THERM SALES - NW	NW Study	Annual_ Firm_NW	1,418,556,506	206,081,756	605,693,246	606,781,504	0.145276	0.426979	0.427746
4 TOTAL FIRM THERM SALES - NW(sales only)		Annual_ Firm_Sales_NW	914,452,500	122,542,753	382,007,337	409,902,410	0.134007	0.417744	0.448249
5 **Non-Firm Annual Weather Gas**									
6 June Sales	Financial Stmt.		19,106,249	4,878,086	10,601,572	3,626,591			
7 July Sales	Financial Stmt.		16,385,284	4,144,577	9,130,761	3,109,946			
8 Aug. Sales	Financial Stmt.		15,994,187	4,074,410	9,020,913	2,898,865			
9 Total Summer Usage	=+6+7+8		51,485,720	13,097,073	28,753,246	9,635,401			
10 Annualization Factor	Constant		4	4	4	4			
11 Annualized Summer Usage	=9*10		205,942,881	52,388,293	115,012,983	38,541,605			
12 Watergate Usage	Financial Stmt.		-	-	-	-			
13 Calculated Base Usage	=11+12		205,942,881	52,388,293	115,012,983	38,541,605			
14 Actual Usage	NW Study		239,874,935	73,882,136	116,925,204	49,067,596			
15 Weather Usage	=14-13		33,932,054	21,493,843	1,912,220	10,525,990			
16 Total Interruptible Therm Sales - NW			263,839,380	77,868,955	133,858,923	52,111,502			
17 Weather Gas Interruptible - NW			57,843,990	26,677,272	19,855,837	11,310,880			
18 TOTAL FIRM THERM SALES - NW(Delivery only)		Annual_ Firm_Delivery_NW	509,207,172	81,663,741	227,864,492	199,678,939	0.160374	0.447489	0.392137
19 TOTAL ALL WEATHER GAS	=2+18	Total_Weather_All_NW	1,024,106,385	168,742,368	435,147,584	420,216,432	0.164770 1	0.424905	0.410325
20 TOTAL ANNUAL THERM SALES	=4+17	Annual_Total_NW	1,682,395,886	283,950,710.85	739,552,169	658,893,006	0.168778	0.439583	0.391640
21 ANNUAL THERMS ADJUSTED	=20-24	Pipeline_NW	1,682,395,886	283,950,711	739,552,169	658,893,006	0.1688	0.4396	0.3916
22 FIRM ANNUAL PIPELINE	=3-24	Firm_Pipe_ Ann_ Adj	1,418,556,506	206,081,756	605,693,246	606,781,504	0.145276	0.426979	0.427746
23 FIRM ANNUAL PIPELINE(Sales only)	=4-24	Firm_Pipe_ Ann_Sales_ Adj	914,452,500	122,542,753	382,007,337	409,902,410	0.134007	0.417744	0.448249
24 **Peak Day Therm Sales- Normal Weather**									
25 Weather Gas	NW Study	Peak_Day _Weather	15,991,500	2,290,271	6,959,692	6,741,537	0.143218	0.435212	0.421570
26 Base Gas	NW Study	Peak_Day_Base	1,218,969	172,345	515,804	530,820	0.141386	0.423148	0.435466
27 Total Peak Day Therms	=29+30	Peak_Day_Total	17,210,469	2,462,616	7,475,496	7,272,357	0.143088	0.434357	0.422554
28 PEAK DAY AND ANNUAL SALES	=(20+31)/2	Comp_Peak_ Ann_NW					0.155933	0.436970	0.407097
29 TOTAL WINTER THERMS (NOV-APR)	NW Study	Wintr_Pipe_NW	1,277,081,957	214,413,097	552,242,395	510,426,464	0.167893	0.432425	0.399682

FC 1169 Undercollection

	FC 1169	Annual	Monthly
Formal Case No. 1169 Approved Amortization (5yrs)	3/ $ 1,649,204	$ 329,841	$ 27,487
Amount collected from December 2023 through July 2025			$ 522,248
Less Approved amortization formal case 1169			$ 3/1,649,204
Amount of over (under) collection up to Rate Effective Period			$ (1,126,956) 1

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

EX:5	Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
EX:5:1	1 **Administrative & General Expenses**							
EX:5:2	2 Administrative & General Salaries-Direct		Financial Stmt.	$ 4,032,355	$ 930,862	$ 1,648,492	$ 1,449,739	$ 3,262
EX:5:3	3 Administrative & General Salaries-Allocable	AL:4:23	Comp_A&G	100,516,479	19,641,740	43,423,120	37,451,620	-
EX:5:4	4 Office Supplies & Expenses-Direct		Financial Stmt.	3,942,404	1,103,503	1,731,733	1,104,963	2,204
EX:5:5	5 Office Supplies & Expenses-Allocable	AL:4:23	Comp_A&G	33,046,634	6,457,582	14,276,146	12,312,906	-
EX:5:6	6 Outside Services	AL:5:30		37,435,574	7,053,669	15,176,292	15,205,613	-
EX:5:7	7 Property Insurance	AL:3:13	Net_GPIS	-	-	-	-	-
EX:5:8	8 Injuries & Damages	AL:4:11	Total_Labor	18,995,900	3,677,954	8,170,412	7,147,535	-
EX:5:9	9 Pension Expense	AL:4:11	Total_Labor	(219,656)	(42,494)	(94,398)	(82,580)	(185)
EX:5:10	10 DC Regulatory			-				
EX:5:11	11 Pension Expense		Financial Stmt.	-	-	-	-	-
EX:5:12	12 Amortization of Rate Case Expenses		Financial Stmt.	475,776	475,776	-	-	-
EX:5:13	13 Least Cost Planning Expenses		Financial Stmt.	-	-	-	-	-
EX:5:14	14 Employee Health Benefits			24,779,774	4,793,783	10,649,176	9,315,976	20,840
EX:5:15	15 OPEB	Labor factor	Financial Stmt.	(34,007,440)	(6,584,462)	(14,627,092)	(12,795,885)	-
EX:5:16	16 Rate Case Expenses-Direct		Financial Stmt.	1,526,109	206,553	1,049,073	269,875.64	607
EX:5:17	17 Rate Case Expenses-Allocable	AL:4:23	Comp_A&G	9,523	1,861	4,114	3,548	-
EX:5:18	18 DC PSC Assessment Expense		Financial Stmt.	-	-	-	-	-
EX:5:19	19 General Advertising Expenses - Direct		Financial Stmt.	1,269	-	984	285	-
EX:5:20	20 General Advertising Expenses - Allocable	AL:4:23	Comp_A&G	644,209	125,884	278,298	240,027	-
EX:5:21	21 Environmental Expense - Regulatory Amortization		Financial Stmt.	686,319	263,068 1	423,250	-	-
EX:5:22	22 Environmental Reserve - Regulatory Adjustment		Financial Stmt.	1,738,655	-	-	1,738,655	-
EX:5:23	23 Rents		Financial Stmt.	263,877	-	-	263,877	-
EX:5:24	24 MD Demand Side Management Expenses		Comp_A&G	1,041,022	203,424	449,721	387,876	-
EX:5:25	25 VA Care Expenses		Financial Stmt.	4,294,347	-	-	4,294,347	-
EX:5:26	26 MD EmPOWER MD Expenses		Financial Stmt.	13,710,995	-	13,710,995	-	-
EX:5:27	27 Multi-Family Unit Contribution Amortization Expense		Financial Stmt.	199,129	17,451	140,914	40,764	-
EX:5:28	28 Multi-Family Unit Contribution Amortization Expense - Allocable			-	-	-	-	-
EX:5:29	29 Miscellaneous General Expenses-Direct		Financial Stmt.	367,847	348,831	(45,528)	64,398	145
EX:5:30	30 Miscellaneous General Expenses-Allocable	AL:4:23	Comp_A&G	2,373,165	463,736	1,025,207	884,222	-
EX:5:								
EX:5:31	31 Total Administrative & General Expenses	= 2 >30		$ 215,854,266	$ 39,138,720	$ 97,390,911	$ 79,297,762	$ 26,873

		Composite Tax Rate
a/ DC Income Tax Rate		0.0825000
b/ Federal Income Tax Rate (1 - 0.0825) x 0.21		0.1926750
Composite Tax Rate		0.2751750
c/ Net of the benefit Composite Tax Rate	1 - 0.275175	0.7248250 1

Washington Gas Light Company
Rate Base Summary
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Gas Plant in Service	RB:3:17		$ 7,249,016,177	$ 1,317,182,832	$ 2,711,617,252	$ 3,190,657,625	$ 29,558,468
2	Gas Plant Held for Future Use	RB:4:13		-	-	-	-	-
3	Unrecovered Plant - Peaking Facility		Total_Weather_All_NW	-	-	-	-	-
4	Construction Work in Progress	RB:5:29		397,111,025	79,322,274	134,339,566	183,449,185	-
5	Materials & Supplies	RB:6:12		123,327,981	19,836,447	52,379,031	51,112,503	-
6	Non Plant - ADIT	RB:12:18	Financial Stmt.	(34,509,521)	(3,062,666)	(21,491,098)	(9,955,757)	0
7	FC 1027 - Rate Base CWIP (Reg Asset)			(0)	(0)			
8	Unamortized East Station Cost (Net of Deferred Taxes)		Financial Stmt.	1,075,846	1,075,846 1	-	-	-
9	Sub-Total	=1>10		$ 7,736,021,508	$ 1,414,354,734	$ 2,876,844,750	$ 3,415,263,556	$ 29,558,468
10	Cash Working Capital	RB:7>9:17		$ 121,292,100	$ 39,219,091	$ 67,230,077	$ 14,826,433	$ 16,500
11	Total Rate Base Additions	= 12 + 11		$ 7,857,313,609	$ 1,453,573,825	$ 2,944,074,827	$ 3,430,089,989	$ 29,574,968
12	LESS:							
13	Reserve for Depreciation	RB:10:35		$ 2,370,279,045	$ 449,057,859	$ 864,931,885	$ 1,054,487,285	$ 1,802,016
14	Accumulated DIT re Depreciation	RB:11:17		1,298,608,831	212,149,665	532,439,389	554,019,777	0
15	Accumulated DIT re Gains/Losses On Reacquired Debt							
16	Federal	RB:11:9	Net_Rate_Base	175,290	29,300	70,009	75,981	-
17	State	RB:11:9	Net_Rate_Base	57,829	10,143	22,631	25,055	-
18	NOL Carryforward Federal		Net_Rate_Base	(78,173,336)	(14,916,809)	(29,119,631)	(34,136,895)	-
19	NOL Carryforward State		Net_Rate_Base	(68,626,785)	(13,095,164)	(25,563,533)	(29,968,088)	-
20	NOL Federal Benefit of State		Net_Rate_Base	14,411,625	2,749,985	5,368,342	6,293,298	-
21	Customer Advances for Construction		Financial Stmt.	2,698,381	305,769	244,862	2,147,750	-
22	Customer Deposits		Financial Stmt.	12,871,928	1,432,785	2,467,234	8,971,908	-
23	Supplier Refunds		Financial Stmt.	4,509,391	626,315	1,675,549	2,207,527	-
24	Deferred Tenant Allowance		Non_Genl_Plnt	16,261,534	3,017,287	6,000,718	7,243,529	-
25	Total Rate Base Deductions	=14>26		$ 3,573,073,733	$ 641,367,135	$ 1,358,537,454	$ 1,571,367,128	$ 1,802,016
26	Net Rate Base	= 13 - 27		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952

Adjustment No. 18

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 18 - Insurance Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Incremental Insurance Premiums, Excluding Property Insurance		
2	Excess Public Liability	Insurance Analysis	$ 2/ 1,225,502
3	Director and Officer Liability	Insurance Analysis	40,201
4	General Liability	Insurance Analysis	38,759
5	Professional	Insurance Analysis	20,210
6	Commercial Crime/Cyber Liability	Insurance Analysis	90,071
7	Workers Compensation	Insurance Analysis	410,501
8	Service Fees	Insurance Analysis	(33,966)
9	Total Incremental Expense, Excluding Property Insurance	= Sum (Ln. 2 > Ln. 8)	$ 1,791,278 A.
10	DC Factor (Total_Labor)	AL:4:11	8/ 19.3618%
11	DC Insurance Expense Adjustment Excluding Property	= Ln. 9 * Ln. 10	$ 346,824
12	Incremental Property Insurance	Insurance Analysis	$ 2/ 5,128 A.
13	DC Factor (Net_GPIS)	AL:3:13	7/ 18.6176%
14	DC Property Insurance Expense Adjustment	= Ln. 12 * Ln. 13	$ 955
15	Adjustment Total 1/	= Ln. 11 + Ln. 14	$ 347,779

16 **Adjustment Description:** To reflect insurance premium increases.

1/ For class cost purposes, the full amount of the adjustment relates to COSA line EX:5:8.

2/ $\boxed{\text{sum of A. = 1,796,405}}$

	Incremental Change in Annual Premium ($)	WGL (%)	WGL ($)
General Liability	$ 38,759	100.00%	$ 38,759 ①
Excess Liability	1,280,337	5/95.72%	1,225,502
Professional	21,114	95.72%	20,210
D & O - Fiduciary	D. 40,201	100.00%	40,201
Commercial Crime	2,706	5/95.72%	2,590 C.
Cyber Liability	91,395	95.72%	87,481 C.
Workers Compensation	420,688	6/97.58%	410,501 ①
Property	5,357	5/95.72%	5,128
Service Fees	(35,486)	95.72%	(33,966)
	$ E. 1,865,071		$ 1,796,405

sum of C. = 90,071 ①

- *Additional Calculations*		
22-23 Policy Year - D&O & Fiduciary		
Regulated	$ 275,435	A
Non-Regulated	33,631	
Total	$ 309,065	
23-24 Policy Year - D&O & Fiduciary		
Regulated	$ 315,635	B
Non-Regulated	25,297	
Total	$ 340,933	
22-23 Policy Year - D&O & Fiduciary, Regulated Only	$ 275,435	A
23-24 Policy Year - D&O & Fiduciary, Regulated Only	$ 315,635	B
Incremental Change in Annual Premium ($)	$ D. 40,201	

3/ D. E.
1,824,870 + 40,201 = 1,865,071

Washington Gas Light Company
Property and Public Liability Insurance Lead Lag Study
For Twelve Months Ended December 31, 2023

Coverage	Current Carrier	Policy Renewal	Policy Expiration	Annual Premium	
General Liability					
WGL w/$250,000 ded	Liberty Mutual	10/1/2023	9/30/2024	$	478,988
SGC	Liberty Mutual	10/1/2023	9/30/2024	included	
				$	**478,988**
Excess Liability [A]					
First Layer	AEGIS	10/1/2023	9/30/2024	$	5,242,604
Second Layer	EIM	10/1/2023	9/30/2024	$	2,288,343
Second Layer	EIM	10/1/2023	9/30/2024	$	440,951
Third Layer	XL Bermuda	10/1/2023	9/30/2024	$	439,945
Fourth Layer	Argo	10/1/2023	9/30/2024	$	333,638
Fifth Layer	Vantage & Hamilton	10/1/2023	9/30/2024	$	190,912
Sixth Layer	Sompo & Helix	10/1/2023	9/30/2024	$	322,299
Seventh Layer	Everen (formerly OCIL)	10/1/2023	9/30/2024	$	649,135
Eight Layer	Chubb & Arch	10/1/2023	9/30/2024	$	502,556
Ninth Layer	Hamilton, Great Lakes & Acot	10/1/2023	9/30/2024	$	586,263
Tenth Layer	CV Starr, Hiscox & Allianz	10/1/2023	9/30/2024	$	430,285
Eleventh Layer					
				$	**11,426,931**
Professional Liability [E]					
Professional Liability	AEGIS	10/1/2023	9/30/2024	**$**	**71,400**
Control of Well [E]					
Control of Well		10/1/2023	9/30/2024	**$**	**19,016**
Pollution Wrap [A]					
Pollution Wrap	Ironshore	10/1/2023	9/30/2024	**$**	**300,329**
Commercial Crime [A]					
Commercial Crime	Travelers	10/1/2023	9/30/2024	$	71,341
Excess Commercial Crime	Berkley	10/1/2023	9/30/2024	included	
				$	**71,341**
Cyber Liability [D]					
Cyber	Lloyds	10/1/2023	9/30/2024	$	1,111,099
				$	**1,111,099**
Property [A]					
Boiler & Mach.	Travelers	10/1/2023	9/30/2024	$	79,281
Property	AEGIS	10/1/2023	9/30/2024	$	1,129,440
Sabotage & Terr.	AEGIS	10/1/2023	9/30/2024	$	200,913
				$	**1,409,634**
Workers Compensation					
WGL	Liberty Mutual	10/1/2023	9/30/2024	$	1,979,085
				$	**1,979,085**
Service Fees					
Aon Risk Services	Property & Casualty	10/1/2023	9/30/2024	$	228,343
				$	**228,343**
			Total Premiums	**$**	A. **17,096,166**

[A] *- Named Insured is WGL Holdings, Inc. and subsidiaries*
[B] *- Named Insured is AltaGas, Ltd and its subsidiaries. Premium shown is internal allocation*
[C] *- 3-Year Policy - Annual Premium Shown*
[D] *- Named Insured is AltaGas, Ltd and its subsidiaries. Premium shown is allocation from broker.*
[E] *- Named Insured is WGL Holdings, Inc. and its subsidiaries and SEMCO, Inc and its subsidiaries. Premium shown is allocation from broker.*

A. 4/
$\boxed{17{,}096{,}166 - 15{,}271{,}296 = 1{,}824{,}870}$ 2

Washington Gas Light Company
Property and Public Liability Insurance Lead Lag Study
For Twelve Months Ended December 31, 2022

Coverage	Current Carrier	Policy Renewal	Policy Expiration	Annual Premium	
General Liability					
WGL w/$250,000 ded	Liberty Mutual	10/1/2022	10/1/2023	$	440,229
SGC	Liberty Mutual	10/1/2022	10/1/2023	included	
				$	**440,229**
Excess Liability [A]					
First Layer	AEGIS	10/1/2022	10/1/2023	$	4,723,056
Second Layer	EIM	10/1/2022	10/1/2023	$	1,793,103
Second Layer	EIM	10/1/2022	10/1/2023	$	440,951
Third Layer	XL Bermuda	10/1/2022	10/1/2023	$	405,479
Fourth Layer	Argo	10/1/2022	10/1/2023	$	307,500
Fifth Layer	SCOR	10/1/2022	10/1/2023	$	179,475
Sixth Layer	Everest/HDI	10/1/2022	10/1/2023	$	298,653
Seventh Layer	Mercer	10/1/2022	10/1/2023	$	598,281
Eight Layer	OCIL	10/1/2022	10/1/2023	$	463,185
Ninth Layer	Chubb/Arch	10/1/2022	10/1/2023	$	540,335
Tenth Layer	Hamilton/Great Lakes/HDI	10/1/2022	10/1/2023	$	396,576
Eleventh Layer	Starr/Hiscox	10/1/2022	10/1/2023		
				$	**10,146,594**
Professional Liability [E]					
Professional Liability	AEGIS	10/1/2022	10/1/2023	**$**	**50,286**
Control of Well [E]					
Control of Well		10/1/2022	10/1/2023	**$**	**35,668**
Pollution Wrap [A]					
Pollution Wrap	Ironshore	10/1/2022	10/1/2023	**$**	**292,368**
Commercial Crime [A]					
Commercial Crime	Travelers	10/1/2022	10/1/2023	$	68,635
Excess Commercial Crime	Berkley	10/1/2022	10/1/2023	included	
				$	**68,635**
Cyber Liability [D]					
Cyber	Lloyds	10/1/2022	10/1/2023	$	1,019,704
				$	**1,019,704**
Property [A]					
Boiler & Mach.	Travelers	10/1/2022	10/1/2023	$	72,984
Property	AEGIS	10/1/2022	10/1/2023	$	1,148,838
Sabotage & Terr.	AEGIS	10/1/2022	10/1/2023	$	173,764
				$	**1,395,586**
Workers Compensation					
WGL	Liberty Mutual	10/1/2022	10/1/2023	$	1,558,397
				$	**1,558,397**
Service Fees					
Aon Risk Services	Property & Casualty	10/1/2022	10/1/2023	$	263,829
				$	**263,829**
			Total Premiums	**$**	**15,271,296** 3

A - Named Insured is WGL Holdings, Inc. and subsidiaries
B - Named Insured is AltaGas, Ltd and its subsidiaries. Premium shown is internal allocation
C - 3-Year Policy - Annual Premium Shown
D - Named Insured is AltaGas, Ltd and its subsidiaries. Premium shown is allocation from broker.
E - Named Insured is WGL Holdings, Inc. and its subsidiaries and SEMCO, Inc and its subsidiaries. Premium shown is allocation from broker.

Journal ID	GL00002008
Account	(Multiple Items)

Row Labels	Sum of Sum Amount	Allocation Factor
00	314,320	2.08%
01	14,448,280	**95.72%** 2
07	394	0.00%
15	331,670	2.20%
302	100	0.00%
Grand Total	**15,094,764**	100.00%

WGLH Allocations Analysis
ALL OTHER FRINGE BENEFITS
AS OF YTD CY23-DECEMBER

BU	Sub. Name	Total Labor	% By BU
00	WGLH	184,429.87	0.10%
01	WG-CAPITAL	36,071,589.75	**20.29%**
01	WG-O&M	137,379,762.72	**77.29%**
07	Hampshire-CAPITAL	399,099.04	0.22%
07	Hampshire-O&M	1,036,078.19	0.58%
15	WGES	1,572,889.05	0.88%
20	WGL Energy Systems	40,811.14	0.02%
24	WGL Sustainable Energy	56,096.16	0.03%
25	WGL Midstream	210,438.15	0.12%
28	WGL Midstream MVP	1,510.17	0.00%
300	ASUS	705,606.07	0.40%
302	AMUS	51,642.59	0.03%
305	APHUS	27,786.11	0.02%
312	Blythe Energy	13,772.56	0.01%
326	Blythe Operations	4,096.60	0.00%
Total		**177,755,608.17**	**100.00%**

sum = 97.58%

2

Washington Gas Light Company
Allocation Factors Based on Gas Plant in Service

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Actual Construction Supplies Issued**									
2 **from Stores Stock**	Analysis	Stores _Stock	$ 781,698	$ 21,833	$ 269,494	$ 490,372	0.027930	0.344754	0.627316
3 **Adjusted Net Rate Base**									
4 Net Rate Base	RB:1:26		$ 4,256,466,925	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862			
5 Less: Chalk Point			-	-	-	-			
6 Adjusted Net Rate Base	=4-5	Net_Rate_Base	$ 4,256,466,925	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	0.190817	0.372501	0.436682
7 **Net Gas Plant in Service**									
8 Gas Plant in Service	RB:1:1		$ 7,219,457,709	$ 1,317,182,832	$ 2,711,617,252	$ 3,190,657,625			
9 Gas Plant Held for Future Use	RB:1:2		-	-	-	-			
10 Construction Work In Progress	RB:1:4	CWIP	397,111,025	79,322,274	134,339,566	183,449,185	0.199748	0.338292	0.461959
11 Less: Reserve for Depreciation	RB:1:14		2,368,477,029	449,057,859	864,931,885	1,054,487,285			
12 Less: Accumulated Deferred Income taxes	RB:1:15		1,298,608,831	212,149,665	532,439,389	554,019,777			
13 Net Gas Plant in Service	=(8>10)-11-12	Net_GPIS	$ 3,949,482,875	$ 735,297,583	$ 1,448,585,543	$ 1,765,599,748	0.186176 1	0.366779	0.447046
14 Adjusted Construction Work In Progress	RB:5:23	ADJ_CWIP	$ 213,661,840	$ 79,322,274	$ 134,339,566	$ -	0.371251	0.628749	0.000000

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618 1	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses -									
25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding									
42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Adjustment No. 19

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 19 - Interest On Customer Deposits

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Amount C
1	**Expense**		
2	Customer Deposits	RB 1:22	$ 2/1,432,785
3	Interest Rate	Per Order	4/5.38%
4	Rate Year Customer Deposit Interest Expense	Ln. 2 * Ln. 3	$ 77,084
5	Test Year Customer Deposit Interest Expense	SM 1:11	5/ 41,769
6	Adjustment to Interest Expense	Ln. 4 - Ln. 5	$ 35,315

7 **Adjustment Description:** To reflect interest rate authorized for customer deposits.

Washington Gas Light Company
Rate Base Summary
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Gas Plant in Service	RB:3:17		$ 7,249,016,177	$ 1,317,182,832	$ 2,711,617,252	$ 3,190,657,625	$ 29,558,468
2	Gas Plant Held for Future Use	RB:4:13		-	-	-	-	-
3	Unrecovered Plant - Peaking Facility		Total_Weather_All_NW	-	-	-	-	-
4	Construction Work in Progress	RB:5:29		397,111,025	79,322,274	134,339,566	183,449,185	-
5	Materials & Supplies	RB:6:12		123,327,981	19,836,447	52,379,031	51,112,503	-
6	Non Plant - ADIT	RB:12:18	Financial Stmt.	(34,509,521)	(3,062,666)	(21,491,098)	(9,955,757)	0
7	FC 1027 - Rate Base CWIP (Reg Asset)			(0)	(0)			
8	Unamortized East Station Cost (Net of Deferred Taxes)		Financial Stmt.	1,075,846	1,075,846	-	-	-
9	Sub-Total	=1>10		$ 7,736,021,508	$ 1,414,354,734	$ 2,876,844,750	$ 3,415,263,556	$ 29,558,468
10	Cash Working Capital	RB:7>9:17		$ 121,292,100	$ 39,219,091	$ 67,230,077	$ 14,826,433	$ 16,500
11	Total Rate Base Additions	= 12 + 11		$ 7,857,313,609	$ 1,453,573,825	$ 2,944,074,827	$ 3,430,089,989	$ 29,574,968
12	LESS:							
13	Reserve for Depreciation	RB:10:35		$ 2,370,279,045	$ 449,057,859	$ 864,931,885	$ 1,054,487,285	$ 1,802,016
14	Accumulated DIT re Depreciation	RB:11:17		1,298,608,831	212,149,665	532,439,389	554,019,777	0
15	Accumulated DIT re Gains/Losses On Reacquired Debt							
16	Federal	RB:11:9	Net_Rate_Base	175,290	29,300	70,009	75,981	-
17	State	RB:11:9	Net_Rate_Base	57,829	10,143	22,631	25,055	-
18	NOL Carryforward Federal		Net_Rate_Base	(78,173,336)	(14,916,809)	(29,119,631)	(34,136,895)	-
19	NOL Carryforward State		Net_Rate_Base	(68,626,785)	(13,095,164)	(25,563,533)	(29,968,088)	-
20	NOL Federal Benefit of State		Net_Rate_Base	14,411,625	2,749,985	5,368,342	6,293,298	-
21	Customer Advances for Construction		Financial Stmt.	2,698,381	305,769	244,862	2,147,750	-
22	Customer Deposits		Financial Stmt.	12,871,928	1,432,785 1	2,467,234	8,971,908	-
23	Supplier Refunds		Financial Stmt.	4,509,391	626,315	1,675,549	2,207,527	-
24	Deferred Tenant Allowance		Non_Genl_Plnt	16,261,534	3,017,287	6,000,718	7,243,529	-
25	Total Rate Base Deductions	=14>26		$ 3,573,073,733	$ 641,367,135	$ 1,358,537,454	$ 1,571,367,128	$ 1,802,016
26	Net Rate Base	= 13 - 27		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
1325 G STREET, N.W., SUITE 800
WASHINGTON, D.C. 20005

ORDER

December 6, 2023

FORMAL CASE NO. 712, IN THE MATTER OF THE INVESTIGATION INTO THE PUBLIC SERVICE COMMISSION'S RULES OF PRACTICE AND PROCEDURE, Order No. 21935

I. INTRODUCTION

1. By this Order, the Public Service Commission of the District of Columbia ("Commission") establishes 5.38 percent as the simple interest rate that regulated utilities in the District of Columbia shall pay to customers on deposits during the calendar year 2024. This rate shall take effect by January 15, 2024.

II. BACKGROUND

2. Section 307.8 of the Commission's Consumer Bill of Rights requires the Commission to establish a simple interest rate for customer deposits on an annual basis. The applicable section reads:

> Each Utility shall be liable for interest on Deposits held from the date the Deposit is made until the date the Deposit has been refunded or until an effort has been made to refund the Deposit. Each Utility shall pay simple interest on deposits with the rate being established not later than January 15th of each year, equal to the average annual yields of one-year Treasury bills for September, October, and November of the preceding year.[1]

III. DECISION

3. The Commission has determined that the simple interest rate the regulated utilities are to pay on customer deposits in the calendar year 2024 will increase from 4.34 percent in 2023[2] to 5.38 percent in 2024. Respectively, the average rates for September, October, and November

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[1] 15 DCMR § 307.8.

[2] By Order No. 21556, the Commission established the simple interest rate of 4.34 percent for 2023. *See, Formal Case No. 712, In the Matter of the Investigation into the Public Service Commission's Rules of Practice and Procedure, Order* No. 21556, rel. December 14, 2022.

2023 were 5.44 percent, 5.42 percent, and 5.28 percent for an average rate of 5.38 percent.[3] Accordingly, the simple interest rate for the calendar year 2024 shall be 5.38 percent pursuant to 15 DCMR § 307.8. This new rate shall become effective by January 15, 2024.

THEREFORE, IT IS ORDERED THAT:

1

4. The simple interest rate of 5.38 percent shall apply to interest calculations on customer deposits held on or after January 15, 2024.

A TRUE COPY: **BY DIRECTION OF THE COMMISSION:**

Brinda Westbrook-Sedgwick

CHIEF CLERK **BRINDA WESTBROOK-SEDGWICK**
COMMISSION SECRETARY

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[3] The source of these figures is the Federal Reserve Board's ("FRB") Daily Treasury Yield Curve (or "Constant Maturity Rates") Rates database available at the FRB's website. *See* https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

Washington Gas Light Company
Income Statement Summary -- Combined
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operating Revenues**	RV:1:34		$ 1,608,715,831	$ 276,904,880	$ 677,942,095	$ 650,536,019	$ 3,332,837
2	Operating Expenses							
3	Gas Purchased	EX:2:2		$ 454,828,378	$ 64,262,645	$ 200,704,535	$ 189,861,198	$ -
4	Operation - Other than Gas Purchased	EX:2:3>44		322,051,962	61,031,214	137,950,468	122,960,170	110,110
5	Maintenance	EX:4:26		114,413,313	25,568,839	46,799,501	41,961,616	83,356
6	Depreciation	EX:6:22		135,410,640	23,907,431	41,034,291	70,456,187	12,731
7	Amortization of Capitalized Software		Financial Stmt.	21,433,284	3,757,163	8,810,769	8,785,972	79,380
8	Amortization of Chalk Point / MD Post 1989 Inter		Financial Stmt.	94,718	-	94,718	-	-
9	Amortization of General Plant			14,127,280	1,878,281	5,415,781	6,833,217	-
10	Amortization of Unrecovered Plant Loss Chillum		Financial Stmt.	-	-	-	-	-
11	Interest on Customer Deposits	EX:1:6		528,578	41,769 1	128,646	358,163	-
12	Interest on Supplier Refunds	EX:1:7		73,600	11,533	31,581	30,486	-
13	General Taxes	EX:8:24		171,665,153	58,992,535	88,254,140	24,335,027	83,452
14	Other Income Taxes	EX:10:23	Financial Stmt.	13,182,317	756,509	5,234,557	7,027,005	164,246
15	Expenses Before Federal Income Taxes	=3>14		$ 1,247,809,223	$ 240,207,920	$ 534,458,986	$ 472,609,042	$ 533,275
16	Federal Income Tax Expense	EX:10:22		$ 50,043,363	$ 2,871,897	$ 19,871,685	$ 26,676,264	$ 623,518
17	ITC Adjustment	EX:10:22		(305,994)	(90,913)	(108,018)	(107,064)	-
18	Loss- Disposition of Utility Plant		Financial Stmt.	451,758	100,274	351,484	-	-
19	Total Operating Expenses	=15 > 17		$ 1,297,998,351	$ 243,089,178	$ 554,574,138	$ 499,178,242	$ 1,156,793
20	Net Operating Income	=1-18		$ 310,717,480	$ 33,815,702	$ 123,367,957	$ 151,357,777	$ 2,176,044
21	Net Income Adjustments							
22	AFUDC	AL:3:14	ADJ_CWIP	1,259,101	467,443	791,658	-	-
23	LCP Equity Accrual			-	-	-	-	-
24	Net Operating Income - Adjusted	19+21-22+23		$ 311,976,581	$ 34,283,145	$ 124,159,615	$ 151,357,777	$ 2,176,044
25	Net Rate Base	RB:1:26		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952
26	Return Earned	=24 / 25		7.28%	4.22%	7.83%	8.14%	7.84%

Exhibit WG (D)-5
Adjustment No. 19
Page 5 of 5

Adjustment No. 20

Washington Gas Light Company
District of Columbia Jurisidiction

Adjustment No. 20 - Commission-Mandated Audit Fees

Twelve Months Ended March 31, 2024

Line No.	Description	Reference		Amount
	A	B		C
1	Regulatory Asset Balance as of July 31, 2025 (FC 1115 Pipes 1)	Analysis	$	2/ 218,773
2	Regulatory Asset Balance as of July 31, 2025 (FC 1175 Pipes 2)	Analysis	$	3/ 832,225
3	Total Annual Amortization (Rate Year)	(Ln. 1 + Ln. 2)/3	$	350,333
4	Test Year Expense (System)	Analysis	$	4/ 91,675
5	Three_Part_Factor	AL:5:30		5/ 18.64%
6	Per Book Expense (District of Columbia)	Ln. 4 * Ln. 5	$	17,091
7	Adjustment	Ln. 3 - Ln. 6	$	333,242 1/

8 **Adjustment Description:** To reflect the amortization of ProjectPipes audit fees at rate year amount.

1/ For Class Cost purposes, note that $333,242 of the adjustment relates to EX:5:6.

Audit Costs	$	**649,023.00**	
Date Amortization Starts		**4/1/2021**	
Monthly Amortization	$	**6,265.00**	from Apr-21 to Dec-23
Monthly Amortization	$	**11,763.42**	from Jan-24 to Jul-25
	$	**6,077.03**	from Aug-25 to Jul-28

No. of Months	Month - Year	Amortization Amount Expense debited to 923000	Regualtory Asset Account 182308 Balance	Regualtory Asset Account 182308 Activity	Total Asset Balance
34	Jan-24	$ 11,763.42	$ 430,514.58		430,514.58
35	Feb-24	$ 11,763.42	$ 418,751.16		418,751.16
36	Mar-24	$ 11,763.42	$ 406,987.74		406,987.74
37	Apr-24	$ 11,763.42	$ 395,224.32		395,224.32
38	May-24	$ 11,763.42	$ 383,460.90		383,460.90
39	Jun-24	$ 11,763.42	$ 371,697.48		371,697.48
40	Jul-24	$ 11,763.42	$ 359,934.06		359,934.06
41	Aug-24	$ 11,763.42	$ 348,170.64		348,170.64
42	Sep-24	$ 11,763.42	$ 336,407.22		336,407.22
43	Oct-24	$ 11,763.42	$ 324,643.80		324,643.80
44	Nov-24	$ 11,763.42	$ 312,880.38		312,880.38
45	Dec-24	$ 11,763.42	$ 301,116.96		301,116.96
46	Jan-25	$ 11,763.42	$ 289,353.54		289,353.54
47	Feb-25	$ 11,763.42	$ 277,590.12		277,590.12
48	Mar-25	$ 11,763.42	$ 265,826.70		265,826.70
49	Apr-25	$ 11,763.42	$ 254,063.28		254,063.28
50	May-25	$ 11,763.42	$ 242,299.86		242,299.86
51	Jun-25	$ 11,763.42	$ 230,536.44		230,536.44
52	**Jul-25**	**$ 11,763.42**	**$ 218,773.02**		**218,773.02** 1

Audit Costs	$	**832,225.00**
Date Amortization Starts		**1/1/2024**
Monthly Amortization	$	- from Jan-24 to Jul-25
	$	**23,117.36** from Aug-25 to Jul-28

No. of Months	Month - Year	Amortization Amount Expense debited to 923000	Regualtory Asset Account 182308 Balance	Regualtory Asset Account 182308 Activity	Total Asset Balance
0	Dec-23		$ 832,225.00		832,225.00
1	Jan-24	$ -	$ 832,225.00		832,225.00
2	Feb-24	$ -	$ 832,225.00		832,225.00
3	Mar-24	$ -	$ 832,225.00		832,225.00
4	Apr-24	$ -	$ 832,225.00		832,225.00
5	May-24	$ -	$ 832,225.00		832,225.00
6	Jun-24	$ -	$ 832,225.00		832,225.00
7	Jul-24	$ -	$ 832,225.00		832,225.00
8	Aug-24	$ -	$ 832,225.00		832,225.00
9	Sep-24	$ -	$ 832,225.00		832,225.00
10	Oct-24	$ -	$ 832,225.00		832,225.00
11	Nov-24	$ -	$ 832,225.00		832,225.00
12	Dec-24	$ -	$ 832,225.00		832,225.00
13	Jan-25	$ -	$ 832,225.00		832,225.00
14	Feb-25	$ -	$ 832,225.00		832,225.00
15	Mar-25	$ -	$ 832,225.00		832,225.00
16	Apr-25	$ -	$ 832,225.00		832,225.00
17	May-25	$ -	$ 832,225.00		832,225.00
18	Jun-25	$ -	$ 832,225.00		832,225.00
19	**Jul-25**	**$ -**	**$ 832,225.00**		**832,225.00** 1

Exhibit WG (D)-5
Adjustment No. 20
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Unit	Journal ID	Period	Account	Process	Product	Project	Dept	Sum Amount	Res Type	Long Descr	Source	Posted	Ref No	Oper Unit	Fund Proj	DateTime	Descr	Date	Year	Ledger Grp
01	PA00007006	4	923000				045	6,265	2201	FC 1115 Audit Fee Amortiz_Apr_2023	EXL	5/1/2023		01		5/1/2023 15:07	FC 1115 Audit Fee Amortiz_Apr_	4/30/2023	23	ACTUALS
01	PA00007006	5	923000				045	6,265	2201	FC 1115 Audit Fee Amortiz_May_2023	EXL	6/3/2023		01		6/3/2023 14:16	FC 1115 Audit Fee Amortiz_May_	5/30/2023	23	ACTUALS
01	PA00007006	6	923000				045	6,265	2201	FC 1115 Audit Fee Amortiz_Jun_2023	EXL	7/5/2023		01		7/5/2023 19:10	FC 1115 Audit Fee Amortiz_Jun_	6/21/2023	23	ACTUALS
01	PA00007006	7	923000				045	6,265	2201	FC 1115 Audit Fee Amortiz_July_2023	EXL	8/3/2023		01		8/3/2023 1:56	FC 1115 Audit Fee Amortiz_July	7/31/2023	23	ACTUALS
01	PA00007006	8	923000				045	6,265	2201	FC 1115 Audit Fee Amortiz_AUG_2023	EXL	9/5/2023		01		9/5/2023 23:14	FC 1115 Audit Fee Amortiz_AUG_	8/29/2023	23	ACTUALS
01	PA00007006	9	923000				045	6,265	2201	FC 1115 Audit Fee Amortiz_Sep_2023	EXL	10/4/2023		01		10/4/2023 10:06	FC 1115 Audit Fee Amortiz_Sep_	9/22/2023	23	ACTUALS
01	PA00007006	10	923000				045	6,265	2201	FC 1115 Audit Fee Amortiz_OCT23	EXL	11/1/2023		01		11/1/2023 10:52	FC 1115 Audit Fee Amortiz_OCT2	10/26/2023	23	ACTUALS
01	PA00007006	11	923000				045	6,265	2201	FC 1115 Audit Fee Amortiz_NOV23	EXL	12/3/2023		01		12/3/2023 0:30	FC 1115 Audit Fee Amortiz_NOV2	11/20/2023	23	ACTUALS
01	PA00007006	12	923000				045	6,265	2201	FC 1115 Audit Fee Amortiz_DEC23	EXL	1/2/2024		01		1/2/2024 19:30	FC 1115 Audit Fee Amortiz_DEC2	12/22/2023	23	ACTUALS
01	PA00007006	1	923000				045	11,763	2201	FC 1115 Audit Fee Amortiz_JAN24	EXL	2/3/2024		01		2/3/2024 14:33	FC 1115 Audit Fee Amortiz_JAN2	1/22/2024	24	ACTUALS
01	PA00007006	2	923000				045	11,763	2201	FC 1115 Audit Fee Amortiz_Feb_2024	EXL	3/1/2024		01		3/1/2024 19:14	FC 1115 Audit Fee Amortiz_Feb_	2/22/2024	24	ACTUALS
01	PA00007006	3	923000				045	11,763	2201	FC 1115 Audit Fee Amortiz_Mar_2024	EXL	4/1/2024		01		4/1/2024 13:22	FC 1115 Audit Fee Amortiz_Mar_	3/25/2024	24	ACTUALS
								91,675	1											

Exhibit WG (D)-5
Adjustment No. 20
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Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses (Continued)

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Appliance Service - Field**									
2 Removing/resetting Meters - Direct	EX:2:27	Direct_Meter_Exp	$ 1,689,348	$ 121,682	$ 1,105,374	$ 462,292	0.072029	0.654320	0.273651
3 Removing/resetting Meters - Allocable	EX:2:28		-	-	-	-			
4 SOCP - Direct	EX:2:31	Direct _SOCP	44,751	1,533	8,132	35,086	0.034256	0.181725	0.784019
5 SOCP - Allocable	EX:2:32		0	0	0	0			
6 Total Appliance Service - Field	=2>5	Appl_Svc_X_Admin	$ 1,734,099	$ 123,215	$ 1,113,507	$ 497,378	0.071054	0.642124	0.286822
7 **Distribution - Field**									
8 Operations Expense:									
9 Mains	EX:2:25		$ 1,368,210	$ 291,861	$ 471,936	$ 604,413			
10 Measuring/Regulating Station	EX:2:29		509,583	303,237	123,239	83,107			
11 Maintenance Expense:									
12 Mains	EX:4:11		33,302,827	8,648,128	12,660,520	11,994,178			
13 Services	EX:4:12		35,487,205	9,541,079	15,284,083	10,662,043			
14 Meter & House Regulators	EX:4:19		30,565,014	3,800,788	12,993,731	13,770,496			
15 Measuring & Regulating Station Equipt.	EX:4:17		1,532,095	911,702	370,526	249,868			
16 Gas Light Services	EX:4:18		1,894	-	-	1,894			
17 Total Distribution - Field	=9>16	Dist_X_Admin	$ 102,766,828	$ 23,496,794	$ 41,904,035	$ 37,365,999	0.228642	0.407758	0.363600
18 **Distribution Maintenance Expenses**									
19 Mains	EX:4:11		$ 33,302,827	$ 8,648,128	$ 12,660,520	$ 11,994,178			
20 Services	EX:4:12		35,487,205	9,541,079	15,284,083	10,662,043			
21 Meter & House Regulators	EX:4:13		30,565,014	3,800,788	12,993,731	13,770,496			
22 Compressor Station Equipment	EX:4:16		-	-	-	-			
23 Measuring & Regulating Station Equip.	EX:4:17		1,532,095	911,702	370,526	249,868			
24 Gas Light Services	EX:4:18		1,894	-	-	1,894			
25 Total Distribution Maintenance Expenses	=19>24	Dist_Maint_Exp	$ 100,889,035	$ 22,901,696	$ 41,308,860	$ 36,678,479	0.226999	0.409448	0.363553
26 **Three Part Factor**									
27 Net Rate Base	AL:3:6	Net_Rate_Base	$ 4,256,466,925	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	0.190817	0.372501	0.436682
28 O&M Adjusted	AL:4:33	O & M_Adjusted	205,007,176	40,938,488	83,457,373	80,611,316	0.199693	0.407095	0.393212
29 Total Annual Therm Sales	AL:1:20	Annual _Total _NW	1,682,395,886	283,950,711	739,552,169	658,893,006	0.168778	0.439583	0.391640
30 Three Part Factor	Average 27>29	Three _Part _Factor					0.186429 (1)	0.406393	0.407178
31 **Gas Costs Recovered**	EX:3:1	Gas_Cost_Rec	$ 381,002,051	$ 51,891,638	$ 167,476,401	$ 161,634,012	0.136198	0.439568	0.424234
32 **Credit and Debit Card Transactions**	Analysis	Credit_Debit_Card	2,450,284	332,924	1,109,744	1,007,616	0.135872	0.452904	0.411224

Adjustment No. 21

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 21 - Non-Labor Inflation

Twelve Months Ended March 31, 2024

Line No.	Description	Allocator	Non-Labor Expense	Calculated Increase
	A	B	C	D
1	Test Year Operations Expense _1/	DC Inc Stmt, Ln. 3, Col. E 2/	$ 57,084,597	
2	Test Year Maintenance Expense	DC Inc Stmt, Ln. 4, Col. E 2/	25,568,839	
3	Labor Expense in Test Year O&M	Workpaper 1 3/	(28,256,576)	
4	Test Year Non Labor O&M Expense	Sum (Ln. 1 > Ln. 3)	$ 54,396,860	
5	Non Labor Expense Adjustments to Cost of Service	Workpaper 2 4/	(12,491,893)	
6	Test Year Non Labor O&M Expense (Adjusted)	Ln. 4 + Ln. 5	$ 41,904,967	
7	Inflation Rate (2024)	5/ 1 + (2.49% * 1)	102.49%	
8	Non Labor O&M Expense @ 12/31/2024	Ln. 6 * Ln. 7	$ 42,948,611	
9	Incremental Increase	Ln. 8 - Ln. 6		1,043,643
10	**Adjustment Total**	**Ln. 8**		**1,043,643**

1/ excludes Gas Purchased Expense

Washington Gas Light Company
District of Columbia Jurisdiction

Income Statement and Rate of Return Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Books	Distribution Adjustments	Distribution Amounts	Ratemaking Adjustments	Ratemaking Amounts	Revenue Deficiency	ROE Amounts
	A	B	C	D	E = C + D	F	G = E + F	H	I = G + H
1	Operating Revenues	Adj List Pg 1, Ln. 11	$ 276,904,880	$ (84,692,285)	$ 192,212,595	$ 19,414,936	$ 211,627,531	$ 45,572,411	$ 257,199,942
2	Operating Expenses								
3	Operation	Adj List Pg 1, Ln. 41	$ 6/125,293,859	$ (68,209,263)	$ 57,084,597 1	$ (267,932)	$ 56,816,665	$ 1,200,094	$ 58,016,759
4	Maintenance	Adj List Pg 1, Ln. 20	6/ 25,568,839	-	25,568,839 1	356,972	25,925,811	-	25,925,811
5	Depreciation	Adj List Pg 1, Ln. 44	23,907,431	-	23,907,431	7,922,823	31,830,254	-	31,830,254
6	Amortization of General Plant	Per Books	1,878,281	-	1,878,281	-	1,878,281	-	1,878,281
7	Amortization of Capitalized Software	Adj List Pg 1, Ln. 45	3,757,163	(97,980)	3,659,183	-	3,659,183	-	3,659,183
8	Amortization of Unrecovered Plant Loss	Per Books	100,274	-	100,274	-	100,274	-	100,274
9	Interest on Customer Deposits	Adj List Pg 1, Ln. 48	41,769	-	41,769	35,315	77,084	-	77,084
10	Interest on Supplier Refunds	Per Books	11,533	(11,533)	-	-	-	-	-
11	General Taxes	Adj List Pg 2, Ln. 7	58,992,535	-	58,992,535	4,443,796	63,436,331	-	63,436,331
12	Expenses Before Income Taxes	Sum of Lns. 3 > 11	$ 239,551,685	$ (68,318,776)	$ 171,232,910	$ 12,490,974	$ 183,723,884	$ 1,200,094	$ 184,923,978
13	Income Taxes	Adj List Pg 2, Ln. 10	3,537,493	(3,089,477)	448,015	166,747	614,762	12,210,152	12,824,914
14	Total Operating Expenses	Sum of Lns. 12 + 13	$ 243,089,178	$ (71,408,253)	$ 171,680,925	$ 12,657,721	$ 184,338,646	$ 13,410,246	$ 197,748,892
15	Net Operating Income	Ln. 1 - Ln. 14	$ 33,815,702	$ (13,284,032)	$ 20,531,669	$ 6,757,215	$ 27,288,885	$ 32,162,165	$ 59,451,050
16	Net Income Adjustments								
17	AFUDC	Per Books	467,443	-	467,443	-	467,443	-	467,443
18	Net Operating Income - Adjusted	Sum of Ln.s 15 > 17	$ 34,283,145	$ (13,284,032)	$ 20,999,112	$ 6,757,215	$ 27,756,328	$ 32,162,165	$ 59,918,493
19	Net Rate Base	Rate Base Stmt, Ln.23	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (35,183,527)	$ 760,992,964	$ -	$ 760,992,964
20	Return Earned	Ln. 18 / Ln. 19	4.22%		2.64%		3.65%		7.87%
21	Return on Common Equity								
22	Interest Expense		$ 19,142,496	$ (330,939)	$ 18,811,557	$ (831,295)	$ 17,980,262		$ 17,980,262
23	Net Income Available for Common Equit	Ln. 18 - Ln. 22	$ 15,140,649		$ 2,187,555		$ 9,776,066		$ 41,938,231
24	Common Equity Ratio	Cost of Capital, Ln. 3	52.49%		52.49%		52.49%		52.49%
25	Common Equity Capital	Ln. 19 * Ln. 24	$ 426,291,579		$ 417,878,033		$ 399,411,746		$ 399,411,746
26	Return Earned on Common Equity	Ln. 23 / Ln. 25	3.55%		0.52%		2.45%		10.50%

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 21 Workpaper 1 - Per Book Labor Expense

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System	Allocation	DC Amount
1	Total O&M Labor Expense	WEX:6:30			21/ $ 25,573,530
1	Involuntary Seperation Reduction	Analysis			22/ (1,978,270)
1	Long-Term Incentive Compensation	920411, 920412, 920421, and 920422	7/ $ 17,350,204	8/ 19.54%	3,390,371
1	Short-Term Incentive Compensation	920401, 920402, 920431, 920432, 920441	12,392,696	19.54%	2,421,634
1	401(k) Expense	Acct 926207 and 926309	8,427,540	19.36%	1,631,726
1	Medical Plans	Account 926274, 926264, 926215	19,856,287	19.36%	3,844,540
2	OPEB Expense	EX:5:15			9/ (6,584,462)
3	Pension Expense	EX:5:9			9/ (42,494)
4	Total Per Book Labor Expense	Sum (Ln. 1 > Ln. 3)			28,256,576 1

Washington Gas Light Company
District of Columbia

Adjustment No. 21 Workpaper 2 - Non Labor Expense Adjustments to Cost of Service

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Amount
1	Uncollectible Expense (per Book)	1/	$ (4,390,162)
2	Environmental Amortization (per Book)	EX:5:21	9/ (263,068)
3	Rate Case Amortization Expense (per Book)	EX:5:12	9/ (475,776)
4	Insurance Expense	Acct 925101 * DC Labor Factor	9/ (2,884,319)
5	Fringe Benefit	Adj. No. 10	10/ (39,094)
6	Medical Plans	Adj. No. 11	7/ (3,844,540)
7	Commission-Mandated Audit Fees	Adj. No. 20	11/ (17,091)
8	Trade Dues, Bus Memberships, and Community Affairs Expense	Adj. No. 22	12/ (97,796)
9	General Advertising Expense	Adj. No. 23	13/(125,884)
10	Legal Expenses	Adj. No. 25	14/ 136,923
11	Prior Period & One Time Entries	Adj. No. 26	15/ (26,978)
12	Meger Cost to Achieve Amortization Elimination	Adj. No. 27	16/ (52,311)
13	Credit/Debit Card Transaction Fees Elimination	Adj. No. 28	17/(411,796)
14	Total Non Labor Expense Adjustments	Sum (Ln. 1 to Ln. 13)	$ (12,491,893) 1

1/ Calculation of Uncollectible Expense (per Book)		
Uncollectible Expense	EX:7:22	$ 18/ 6,226,265
Less: GAC Uncollectible Expense	Adj. No. 2D	19/ (1,694,830)
Less: POR Bad Debt Expense	Adj. No. 7D, Ln. 17	20/ (141,274)
Total Uncollectible Expense (per Book)		$ 4,390,162

The SAS System

YEAR	QUARTER	CPI1	CPI2	CPI3	CPI4	CPI5	CPI6	CPIA	CPIB	CPIC
2022	1	8.20	5.50	3.84	2.75	2.72	2.50	3.75	2.37	2.30
2022	2	9.20	7.10	4.53	3.73	3.11	3.03	6.12	2.90	2.30
2022	3	10.50	6.68	4.34	3.56	3.40	3.00	7.54	3.21	2.50
2022	4	5.70	5.40	4.47	3.50	3.10	2.94	7.69	3.37	2.50
2023	1	3.10	3.33	3.41	3.05	2.77	2.60	3.11	2.46	2.37
2023	2	3.80	3.50	3.20	2.95	2.70	2.42	3.35	2.51	2.25
2023	3	2.70	3.07	2.92	2.61	2.55	2.59	3.10	2.49	2.40
2023	4	3.60	3.26	2.78	2.62	2.50	2.40	3.34	2.52	2.27
2024	1	2.80	2.51	2.50	2.40	2.35	2.27	2.49 1	2.20	2.25

Washington Gas Light Company
Operation and Maintenance Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	---- Reference ---- Sc-Pg-Ln	Allocator		WG		DC		MD		VA		FERC
	A	B	C		D		E		F		G		H
1	**Maintenance Expenses**												
2	Storage	AL:1:19	Total_Weather_All_NW	$	380,003	$	62,613	$	161,465	$	155,925		-
3	Transmission	AL:2:8	Transmission_Plnt		2,993,733		441,583		1,160,617		1,314,014		77,518
4	Transmission - Chalk Point												
5	Structures & Improvements		Financial Stmt.		43,547		-		43,547		-		-
6	Measuring & Regulating Station Equipment		Financial Stmt.		25,542		-		25,542		-		-
7	Transmission - Panda												
8	Structures & Improvements		Financial Stmt.		-		-		-		-		-
9	Measuring & Regulating Station Equipment		Financial Stmt.		25,208		-		25,208		-		-
10	Distribution												
11	Mains		Financial Stmt.		33,302,827		8,648,128		12,660,520		11,994,178		-
12	Services		Financial Stmt.		35,487,205		9,541,079		15,284,083		10,662,043		-
13	Meter & House Regulator Installations Direct		Financial Stmt.		29,865,372		3,713,786		12,696,300		13,455,285		-
14	Meter & House Regulator Installations Allocable		Financial Stmt.		699,643		87,001		297,431		315,211		-
15	General DIMP Expenditures		Financial Stmt.		2,519		-		-		2,519		-
16	Compressor Station Equipment	AL:1:19	Total_Weather_All_NW		-		-		-		-		-
17	Measuring and Regulating Station Equipment		Dist_Meas_Reg_Plnt		1,532,095		911,702		370,526		249,868		-
18	Gas Light Services		Financial Stmt.		1,894		-		-		1,894		-
19	Meter & House Regulators	AL:2:14	Mtr_Hse_Reg_Plnt		800,351		127,191		296,513		376,647		-
20	Supervision and Engineering -												-
21	Appliance Service	AL:2:14	Mtr_Hse_Reg_Plnt		-		-		-		-		-
22	Other	AL:5:25	Dist_Maint_Exp		7,321,829		1,662,047		2,997,912		2,661,870		-
23	Other Equipment - Direct		Financial Stmt.		4,430		389		270		3,771		-
24	Other Equipment - Allocable	AL:5:17	Dist_X_Admin		358,079		81,872		146,010		130,197		-
25	Maintenance of General Plant	AL:2:26	Genl_Plnt		1,569,038		291,448		633,558		638,194		5,838
26	Total Maintenance	=2>25		$	114,413,313	$	25,568,839	$	46,799,501	$	41,961,616	$	83,356
27	Total Operation	EX:2:46			776,880,340		125,293,859		338,655,003		312,821,368		110,110
28	Total Operation and Maintenance Expenses	=26>27		$	891,293,653	$	150,862,698	$	385,454,504	$	354,782,984	$	193,466

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Description A	----Reference---- Sc-Pg-Ln B	Allocator C			WG D		DC E	MD F	VA G	FERC H
1 **Administrative & General Expenses**										
2 Administrative & General Salaries-Direct		Financial Stmt.	Sub Total		$ 4,032,355		$ 930,862	$ 1,848,492	$ 1,449,739	$ 3,262
			920000	Admin & General Salaries	3,941,386		839,893	1,848,492	1,449,739	3,262
			920431	Employee Incentive - ROE Gross	63,991	B	63,991	-	-	-
			920432	Empl Incentive-ROE Distr	26,978	B	26,978	-	-	-
			920199	Admin & Gen Sal Distr - Strtgy	-		-	-	-	-
3 Administrative & General Salaries-Allocable	AL:4:23	Comp_A&G	Sub Total		100,516,479		19,641,740	43,423,120	37,451,620	-
			920000	Admin & General Salaries	55,145,308					-
			920188	Admin & Gen Sal Distr-Finance	16,058,651					-
			920190	Admin & Gen Sal Distr	(339,411)			Sum of A = $17,350,204 (3)		-
			920401	Exec IncentiveProgram-Gross	-	B				
			920402	Exec Incentive Progr-Distr	-	B				
			920411	ExecPerforShare(99Progr)-Gross	41,348	A				
			920412	ExecPerfShares(99Prog)-Distr	(839)	A		Sum of B = $12,392,696 (3)		
			920421	Exec&MgtPerformanceUnit-Gross	17,490,643	A				
			920422	Exec&Mgt PerformanceUnit Distr	(180,948)	A				
			920431	Employee Incentive - ROE Gross	11,612,309	B				
			920441		3,373,243	B				
			920432	Empl Incentive-ROE Distr	(2,683,825)	B				
4 Office Supplies & Expenses-Direct		Financial Stmt.	Sub Total		3,942,404		1,103,503	1,731,733	1,104,963	2,204
5 Office Supplies & Expenses-Allocable	AL:4:23	Comp_A&G	Sub Total		33,046,634		6,457,582	14,276,146	12,312,906	-
6 Outside Services	AL:5:30		Sub Total	Outside Services Employed	37,435,574		7,053,669	15,176,292	15,205,613	-
7 Property Insurance	AL:3:13	Net_GPIS	Manual Data		-			-	-	-
8 Injuries & Damages	AL:4:11	Total_Labor	Sub Total		18,995,900		3,677,954	8,170,412	7,147,535	-
9 Pension Expense	AL:4:11	Total_Labor	Sub Total		(219,656)		(42,494)	(94,398)	(82,580)	(185)
10 DC Regulatory					-					
11 Pension Expense		Financial Stmt.	926104	Appl-Def Pen Cost-DC Ord 9146	-		-	-	-	-
12 Amortization of Rate Case Expenses		Financial Stmt.	928001	Rg Com Exp-Amrt DC Rte Cse Exp	475,776		475,776	-	-	-
13 Least Cost Planning Expenses		Financial Stmt.	930201	Amrtz LCP Exp Recov Curr Rate	-		-	-	-	-
14 Employee Health Benefits			Sub Total		24,779,774		4,793,783	10,649,176	9,315,976	20,840
14 Employee Health Benefits MD Write-Off		Financial Stmt.	926202_write-off		-		-	-	-	-
14 Employee Health Benefits less Write-Off	AL:4:11	Total_Labor	Sub Total		24,779,774		4,793,783	10,649,176	9,315,976	20,840
			X_926202_less_write-off		217,451					183
			926205	Educational Refunds	771					1
			926207	Emp Benefit-Thrift Saving Plan	10,900,486	C				9,167
			926208	Emp Benefits	310,259			Sum of C = $8,427,541 (3)		261
			926209	Employee Benefits Distributed	(5,106,949)					(4,295)
			926212	Grp Ins Prem App To Life Insur	(21,266)					(18)
			926215	Self-Funded Grp Dental Care	1,173,961	D				987
			926260	Basic Life Insur-CIGNA-Mgt	180,039			Sum of D = $19,856,287 (3)		151
			926263_T	Long Term Disability-UNUM-Mgt	680,756					573
			926264	Kaiser HMO - Mgt/Union	1,590,804	D				1,338
			926265	Emplr Non Taxbl HAS Plan Contr	160,242					135
			926274	Blue Cross/Blue Shield Pln	17,091,522	D				14,374
			926277	LTD-Union	74,645					63
			926309	Thrift Savings Distributed	(2,472,945)	C				(2,080)

8/
D * DC Labor Factor = $19,856,287 * 0.193618 = $3,844,540 (4)

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

	Description	------ Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
	A	B	C	D	E	F	G	H	I	J
1	**Customer Accounts**									
2	General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3	Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4	Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5	Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6	Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7	Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8	Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9	Billing and Accounting	EX:7:21		5,025,412	929,915	2,091,803	2,003,695			
10	Total Customer Accounts	= 2 > 9	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11	**Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618 3	0.430114	0.376267
								7 9		
12	**Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13	**Expenses allocated on**									
14	**Composite A&G Factor**									
15	Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16	Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17	Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18	Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19	Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20	Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21	Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22	Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23	Composite A&G Factor	= 15 > 22	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954 3	0.4320	0.3726
24	**Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25	**Operations & Maintenance**									
26	**Expenses - Adjusted**									
27	Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28	Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29	Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30	Subtotal	= 27+28-29	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31	Less: Uncollectible Accounts	EX:7:22		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32	Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33	Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34	Operations & Maintenance Expenses -									
25	Adjusted	= 30-(31>33)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36	**Operations Expense Excluding**									
37	**Purchased Gas & Uncollectibles**									
38	Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39	Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40	Less: Uncollectible Accounts	EX:7:22		15,334,992	6,420,597	3,901,686	5,012,709			
41	Operations Expense Excluding									
42	Purchased Gas & Uncollectibles	= 38-39-40	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43	Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
A	B	C	D	E	F	G	H
1 **Administrative & General Expenses**							
2 Administrative & General Salaries-Direct		Financial Stmt.	$ 4,032,355	$ 930,862	$ 1,648,492	$ 1,449,739	$ 3,262
3 Administrative & General Salaries-Allocable	AL:4:23	Comp_A&G	100,516,479	19,641,740	43,423,120	37,451,620	-
4 Office Supplies & Expenses-Direct		Financial Stmt.	3,942,404	1,103,503	1,731,733	1,104,963	2,204
5 Office Supplies & Expenses-Allocable	AL:4:23	Comp_A&G	33,046,634	6,457,582	14,276,146	12,312,906	-
6 Outside Services	AL:5:30		37,435,574	7,053,669	15,176,292	15,205,613	-
7 Property Insurance	AL:3:13	Net_GPIS	-	-	-	-	-
8 Injuries & Damages	AL:4:11	Total_Labor	18,995,900	3,677,954	8,170,412	7,147,535	-
			613,126				
			14,896,935 A				
			4,224,103				
			(738,264)				
			-				
9 Pension Expense	AL:4:11	Total_Labor	(219,656)	(42,494) 3	(94,398)	(82,580)	(185)
10 DC Regulatory							
11 Pension Expense		Financial Stmt.	-	-	-	-	-
12 Amortization of Rate Case Expenses		Financial Stmt.	475,776	475,776 4	-	-	-
13 Least Cost Planning Expenses		Financial Stmt.	-	-	-	-	-
14 Employee Health Benefits			24,779,774	4,793,783	10,649,176	9,315,976	20,840
15 OPEB	Labor factor	Financial Stmt.	(34,007,440)	(6,584,462) 3	(14,627,092)	(12,795,885)	-
16 Rate Case Expenses-Direct		Financial Stmt.	1,526,109	206,553	1,049,073	269,875.64	607
17 Rate Case Expenses-Allocable	AL:4:23	Comp_A&G	9,523	1,861	4,114	3,548	-
18 DC PSC Assessment Expense		Financial Stmt.	-	-	-	-	-
19 General Advertising Expenses - Direct		Financial Stmt.	1,269	-	984	285	-
20 General Advertising Expenses - Allocable	AL:4:23	Comp_A&G	644,209	125,884	278,298	240,027	-
21 Environmental Expense - Regulatory Amortization		Financial Stmt.	686,319	263,068 4	423,250	-	-
22 Environmental Reserve - Regulatory Adjustment		Financial Stmt.	1,738,655	-	-	1,738,655	-
23 Rents		Financial Stmt.	263,877	-	-	263,877	-
24 MD Demand Side Management Expenses	AL:4:23	Comp_A&G	1,041,022	203,424	449,721	387,876	-
25 VA Care Expenses		Financial Stmt.	4,294,347	-	-	4,294,347	-
26 MD EmPOWER MD Expenses		Financial Stmt.	13,710,995	-	13,710,995	-	-
27 Multi-Family Unit Contribution Amortization Expense		Financial Stmt.	199,129	17,451	140,914	40,764	-
28 Multi-Family Unit Contribution Amortization Expense - Allocable			-	-	-	-	-
29 Miscellaneous General Expenses-Direct		Financial Stmt.	367,847	348,831	(45,528)	64,398	145
30 Miscellaneous General Expenses-Allocable	AL:4:23	Comp_A&G	2,373,165	463,736	1,025,207	884,222	-
31 Total Administrative & General Expenses	=2>30		$ 215,854,266	$ 39,138,720	$ 97,390,911	$ 79,297,762	$ 26,873

8/
A * DC Labor Factor = $14,896,935 * 0.193618 = $2,884,319 4

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 10 - Employee Benefits Expense (Fringe) Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	O&M Factor	DC Factor	DC Amount _2/	
	A	B	C	D	E	F=C*D*E	
1	Professional Services	Workpaper 2	$ (22,490)	100.00%	19.36%	$ (4,354)	_1/
2	Physicals	Workpaper 2	(7,150)	100.00%	19.36%	(1,384)	_1/
3	Parking	Workpaper 3	(71,760)	86.17%	19.36%	(11,972)	
4	Car Allowance	Workpaper 4	(110,439)	100.00%	19.36%	(21,383)	_1/
5	**Adjustment to Fringe Benefits (Current Employees)**	**Ln. 1 > Ln. 4**	**$ (211,838)**			**$ (39,094)**	4

6 **Adjustment Description:** To remove executive fringe benefits expense.

_1/ O&M factor not applicable because this amount already excludes affiliate transactions.
_2/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line EX:5:14.

Washington Gas Light Company
District of Columbia Jurisidiction

Adjustment No. 20 - Commission-Mandated Audit Fees

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C	
1	Regulatory Asset Balance as of July 31, 2025 (FC 1115 Pipes 1)	Analysis	$ 218,773	
2	Regulatory Asset Balance as of July 31, 2025 (FC 1175 Pipes 2)	Analysis	$ 832,225	
3	Total Annual Amortization (Rate Year)	(Ln. 1 + Ln. 2)/3	$ 350,333	
4	Test Year Expense (System)	Analysis	$ 91,675	
5	Three_Part_Factor	AL:5:30	18.64%	
6	Per Book Expense (District of Columbia)	Ln. 4 * Ln. 5	$ 17,091	4
7	Adjustment	Ln. 3 - Ln. 6	$ 333,242	1/

8 **Adjustment Description:** To reflect the amortization of ProjectPipes audit fees at rate year amount.

1/ For Class Cost purposes, note that $333,242 of the adjustment relates to EX:5:6.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 22 - Trade Dues, Business Memberships, and Community Affairs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Allocator C	System Amount D	DC Factor E	Ratemaking Adjustment F = C * D * E
1	Direct Charges - District of Columbia	Analysis	100% DC	$ 17,683	100%	$ (17,683)
2	Allocated Charges - Support Payments	Analysis	Comp_A&G	$ 409,981	19.54%	$ (80,114)
3	Direct Charges - Other Jurisdictions					
4	Maryland		100% MD	$ 275,283	0%	$ -
5	Virginia		100% VA	$ 318,274	0%	$ -
6	Total Other Jurisdictions	Ln. 4 + Ln. 5		$ 593,557		$ -
7	Total Company Memberships & Trade Dues	Ln. 1 + Ln. 2 + Ln. 7	1/	$ 1,021,220		$ (97,796)
8	Trade Dues & Business Associations					$ (48,991)
9	American Gas Association Dues					$ (59,768)
10	Community Affairs					$ 10,962
11	Total					$ (97,796) 4

12 **Adjustment Description:** To exclude Trade Dues, Business Memberships, and Community Affairs payments, as directed in prior
13 Commission Orders.

1/ For class cost purposes the total adjustment relates to COSA line EX:5:29

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 23 - General Advertising Expense Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Allocator	Reference	DC Amount
	A	B	C	D
1	Eliminate Advertising Expense Direct	Financial Statement	EX:5:19	$ -
2	Eliminate Advertising Expense Allocable	Comp A&G	EX:5:20	(125,884)
3	Total Adjustment		Ln. 1 + Ln. 2	$ (125,884) 4

4 **Adjustment Description:** To eliminate direct and indirect general advertising expenses (account 930100)
5 incurred during the study period.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 25 - Legal Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Legal Expenses (DC - Per Book Amount)	Financial Statements	$ 338,684
2	DC Corrected Per Book Amount	Analysis	475,607
3	Proforma Adjustment Amount	Line 2 - Line 1	$ 136,923 1/

4 **Adjustment Description:** To correct Legal expenses on a jurisdictional basis for
5 twelve months ended March 31, 2024.

1/ For Class Cost purposes, note that -$65.07 of the adjustment relates to EX:5:5, and $136,988.08 of the adjustment relates to EX:5:6.

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 26 - Prior Period Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Account B	DC Total C
1	Prior Period Items		
2	Short Term Incentive Reclass	920432 (EX:5:2)	$ (26,978)
3	Adjustment Total		$ (26,978) ④
4	**Adjustment Description:** To adjust test year expense to remove prior period adjustments.		

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 27 - Merger Transition Cost to Achieve Amortization Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Total Company B	Allocation Factor C	District of Columbia D = B * C
1	**Transition Cost Amortization**			
2	Account 921003 - Merger Transition Amortization Expense	$ 308,014	16.98%	$ 52,311
3	**Elimination of Merger Transition Amortization Expense**			**$ (52,311)** 4

4 **Adjustment Description:** To eliminate merger-related cost to achieve amortizaton for the period for twelve months
5 ending March 2024.

Note: The merger amortizations ended in July 2023

_1/ For class cost purposes, the full amount of this adjustment relates to COSA line EX 5:5.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 28 - Credit/Debit Card Transaction Fees Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference		MD Amount
	A	B		C
1	Credit/Debit Card Transaction Fees (Per Book)	EX:7:16	$	478,381
2	ACH Payment Increase	Analysis	$	66,585
3	Net Credit/Debit Card Fees	Ln. 1 - Ln. 2	$	411,796
4	Elimination of Credit/Debit Card Transaction Fees		$	(411,796) 4

5 **Adjustment Description:** To eliminate credit/debit card fees for twelve months ended March 31, 2024.

Washington Gas Light Company
Customer Accounts
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
A	B	C	D	E	F	G	H
1 **Customer Accounts**							
2 General Supervision-Direct		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
3 General Supervision-Allocable	AL:4:10	Customer_Accts	-	-	-	-	-
4 Total General Supervision	=2+3		$ -	$ -	$ -	$ -	$ -
5 Meter Reading-Direct		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
6 Meter Reading-Allocable	AL:4:12	Avg_Meters	5,504,551	762,664	2,174,130	2,567,758	-
7 Total Meter Reading	=5+6		$ 5,504,551	$ 762,664	$ 2,174,130	$ 2,567,758	$ -
8 Dispatch Applications and Orders-Direct		Financial Stmt.	$ 2,171,311	$ 296,545	$ 1,132,179	$ 742,587	$ -
9 Dispatch Applications and Orders-Allocable	AL:4:12	Avg_Meters	13,855,708	1,919,729	5,472,583	6,463,397	-
10 Total Dispatch Applications and Orders	=8+9		$ 16,027,019	$ 2,216,274	$ 6,604,762	$ 7,205,984	$ -
11 Customer Collection Expenses							
12 Customer Credit and Appliance Service-Direct		Financial Stmt.	$ 8,268	$ -	$ (46,049)	$ 54,317	$ -
13 Customer Credit and Appliance Service-Allocable	AL:4:5	Avg_AR	8,373,169	2,191,914	3,899,276	2,281,979	-
14 Other-Direct		Financial Stmt.	-	-	-	-	-
15 Other-Allocable	AL:5:32	Avg_Meters	(1,669,693)	(231,338)	(659,478)	(778,877)	-
16 Credit and Debit Card Transactions	AL:5:32	Credit_Debit_Card	3,520,829	478,381	1,594,599	1,447,850	
17 Total Customer Collection Expenses	=12>16		$ 10,232,573	$ 2,438,956	$ 4,788,348	$ 3,005,269	$ -
18 Customer Billing and Accounting-Direct		Financial Stmt.	$ 108,799	$ 108,700	$ -	$ 99	$ -
19 Customer Billing and Acct-POR Collection Exp		Financial Stmt.	621,466	226,115	395,350	-	-
20 Customer Billing and Accounting-Allocable	AL:4:12	Avg_Meters	4,295,147	595,099	1,696,452	2,003,596	-
21 Total Customer Billing and Accounting	=18>20		$ 5,025,412	$ 929,915	$ 2,091,803	$ 2,003,695	$ -
22 Total Uncollectible Accounts			$ 15,334,992	$ 6,420,597	$ 3,901,686	$ 5,012,709	$ -
			-	-	-	-	-
			-	-	-	-	-
			-	-	-	-	-
			10,027	(11,815)	(49,416)	71,257	-
			154,072	64,873	38,243	50,955	-
			-				
			14,787,223	6,226,265 4	3,670,461	4,890,497	-
			383,671	141,274	242,397	-	-
		Total_Weather_All_NW	-	-	-	-	-
23 Total Customer Accounts	sum (4,7,10,17,21,22)		$ 52,124,547	$ 12,768,405	$ 19,560,728	$ 19,795,414	$ -

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 2D - GAC Revenues and Uncollectible Expense Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Gas Administration Charge Revenues		
2	Residential	Analysis	$ (1,074,697)
3	Commercial and Industrial Other Than Group Metered Apartments	Analysis	(507,259)
4	Group Metered Apartments	Analysis	(191,045)
5	Gas Administration Charge Revenues Elimination Amount	1/	(1,773,001)
6	Less: Gas Procurement Cost		
7	Residential	Analysis	47,400
8	Commercial and Industrial Other Than Group Metered Apartments	Analysis	22,294
9	Group Metered Apartments	Analysis	8,477
10	Gas Procurement Cost Total	Adj No. 3D	78,171
11	GAC Uncollectible Expense Elimination Amount 2/	Line 5 + Line 9	$ (1,694,830) 4

12 **Adjustment Description:** To remove Gas Administration Charge uncollectible amounts.

1/ For Class Cost purposes, note that this adjustment relates to RV:1:14.
2/ For Class Cost purposes, note that this adjustment relates to EX:7:21.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 7D - Purchase of Receivables (POR) Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Book Amount C	Ratemaking Adjustment D
1	**Capitalized Software**			
2	Capitalized Software (POR)	303006 (RB:2:2)	$ 762,920	$ (762,920)
3	Computer Equipment (POR)	373106 (RB:2:35)	7,234	(7,234)
4	Total Plant in Service	Ln. 2 + Ln. 3	$ 770,154	$ (770,154)
5	**Reserve for Depreciation**			
6	DC POR Software	Property Analysis	$ 352,999	$ (352,999)
7	DC POR Equipment	Property Analysis	3,331	(3,331)
8	Total Depreciation Reserve	Ln. 6 + Ln. 7	$ 356,329	$ (356,329)
9	**Other Operating Revenues**			
10	Late Payment Charges (POR)	487107 (RV:1:16)	$ 360,143	$ (360,143)
11	Other Gas Revenues	495306 (RV:1:32)	736,920	(736,920)
12	Total Revenues	Ln. 10 + Ln. 11	$ 1,097,063	$ (1,097,063)
13	**Depreciation and Amortization**			
14	Amortization of Capitalized Software (POR)	404311 (SM:1:7)	$ 97,980	$ (97,980)
15	**Customer Accounts**			
16	Collection Expense (POR)	903307 (EX:7:19)	$ 226,115	$ (226,115)
17	Uncollectible Accounts (POR)	904107 (EX:7:22)	141,274 4	(141,274)
18	Total Customer Accounts	Ln. 16 + Ln. 17	$ 367,389	$ (367,389)
19	**Interest Expense**			
20	POR CWC Costs	431135 (EX:9:12)	$ 58,019	$ (58,019) a/

21 a/ Adjustment is reflected in the Interest on Debt Adjustment #8D.

22 <u>**Adjustment Description:**</u> To eliminate purchase of receivables costs incurred during the study period.
Note:

Washington Gas Light Company
Operation and Maintenance Expenses - Labor
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Maintenance Expenses**							
2	Storage	AL:1:19	Total_Weather_All_NW	$ 182,296	$ 30,037	$ 77,458	$ 74,801	$ -
								0
3	Transmission	AL:2:8	Transmission_Plnt	1,413,305	208,466	547,913	620,330	36,595
4	Transmission - Chalk Point							
5	Structures & Improvements		Financial Stmt.	27,724	-	27,724	-	-
6	Measuring & Regulating Station Equipment		Financial Stmt.	16,430		16,430	-	-
7	Transmission - Panda							
8	Structures & Improvements							
9	Measuring & Regulating Station Equipment			-	-	-	-	-
10	Distribution							0
11	Mains		Financial Stmt.	6,090,916	996,933	2,807,037	2,286,945	-
12	Services		Financial Stmt.	12,162,250	3,357,534	5,600,047	3,204,669	-
13	Meter & House Regulator Installations Direct		Financial Stmt.	13,823,239	1,879,116	5,470,734	6,473,388	-
14	Meter & House Regulator Installations Allocable		Financial Stmt.	427,767	58,150	169,295	200,322	-
15	General DIMP Expenditures		Financial Stmt.					
16	Compressor Station Equipment	AL:4:12	Avg_Meters	-	-	-	-	-
17	Measuring and Regulating Station Equipment	AL:1:19	Total_Weather_All_NW	589,570	45,835	488,989	54,746	-
18	Gas Light Services		Financial Stmt.	1,115	-	-	1,115	-
19	Meter & House Regulators		Financial Stmt.	313,328	49,794	116,081	147,453	-
20	Supervision and Engineering -							0
21	Appliance Service	AL:2:14	Mtr_Hse_Reg_Plnt	-	-	-	-	-
22	Other	AL:5:25	Dist_Maint_Exp	5,053,459	1,147,129	2,069,131	1,837,199	-
23	Other Equipment - Direct		Financial Stmt.	228	228	-	-	-
24	Other Equipment - Allocable	AL:5:17	Dist_X_Admin	54,879	12,548	22,377	19,954	-
25	Maintenance of General Plant	AL:2:26	Genl_Plnt	216,752	40,262	87,522	88,162	806
26	Total Maintenance - Labor	= 2 > 25		$ 40,373,257	$ 7,826,032	$ 17,500,740	$ 15,009,083	$ 37,402
27	Total Operation - Labor	WEX:5:46		73,084,468	14,120,535	31,252,588	27,640,678	70,667
28	Total Ops and Maintenance Exp.-Direct Labor	= 26 + 27		$ 113,457,726	$ 21,946,567	$ 48,753,328	$ 42,649,762	$ 108,069
29	Total Ops and Maintenance Exp.-Indirect Labor	AL:4:11	Total_Labor	18,750,406	3,626,964	8,057,139	7,048,443	17,860
30	Total Ops and Maintenance Expense - Labor	= 28 + 29		132,208,131	25,573,530 3	56,810,467	49,698,205	125,929

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 13 - Involuntary Separation Program Labor O&M Expense Reduction

Twelve Months Ended March 31, 2024

Line	Description	Reference		Amount
1	Reduction in salaries	Workpaper 1	$	(7,233,986)
2	Reduction in short-term incentives	Workpaper 1		(986,995)
3	Reduction in medical plans	Workpaper 2		(730,291)
4	Reduction in 401(k)	Workpaper 2		(556,223)
5	Reduction in payroll taxes	Workpaper 2		(697,386)
6	Reduction in life insurance	Workpaper 2		(12,492)
7	Reduction in rate year labor expenses (System)	Sum Lns. 1 to 6	$	(10,217,373)
8	DC Labor Factor	AL 4:11		19.36%
9	**Reduction in rate year labor expense (DC)**	**Ln. 7 * Ln. 8**	**$**	**(1,978,270)** 3

10 **Adjustment Description:** To reflect the reduction in salaries and other related expenses
11 related to the Involuntary Separation Program in April 2024.

Adjustment No. 22

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 22 - Trade Dues, Business Memberships, and Community Affairs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Allocator C	System Amount D	DC Factor E	Ratemaking Adjustment F = C * D * E
1	Direct Charges - District of Columbia	Analysis	100% DC	$ 2/ 17,683	100%	$ (17,683)
2	Allocated Charges - Support Payments	Analysis	Comp_A&G	$ 409,981	3/ 19.54%	$ (80,114)
3	Direct Charges - Other Jurisdictions					
4	Maryland		100% MD	$ 275,283	0%	$ -
5	Virginia		100% VA	$ 318,274	0%	$ -
6	Total Other Jurisdictions	Ln. 4 + Ln. 5		$ 593,557		$ -
7	Total Company Memberships & Trade Dues	Ln. 1 + Ln. 2 + Ln. 7	1/	$ 1,021,220		$ (97,796)
8	Trade Dues & Business Associations					$ 2/ (48,991)
9	American Gas Association Dues					$ (59,768)
10	Community Affairs					$ 10,962
11	Total					$ (97,796)

12 **<u>Adjustment Description:</u>** To exclude Trade Dues, Business Memberships, and Community Affairs payments, as directed in prior
13 Commission Orders.

1/ For class cost purposes the total adjustment relates to COSA line EX:5:29

GL Unit	(All)
Account	930200

Sum of Sum Amount		Column Labels					
Row Labels	Process	01	02	03	10	Grand Total	
AMERICAN GAS ASSOCIATION	75102				305,860.50	305,860.50	AGA Dues
DAVID E. WARR	75203	1,200.00				1,200.00	Community Affairs
DEAN HUNTER	75203	1,200.00				1,200.00	Community Affairs
KENYATTAH A. ROBINSON	75203	1,500.00				1,500.00	Community Affairs
KIMBERLY GREENFIELD ALFONSO	75203	1,200.00				1,200.00	Community Affairs
MARIA GOMEZ	75203	600.00				600.00	Community Affairs
MARY EVA CANDON	75203	1,200.00				1,200.00	Community Affairs
MONTGOMERY COUNTY CHAMBER OF COMMERCE	75102		25,000.00			25,000.00	Trade Dues
OPERATIONS TECHNOLOGY DEVELOPMENT	75102		220,443.00	263,313.00		483,756.00	Trade Dues
PIERPONT M. MOBLEY	75203	1,200.00				1,200.00	Community Affairs
RONALD LEONARD MOTEN	75203	900.00				900.00	Community Affairs
SHARON SHANKLIN BROWNE	75203	1,500.00				1,500.00	Community Affairs
US BANK	75102	23,505.00	25,305.00	24,960.79	26,966.37	100,737.16	Trade Dues
	75203				753.99	753.99	Trade Dues
VIRGINIA CHAMBER OF COMMERCE	75102			5,000.00		5,000.00	Trade Dues
ASTON CARTER, INC.	75203	1,572.00				1,572.00	Community Affairs
C.B. CONSULTING	75203	12,000.00				12,000.00	Community Affairs
GREATER WASHINGTON DC BLACK CHAMBER	75102	3,500.00				3,500.00	Trade Dues
ICE LAB, LLC	75203	(39,200.00)				(39,200.00)	Community Affairs
JUSTIN HARRISON	75203	1,200.00				1,200.00	Community Affairs
MARYLAND BLACK CAUCUS FOUNDATION INC.	75203	750.00				750.00	Community Affairs
MICHAEL L. CHAMBERS II	75203	1,200.00				1,200.00	Community Affairs
NORTHERN VIRGINIA CHAMBER OF COMMERCE	75102			25,000.00		25,000.00	Trade Dues
PRINCE GEORGE'S CHAMBER OF COMMERCE	75102	1,640.00	3,000.00			4,640.00	Trade Dues
SOUTHERN GAS ASSOCIATION	75102				46,400.00	46,400.00	Trade Dues
THE GREATER BETHESDA CHAMBER OF COMMERCE	75102		1,535.00			1,535.00	Trade Dues
WASHINGTON AREA FUEL FUND	75203	1,015.81				1,015.81	Community Affairs
GREATER WASHINGTON BOARD OF TRADE	75102				30,000.00	30,000.00	Trade Dues
Grand Total		**17,682.81** 1	**275,283.00** 1	**318,273.79** 1	**409,980.86** 1	**1,021,220.46**	

Comp A&G Factor 3/ 19.54%

	DC Direct	DC Allocated Portion	DC Total
Trade Dues & Business Associations	$28,645.00	$20,345.97	$48,990.97 1
American Gas Association Dues	$0.00	$59,767.64	$59,767.64
Community Affairs	-$10,962.19	$0.00	-$10,962.19

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.368779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954 1 2	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses -									
25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding									
42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Adjustment No. 23

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 23 - General Advertising Expense Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Allocator	Reference	DC Amount
	A	B	C	D
1	Eliminate Advertising Expense Direct	Financial Statement	EX:5:19	$ 2/ -
2	Eliminate Advertising Expense Allocable	Comp A&G	EX:5:20	2/(125,884)
3	Total Adjustment		Ln. 1 + Ln. 2	$ (125,884)

4 **Adjustment Description:** To eliminate test year direct and indirect general advertising expenses (account 930100).

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Allocator	WG	DC	MD	VA	FERC
	A	C	D	E	F	G	H
1	**Administrative & General Expenses**						
2	Administrative & General Salaries-Direct	Financial Stmt.	$ 4,032,355	$ 930,862	$ 1,648,492	$ 1,449,739	$ 3,262
3	Administrative & General Salaries-Allocable	Comp_A&G	100,516,479	19,641,740	43,423,120	37,451,620	-
4	Office Supplies & Expenses-Direct	Financial Stmt.	3,942,404	1,103,503	1,731,733	1,104,963	2,204
5	Office Supplies & Expenses-Allocable	Comp_A&G	33,046,634	6,457,582	14,276,146	12,312,906	-
6	Outside Services		37,435,574	7,053,669	15,176,292	15,205,613	-
7	Property Insurance	Net_GPIS	-	-	-	-	-
8	Injuries & Damages	Total_Labor	18,995,900	3,677,954	8,170,412	7,147,535	-
9	Pension Expense	Total_Labor	(219,656)	(42,494)	(94,398)	(82,580)	(185)
10	DC Regulatory		-				
11	Pension Expense	Financial Stmt.	-	-	-	-	-
12	Amortization of Rate Case Expenses	Financial Stmt.	475,776	475,776	-	-	-
13	Least Cost Planning Expenses	Financial Stmt.	-	-	-	-	-
14	Employee Health Benefits		24,779,774	4,793,783	10,649,176	9,315,976	20,840
15	OPEB	Financial Stmt.	(34,007,440)	(6,584,462)	(14,627,092)	(12,795,885)	-
16	Rate Case Expenses-Direct	Financial Stmt.	1,526,109	206,553	1,049,073	269,875.64	607
17	Rate Case Expenses-Allocable	Comp_A&G	9,523	1,861	4,114	3,548	-
18	DC PSC Assessment Expense	Financial Stmt.	-	-	-	-	-
19	General Advertising Expenses - Direct	Financial Stmt.	1,269	-	984	285	-
20	General Advertising Expenses - Allocable	Comp_A&G	644,209	125,884	278,298	240,027	-
21	Environmental Expense - Regulatory Amortization	Financial Stmt.	686,319	263,068	423,250	-	-
22	Environmental Reserve - Regulatory Adjustment	Financial Stmt.	1,738,655	-	-	1,738,655	-
23	Rents	Financial Stmt.	263,877	-	-	263,877	-
24	MD Demand Side Management Expenses	Comp_A&G	1,041,022	203,424	449,721	387,876	-
25	VA Care Expenses	Financial Stmt.	4,294,347	-	-	4,294,347	-
26	MD EmPOWER MD Expenses	Financial Stmt.	13,710,995	-	13,710,995	-	-
27	Multi-Family Unit Contribution Amortization Expense	Financial Stmt.	199,129	17,451	140,914	40,764	-
28	Multi-Family Unit Contribution Amortization Expense - Allocable		-	-	-	-	-
29	Miscellaneous General Expenses-Direct	Financial Stmt.	367,847	348,831	(45,528)	64,398	145
30	Miscellaneous General Expenses-Allocable	Comp_A&G	2,373,165	463,736	1,025,207	884,222	-
31	Total Administrative & General Expenses		$ 215,854,266	$ 39,138,720	$ 97,390,911	$ 79,297,762	$ 26,873

Adjustment No. 24

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 24 - Elimination of CIAC & Non-Includable ADIT

Twelve Months Ended March 31, 2024

Line No.	Description	COSA Reference	Reference	Test Year	Adjustment
	A	B	C	D	E
1	ADIT Reclassification and Elimination	RB:12:2	Workpaper 1	$ 2/ -	$2/ (225,491)
2	CIAC Grossup Balance	RB:11:4	Workpaper 2	$8/ (994,920)	$ 994,920
3	Environmental ADIT	RB:12:1	Per Book	$ 7/ (118,865)	$ 118,865
4	Merger Commitment Costs ADIT	RB:12:12	Per Book	$ 7/ 186,630	$ (186,630)

5 **Adjustment Description:** To eliminate CIAC and non-includable ADIT.

Washington Gas Light Company
District of Columbia Jurisdiction

Workpaper 1 - Regulatory Asset/Liability ADIT Balance Adjustment

Twelve Months Ended March 31, 2024

Line	Description	Reference	13 Mo. Average	Tax Rate	Calculated ADIT Balance 13 Mo. Average	Allocator	Factor	Expected Per Book DC	Ratemaking DC
1	ORA – Peaking Facility	182201	$ 6/ 876,865	3/ 26.01%	$ (228,029)	1/	66.36%	$ (151,322)	$ -
2	FC 1115 Audit Fees	182308	867,105	26.01%	(225,491)	DC Only	100.00%	(225,491)	(225,491)
3	Asset – EmPOWER MD Program	182341	25,497,790	26.01%	(6,630,717)	MD Only	0.00%	-	-
4	MD STRIDE Audit Costs	182343	59,284	26.01%	(15,417)	MD Only	0.00%	-	-
5	ORA-VA DIMP Deferral	182349	(0)	26.01%	0	VA Only	0.00%	-	-
6	IT - SAP Implementation (MD)	182387	75,531	26.01%	(19,642)	MD Only	0.00%	-	-
7	Other Reg Asset - DC Case #934 _2/	182398/229222	4,683,724	26.01%	(1,218,006)	DC Only	100.00%	(1,218,006)	-
8	OthRegLiability - General	229299	(0)	26.01%	0	DC Only	100.00%	0	0
9	ODC -DC Tracker -RegCommExpROE	253020	(1,583,824)	26.01%	411,875	DC Only	100.00%	411,875	-
10	Total		$ 30,476,476		$ (7,925,428)			$ (1,182,945)	$ (225,491)
11	Per Book Balance	RB 12:2							7/ - 1
12	**Adjustment**	**Line 10 - Line 11**							**$ (225,491)** 1

1/ Peak Plant Mar 2024 13 month average (per amort sch)

			Ratio
$	4/ 735,090	DC	66.36%
$	5/ 372,626	MD	33.64%
$	-	VA	0.00%
$	1,107,716		

2/ Regulary liability account 229222 (rate case expense tracker) debit balance is reclassed to regulatory asset account 182398 in quarter-end months. The sum of these accounts each month shows the net balance sheet position.

Washington Gas Light Company
2023 Deferred Tax Rates

	Co.01 Washington Gas Light Company			
State Structure	**Jurisdiction**	**State Appt**	**2022**	**State ETR**
Separate	LA	0.0000%	7.5000%	0.0000%
Separate	MD	32.7389%	8.2500%	2.7010%
Separate	NC	0.0000%	0.0000%	0.0000%
Separate	PA	0.0000%	8.4900%	0.0000%
Consolidated/Comb.	DC	9.3295%	8.2500%	0.7697%
Nexus Combined	VA	42.3522%	6.0000%	2.5411%
Consolidated/Comb.	WV	4.9808%	6.5000%	0.3238%
	Composite Rate			**6.3355%**
				26.0051% 2

Regulatory Asset
Present Value of Future Revenues Expected from Plant

	Yearly	Monthly	Total Expected	
Future Revenues Expected	$100,274	$8,356.17		$1,504,110

($8,356)	Monthly amortization
$1,165,949	Present Value Calculation
($338,161)	Expected Loss

Incremental Borrowing Rate (15		Monthly
DC	3.537%	0.29%

Monthly Journal Starting April - 2017		One time Entry in March-2017
411700	$8,356.17	$338,161
419092	(3,436.29)	
182201	($4,919.87)	($338,161)

# of Months	Mo.	PVC of Amortization	Monthly Amortization	Carrying Charge Loss	Net
			1,504,110.00	($338,161)	
68	11/30/2022	802,110.96	($8,356.17)	2,363.99	796,118.78
69	12/31/2022	796,118.78	($8,356.17)	2,346.33	790,108.94
70	1/31/2023	790,108.94	($8,356.17)	2,328.62	784,081.39
71	2/28/2023	784,081.39	($8,356.17)	2,310.85	778,036.07
72	3/31/2023	778,036.07	($8,356.17)	2,293.03	771,972.94
73	4/30/2023	771,972.94	($8,356.17)	2,275.17	765,891.94
74	5/31/2023	765,891.94	($8,356.17)	2,257.24	759,793.02
75	6/30/2023	759,793.02	($8,356.17)	2,239.27	753,676.12
76	7/31/2023	753,676.12	($8,356.17)	2,221.24	747,541.19
77	8/31/2023	747,541.19	($8,356.17)	2,203.16	741,388.19
78	9/30/2023	741,388.19	($8,356.17)	2,185.03	735,217.04
79	10/31/2023	735,217.04	($8,356.17)	2,166.84	729,027.72
80	11/30/2023	729,027.72	($8,356.17)	2,148.60	722,820.15
81	12/31/2023	722,820.15	($8,356.17)	2,130.30	716,594.28
82	1/31/2024	716,594.28	($8,356.17)	2,111.95	710,350.07
83	2/29/2024	710,350.07	($8,356.17)	2,093.55	704,087.45
84	3/31/2024	704,087.45	($8,356.17)	2,075.09	697,806.37
85	4/30/2024	697,806.37	($8,356.17)	2,056.58	691,506.79

Average of A
$735,089.73 2

Chillum LNG Facility
9/30/2013
Loss on Abandonment

	Assets	Notes
Total Cost	8,462,017	**Tab 2.**
Land Cost (Charge to Cost of Removal)	-	
Additional Disallowance	-	
Total Amount for Recovery	8,462,017	**Tab 2.**

Jurisdictional % breakout of Recovery			Tickmarks
MD	3,514,843	42%	**Tab 3.**
VA	3,469,410	41%	**Tab 3.**
DC	1,477,756	17%	**Tab 3.**
	8,462,009	100%	

Incremental Borrowing Rate		Monthly	
MD	3.462%	0.29%	**Tab 4.**

Important Dates

1. **October 10th Assessment to be received from Examiner**
2. **October 24th to determine if we appeal any judgment placed by MD PSC**
3. **November 22nd**

29,290.36	Monthly amortization
($2,967,375.41)	Present Value Calculation
547,467.38	Expected Loss

Maryland - Assumes 10 year amortization

	Mo.	(1) Beginning of Month Gross Investment	(2) Amortization Recovery of MD	(5) Carrying Charges Loss	(4) Net Investment
			3,514,843	547,467.38	
11/30/2014	1	$2,967,375.41	(29,290.36)	8,560.88	$2,946,645.93
12/31/2014	2	$2,946,645.93	(29,290.36)	8,501.07	$2,925,856.65
1/31/2015	3	$2,925,856.65	(29,290.36)	8,441.10	$2,905,007.39
2/28/2015	4	$2,905,007.39	(29,290.36)	8,380.95	$2,884,097.98
3/31/2015	5	$2,884,097.98	(29,290.36)	8,320.62	$2,863,128.24
4/30/2015	6	$2,863,128.24	(29,290.36)	8,260.12	$2,842,098.01
5/31/2015	7	$2,842,098.01	(29,290.36)	8,199.45	$2,821,007.11
6/30/2015	8	$2,821,007.11	(29,290.36)	8,138.61	$2,799,855.36
7/31/2015	9	$2,799,855.36	(29,290.36)	8,077.58	$2,778,642.58
8/31/2015	10	$2,778,642.58	(29,290.36)	8,016.38	$2,757,368.61
9/30/2015	11	$2,757,368.61	(29,290.36)	7,955.01	$2,736,033.26
10/31/2015	12	$2,736,033.26	(29,290.36)	7,893.46	$2,714,636.36
12/31/2022	98	$650,905.83	(29,290.36)	1,877.86	$623,493.33
1/31/2023	99	$623,493.33	(29,290.36)	1,798.78	$596,001.75
2/28/2023	100	$596,001.75	(29,290.36)	1,719.47	$568,430.86
3/31/2023	101	$568,430.86	(29,290.36)	1,639.92	$540,780.43
4/30/2023	102	$540,780.43	(29,290.36)	1,560.15	$513,050.22
5/31/2023	103	$513,050.22	(29,290.36)	1,480.15	$485,240.02
6/30/2023	104	$485,240.02	(29,290.36)	1,399.92	$457,349.58
7/31/2023	105	$457,349.58	(29,290.36)	1,319.45	$429,378.68
8/31/2023	106	$429,378.68	(29,290.36)	1,238.76	$401,327.08
9/30/2023	107	$401,327.08	(29,290.36)	1,157.83	$373,194.55
10/31/2023	108	$373,194.55	(29,290.36)	1,076.67	$344,980.86
11/30/2023	109	$344,980.86	(29,290.36)	995.27	$316,685.77
12/31/2023	110	$316,685.77	(29,290.36)	913.64	$288,309.05
1/31/2024	111	$288,309.05	(29,290.36)	831.77	$259,850.47
2/29/2024	112	$259,850.47	(29,290.36)	749.67	$231,309.78
3/31/2024	113	$231,309.78	(29,290.36)	667.33	$202,686.75
4/30/2024	114	$202,686.75	(29,290.36)	584.75	$173,981.15
5/31/2024	115	$173,981.15	(29,290.36)	501.94	$145,192.73
6/30/2024	116	$145,192.73	(29,290.36)	418.88	$116,321.25
7/31/2024	117	$116,321.25	(29,290.36)	335.59	$87,366.48
8/31/2024	118	$87,366.48	(29,290.36)	252.05	$58,328.18
9/30/2024	119	$58,328.18	(29,290.36)	168.28	$29,206.10
10/31/2024	120	$29,206.10	(29,290.36)	84.26	$0.00
			(3,514,842.79)	547,467.38	

Average of B
$372,626.40 2

G_L_REG_BALANCES_UTILITY

Unit	Account	Descr	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul-2023	Aug-2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024	Feb 2024	Mar 2024	13 Mo. Avg
01	182201	ORA – Peaking Facility	1,081,901	1,048,090	1,014,181	980,174	946,069	911,864	877,561	843,158	808,655	774,053	739,351	704,547	669,644	876,865
01	182308	FC 1115 Audit Fees	498,663	492,398	486,133	479,868	473,603	783,338	778,146	1,087,881	1,160,616	1,275,576	1,263,812	1,252,049	1,240,285	867,105
01	182309	Transition Costs to Achieve	308,014	231,011	154,007	77,004	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	59,233
01	182341	Asset – EmPOWER MD Program	21,368,134	21,483,051	21,993,560	23,856,846	24,915,964	25,722,784	26,737,858	27,750,241	27,562,733	29,925,463	28,144,443	26,676,907	25,333,289	25,497,790
01	182343	MD STRIDE Audit Costs	84,691	80,456	76,222	71,987	67,753	63,518	59,284	55,049	50,815	46,580	42,345	38,111	33,876	59,284
01	182349	ORA-VA DIMP Deferral	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
01	182387	IT - SAP Implementation (MD)	196,382	174,562	152,742	130,921	109,101	87,281	65,461	43,640	21,820	(0)	(0)	(0)	(0)	75,531
01	182399	OthRegAssets - General	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
01	229299	OthRegLiability - General	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
01	253020	ODC -DC Tracker -RegCommExpROE	(1,418,102)	(1,442,874)	(1,467,665)	(1,493,322)	(1,520,198)	(1,547,522)	(1,578,038)	(1,608,493)	(1,639,719)	(1,671,066)	(1,702,477)	(1,734,031)	(1,766,208)	(1,583,824)
01	182398	Other Reg Asset - DC Case #934	3,857,808	3,843,092	3,829,078	4,256,105	4,239,135	4,313,593	4,878,326	4,944,973	4,941,541	5,085,713	5,061,478	5,069,835	5,074,513	4,568,861
01	229222	OthRegLiab-DC Case #934-PhsIII	0	52,633	207,052	0	247,654	594,566	0	72,404	97,744	0	58,508	162,669	0	114,864
	NET	Net Reg Asset/Liability - DC Case #934	3,857,808	3,895,725	4,036,130	4,256,105	4,486,789	4,908,159	4,878,326	5,017,377	5,039,285	5,085,713	5,119,986	5,232,504	5,074,513	4,683,724

2

Washington Gas Light Company
Accumulated Deferred Income Taxes - Non Plant Items
System
Twelve Months Ended March 2024 - AVG
Average Rate Base

	Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
	Non Plant Items							
1	Environmental		Total_Weather_All_NW	$ (721,399)	$ (118,865) 1	$ (306,526)	$ (296,008)	$ -
2	Regulatory Assets & Liabilities - Rate cases		Financial Statement	(7,973,446)	- 2	(7,973,446)	-	-
3	Employee Benefits		Total_Labor	(51,724,255)	(10,014,762)	(22,247,351)	(19,462,142)	-
4	Amortization Gain on Sale of Property		Net_Rate_Base	42,691	8,146	15,902	18,642	-
5	Uncollectible Accounts		Uncoll. Accounts	5,410,038	2,265,125	1,376,477	1,768,436	-
6	ADIT - Debt / Interest		Net_Rate_Base	(1,277,582)	(243,784)	(475,900)	(557,897)	-
7	General Taxes		Financial Statement	1,401,810	1,401,810	-	-	-
8	Lawsuits		Total_Labor	139,206	26,953	59,874	52,379	-
9	Customer Advances		ADJ_CWIP	162,864	60,464	102,401	-	-
10	Gas Costs		Gas_Cost_Rec	(31,708)	(4,319)	(13,938)	(13,452)	-
11	Misc. Derivative Reserves		Net_Rate_Base	574,090	109,546	213,849	250,695	-
12	Merger Commitment Costs		Total_Labor	963,908	186,630 1	414,591	362,687	-
13	BPO		Comp_A&G	-	-	-	-	-
14	Deferred Rent		Non_Genl_Plnt	1,698,724	315,194	626,851	756,679	-
15	Misc. Items		Total_Labor	2,418,586	468,283	1,040,269	910,035	-
16	Sec. 174 R&D Expense Amort.		Net_Rate_Base	2,905,701	554,457	1,082,376	1,268,867	
17	Non-Plant ADIT Regulatory Asset		Macrs APB 11	11,501,250	1,922,456	4,593,472	4,985,322	-
18	Total Non-Plant ADIT	Sum of 1 > 14		$ (34,509,521)	$ (3,062,666)	$ (21,491,098)	$ (9,955,757)	$ -

Exhibit WG (D)-5
Adjustment No. 24
Page 7 of 11

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment 24 Workpaper 2 - CIAC Grossup Balance Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Amount
A	B	C	D
1	CIAC Balance (Allocable)	Workpaper 2.1	$ 9/ (5,833)
2	DC Allocator	APB 11 MACRS	11/ 16.72%
3	DC Allocated Portion	Ln. 1 * Ln. 2	$ (975)
4	CIAC Balance (DC Direct)	Workpaper 2.1	9/ (993,945)
5	Total DC CIAC Balance (Test Year)	Ln. 3 + Ln. 4	$ (994,920) 1

Washington Gas Light Company
All Jurisdictions

Adjustment 24 Workpaper 2.1 - CIAC Grossup (ADIT) Balance

Twelve Months Ended March 31, 2024

			DC		COMMON	
Line No.	Period	Reference	Monthly Activity	Cumulative Balance	Monthly Activity	Cumulative Balance
A	B	C	D	E	F	G
1	Dec-2022	Analysis		(1,008,883)		(5,927)
2	Jan-2023	Analysis	1,660	(1,007,223)	10	(5,916)
3	Feb-2023	Analysis	1,660	(1,005,563)	10	(5,906)
4	Mar-2023	Analysis	1,660	(1,003,903)	10	(5,895)
5	Apr-2023	Analysis	10/ 1,660	(1,002,244)	10/ 10	(5,885)
6	May-2023	Analysis	1,660	(1,000,584)	10	(5,875)
7	Jun-2023	Analysis	1,660	(998,924)	10	(5,864)
8	Jul-2023	Analysis	1,660	(997,264)	10	(5,854)
9	Aug-2023	Analysis	1,660	(995,605)	10	(5,843)
10	Sep-2023	Analysis	1,660	(993,945)	10	(5,833)
11	Oct-2023	Analysis	1,660	(992,285)	10	(5,822)
12	Nov-2023	Analysis	1,660	(990,626)	10	(5,812)
13	Dec-2023	Analysis	1,660	(988,966)	10	(5,802)
14	Jan-2024	Analysis	1,660	(987,306)	10	(5,791)
15	Feb-2024	Analysis	1,660	(985,646)	10	(5,781)
16	Mar-2024	Analysis	1,660	(983,987)	10	(5,770)
17	13 Month Average	Ave (Ln. 4 to Ln.16)		$ (993,945) 8		$ (5,833) 8

Common	Jan 2023 Balance	Dec 2023 Balance	2023 Annual Activity	2023 Monthly Activity	
CM	(5,926.59)	(5,801.66)	124.93	10.41	9
DC	(1,008,882.71)	(988,965.76)	19,916.95	1,659.75	9
MD	(1,637,853.08)	(1,603,560.85)	34,292.23	2,857.69	
VA	(3,802,304.67)	(3,716,291.26)	86,013.41	7,167.78	

Income Statement Related Deferred Tax Analysis
Tax Year 2023
Federal Damped for the State Impact and State(s) @ The Statutory Rate

Pulls Only - Do not change

Federal	PowerTax Federal APB11	Rate True Up	Net
CMWG	92,349,123	668,554	93,017,678
DCWG	154,622,878	609,507	155,232,386
MDWG	375,856,696	1,398,576	377,255,272
VAWG	403,686,917	2,034,430	405,721,347
WG Fed Tot	1,026,515,614	4,711,068	1,031,226,682
WG State Totals			234 807 214
WG Grand T	1,026,515,614	4,711,068	1,266,033,897
HAMP Fed		-	-
HAMP State			
HAMP Total	-	-	-

PowerTax States	
VA	**VA APB11**
CMWG	8,796,211
DCWG	15,246,048
MDWG	32,747,966
VAWG	38,678,944
Virginia To	95,469,170
MD	**MD APB11**
CMWG	7,897,335
DCWG	14,042,376
MDWG	30,730,389
VAWG	34,431,908
Maryland T	87,102,007
DC	**DC APB11**
CMWG	3,470,528
DCWG	6,504,836
MDWG	17,251,616
VAWG	15,361,550
D.C. Total	42,588,531
WV	**WV APB11**
CMWG	871,836
DCWG	1,517,049
MDWG	3,333,744
VAWG	3,660,445
WV Total	9,383,074
PA	**PA APB11**
CMWG	
DCWG	
MDWG	
VAWG	240,622
PA Total	240,622
NY	**NY APB11**
CMWG	
DCWG	
MDWG	
VAWG	23,810
NY Total	23,810
HAMP	-

		PBCOSA Dec-2023 Avg Study#288 Tot_GPIS_X_Chalk Point		Ratebase MACRS Plant Allocation Factor
Fed				
CMWG	93,017,678			
DCWG	155,232,386	0.184257	172,371,533.65	0.1671519 (8)
MDWG	377,255,272	0.372029	411,860,505.40	0.3993889
VAWG	405,721,347	0.443715	446,994,643.20	0.4334592
	1,031,226,682		1,031,226,682.25	
State				
CMWG	21,035,910			
DCWG	37,310,308	0.184257	41,186,319.68	0.1754048
MDWG	84,063,716	0.372029	91,889,675.62	0.3913409
VAWG	92,397,280	0.443715	101,731,219.11	0.4332542
	234,807,214		234,807,214.41	

no state apportionment factor

no state apportionment factor

Adjustment No. 25

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 25 - Legal Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Legal Expenses (DC - Per Book Amount)	Financial Statements	$ 2/ 338,684
2	DC Corrected Per Book Amount	Analysis	475,607
3	Proforma Adjustment Amount	Line 2 - Line 1	$ 136,923 1/

4 **Adjustment Description:** To correct Legal expenses on a jurisdictional basis for
5 twelve months ended March 31, 2024.

1/ For Class Cost purposes, note that -$65.07 of the adjustment relates to EX:5:5, and $136,988.08 of the adjustment relates to EX:5:6.

- Legal Expenses by Jurisdiction & Account (TME Mar-2024) - As Recorded

GL Unit	01
Clerk Identifier	N

Sum of Sum Amount	Account	Oper Unit					
	921000		923000				
Supplier2	10	02	10	01	02	03	
ANN SCHOOFER HARRINGTON		333					MD
ASMAR SCHOR & MCKENNA PLLC			151,416				allocable
BAKER BOTTS L.L.P.			377,070				allocable
BEVERIDGE & DIAMOND PC			520,010	45,065		3,928	allocable
BLOOMBERG INDUSTRY GROUP INC			24,810				allocable
BRACEWELL LLP			28,259				VA
DAVIS WRIGHT TREMAINE LLP			44,421				allocable
FRONTEO USA INC.			7,618				MD
GEOSYNTEC CONSULTANTS, INC.			64,547				DC
HOLLAND & KNIGHT LLP			53,371	4,370			DC
HUNTON ANDREWS KURTH LLP	1,463		20,682				allocable
INTEGRAL CONSULTING INC			3,286				DC
IVERA GROUP, INC.			8,241				DC
LAW OFFICE OF MIDGETT S PARKER P A			2,830		735		MD
PLAUCHE MASELLI PARKERSON LLP			119		1,800		MD
PORTFOLIO MEDIA INC.,			32,880				allocable
ROLLINS SMALKIN RICHARDS AND MACKLE LLC					2,500		MD
SHIPLEY AND HORNE P A			2,680				MD
STINSON MORRISON HECKER LLP			13,448				allocable
THOMSON REUTERS-WEST PUBLISHING CORP.			24,118	1,268			allocable
VENABLE LLP			895				MD
VINSON & ELKINS LLP			338,893				allocable
VLP LAW GROUP LLP			3,803				allocable
WILSON ELSER MOSKOWITZ EDELMAN &			31,744				allocable
Grand Total	1,463	333	1,755,141	50,702	5,035	3,928	
Items to Exclude (Not DC Related)							Exclude
Total	1,463	333	1,755,141	50,702	5,035	3,928	

A.

- Legal Expenses by Jurisdiction & Account (TME Mar-2024) - As Corrected

DC	-	180,148	180,148
VA	-	*32,186*	*32,186*
MD	*333*	*19,176*	*19,509*
Exclude	-	-	-
Items to Exclude (Not DC Related)	333	51,362	51,695
Allocable	1,463	1,583,295	1,584,757
Total	1,796	1,814,805	1,816,601
CHECK A.	-	-	-

- PBCOSA Details (Allocation Factors)

CUBE:	tm1serv:QTR_WG_PB_to_RM
QTR_Study#	**Study#292**
QTR_Jurisdiction	DC
QTR_PB_to_RM_Period	**Mar-2024**
QTR_PB_to_RM_Ln_Item	*see below*

Description	DC Factor	Comments
Comp_A&G	3/ 19.54%	Used for Account 921000
Three _Part _Factor	18.64%	Used for Account 923000

- Jurisdictional Reconciliation

Account	DC - Per Books	DC - Corrected PB Balance	Adjustment
921000	$ 351	$ 286	$ (65)
923000	338,333	475,321	136,988
	$ 338,684	$ 475,607	$ 136,923
	1		

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

	------ Reference ------								
Description	Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Customer Accounts**									
2 General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3 Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4 Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5 Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6 Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7 Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8 Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9 Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10 Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11 **Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618	0.430114	0.376267
12 **Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13 **Expenses allocated on**									
14 **Composite A&G Factor**									
15 Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16 Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429 1	0.406393	0.407178
17 Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18 Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19 Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20 Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21 Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22 Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23 Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954 1	0.4320	0.3726
24 **Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25 **Operations & Maintenance**									
26 **Expenses - Adjusted**									
27 Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28 Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29 Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30 Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32 Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33 Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34 Operations & Maintenance Expenses -									
25 Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36 **Operations Expense Excluding**									
37 **Purchased Gas & Uncollectibles**									
38 Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39 Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40 Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41 Operations Expense Excluding									
42 Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43 Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Adjustment No. 26

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 26 - Prior Period Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description	Account	DC Total
	A	B	C
1	Prior Period Items		
2	Short Term Incentive Reclass	920432 (EX:5:2)	$ 2/ (26,978)
3	Adjustment Total		$ (26,978)

4 **Adjustment Description:** To adjust test year expense to remove prior period adjustments.

1JOURNALQUERY

Unit	Journal ID	Year	Period	Account	Sum Amount	Res Type	Long Descr	Line Descr	Source	Oper Unit	Posted	Project	Date
01	PA00007006	24	2	920432	26,978.00	1503	To adjust Disallowed DC Capitalized STI-RT1503	Empl Incentive-ROE Distr	EXL	10	3/4/2024		2/2/2024
01	PA00007006	24	3	920432	(26,978.00)	1503	To correct OU on PA00007006 dated 2/2/2024	Empl Incentive-ROE Distr	EXL	10	3/29/2024		3/2/2024
01	**PA00007006**	**24**	**3**	**920432**	**26,978.00**	**1503**	**To correct OU on PA00007006 dated 2/2/2024**	**Empl Incentive-ROE Distr**	**EXL**	**01**	**3/29/2024**		**3/2/2024**

1

Adjustment No. 27

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 27 - Merger Transition Cost to Achieve Amortization Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Total Company B	Allocation Factor C	District of Columbia D = B * C
1	**Transition Cost Amortization**			
2	Account 921003 - Merger Transition Amortization Expense	$ 2/ 308,014	16.98%	$ 2/ 52,311
3	**Elimination of Merger Transition Amortization Expense**			**$ (52,311)**

4 **Adjustment Description:** To eliminate merger-related cost to achieve amortizaton for the period for twelve months
5 ending March 2024.

Note: The merger amortizations ended in July 2023

_1/ For class cost purposes, the full amount of this adjustment relates to COSA line EX 5:5.

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
A	B	C	D	E	F	G	H
1 **Administrative & General Expenses**							
2 Administrative & General Salaries-Direct		Financial Stmt.	$ 4,032,355	$ 930,862	$ 1,648,492	$ 1,449,739	$ 3,262
3 Administrative & General Salaries-Allocable	AL:4:23	Comp_A&G	100,516,479	19,641,740	43,423,120	37,451,620	-
4 Office Supplies & Expenses-Direct		Financial Stmt.	3,942,404	1,103,503	1,731,733	1,104,963	2,204
			3,634,389	1,051,192	1,601,521	979472.3669	2,204
			-	-	-	-	-
			-	-	-	-	-
			-	-	-	-	-
			-	-	-	-	-
			308,014 1	52,311 1	130,212	125,490.84	-
			-	-	-	-	-
5 Office Supplies & Expenses-Allocable	AL:4:23	Comp_A&G	33,046,634	6,457,582	14,276,146	12,312,906	-
6 Outside Services	AL:5:30		37,435,574	7,053,669	15,176,292	15,205,613	-
7 Property Insurance	AL:3:13	Net_GPIS	-	-	-	-	-
8 Injuries & Damages	AL:4:11	Total_Labor	18,995,900	3,677,954	8,170,412	7,147,535	-
9 Pension Expense	AL:4:11	Total_Labor	(219,656)	(42,494)	(94,398)	(82,580)	(185)
10 <u>DC Regulatory</u>			-				
11 Pension Expense		Financial Stmt.	-	-	-	-	-
12 Amortization of Rate Case Expenses		Financial Stmt.	475,776	475,776	-	-	-
13 Least Cost Planning Expenses		Financial Stmt.	-	-	-	-	-
14 Employee Health Benefits			24,779,774	4,793,783	10,649,176	9,315,976	20,840
15 OPEB	Labor factor	Financial Stmt.	(34,007,440)	(6,584,462)	(14,627,092)	(12,795,885)	-
16 Rate Case Expenses-Direct		Financial Stmt.	1,526,109	206,553	1,049,073	269,875.64	607
17 Rate Case Expenses-Allocable	AL:4:23	Comp_A&G	9,523	1,861	4,114	3,548	-
18 DC PSC Assessment Expense		Financial Stmt.	-	-	-	-	-
19 General Advertising Expenses - Direct		Financial Stmt.	1,269	-	984	285	-
20 General Advertising Expenses - Allocable	AL:4:23	Comp_A&G	644,209	125,884	278,298	240,027	-
21 Environmental Expense - Regulatory Amortization		Financial Stmt.	686,319	263,068	423,250	-	-
22 Environmental Reserve - Regulatory Adjustment		Financial Stmt.	1,738,655	-	-	1,738,655	-
23 Rents		Financial Stmt.	263,877	-	-	263,877	-
24 MD Demand Side Management Expenses		Comp_A&G	1,041,022	203,424	449,721	387,876	-
25 VA Care Expenses		Financial Stmt.	4,294,347	-	-	4,294,347	-
26 MD EmPOWER MD Expenses		Financial Stmt.	13,710,995	-	13,710,995	-	-
27 Multi-Family Unit Contribution Amortization Expense		Financial Stmt.	199,129	17,451	140,914	40,764	-
28 Multi-Family Unit Contribution Amortization Expense - Allocable			-	-	-	-	-
29 Miscellaneous General Expenses-Direct		Financial Stmt.	367,847	348,831	(45,528)	64,398	145
30 Miscellaneous General Expenses-Allocable	AL:4:23	Comp_A&G	2,373,165	463,736	1,025,207	884,222	-
31 Total Administrative & General Expenses	= 2 >30		$ 215,854,266	$ 39,138,720	$ 97,390,911	$ 79,297,762	$ 26,873

Adjustment No. 28

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 28 - Credit/Debit Card Transaction Fees Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	MD Amount C	
1	Credit/Debit Card Transaction Fees (Per Book)	EX:7:16	$	2/ 478,381
2	ACH Payment Increase	Analysis	$	3/ 66,585
3	Net Credit/Debit Card Fees	Ln. 1 - Ln. 2	$	411,796
4	Elimination of Credit/Debit Card Transaction Fees		$	(411,796)

5 **Adjustment Description:** To eliminate credit/debit card fees for twelve months ended March 31, 2024.

Washington Gas Light Company
Customer Accounts
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Customer Accounts**							
2	General Supervision-Direct		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
3	General Supervision-Allocable	AL:4:10	Customer_Accts	-	-	-	-	-
4	Total General Supervision	=2+3		$ -	$ -	$ -	$ -	$ -
5	Meter Reading-Direct		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
6	Meter Reading-Allocable	AL:4:12	Avg_Meters	5,504,551	762,664	2,174,130	2,567,758	-
7	Total Meter Reading	=5+6		$ 5,504,551	$ 762,664	$ 2,174,130	$ 2,567,758	$ -
8	Dispatch Applications and Orders-Direct		Financial Stmt.	$ 2,171,311	$ 296,545	$ 1,132,179	$ 742,587	$ -
9	Dispatch Applications and Orders-Allocable	AL:4:12	Avg_Meters	13,855,708	1,919,729	5,472,583	6,463,397	-
10	Total Dispatch Applications and Orders	=8+9		$ 16,027,019	$ 2,216,274	$ 6,604,762	$ 7,205,984	$ -
11	Customer Collection Expenses							
12	Customer Credit and Appliance Service-Direct		Financial Stmt.	$ 8,268	$ -	$ (46,049)	$ 54,317	$ -
13	Customer Credit and Appliance Service-Allocable	AL:4:5	Avg_AR	8,373,169	2,191,914	3,899,276	2,281,979	-
14	Other-Direct		Financial Stmt.	-	-	-	-	-
15	Other-Allocable	AL:5:32	Avg_Meters	(1,669,693)	(231,338)	(659,478)	(778,877)	-
16	Credit and Debit Card Transactions	AL:5:32	Credit_Debit_Card	3,520,829	478,381 1	1,594,599	1,447,850	
17	Total Customer Collection Expenses	=12>15		$ 10,232,573	$ 2,438,956	$ 4,788,348	$ 3,005,269	$ -
18	Customer Billing and Accounting-Direct		Financial Stmt.	$ 108,799	$ 108,700	$ -	$ 99	$ -
19	Customer Billing and Acct-POR Collection Exp		Financial Stmt.	621,466	226,115	395,350	-	-
20	Customer Billing and Accounting-Allocable	AL:4:12	Avg_Meters	4,295,147	595,099	1,696,452	2,003,596	-
21	Total Customer Billing and Accounting	=17>19		$ 5,025,412	$ 929,915	$ 2,091,803	$ 2,003,695	$ -
22	Total Uncollectible Accounts			$ 15,334,992	$ 6,420,597	$ 3,901,686	$ 5,012,709	$ -
23	Total Customer Accounts	=4+7+10+16+20+21		$ 52,124,547	$ 12,768,405	$ 19,560,728	$ 19,795,414	$ -

Card Payment

TME Mar-2024	# of Transactions	Payment Fees		Cost per Transaction	
DC	332,924	$	478,381	$	1.44
MD	1,109,744	$	1,594,599	$	1.44
VA	1,007,616	$	1,447,850	$	1.44

ACH Payment

TME Mar-2024	# of Transactions	ACH Fees		ACH Cost per Transaction	
DC	332,924	$	66,585	$	0.20
MD	1,109,744	$	221,949	$	0.20
VA	1,007,616	$	201,523	$	0.20

Since most card transactions are processed through our Utilli platform, we will assume customers will switch to the Utilli echeck payment (20 cents per transaction)

Adjustment No. 29

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 8D & 29 - Interest on Debt (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	Distribution Amount	Ratemaking Amount
	A	B	C	D	E
1	**Interest on Total Debt**				
2	Net Rate Base	Rate Base Stmt, Ln.23	$ 2/ 4,284,239,876	$ 3/ 796,176,491	$ 3/ 760,992,964
3	Weighted Average Cost of Debt	Cost of Capital, Ln. 1 + Ln. 2	4/ 2.36%	4/ 2.36%	4/ 2.36%
4	Interest on Debt	Ln. 2 * Ln. 3	$ 101,225,321	$ 18,811,557	$ 17,980,262
5	Per Books Interest Expense	Per Books	5/ 100,062,947	5/ 19,142,496	18,811,557
6	Adjustment to Interest Expense _1/	Ln. 4 - Ln. 5	$ 1,162,374	$ (330,939)	$ (831,295)

7 **Adjustment Description**: To synchronize interest expense used in determining the overall return requirement with the interest
8 expense used to calculate income taxes.

_1/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line 9:16.

Washington Gas Light Company
Rate Base Summary
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Gas Plant in Service	RB:3:17		$ 7,249,016,177	$1,317,182,832	$ 2,711,617,252	$ 3,190,657,625	$ 29,558,468
2	Gas Plant Held for Future Use	RB:4:13		-	-	-	-	-
3	Unrecovered Plant - Peaking Facility		Total_Weather_All_NW	-	-	-	-	-
4	Construction Work in Progress	RB:5:29		397,111,025	79,322,274	134,339,566	183,449,185	-
5	Materials & Supplies	RB:6:12		123,327,981	19,836,447	52,379,031	51,112,503	-
6	Non Plant - ADIT	RB:12:18	Financial Stmt.	(34,509,521)	(3,062,666)	(21,491,098)	(9,955,757)	0
7	FC 1027 - Rate Base CWIP (Reg Asset)			(0)	(0)			
	Unamortized East Station Cost (Net of							
8	Deferred Taxes)		Financial Stmt.	1,075,846	1,075,846	-	-	-
9	Sub-Total	= 1>10		$ 7,736,021,508	$1,414,354,734	$ 2,876,844,750	$ 3,415,263,556	$ 29,558,468
10	Cash Working Capital	RB:7>9		$ 121,292,100	$ 39,219,091	$ 67,230,077	$ 14,826,433	$ 16,500
11	Total Rate Base Additions	= 9+10		$ 7,857,313,609	$1,453,573,825	$ 2,944,074,827	$ 3,430,089,989	$ 29,574,968
12	LESS:							
13	Reserve for Depreciation	RB:10:35		$ 2,370,279,045	$ 449,057,859	$ 864,931,885	$ 1,054,487,285	$ 1,802,016
14	Accumulated DIT re Depreciation	RB:11:21		1,298,608,831	212,149,665	532,439,389	554,019,777	0
	Accumulated DIT re Gains/Losses On							
15	Reacquired Debt							
16	Federal	RB:11:9	Net_Rate_Base	175,290	29,300	70,009	75,981	-
17	State	RB:11:9	Net_Rate_Base	57,829	10,143	22,631	25,055	-
18	NOL Carryforward Federal		Net_Rate_Base	(78,173,336)	(14,916,809)	(29,119,631)	(34,136,895)	-
19	NOL Carryforward State		Net_Rate_Base	(68,626,785)	(13,095,164)	(25,563,533)	(29,968,088)	-
20	NOL Federal Benefit of State		Net_Rate_Base	14,411,625	2,749,985	5,368,342	6,293,298	-
21	Customer Advances for Construction		Financial Stmt.	2,698,381	305,769	244,862	2,147,750	-
22	Customer Deposits		Financial Stmt.	12,871,928	1,432,785	2,467,234	8,971,908	-
23	Supplier Refunds		Financial Stmt.	4,509,391	626,315	1,675,549	2,207,527	-
24	Deferred Tenant Allowance		Non_Genl_Plnt	16,261,534	3,017,287	6,000,718	7,243,529	-
25	Total Rate Base Deductions	= 13>24		$ 3,573,073,733	$ 641,367,135	$ 1,358,537,454	$ 1,571,367,128	$ 1,802,016
26	Net Rate Base	= 11 - 25		$ 4,284,239,876 1	$ 812,206,690 3	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952

Exhibit WG (D)-5
Adjustment No. 8D & 29
Page 3 of 5

Washington Gas Light Company
District of Columbia Jurisdiction

Average Rate Base Summary

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Books Amount C	Distribution Adjustments D	Distribution Amount E = C + D	Ratemaking Adjustments F	Ratemaking Amount G = E + F
1	Gas Plant in Service		$ 1,317,182,832	$ (770,154)	$ 1,316,412,678	$ 27,107,163	$ 1,343,519,841
2	Construction Work in Progress		79,322,274	-	79,322,274	(72,437,698)	6,884,577
3	Materials & Supplies	Adj List Pg 2, Ln. 14	19,836,447	(16,895,300)	2,941,148	-	2,941,148
4	Non-Plant ADIT		(3,062,666)		(3,062,666)	(293,256)	(3,355,922)
5	FC 1027 - Rate Base CWIP (Reg Asset) _a/		(0)	-	(0)	-	(0)
6	Unamortized East Station _a/	Adj List Pg 2, Ln. 19	1,075,846	-	1,075,846	690,481	1,766,327
7	Sub-Total	Sum of Lns. 1 > 3	$ 1,414,354,734	$ (17,665,454)	$ 1,396,689,281	$ (44,933,310)	$ 1,351,755,971
8	Cash Working Capital	Adj List Pg 2, Ln. 17	39,219,091	652,610	39,871,701	954,625	40,826,325
9	Gross Rate Base	Ln. 7 + Ln. 8	$ 1,453,573,825	$ (17,012,844)	$ 1,436,560,981	$ (43,978,685)	$ 1,392,582,296
10	LESS:						
11	Reserve for Depreciation	Per Books	$ 449,057,859	$ (356,329)	$ 448,701,530	$ 7,495,833	$ 456,197,363
12	ADIT: M.A.C.R.S. Depreciation	Per Books	212,149,665	-	212,149,665	3,877,037	216,026,702
13	ADIT: Gains/Losses on Reaquired Debt (Federal)	Per Books	29,300	-	29,300	-	29,300
14	ADIT: Gains/Losses on Reaquired Debt (State)	Per Books	10,143	-	10,143	-	10,143
15	NOL Carryforward Federal	Per Books	(14,916,809)	-	(14,916,809)	(20,845,267)	(35,762,077)
16	NOL Carryforward State	Per Books	(13,095,164)	-	(13,095,164)	857,264	(12,237,900)
17	NOL Federal Benefit of State	Per Books	2,749,985	-	2,749,985	(180,026)	2,569,959
18	Customer Advances for Construction	Per Books	305,769	-	305,769	-	305,769
19	Customer Deposits	Per Books	1,432,785	-	1,432,785	-	1,432,785
20	Supplier Refunds	Adj List Pg 2, Ln. 25	626,315	(626,315)	-	-	-
21	Deferred Tenant Allowance	Per Books	3,017,287	-	3,017,287	-	3,017,287
22	Total Rate Base Deductions	Sum of Lns. 11 > 21	$ 641,367,135	$ (982,644)	$ 640,384,490	$ (8,795,158)	$ 631,589,332
23	Net Rate Base	Ln. 9 - Ln. 22	$ 2/ 812,206,690	$ (16,030,199)	$ 796,176,491 1	$ (35,183,527)	$ 760,992,964 1

a/ Net of deferred taxes

Washington Gas Light Company
District of Columbia Jurisdiction

Utility Cost of Capital

Twelve Months Ended March 31, 2024

Line No.	Description A	Ratio C	Cost D	Weighted Cost E = C x D	
1	Long-term Debt	42.88%	4.84%	A 2.08%	Sum of A = 2.36%
2	Short-term Debt	4.63%	6.20%	A 0.29%	(rounded down) 1
3	Common Equity	52.49%	10.50%	5.51%	
4	Total	100.00%		7.87%	

Washington Gas Light Company
Interest Expense
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Interest Expense**							
2	Interest on Long Term Debt	AL:3:6	Net_Rate_Base	85,860,916	16,374,320	31,994,268	37,492,328	-
4	Interest on Commercial Paper	AL:3:6	Net_Rate_Base	11,735,620	2,239,357	4,371,528	5,124,735	-
5	Interest on Credit Line Fees	AL:3:6	Net_Rate_Base	48,962	9,343	18,238	21,381	-
6	Interest on Credit Line Fees	AL:3:6	Net_Rate_Base	1,006,084	191,978	374,767	439,339	-
7	Interest On Bank Loans	AL:3:6	Net_Rate_Base	-	-	-	-	-
8	Interest on Financing Leases	AL:3:6	Net_Rate_Base	493,872	94,239	183,968	215,665	-
9	Interest on Short-Term Revolver	AL:3:6	Net_Rate_Base	-	-	-	-	-
9	Amortization of Debt Discount/Expenses	AL:3:6	Net_Rate_Base	753,779	149,466	267,345	336,969	-
10	Amort. Gain/Loss/Premium on Reacquired Debt	AL:3:6	Net_Rate_Base	(365,099)	(64,061)	(149,669)	(151,368)	-
11	AFUDC	AL:3:14	ADJ_CWIP	(1,259,101)	(467,443)	(791,658)	-	-
12	POR CWC Costs		Financial Stmt.	58,019	58,019	0	0	-
13	Interest on Supplier Refunds		Financial Stmt.	73,600	11,533	31,581	30,486	-
14	Interest on Customer Deposits		Financial Stmt.	528,578	41,769	128,646	358,163	-
15	Interest re LCP Expenses		Financial Stmt.	-	-	-	-	-
16	Int Exp re DC Carrying Costs		Financial Stmt.	-	-	-	-	-
17	Oth Int Costs VA Save Carrying Costs		Financial Stmt.	-	-	-	-	-
18	Interest re Maryland Demand Side Management Expenses		Financial Stmt.	-	-	-	-	-
19	Other Interest Expense	AL:3:6	Net_Rate_Base	470,794	89,836	175,371	205,587	-
20	Total Interest	=2>19		$ 99,406,025	$ 18,728,355	$ 36,604,384	$ 44,073,285	$ -
	Adjusted to Remove:							
21	Interest on debt to Associated Company	AL:3:6	Net_Rate_Base	$ -	$ -	$ -	$ -	$ -
22	Non-Utility Interest Charges	AL:3:6	Net_Rate_Base	-	-	-	-	-
23	AFUDC	AL:3:14	ADJ_CWIP	(1,259,101)	(467,443)	(791,658)	-	-
24	Interest on Supplier Refunds		Financial Stmt.	73,600	11,533	31,581	30,486	-
25	Int Exp re DC Carrying Costs		Financial Stmt.	-	-	-	-	-
26	Oth Int Costs VA Save Carrying Costs		Financial Stmt.	-	-	-	-	-
27	Oth Int Exp Customer Deposits		Financial Stmt.	528,578	41,769	128,646	358,163	-
28	Non-Utility Interest on Equity Investment in Comme	AL:3:6	Net_Rate_Base	-	-	-	-	-
29	Non-Utility Interest on Equity Investment in Primary	AL:3:6	Net_Rate_Base	-	-	-	-	-
30	Interest per Cost of Service	=20-(21>29)		$ 100,062,947 1	$ 19,142,496 1	$ 37,235,816	$ 43,684,636	$ -

* Based on weighted average of Commercial Paper rates on average investment.

Adjustment No. 30

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 9D - Cash Working Capital (Distribution)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Per Books C	DC Dist. Adjustment D	DC Dist. Amount E	DC Lag Days F	DC Dollar Days G = E x F
1	Composite Revenue Lag					9/ 89.00	
2	Gas Purchased	Per Books Adj 2D	$10/ 64,262,645	$4/ 1,806,227 A	$4/ 66,068,873 2	38.19	$ 2,523,164,162
3	Payroll	Per Books	10/ 25,573,530	-	25,573,530	11.71	299,504,692
4	Other Operations and Maintenance Expenses						
5	Employee Health Benefits	Per Books	4,793,783 B	-	4,793,783	30.37	145,571,833
6	Property and Public Liability Insurance	Per Books	3,677,954	-	3,677,954	(163.46)	(601,213,770)
7	Other O&M	Adj 8D WP 1 Adj 2D	3/ 52,683,423	(3,946,617) A	48,736,805	25.47	1,241,251,457
8	Less: Pension Benefit (Non Cash)	Per Books	10/ 42,494	-	42,494	25.47	1,082,247
9	Less: OPEB Benefit (Non Cash)	Per Books	6,584,462	-	6,584,462	25.47	167,696,128
10	Property Taxes	Per Books	2,013,868	-	2,013,868	71.02	143,032,994
11	Delivery Tax	Per Books	23,451,041	-	23,451,041	26.13	612,799,160
12	Rights-of-Way Fee	Per Books	12,518,268	-	12,518,268	(54.53)	(682,621,127)
13	FICA Taxes	Per Books	2,103,553	-	2,103,553	9.97	20,970,937
14	Unemployment Tax	Per Books	(6,961)	-	(6,961)	9.99	(69,562)
15	Environmental Tax	Per Books	-	-	-	-	-
16	Federal Excise Tax	Per Books	(21,714)	-	(21,714)	(17.51)	380,156
17	Sustainable Trust Fund	Per Books	16,761,017	-	16,761,017	26.13	437,982,135
18	Energy Assistance Fund	Per Books	2,156,914	-	2,156,914	26.13	56,362,323
19	Firm Storage Service	Per Books	29	-	29	308.86	8,840
20	Other Taxes - Direct Assignment	Per Books	16,520	-	16,520	79.00	1,305,080
21	Income Taxes (Current)	Per Books Adj 10D	(1,897,447)	8/ (3,089,477)	(4,986,924)	-	-
22	Subtotal	Sum of Lns. 2 > 21	214,713,379	(5,229,867)	209,483,512	20.85	$ 4,367,207,685
23	Lead Lag Requirement	Ln. 22, Col/ E / 365			$ 573,927	68.16	$ 39,116,900
24	Other Lead-Lag Items						
25	Imprest Funds	Per Books	-	-	-	-	-
26	Special Deposits	Per Books	-	-	-	-	-
27	Interest on Long-Term Debt	Adj 8D	-	7/ (330,939)	(330,939)	91.25	2,036
28	Economic Evaluation of Facility Extenstion (GSP 14)	Accts. 186.200 & 174.400	10/ 752,764	-	752,764	-	752,764
29	Cash Working Capital - Distribution						$ 39,871,701 2
30	Cash Working Capital - Per Books						10/ 39,219,091
31	Cash Working Capital Distribution Adjustment	RB:1:10					$ 652,610

5/
Sum of A = ($2,140,390)

10/
Sum of B = $61,155,160

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 30 - Cash Working Capital (Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	DC Dist. Amount C	DC RM Adjustment D	DC RM Amount E	DC Lag Days F	DC Dollar Days G = E x F
1	Composite Revenue Lag					9/ 89.00	
2	Gas Purchased	Adj 1	1/ $ 66,068,873	$ 15/ 7,674,914	$ 73,743,787	38.19	$ 2,816,268,422
3	Payroll	Adj 5 & Adj 6	25,573,530	12/ (2,389,314)	23,184,216	11.71	271,522,214
4	Other Operations and Maintenance Expenses						
5	Employee Health Benefits	Adj 9	4,793,783	13/ 79,796	4,873,579	30.37	147,994,982
6	Property and Public Liability Insurance	Adj 18	3,677,954	14/ 347,779	4,025,733	(163.46)	(658,063,186)
7	Other O&M	Various	48,736,805	17/ (557,652)	48,179,153	25.47	1,227,048,919
8	Less: Pension Benefit (Non Cash)		42,494	-	42,494	25.47	1,082,247
9	Less: OPEB Benefit (Non Cash)		6,584,462	-	6,584,462	25.47	167,696,128
10	Property Taxes		2,013,868	-	2,013,868	71.02	143,032,994
11	Delivery Tax	Adj 1	23,451,041	34/ 2,241,912	25,692,953	26.13	671,382,563
12	Rights-of-Way Fee	Adj 1	12,518,268	34/ (2,608,388)	9,909,880	(54.53)	(540,385,729)
13	FICA Taxes	Adj 12	2,103,553	16/ 22,322	2,125,875	9.97	21,193,472
14	Unemployment Tax		(6,961)	-	(6,961)	9.99	(69,562)
15	Environmental Tax		-	-	-	-	-
16	Federal Excise Tax		(21,714)	-	(21,714)	(17.51)	380,156
17	Sustainable Trust Fund	Adj 1	16,761,017	34/ 4,577,879	21,338,896	26.13	557,606,691
18	Energy Assistance Fund	Adj 1	2,156,914	34/ 210,071	2,366,985	26.13	61,851,688
19	Firm Storage Service		29	-	29	308.86	8,840
20	Other Taxes - Direct Assignment		16,520	-	16,520	79.00	1,305,080
21	Income Taxes	Adj. 31	(4,986,924)	8/ 166,747	(4,820,177)	-	-
22	Subtotal	Sum of Lns. 2 > 21	$ 209,483,512	$ 9,766,066	$ 219,249,578	22.30	$ 4,889,855,917
23	Lead Lag Requirement	Ln. 22, Col. E / 365			$ 600,684	66.70	$ 40,066,410
24	Other Lead-Lag Items						
25	Interest on Long-Term Debt	Adj 29	7/ (330,939)	7/ (831,295)	(1,162,234)	91.25	7,152
26	Economic Evaluation of Facility Extenstion (GSP 14)	Accts. 186.200 & 174.400	10/ 752,764	-	752,764	-	752,764
27	Cash Working Capital - Ratemaking						$ 40,826,325
28	Cash Working Capital - Distribution Amount						1/ 39,871,701
29	Cash Working Capital Ratemaking Adjustment	RB:1:10					$ 954,625

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 9D Workpaper No. 1 - Other O&M Expenses (Per Book)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	DC Per Books
	A	B	C
1	Operation Expenses	DC Inc Stmt, Ln. 3	$ 125,293,859
2	Maintenance Expenses	DC Inc Stmt, Ln. 4	25,568,839
3	Total O&M Expenses	Ln. 1 + Ln. 2	$ 150,862,698
4	Deductions		
5	Gas Purchased	Per Books	$ 64,262,645
6	Payroll	Per Books	25,573,530
7	Employee Benefits	Per Books	4,793,783
8	Property and Public Liability Insurance	Per Books	3,677,954
9	Depreciation Elimination	Per Books	(128,636)
10	Total Deductions	Sum of Lns. 5 > 9	$ 98,179,276
11			
12	Total Other O&M Expenses	Ln. 3 - Ln. 10	$ 52,683,423 ①

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1D - Purchased Gas Costs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		Amount C
1	*Purchased Gas Revenues*			
2	Fuel Revenues	RV:1:13	$	(59,477,160)
3	Third Party Balancing Charges	RV:1:27		(6,609,061)
4	Balancing Charges Reconciliation Factor	Analysis		-
5	Total Adjustment for Purchased Gas Revenues	Lines 2 > 4	$	(66,086,221)
6	*Purchased Gas Costs*			
7	Hampshire Exchange Service	EX:2:9	$	(40,957)
8	Storage - Allocable	EX:2:12		(1,765,271)
9	Gas Purchase Costs	EX:3:3		(66,068,873) 1
10	Propane Gasified	EX:3:4		1,806,227 1
11	Total Adjustment for Purchased Gas Costs	Lines 7 > 10 (EX:3:3)	$	(66,068,873)

Adjustment Description: To remove fuel revenues, purchased gas costs, and gas supplier revenues from distribution revenues and expenses.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 2D - GAC Revenues and Uncollectible Expense Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C	
1	Gas Administration Charge Revenues			
2	Residential	Analysis	$ (1,074,697)	
3	Commercial and Industrial Other Than Group Metered Apartments	Analysis	(507,259)	
4	Group Metered Apartments	Analysis	(191,045)	
5	Gas Administration Charge Revenues Elimination Amount	1/	(1,773,001)	
6	Less: Gas Procurement Cost			
7	Residential	Analysis	47,400	
8	Commercial and Industrial Other Than Group Metered Apartments	Analysis	22,294	
9	Group Metered Apartments	Analysis	8,477	
10	Gas Procurement Cost Total	Adj No. 3D	78,171	A
11	GAC Uncollectible Expense Elimination Amount 2/	Line 5 + Line 9	$ (1,694,830)	B

12 **Adjustment Description:** To remove Gas Administration Charge uncollectible amounts.

1/ For Class Cost purposes, note that this adjustment relates to RV:1:14.
2/ For Class Cost purposes, note that this adjustment relates to EX:7:21.

6/
B - A = ($1,694,830) - $78,171 - $367,389 = ($2,140,390) 1

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 7D - Purchase of Receivables (POR) Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Book Amount C	Ratemaking Adjustment D
1	**Capitalized Software**			
2	Capitalized Software (POR)	303006 (RB:2:2)	$ 762,920	$ (762,920)
3	Computer Equipment (POR)	373106 (RB:2:35)	7,234	(7,234)
4	Total Plant in Service	Ln. 2 + Ln. 3	$ 770,154	$ (770,154)
5	**Reserve for Depreciation**			
6	DC POR Software	Property Analysis	$ 352,999	$ (352,999)
7	DC POR Equipment	Property Analysis	3,331	(3,331)
8	Total Depreciation Reserve	Ln. 6 + Ln. 7	$ 356,329	$ (356,329)
9	**Other Operating Revenues**			
10	Late Payment Charges (POR)	487107 (RV:1:16)	$ 360,143	$ (360,143)
11	Other Gas Revenues	495306 (RV:1:32)	736,920	(736,920)
12	Total Revenues	Ln. 10 + Ln. 11	$ 1,097,063	$ (1,097,063)
13	**Depreciation and Amortization**			
14	Amortization of Capitalized Software (POR)	404311 (SM:1:7)	$ 97,980	$ (97,980)
15	**Customer Accounts**			
16	Collection Expense (POR)	903307 (EX:7:19)	$ 226,115	$ (226,115)
17	Uncollectible Accounts (POR)	904107 (EX:7:22)	141,274	(141,274)
18	Total Customer Accounts	Ln. 16 + Ln. 17	$ 367,389	$ (367,389) 5
19	**Interest Expense**			
20	POR CWC Costs	431135 (EX:9:12)	$ 58,019	$ (58,019) a/

21 a/ Adjustment is reflected in the Interest on Debt Adjustment #8D.

22 **Adjustment Description:** To eliminate purchase of receivables costs incurred during the study period.
Note:

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 8D & 29 - Interest on Debt (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	Distribution Amount	Ratemaking Amount
	A	B	C	D	E
1	**Interest on Total Debt**				
2	Net Rate Base	Rate Base Stmt, Ln.23	$ 4,284,239,876	$ 796,176,491	$ 760,992,964
3	Weighted Average Cost of Debt	Cost of Capital, Ln. 1 + Ln. 2	2.36%	2.36%	2.36%
4	Interest on Debt	Ln. 2 * Ln. 3	$ 101,225,321	$ 18,811,557	$ 17,980,262
5	Per Books Interest Expense	Per Books	100,062,947	19,142,496	18,811,557
6	Adjustment to Interest Expense _1/	Ln. 4 - Ln. 5	$ 1,162,374	$ (330,939) [1] [2]	$ (831,295) [2]

7 **Adjustment Description**: To synchronize interest expense used in determining the overall return requirement with the interest
8 expense used to calculate income taxes.

_1/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line 9:16.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 10D & 31 - State and Federal Income Taxes (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Distribution Amount C	Ratemaking Amount D
1	**Net Operating Income - Adjusted**	**DC Inc Stmt, Ln. 18**	**$ 20,999,112**	**$ 27,756,328**
2	Add: Income Taxes	DC Inc Stmt, Ln. 12	448,015	614,762
3	Less: Interest Expense	Adj 8D / Adj 29, Ln. 4	(18,811,557)	(17,980,262)
4	Taxable Income	Ln. 1 + Ln. 2 + Ln. 3	2,635,571	10,390,828
5	Flow-Throughs and Permanent Items (Basis)			
6	AFUDC Equity	Per Book ETR / Analysis	70,134	18,597
7	Meals and Entertainment	Per Book ETR / Analysis	184,959	184,959
8	Compensation Limitation	Per Book ETR / Analysis	-	-
9	Parking	Per Book ETR / Analysis	96,216	96,216
10	R&D credit	Per Book ETR / Analysis	-	-
11	Return to Provision True Up	Per Book ETR / Analysis	(806,112)	-
12	Other Tax Adjustments	Per Book ETR / Analysis	(176,160)	-
13	NOL Flow-through	Adj. 32	-	-
14	Total Flow-Throughs and Permanent Items	Ln. 6 > Ln. 12	(630,964)	299,771
15	Taxable Income (Adjusted)	Ln. 4 + Ln. 14	2,004,607	10,690,600
16	Federal Income Tax	Ln. 15 * 21.00%	420,968	2,245,026
17	Add: Excess Deferred Tax (Protected)		-	5,397,883
18	Add: Excess Deferred Tax (Unprotected)		-	(7,908,370)
19	Add: Excess Deferred Tax on PLR NOL			(140,599)
20	Less: Remove EDIT amortization related to FC 1027 Write Off			343,555
21	Add: Capitalizated OPEB		(12,689)	-
22	Add: ITC		(90,913)	(90,913)
23	Add: Amortization of Prior Flow-Through Balance		-	71,421
24	Total Federal Income Taxes	Ln. 17 > Ln. 22	317,365	(81,998)
25	Per Book / Ratemaking Federal Income Taxes		2,780,984	317,365
26	Federal Income Tax Adjustment	Ln. 24 - Ln. 25	(2,463,619)	(399,363)
27	State Income Tax (Net of Federal Tax Benefit)	Ln. 15 * 6.52%	130,650	696,760
28	Per Book / Ratemaking State Income Taxes		756,509	130,650
29	State Income Tax Adjustment	Ln. 27 - Ln. 28	(625,859)	566,110
30	Income Tax Adjustment	Ln. 26 + Ln. 29	(3,089,477) 1	166,747 2

31 **Adjustment Description:** To adjust state and federal income tax to rate year amounts.

Washington Gas Light Company
District of Columbia Jurisdiction

Summary of Lead / Lag Studies

For 12 Months Ended March 31, 2024

Line No.	Description	Lead / Lag Days	
1	Revenue Lag	89.00	1 2
2	Gas Purchase Lag	38.19	
3	Payroll Lead	11.71	
4	Employee Health Benefits	30.37	
5	Other O&M	25.47	
6	FICA Taxes	9.97	
7	Public Insurance Liability	(163.46)	
8	Property Tax Lag	71.02	
9	Federal Unemployment Tax Lag	9.99	
10	Federal Excise Tax Lag	(17.51)	
11	Other Tax Lag	308.86	
12	Interest on Long-term Debt	91.25	
13	Arena Fee (Other Taxes - Direct Assignment)	79.00	
14	Delivery Tax	26.13	
15	Rights-of-Way Fee	(54.53)	

1/ Lead/Lags 1 and 2 are based on the Twelve Months Ended March 31, 2024.
2/ Lead/Lags 3 - 15 are base on the Twelve Months Ended December 31, 2020

Washington Gas Light Company
Cash Working Capital
District of Columbia
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	---- Reference ---- Sc-Pg-Ln	Allocator	Expenses	Adjustments	Adjusted Expenses	Lead/Lag Days	Cash Working Capital Requirement
	A	B	C	D	E	F	G	H
1	Composite Revenue Lag						89.00	
2	Gas Purchased	EX:3:5		$ 64,262,645	$ -	$ 64,262,645 (1)	38.19	$ 2,454,184,506
3	Payroll	WEX:6:30		25,573,530	-	25,573,530	11.71	299,504,692
4	Other Operations and Maintenance Expenses 1/			61,026,523	128,636 1/	61,155,159	25.47	1,557,527,820
5	Less: Pension Benefit 2/		Total_Labor	42,494	-	42,494	25.47	1,082,247
6	Less: OPEB Benefit 3/		Total_Labor	6,584,462	-	6,584,462	25.47	167,696,128
7	General Taxes							
8	Property Taxes	EX:8:2		2,013,868	-	2,013,868	71.02	143,032,994
9	Delivery Tax	EX:8:8		23,451,041	-	23,451,041	26.13	612,799,160
10	Rights-of-Way Fee	EX:8:9		12,518,268	-	12,518,268	(54.53)	(682,621,127)
11	FICA Taxes	EX:8:10>11		2,103,553	-	2,103,553	9.97	20,970,937
12	Unemployment Tax	EX:8:12		(6,961)	-	(6,961)	9.99	(69,562)
13	Federal Excise Tax	EX:8:17		(21,714)	-	(21,714)	(17.51)	380,156
14	Sustainable Trust Fund	EX:8:18		16,761,017	-	16,761,017	26.13	437,982,135
15	Energy Assistance Fund	EX:8:19		2,156,914	-	2,156,914	26.13	56,362,323
16	Firm Storage Service	EX:8:23		29	-	29	308.86	8,840
17	Other Taxes - Direct Assignment	EX:8:22		16,520	-	16,520	79.00	1,305,080
18	Federal Income Taxes	EX:10:2		(1,201,342)	-	A (1,201,342)	-	0
19	Other Income Taxes	EX:10:3		(696,105)	-	A (696,105)	-	0
20	Total Net Expenses	= 2 > 19		$ 214,584,743	$ 128,636	$ 214,713,379	23.61	$ 5,070,146,329
21	Subtotal					$ 588,256	65.39	$ 38,466,327
22	**Other Lead-Lag Items:**							
23	Imprest Funds	AL:4:30	O&M _X_ Gas	$ -				$ -
24	Economic Eval. of Facility Ext. (GSP 14)		Accts186200 & 174400	752,764	-	752,764 (1) (2)		752,764
25	Interest on Long-Term Debt	EX:9:2		0		$ -	91.25	0
26	Preferred Dividends			812,206,690	0.00%	-	0.00	-
27	Total Cash Working Capital	= 21 > 26						$ 39,219,091 (1)

1/ Represents an adjustment to exclude depreciation expense for transportation and POE equipment from the calculation of cash working capital.(WEX13:10)
2/ To exclude Pension Benefit from Working Capital calculations, because it is a noncash item.
3/ To exclude OPEB Benefit from Working Capital calculations, because it is a noncash item.

Sum of A = ($1,897,447)
(1)

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 5 - Wages and Salaries Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		Frederick/Shen Unions C	Teamsters & Local 2 Unions D	Management E	Total F=C+D+E
1	**Annual Payroll (Gross) TME March 31, 2024**	Analysis		$ 5,108,819	$ 72,615,991	$ 106,452,220	$ 184,177,030
2	Pro Forma Increase - Test Year (Apr-2023 to Mar-2024)	Workpaper 2		50,086	320,862	3,138,466	3,509,414
3	Pro Forma Gross Payroll TME March 31, 2024	Ln. 1 + Ln. 2		$ 5,158,906	$ 72,936,853	$ 109,590,685	$ 187,686,444
4	Pro Forma Increase - (Apr-2024 to Mar-2025)	Workpaper 2		103,178	1,857,618	1,362,578	3,323,373
5	Pro Forma Gross Payroll in Rate Effective Period (Aug-2025 to Jul-2026)	Ln. 3 + Ln. 4		$ 5,262,084	$ 74,794,471	$ 110,953,263	$ 191,009,817
6	Pro Forma Payroll Increase	(Ln. 5 - Ln. 1)		$ 153,265	$ 2,178,480	$ 4,501,043	$ 6,832,788
7	Operations & Maintenance Allocation Factor	Analysis		75.53%	75.53%	75.53%	75.53%
8	Proforma Payroll Increase Allocable to Operations & Maintenance (System)	Ln. 6 * Ln. 7		$ 115,757	$ 1,645,354	$ 3,399,531	$ 5,160,643
9	District of Columbia Allocation Factor			19.36%	19.36%	19.36%	19.36%
10	Proforma Payroll Increase Allocable to Operations & Maintenance (District of Columbia)	Ln. 8 * Ln. 9		$ 22,411	$ 318,541	$ 658,149	$ 999,100
11	Adjust to reflect amortization of ratification bonus	Workpaper 3					$ 1,957
12	**Total Wages and Salaries Adjustment**	Ln. 10 + Ln. 11					**$ 1,001,057** 12
13	Wages & Salaries Expense Adjustment - Operations	Ln. 10 * 0.6434	_2/				$ 644,085
14	Wages & Salaries Expense Adjustment - Maintenance	Ln. 10 * 0.3566	_2/				$ 356,972

15 **Adjustment Description:** To reflect pro forma labor wage increases through the rate effective period.

1/ Per book Short-term incentive compensation and benefits expenses are excluded from the cost of service here rather than in 401(k) adjustment (#8).
2/ For class cost purposes, the full amount of this adjustment relates to COSA line EX 5:3.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 6 - LTI Expense Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	Factor Comp_A&G D	DC Amount E = C * D
1	Long-Term Incentive - Performance Shares	Acct 920411 & 920412	$ (40,509)		
2	Long-Term Incentive - Performance Units	Acct 920421 & 920422	$ (17,309,695)		
3	**Total Expense Adjustment _1/**	Ln. 1 + Ln. 2	$ (17,350,204)	19.54%	$ (3,390,371) A

4 **Adjustment Description:** To remove 100% of per book long-term incentive expense.

_1/ For class cost purposes, the full amount of this adjustment relates to COSA line EX:5:3.

11/
(3,390,371) + $1,001,057 = $2,389,314 2

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 9 - Employee Benefits Expense 401(k)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference		Amount
	A	B		C
1	Per Book Test Year Contributions	Account 926207 (EX:5:14)	$	10,900,486
2	Test Year Contribution Related to Organizational redesign	Analysis	$	(579,010)
3	Test Year Contributions Adjusted	Ln. 1 + Ln. 2	$	10,321,475
4	Three Year Average Growth Factor	Workpaper 1		5.29%
5	Employee Savings Plans Expense Increase	Ln. 3 * Ln. 4	$	545,669
6	Operations & Maintenance Allocation Factor	Analysis		75.53%
7	Expense Adjusment (System)	Ln. 5 * Ln.6	$	412,131
8	District of Columbia Allocation Factor	Total_Labor		19.36%
9	Expense Adjusment (District of Columbia)	Ln. 7 * Ln. 8	$	79,796 2

10 **Adjustment Description:** To adjust 401(k) employee benefits expense for current employees to a pro forma basis.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 18 - Insurance Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Incremental Insurance Premiums, Excluding Property Insurance		
2	Excess Public Liability	Insurance Analysis	$ 1,225,502
3	Director and Officer Liability	Insurance Analysis	40,201
4	General Liability	Insurance Analysis	38,759
5	Professional	Insurance Analysis	20,210
6	Commercial Crime/Cyber Liability	Insurance Analysis	90,071
7	Workers Compensation	Insurance Analysis	410,501
8	Service Fees	Insurance Analysis	(33,966)
9	Total Incremental Expense, Excluding Property Insurance	= Sum (Ln. 2 > Ln. 8)	$ 1,791,278
10	DC Factor (Total_Labor)	AL:4:10	19.3618%
11	DC Insurance Expense Adjustment Excluding Property	= Ln. 9 * Ln. 10	$ 346,824
12	Incremental Property Insurance	Insurance Analysis	$ 5,128
13	DC Factor (Net_GPIS)	AL:3:13	18.6176%
14	DC Property Insurance Expense Adjustment	= Ln. 12 * Ln. 13	$ 955
15	Adjustment Total 1/	= Ln. 11 + Ln. 14	$ 347,779 ②

16 **Adjustment Description:** To reflect insurance premium increases.

1/ For class cost purposes, the full amount of the adjustment relates to COSA line EX:5:8.

Washington Gas Light Company
System

Jurisdictional Allocation of Purchased Gas Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Allocator C	System D=E+F+G	D.C. E	Maryland F	Virginia G
1	Commodity						
2	Allocable	Line 4 - Line 3	Sales Normal Weather Therms	$ 236,353,873	$ 31,673,000	$ 98,735,488	$ 105,945,385
3	Interruptible	Page 21, Line 7	Direct Assignment	-	-	-	-
4	Total Commodity	Page 20, Line 10		$ 236,353,873	$ 31,673,000	$ 98,735,488	$ 105,945,385
5	Firm Transportation Demand						
6	Base Gas	footnote 1/	Peak_Day_Base	$ 15,505,776	$ 2,192,298	$ 6,561,234	$ 6,752,244
7	Weather Gas	footnote 1/	Peak_Day_Weather	126,618,658	18,134,074	55,105,954	53,378,630
8	Total FT Demand	RM Demand Cost, Line 12		$ 142,124,434	$ 20,326,372	$ 61,667,188	$ 60,130,874
9	Storage Service Demand						
10	Demand	RM Demand Cost, Line 25	Peak_Day_Weather	$ 75,541,326	$ 10,818,879	$ 32,876,488	$ 31,845,959
11	Capacity	RM Demand Cost, Line 35	Wintr_Pipe_NW	38,219,634	6,416,808	16,527,132	15,275,694
12	Injection/Withdrawal	N/A	Wintr_Pipe_NW	-	-	-	-
13	Total Storage Service Demand	Sum of Lines 10 - 12		$ 113,760,961	$ 17,235,687	$ 49,403,621	$ 47,121,653
14	Peaking Service Demand	RM Demand Cost, Line 52	Firm Weather_NW	$ 18,381,178	$ 2,702,500	$ 7,900,081	$ 7,778,597
15	Total Ratemaking Pipeline Cost of Gas	Sum of Lines 4, 8, 13 & 14		$ 510,620,446	$ 71,937,559	$ 217,706,378	$ 220,976,509
16	Purchased Gas Cost Per Books	footnote 2/		454,828,378	64,262,645	200,704,535	189,861,198
17	Adjustment to Purchased Gas Cost 3/	Line 15 - Line 16		$ 55,792,068	$ 7,674,914 2	$ 17,001,843	$ 31,115,311

18 Adjustment Description: To adjust purchased gas costs to a Ratemaking basis.

1/ 10.91% of Line 8 assigned to base gas and the balance assigned to Weather Gas.
2/ Excludes Other Gas Cost included in O&M Expenses (Hampshire Gas Company).
3/ For Class Cost purposes, note that this adjustment relates to EX:3:5.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 12 - FICA / Medicare Tax Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	Labor Factor D	DC Amount E
1	Incremental Payroll Expense	Adj. No. 5	$ 5,160,643		
2	Adjust to reflect 5 year amortization of ratification bonus	Adj. No. 5	1,957		
3	Labor Adjustment Change	Ln. 1 + Ln. 2	**$ 5,162,599**		
4	Factor - SSI Wages to Gross Wages	Analysis	91.23%		
5	Social Security Insurance (SSI) Base	Ln. 1 * Ln. 4	$ 4,709,839		
6	SSI Rate		6.20%		
7	SSI Tax	Ln. 5 * Ln. 6	292,010	19.36%	56,538
8	Base - Medicare (Payroll Increase)	Ln. 3	$ 5,162,599		
9	Base - Medicare (Long-Term Incentive Elimination)	Adj. No. 6	(17,350,204)		
10	Total Medicare Base	Ln. 8 + Ln. 9	(12,187,604)		
11	Medicare Rate		1.45%		
12	Medicare Tax - Medicare	Ln. 10 * Ln. 11	(176,720)	19.36%	(34,216)
13	Total Pro Forma Adjustment	Ln. 7 + Ln. 12	**$ 115,290**	19.36%	**$ 22,322** _1/

2

14
15 **Adjustment Description:** To reflect increase in employer's portion of FICA taxes to reflect proforma increase in salaries and wages.

_1/ For class cost purposes, $56,538 relates to EX:8:10 and -$34,216 relates to EX:8:11.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 Workpaper 9 - Ratemaking Adjustment to Uncollectible Accounts Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Ratemaking Sales and Delivery Revenues 1/	Adj 1 WP 7, Column C, Line 27	$ 205,930,738
2	Accrual Rate for Uncollectible Gas Accounts	Adj 1 WP 2	2.7046%
3	Ratemaking Uncollectible Gas Accounts Expense	Line 1 x Line 2	$ 5,569,603
4	Per Books Uncollectible Gas Accounts Expense	Per Books	6,226,265
5	Distribution Adjustment to Uncollectible Expense	Adjustment No. 2D	(1,694,830)
6	Distribution Only, Per Book Uncollectible Expense	Line 4 + Line 5 + Line 6	4,531,435
7	Ratemaking Adjustment to Uncollectible Gas Accounts 2/	Line 3 - Line 6	$ 1,038,168 A

8 **Adjustment Description:** To adjust per book uncollectible accounts expense to reflect adjusted non-gas ratemaking revenues.

A $1,038,168 -
18/ $630,366 -
19/ $565,665 -
20/ $39,094+
21/ $73,633+
22/ $278,465+
23/ $333,242+
24/ $1,043,643 -
25/ $97,796 -
26/ $125,884+
27/ $136,923 -
28/ $26,978+
29/ $195,423 -
30/ $1,978,270

31/ -$52,311
32/ -$411,796
33/ +$271,011

=($557,652) 2

1/ Less: Gas Cost.
2/ For Class Cost purposes, note that this adjustment relates to EX:7:22.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 7 - Postretirement Benefits Other Than Pensions (OPEB) Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	DC Amount D = C * 19.36%
1	**Current Employees**			
2	Employer Service Cost	Actuarial Rpt	$ 4,010,336	
3	Washington % of Basic Pay (eliminates Hampshire)	Analysis	99.41%	
4	Washington Gas Portion of Expense	Ln. 2 * Ln. 3	$ 3,986,626	
5	O&M Factor (OPEB Service Costs)	Analysis	81.48%	
6	Total Employer Service Cost	Ln. 4 * Ln. 5	$ 3,248,198	$ 628,910
7	Other Components of Net Periodic Expense	Actuarial Rpt	$ (41,549,691)	
8	Washington % of Basic Pay (eliminates Hampshire)	Analysis	99.41%	
9	Washington Gas Portion of Expense	Ln. 7 * Ln. 8	$ (41,304,041)	
10	O&M Factor (OPEB Other Costs)	Analysis	98.08%	
11	Total Other Components of Net Periodic Expense	Ln. 9 * Ln. 10	$ (40,511,351)	$ (7,843,739)
12	Total Net Periodic Post-Retirement Benefit Expense	Ln. 6 + Ln. 11	$ (37,263,153)	$ (7,214,828)
13	District of Columbia OPEB Costs Per Book	EX:5:15		(6,584,462)
14	Adjustment to OPEB Cost	Ln. 12 - Ln. 13		$ (630,366) 17

15 **Adjustment Description:** To calculate OPEB expense on a pro forma basis.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 8 - Pension & SERP Expense

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	DC Amount
	A	B	C	D = C * 19.36%
1	Pro Forma Employer Service Cost	Workpaper 1	$ 6,934,286	
2	O&M Factor (Pension Service Cost)		81.17%	
3	PF Employer Service Cost	Ln. 1 * Ln. 2	$ 5,628,648	$ 1,089,809
4	Pro Forma Other Components of Net Periodic Expense	Workpaper 1	$ (8,881,587)	
5	O&M Factor (Pension Other Costs)		98.74%	
6	PF Other Components of Net Periodic Expense	Ln. 4 * Ln. 5	$ (8,769,665)	$ (1,697,967)
7	Total Pro Forma Pension Expense	Ln. 3 + Ln. 6	$ (3,141,017)	$ (608,158)
8	Per Book Qualified Pension Expense	EX:5:9	$ (1,529,287)	$ (295,849) a/
9	Per Book SERP/Restoration	EX:5:9	$ 1,309,631	$ 253,355 b/
10	Total Per Book Pension Expense	Ln. 8 + Ln. 9		$ (42,494)
11	Pro Forma Pension Adjustment	Ln. 7 - Ln. 10		$ (565,665) 17

12 **Adjustment Description:** To calculate pension expense on a pro forma basis.

a/ Qualified Pension Expense Accounts are: 926101, 926107, 926109, 926115, 926116, 926116
b/ SERP/Restoration Expense Accounts are: 926103, 926105, 926106, 926113, 926114, 926114

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 10 - Employee Benefits Expense (Fringe) Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	O&M Factor	DC Factor	DC Amount _2/	
	A	B	C	D	E	F=C*D*E	
1	Professional Services	Workpaper 2	$ (22,490)	100.00%	19.36%	$ (4,354)	_1/
2	Physicals	Workpaper 2	(7,150)	100.00%	19.36%	(1,384)	_1/
3	Parking	Workpaper 3	(71,760)	86.17%	19.36%	(11,972)	
4	Car Allowance	Workpaper 4	(110,439)	100.00%	19.36%	(21,383)	_1/
5	**Adjustment to Fringe Benefits (Current Employees)**	**Ln. 1 > Ln. 4**	**$ (211,838)**			**$ (39,094)**	17

6 **Adjustment Description:** To remove executive fringe benefits expense.

_1/ O&M factor not applicable because this amount already excludes affiliate transactions.
_2/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line EX:5:14.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 15 - Amortization of COVID Regulatory Asset

Twelve Months Ended March 31, 2024

Line	Description		Reference		Amount
1	Total Regulatory Asset Balance allowed in FC 1169		Order No. 21939	$	368,163
2	Amortization Period (Years)		5 Years		5
3	Annual Amortization		Ln. 1 / Ln. 2	$	73,633
4	Test Year Amortization Expense (Per Book)				-
5	**Total Adjustment to Amortization Expense**	_1/	**Ln. 3 - Ln. 4**	**$**	**73,633** 17

6 Adjustment Description: To amortize the COVID regulatory asset over 5 years.

1/ For class cost purposes:
$73,633 relates to EX:5:5

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 17 - Environmental Costs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C
1	Actual Remediation Expenses as of March 31, 2024	Financial Statement	$ 37,232,664
2	Less: Expenses approved in Prior Cases	Order 21939	27,639,236
3	Total Environmental Expenses Incurred Subsequent to FC Case No. 1169	= Ln. 1 - Ln. 2	$ 9,593,428
4	District of Columbia Factor (Total_Weather_All_NW)	AL:1:19	0.164770
5	Environmental Expenses Applicable to DC	= Ln. 3 * Ln. 4	$ 1,580,712
6	Less: Amount over (under) collected since FC 1169 through July 2025	Financial Statement	(1,126,956)
7	Balance of expenditures incurred to be amortized over 5 years	= Ln. 5 - Ln. 6	2,707,668
8	Annual amortization for 5-year period	= Ln. 7 / 5	$ 541,534
9	Less: Per book annual amortization expense	EX: 5:21	263,068
10	**Total DC Amortization Expense adjustment**	Ln. 8 - Ln. 9	**278,465** 17
11	Rate Base:		
12	Deferred Balance of Environmental Cost, Net of Deferred Taxes	[Ln. 7 - (Ln. 8/2)] * 0.724825	$ 1,766,327
13	Less: Unamortized East Station Cost (Net of Deferred Taxes) March 31, 2024	RB:1:8	1,075,846
14	**Total DC Ratebase Adjustment**	**= Ln. 12 - Ln. 13**	**$ 690,481**

15 **Adjustment Description:** To reflect additional environmental cost incurred since Formal Case No. 1169.

1/ For class cost purposes the total adjustment relates to COSA line EX:5:21.

Washington Gas Light Company
District of Columbia Jurisidiction

Adjustment No. 20 - Commission-Mandated Audit Fees

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B		Amount C
1	Regulatory Asset Balance as of July 31, 2025 (FC 1115 Pipes 1)	Analysis	$	218,773
2	Regulatory Asset Balance as of July 31, 2025 (FC 1175 Pipes 2)	Analysis	$	832,225
3	Total Annual Amortization (Rate Year)	(Ln. 1 + Ln. 2)/3	$	350,333
4	Test Year Expense (System)	Analysis	$	91,675
5	Three_Part_Factor	AL:5:30		18.64%
6	Per Book Expense (District of Columbia)	Ln. 4 * Ln. 5	$	17,091
7	Adjustment	Ln. 3 - Ln. 6	$	333,242 1/

17

8 **Adjustment Description:** To reflect the amortization of ProjectPipes audit fees at rate year amount.

1/ For Class Cost purposes, note that $333,242 of the adjustment relates to EX:5:6.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 21 - Non-Labor Inflation

Twelve Months Ended March 31, 2024

Line No.	Description A	Allocator B	Non-Labor Expense C	Calculated Increase D
1	Test Year Operations Expense _1/	DC Inc Stmt, Ln. 3, Col. E	$ 57,084,597	
2	Test Year Maintenance Expense	DC Inc Stmt, Ln. 4, Col. E	25,568,839	
3	Labor Expense in Test Year O&M	Workpaper 1	(28,256,576)	
4	Test Year Non Labor O&M Expense	Sum (Ln. 1 > Ln. 3)	$ 54,396,860	
5	Non Labor Expense Adjustments to Cost of Service	Workpaper 2	(12,491,893)	
6	Test Year Non Labor O&M Expense (Adjusted)	Ln. 4 + Ln. 5	$ 41,904,967	
7	Inflation Rate (2024)	1 + (2.49% * 1)	102.49%	
8	Non Labor O&M Expense @ 12/31/2024	Ln. 6 * Ln. 7	$ 42,948,611	
9	Incremental Increase	Ln. 8 - Ln. 6		1,043,643
10	**Adjustment Total**	**Ln. 8**		**1,043,643** 17

1/ excludes Gas Purchased Expense

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 22 - Trade Dues, Business Memberships, and Community Affairs

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Allocator C	System Amount D	DC Factor E	Ratemaking Adjustment F = C * D * E
1	Direct Charges - District of Columbia	Analysis	100% DC	$ 17,683	100%	$ (17,683)
2	Allocated Charges - Support Payments	Analysis	Comp_A&G	$ 409,981	19.54%	$ (80,114)
3	Direct Charges - Other Jurisdictions					
4	Maryland		100% MD	$ 275,283	0%	$ -
5	Virginia		100% VA	$ 318,274	0%	$ -
6	Total Other Jurisdictions	Ln. 4 + Ln. 5		$ 593,557		$ -
7	Total Company Memberships & Trade Dues	Ln. 1 + Ln. 2 + Ln. 7	1/	$ 1,021,220		$ (97,796)
8	Trade Dues & Business Associations					$ (48,991)
9	American Gas Association Dues					$ (59,768)
10	Community Affairs					$ 10,962
11	Total					$ (97,796) 17

12 **Adjustment Description:** To exclude Trade Dues, Business Memberships, and Community Affairs payments, as directed in prior
13 Commission Orders.

1/ For class cost purposes the total adjustment relates to COSA line EX:5:29

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 23 - General Advertising Expense Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Allocator B	Reference C	DC Amount D
1	Eliminate Advertising Expense Direct	Financial Statement	EX:5:19	$ -
2	Eliminate Advertising Expense Allocable	Comp A&G	EX:5:20	(125,884)
3	Total Adjustment		Ln. 1 + Ln. 2	$ (125,884) 17

4 **Adjustment Description:** To eliminate direct and indirect general advertising expenses (account 930100)
5 incurred during the study period.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 25 - Legal Expense

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Amount C	
1	Legal Expenses (DC - Per Book Amount)	Financial Statements	$ 338,684	
2	DC Corrected Per Book Amount	Analysis	475,607	
3	Proforma Adjustment Amount	Line 2 - Line 1	$ 136,923	1/

4 **Adjustment Description:** To correct Legal expenses on a jurisdictional basis for
5 twelve months ended March 31, 2024.

1/ For Class Cost purposes, note that -$65.07 of the adjustment relates to EX:5:5, and $136,988.08 of the adjustment relates to EX:5:6.

17

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 26 - Prior Period Eliminations

Twelve Months Ended March 31, 2024

Line No.	Description	Account	DC Total
	A	B	C
1	Prior Period Items		
2	Short Term Incentive Reclass	920432 (EX:5:2)	$ (26,978)
3	Adjustment Total		$ (26,978) 17

4 **Adjustment Description:** To adjust test year expense to remove prior period adjustments.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 11 - Medical Plans Inflation

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	O&M Factor D	Labor Factor E	MD Amount F=C*D*E
1	Insurance Benefits Expense - Carefirst / BCBS	Account 926.274	$ 17,091,522			
2	Insurance Benefits Expense - Kaiser-Permanente	Account 926.264	$ 1,590,804			
3	Insurance Benefits Expense - Delta Dental	Account 926.215	$ 1,173,961			
4	Test Year Expense Related to Organizational redesign	Analysis	(765,460)			
5	Total Group Meidcal Expense (Test Year)	Ln. 1 + Ln. 2 + Ln. 3 + Ln. 4	19,090,827			
6	Inflation Rate	Analysis	7.00%			
7	**Total Expense Adjustment _1/**	Ln. 5 * Ln. 6	**$ 1,336,358**	75.53%	19.36%	**$ 195,423** 17

8 **Adjustment Description:** To adjust employee medical benefits expense for current employees to a pro forma basis.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 13 - Organizational Redesign Labor O&M Expense Reduction

Twelve Months Ended March 31, 2024

Line	Description	Reference		Amount
1	Reduction in salaries	Analysis	$	(7,233,986)
2	Reduction in short-term incentives	Analysis		(986,995)
3	Reduction in medical plans	Analysis		(730,291)
4	Reduction in 401(k)	Analysis		(556,223)
5	Reduction in payroll taxes	Analysis		(697,386)
6	Reduction in life insurance	Analysis		(12,492)
7	Reduction in rate year labor expenses (System)	Sum Lns. 1 to 6	$	(10,217,373)
8	DC Labor Factor	AL 4:11		19.36%
9	Reduction in rate year labor expense (DC)	Ln. 7 * Ln. 8	$	(1,978,270) 17

10 **Adjustment Description:** To reflect the reduction in salaries and other related expenses
11 related to the reduction in force as part of the organizational redesign.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 27 - Merger Transition Cost to Achieve Amortization Elimination

Twelve Months Ended March 31, 2024

Line No.	Description A	Total Company B	Allocation Factor C	District of Columbia D = B * C
1	**Transition Cost Amortization**			
2	Account 921003 - Merger Transition Amortization Expense	$ 308,014	16.98%	$ 52,311
3	**Elimination of Merger Transition Amortization Expense**			**$ (52,311)** 17

4 **Adjustment Description:** To eliminate merger-related cost to achieve amortizaton for the period for twelve months
5 ending March 2024.

Note: The merger amortizations ended in July 2023

_1/ For class cost purposes, the full amount of this adjustment relates to COSA line EX 5:5.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 28 - Credit/Debit Card Transaction Fees Elimination

Twelve Months Ended March 31, 2024

Line No.	Description	Reference		MD Amount
	A	B		C
1	Credit/Debit Card Transaction Fees (Per Book)	EX:7:16	$	478,381
2	ACH Payment Increase	Analysis	$	66,585
3	Net Credit/Debit Card Fees	Ln. 1 - Ln. 2	$	411,796
4	Elimination of Credit/Debit Card Transaction Fees		$	(411,796) 17

5 **Adjustment Description:** To eliminate credit/debit card fees for twelve months ended March 31, 2024.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 14 - Involuntary Separation Program Cost to Implement Amortization

Twelve Months Ended March 31, 2024

Line	Description	Reference		System
1	Severance	Workpaper 1	$	4,479,772
2	COBRA Continuation Coverage	Adj 13		730,291
3	Short-Term Incentive	Workpaper 1		144,628
4	Paid Time Off	Workpaper 1		360,408
5	Outplacement Services	ledger		32,000
6	Additional Security Costs	ledger		35,112
7	Consultant Services for Organizational Redesign	Analysis		1,216,372
8	Cost to Implement Organizational Redesign	Lns. 1 to 7	$	6,998,583
9	Annual Amortization (System)	Ln. 8 / 5	$	1,399,717
10	DC Labor Factor	AL 4:11		19.36%
11	Annual Amortization (DC)	Ln. 9 * Ln. 10	$	271,011 17

12 **Adjustment Description:** To reflect the costs associated with implementing the April 2024
13 Involutary Separation Program amortized over 5 years.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 - Ratemaking Revenues and Related Expenses Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Book Amount	Distribution Adjustments	Distribution-Only Amount	Ratemaking Adjustments	Ratemaking Amount 2/
	A	B	C	D	E = C + D	F	G = E + F
1	**Operating Revenues**						
2	Base Revenues						
3	Base Rate Revenues (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	$ 127,731,965	$ -	$ 127,731,965	$ 18,877,467	$ 146,609,432
4	Distribution Charge & Plant Recovery Adjustments	Rev WP 1 + Adj 1 WP 7	(8,444,784)	-	(8,444,784)	8,444,784	-
5	Peak Usage Charge	Rev WP 1 + Adj 1 WP 7	4,254,611	-	4,254,611	229,056	4,483,667
6	Fuel Revenues _1/	Rev WP 1 + Adjs 1D, 2D, 4D	69,417,982	(69,417,982)	-	-	-
7	Revenue Taxes						
8	DC Right of Way Tax (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	12,367,741	-	12,367,741	(2,457,862)	9,909,879
9	Delivery Tax (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	19,243,088	-	19,243,088	1,978,792	21,221,880
10	Sustainable Energy Trust Fund (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	16,438,143	-	16,438,143	4,900,753	21,338,896
11	Energy Assistance Trust Fund (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	2,109,146	-	2,109,146	257,838	2,366,984
12	Non-District of Columbia Tariff Rates & Revenue Taxes	Rev WP 1 + Adj 1 WP 7	(50,138)	-	(50,138)	50,138	-
13	Off-System Sales Revenue (Asset Optimization)	Rev WP 1 + Adj 5D	14,177,234	(14,177,234)	-		-
14	PROJECTpipes	Rev WP 1 + Adj 1 WP 7	13,157,184	-	13,157,184	(13,157,184)	-
15	Sales of Gas to Customers (excl. CNG customers)	Sum Lns. 2 to 14	$ 270,402,172	$ (83,595,216)	$ 186,806,956	$ 19,123,782	$ 205,930,738
16	Late Payment Fees	Rev WP 1 + Adj 7D + Adj 1 WP 8	3,605,596	(360,143)	3,245,453	332,243	3,577,696
17	Other Operating Revenues	Adj No. 1, Page 2, Line 40	2,897,112	(736,920)	2,160,192	(41,088)	2,119,103
18	**Total Operating Revenues (RV 1:35)**	**Sum Lns. 15 to 17**	**$ 276,904,880**	**$ (84,692,279)**	**$ 192,212,601**	**$ 19,414,936**	**$ 211,627,537**
19	**Revenue Related Expenses**						
20	Uncollectible Accounts Expense	EX 7:19 + Adj 2D + Adj 1 WP 9	$ 6,226,265	$ (1,694,830)	$ 4,531,435	$ 1,038,168	$ 5,569,603
21	Delivery Tax Expense Expense (excl. PSC assessment)	EX 8:8 + Adj 1 WP 10	18,979,968	-	18,979,968	2,241,912	21,221,880
22	Rights of Way Fee Expense	EX 8:9 + Adj 1 WP 11	12,518,268	-	12,518,268	(2,608,389)	9,909,879
23	Sustainable Energy Trust Fund	EX 8:17 + Adj 1 WP 12	16,761,017	-	16,761,017	4,577,879	21,338,896
24	Energy Assistance Trust Fund Fee	EX 8:17 + Adj 2 WP 13	2,156,914	-	2,156,914	210,070	2,366,984
25	**Total Revenue Related Expenses**	**Sum Lns. 20 to 24**	**$ 56,642,432**	**$ (1,694,830)**	**$ 54,947,602**	**$ 5,459,640**	**$ 60,407,242**

26 **Adjustment Description:** To adjust Operating Revenues to a Ratemaking basis.

Adjustment No. 31

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 10D & 31 - State and Federal Income Taxes (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Distribution Amount C	Ratemaking Amount D	
1	**Net Operating Income - Adjusted**	**DC Inc Stmt, Ln. 18**	$ 2/ **20,999,112**	$ 2/ **27,756,328**	
2	Add: Income Taxes	DC Inc Stmt, Ln. 12	2/ 448,015	2/ 614,762	
3	Less: Interest Expense	Adj 8D / Adj 29, Ln. 4	3/ (18,811,557)	3/ (17,980,262)	
4	Taxable Income	Ln. 1 + Ln. 2 + Ln. 3	2,635,571	10,390,828	
5	Flow-Throughs and Permanent Items (Basis)				
6	AFUDC Equity	Per Book ETR / Analysis	5/ 70,134	5/ 18,597	
7	Meals and Entertainment	Per Book ETR / Analysis	184,959	184,959	
8	Compensation Limitation	Per Book ETR / Analysis	-	-	
9	Parking	Per Book ETR / Analysis	96,216	96,216	
10	R&D credit	Per Book ETR / Analysis	-	-	
11	Return to Provision True Up	Per Book ETR / Analysis	(806,112)	-	
12	Other Tax Adjustments	Per Book ETR / Analysis	(176,160)	-	
13	NOL Flow-through	Adj. 32	-	-	
14	Total Flow-Throughs and Permanent Items	Ln. 6 > Ln. 12	(630,964)	299,771	
15	Taxable Income (Adjusted)	Ln. 4 + Ln. 14	2,004,607	10,690,600	
16	Federal Income Tax	5/ Ln. 15 * 21.00%	420,968	2,245,026	5/ Sum of A = $5,257,284
17	Add: Excess Deferred Tax (Protected)		5/ -	5/ 5,397,883 A	
18	Add: Excess Deferred Tax (Unprotected)		-	(7,908,370)	
19	Add: Excess Deferred Tax on PLR NOL			(140,599) A	
20	Less: Remove EDIT amortization related to FC 1027 Write Off			343,555	
21	Add: Capitalizated OPEB		(12,689)	-	
22	Add: ITC		(90,913)	(90,913)	
23	Add: Amortization of Prior Flow-Through Balance		-	71,421	
24	Total Federal Income Taxes	Ln. 17 > Ln. 22	317,365	(81,998)	
25	Per Book / Ratemaking Federal Income Taxes		2,780,984 B	317,365 C	
26	Federal Income Tax Adjustment	Ln. 24 - Ln. 25	(2,463,619)	(399,363)	
27	State Income Tax (Net of Federal Tax Benefit)	5/ Ln. 15 * 6.52%	130,650	696,760	
28	Per Book / Ratemaking State Income Taxes		756,509 B	130,650 C	
29	State Income Tax Adjustment	Ln. 27 - Ln. 28	(625,859)	566,110	
30	Income Tax Adjustment	Ln. 26 + Ln. 29	(3,089,477) 2	166,747 2	

31 **Adjustment Description:** To adjust state and federal income tax to rate year amounts.

2/ Sum of B = $3,537,493
2/ Sum of C = $448,015

Washington Gas Light Company
District of Columbia Jurisdiction

Income Statement and Rate of Return Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Books	Distribution Adjustments	Distribution Amounts	Ratemaking Adjustments	Ratemaking Amounts	Revenue Deficiency	ROE Amounts
	A	B	C	D	E = C + D	F	G = E + F	H	I = G + H
1	Operating Revenues	Adj List Pg 1, Ln. 11	$ 276,904,880	$ (84,692,285)	$ 192,212,595	$ 19,414,936	$ 211,627,531	$ 45,572,411	$ 257,199,942
2	Operating Expenses								
3	Operation	Adj List Pg 1, Ln. 41	$ 125,293,859	$ (68,209,263)	$ 57,084,597	$ (267,932)	$ 56,816,665	$ 1,200,094	$ 58,016,759
4	Maintenance	Adj List Pg 1, Ln. 20	25,568,839	-	25,568,839	356,972	25,925,811	-	25,925,811
5	Depreciation	Adj List Pg 1, Ln. 44	23,907,431	-	23,907,431	7,922,823	31,830,254	-	31,830,254
6	Amortization of General Plant	Per Books	1,878,281	-	1,878,281	-	1,878,281	-	1,878,281
7	Amortization of Capitalized Software	Adj List Pg 1, Ln. 45	3,757,163	(97,980)	3,659,183	-	3,659,183	-	3,659,183
8	Amortization of Unrecovered Plant Loss	Per Books	100,274	-	100,274	-	100,274	-	100,274
9	Interest on Customer Deposits	Adj List Pg 1, Ln. 48	41,769	-	41,769	35,315	77,084	-	77,084
10	Interest on Supplier Refunds	Per Books	11,533	(11,533)	-	-	-	-	-
11	General Taxes	Adj List Pg 2, Ln. 7	58,992,535	-	58,992,535	4,443,796	63,436,331	-	63,436,331
12	Expenses Before Income Taxes	Sum of Lns. 3 > 11	$ 239,551,685	$ (68,318,776)	$ 171,232,910	$ 12,490,974	$ 183,723,884	$ 1,200,094	$ 184,923,978
13	Income Taxes	Adj List Pg 2, Ln. 10	5/ 3,537,493 1	1/ (3,089,477)	448,015 1	1/ 166,747	614,762 1	12,210,152	12,824,914
14	Total Operating Expenses	Sum of Lns. 12 + 13	$ 243,089,178	$ (71,408,253)	$ 171,680,925	$ 12,657,721	$ 184,338,646	$ 13,410,246	$ 197,748,892
15	Net Operating Income	Ln. 1 - Ln. 14	$ 33,815,702	$ (13,284,032)	$ 20,531,669	$ 6,757,215	$ 27,288,885	$ 32,162,165	$ 59,451,050
16	Net Income Adjustments								
17	AFUDC	Per Books	467,443	-	467,443	-	467,443	-	467,443
18	Net Operating Income - Adjusted	Sum of Ln.s 15 > 17	$ 34,283,145	$ (13,284,032)	$ 20,999,112 1	$ 6,757,215	$ 27,756,328 1	$ 32,162,165	$ 59,918,493
19	Net Rate Base	Rate Base Stmt, Ln.23	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (35,183,527)	$ 760,992,964	$ -	$ 760,992,964
20	Return Earned	Ln. 18 / Ln. 19	4.22%		2.64%		3.65%		7.87%
21	Return on Common Equity								
22	Interest Expense		$ 19,142,496	$ (330,939)	$ 18,811,557	$ (831,295)	$ 17,980,262		$ 17,980,262
23	Net Income Available for Common Equit	Ln. 18 - Ln. 22	$ 15,140,649		$ 2,187,555		$ 9,776,066		$ 41,938,231
24	Common Equity Ratio	Cost of Capital, Ln. 3	52.49%		52.49%		52.49%		52.49%
25	Common Equity Capital	Ln. 19 * Ln. 24	$ 426,291,579		$ 417,878,033		$ 399,411,746		$ 399,411,746
26	Return Earned on Common Equity	Ln. 23 / Ln. 25	3.55%		0.52%		2.45%		10.50%

Washington Gas Light Company
District of Columbia Jurisdiciton

Adjustment No. 8D & 29 - Interest on Debt (Distribution and Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	System Amount	Distribution Amount	Ratemaking Amount
	A	B	C	D	E
1	**Interest on Total Debt**				
2	Net Rate Base	Rate Base Stmt, Ln.23	$ 4,284,239,876	$ 796,176,491	$ 760,992,964
3	Weighted Average Cost of Debt	Cost of Capital, Ln. 1 + Ln. 2	2.36%	2.36%	2.36%
4	Interest on Debt	Ln. 2 * Ln. 3	$ 101,225,321	$ 18,811,557 1	$ 17,980,262 1
5	Per Books Interest Expense	Per Books	100,062,947	19,142,496	18,811,557
6	Adjustment to Interest Expense _1/	Ln. 4 - Ln. 5	$ 1,162,374	$ (330,939)	$ (831,295)

7 **Adjustment Description**: To synchronize interest expense used in determining the overall return requirement with the interest
8 expense used to calculate income taxes.

_1/ For purposes of the class cost study, the full amount of this adjustment relates to COSA line 9:16.

CUBE: tm1serv:ETR Cube
ETR Study# Study#292
ETR_Period Mar-2024

Washington Gas Light Company
ETR Calculation by Jurisdiction
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Ln.		System Basis	System Tax rate	System Taxes	DC Basis	DC Tax rate	DC Taxes	MD Basis	MD Tax rate	MD Taxes	VA Basis	VA Tax rate	VA Taxes	Ferc Basis	Ferc Tax rate	Ferc Taxes
		274,833,320			18,678,142	18,678,142		111,922,024	111,922,024		141,269,347	141,269,347		2,963,808	2,963,808	
					-			-			-			-		
1	**Taxable Income Before Permanent Items**	274,833,320	26.58%	73,049,193	18,678,142 5	26.58% 5	4,964,548 5	111,922,024	26.58%	29,748,262	141,269,347	26.58%	37,548,620	2,963,808	26.58%	787,764
2	Flow-Through, Permanent Items, and Other Tax Adjustments															
3	Depreciation	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
4	Cost of Removal	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
5	AFUDC Equity	-	0.02%	50,092	70,134	0.10%	18,608	118,666	0.03%	31,484	-	0.00%	-	-	0.00%	-
6	Excess Deferred	-	-2.73%	(7,509,698)	-	-5.41%	(1,010,925)	-	-3.17%	(3,551,810)	-	-2.09%	(2,946,963)	-	0.00%	-
7	Meals and Entertainment	-	0.09%	253,970	184,959	0.26%	49,073	410,911	0.10%	109,022	361,359	0.07%	95,875	-	0.00%	-
8	Medicare Part D	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
9	FAS 123 R - write off	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
10	Non-deductible executive compensation under 162(m) (Perm item, est.)	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
11	Return to Provision True-Up	-	-0.58%	(1,588,785)	(806,112)	-1.15%	(213,876)	(2,832,214)	-0.67%	(751,437)	(2,349,909)	-0.44%	(623,472)	-	0.00%	-
12	Capitalized OPEB	-	-0.02%	(60,597)	(46,113)	-0.07%	(12,235)	(182,281)	-0.04%	(48,362)	-	0.00%	-	-	0.00%	-
13	Unprotected EDIT Amortization	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
	Prior Period Flow through Income Tax															
14	Reg Asset- VA	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
15	Charitable Contributions	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
16	Parking	-	0.05%	132,115	96,216	0.14%	25,528	213,756	0.05%	56,713	187,979	0.04%	49,874	-	0.00%	-
16	R&D credits	-	-0.27%	(753,411)	-	-0.78%	(145,577)	-	-0.29%	(323,418)	-	-0.20%	(284,417)	-	0.00%	-
17	Other Tax Adjustments	-	-0.13%	(347,198)	(176,160)	-0.25%	(46,738)	(618,925)	-0.15%	(164,212)	(513,527)	-0.10%	(136,248)	-	0.00%	-
18	Total Flow-through, Permanent Items, and Other Tax Adjustments	-	-3.57%	(9,823,512)	(677,077)	-7.15%	(1,336,142)	(2,890,087)	-4.15%	(4,642,020)	(2,314,097)	-2.72%	(3,845,351)	-	0.00%	-
19	Investment Tax Credit (ITC)	-	-0.11%	(305,994)	-	-0.49%	(90,913)	-	-0.10%	(108,018)	-	-0.08%	(107,064)	-	0.00%	-
20	Total Tax & Effective tax Rate	274,833,320	22.89%	62,919,686	18,001,065	18.94%	3,537,492	109,031,937	22.34%	24,996,224	138,955,249	23.78%	33,596,205	2,963,808	26.58%	787,764

Washington Gas Light Company
District of Columbia Juris

Income Tax Proof

Twelve Months Ended March 31, 2024

Line No.	Description	Per Books Amount	Per Books Tax Rate	Per Books Taxes	Distribution Amount	Distribution Tax Rate	Distribution Taxes	Ratemaking Amount	Ratemaking Tax Rate	Ratemaking Taxes	After Required Increase Amount	After Required Increase Tax Rate	After Required Increase Taxes
	A	C	D	E	F	G	H	I	J	K	I	J	K
1	**Net Operating Income - Adjusted**	**$ 34,283,145**			**$ 20,999,112**			**$ 27,756,328**			**$ 59,918,493**		
2	Income Taxes	3,537,493			448,015			614,762			12,824,914		
3	Net Operating Income, Before Tax	37,820,638			21,447,128			28,371,090			72,743,407		
4	Less: Interest Expense	19,142,496			18,811,557			17,980,262			17,980,262		
5	**Taxable Income**	**18,678,142**			**2,635,571**			**10,390,828**			**54,763,145**		
6	Effective Tax Rate	18.94%			17.00%			5.92%			23.42%		
7	**Reconciliation of the Effective Tax Rate**												
8	Taxable Income Before Permanent Items	4/ 18,678,142	4/ 26.58%	4/ 4,964,548	2,635,571	27.52%	725,243	10,390,828	27.52%	2,859,296	54,763,145	27.52%	15,069,448
9	Flow-Through and Permanent Items												
10	AFUDC Equity	70,134	0.10%	18,608	70,134 ①	0.73%	19,299	18,597 ①	0.05%	5,117	18,597	0.01%	5,117
11	Meals and Entertainment	184,959	0.26%	49,073	184,959	1.93%	50,896	184,959	0.49%	50,896	184,959	0.09%	50,896
12	Compensation Limitation	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
13	Parking	96,216	0.14%	25,528	96,216	1.00%	26,476	96,216	0.25%	26,476	96,216	0.05%	26,476
14	R&D credits	-	-0.78%	(145,577)	-	0.00%	-	-	0.00%	-	-	0.00%	-
15	Amortization of Prior Flow-Through Bal (COR	-	0.00%	-	-	0.00%	- ①	259,549	0.69%	7/ 71,421 ①	259,549	0.13%	71,421
16	Excess Deferred (Protected) _1/	-	-5.41%	(1,010,925)	-	0.00%	-	6/ 19,616,181	50.60%	5,257,284	19,616,181	9.60%	5,257,284
17	Excess Deferred (Unprotected) _1/	-	0.00%	-	-	0.00%	-	6/ (28,739,422)	-76.11%	(7,908,370)	(28,739,422)	-14.44%	(7,908,370)
18	Excess Deferred - FC 1027 Write Off		0.00%		-	0.00%	-	1,248,495	3.31%	8/ 343,555	1,248,495	0.63%	343,555
19	Capitalized OPEB	(46,113)	-0.07%	(12,235)	(46,113)	-0.48%	(12,689)		0.00%	-		0.00%	-
20	Return to Provision True-up	(806,112)	-1.15%	(213,876)	(806,112) ①	-8.42%	(221,822)	①	0.00%	-		0.00%	-
21	Other Tax Adjustments	(176,160)	-0.25%	(46,738)	(176,160) ①	-1.84%	(48,475)	①	0.00%	-		0.00%	-
22	Total Flow-through and Permanent Items	(677,077)	-7.15%	(1,336,142)	(677,077)	-7.07%	(186,315)	(7,315,425)	-20.73%	(2,153,621)	(7,315,425)	-3.93%	(2,153,621)
23	Investment Tax Credit (ITC)	(90,913)	-0.49%	(90,913)	(90,913)	-3.45%	(90,913) ①	(90,913)	-0.87%	(90,913) ①	(90,913)	-0.17%	(90,913)
24	Total	17,910,152	18.94%	3,537,492 ②	1,867,581	17.00%	448,015	2,984,490	5.92%	614,762	47,356,807	23.42%	12,824,914
25	Tax Variance			-			-			-			-
26	Pre-tax Variance			-			-			-			-

Calculation of Combined Income Tax Rates	(a) Per Book		(b) Distribution		(c) Ratemaking		(d) Revenue Requirement	
Federal Income Tax Rate				21.00% ①		21.00%		21.00%
State Income Tax Rate			8.25%		8.25%		8.25%	
Federal Benefit of State Taxes			-1.73%		-1.73%		-1.73%	
State Income Tax Rate net of Federal Benefit				6.52% ①		6.52%		6.52%
Combined Tax Rate		26.58%		27.5175%		27.52%		27.52%

Notes
_1/ "Excess Deferred (Protected)" tax basis and tax amount includeds both the protected and unprotected amount for per book and distribution. Protected and unprocted excess deferred taxes are calcualted separately for ratemaking pu

Washington Gas Light Company
District of Columbia Jurisdiction

Estimate of Excess Deferred Income Taxes - Annual Revenue Requirement (Plant)

Line No.	Description	Reference	Protected Differences: Deferred Tax Liability - Plant Method/Life Differences	Protected Differences: Deferred Tax Asset - NOL	Unprotected Differences /5: Deferred Tax Liability - Plant Basis and State Differences	Unprotected Differences /5: Non-Plant ADIT	DC Amount	
	A	B	C _2/	D _3/		E _4/	F = E + D + C	
1	ADIT Balance Before Reduction in Federal Tax		(63,509,794)	7,249,611	(93,309,418)	1,088,207	(148,481,394)	
2	ADIT Balance After Reduction in Federal Tax Rate		(38,179,031)	4,349,767	(65,043,833)	652,924	(98,220,174)	
3	Change in ADIT Balance	Ln 1 - Ln 2	(25,330,763)	2,899,844	(28,265,584)	435,283	(50,261,220)	
4	Amortization Periods (Years)		_1/	15	15	15		
5	ARAM / Amortization Protected	Ln 3 / Ln 4	(5,204,560) _1/	(193,323)	7,937,389	(29,019)	2,510,488	(19,616,181) 5
7	Tax Gross Up Factor	_6/	39.10%	39.10%	39.10%	39.10%	39.10%	28,739,422 5
8	Gross Up Amount	Ln. 5 * Ln. 7	(2,035,035)	(75,591)	3,103,599	(11,347)	981,626	0
9	ARAM Currently in Rates	Tax Analysis	(169,545)				(169,545)	
10	Annual Revenue Requirement	Ln. 5 + Ln. 8 - Ln. 9	(7,070,049)	(268,914)	11,040,988	(40,366)	3,661,659	

Notes:

_1/ Representative level of amortization under the Average Rate Assumption Method (ARAM)
_2/ The balance of the deferred tax liability is estimated at 12/31/17
_3/ The balance of the deferred tax asset NOL at 09/30/17 allocated from the jurisdictional Per Book Cost of Service Study.
_4/ The balance of the non-plant ADIT at 09/30/17 allocated from the jurisdictional Per Book Cost of Service Study.
_5/ Unprotected plant difference amortized over 29 year average remianing service life of plant as the PSC adopted in Order No. 18712.
_6/ Tax Gross Up Factor Calculation:

A	New Statutory Rate	28.1100%
B = (1-A)		71.8900%
C	Gross Up Factor (Tax)	39.1010%

New Statutory Combined Rate

	Revised Rate Calc.
Statutory Rate - State	9.0000%
Statutory Rate - Federal	21.000%
Statutory Rate - Federal Benefit of State Tax	(0.0189)
Revised Statutory Tax Rate - Total	28.1100%

		DC FY17 End of Period Amount
Balance of Flowthrough Taxes at 9/30/17	$	1,071,321
Average Remaining Service Life		15
Amortization	$	71,421 (5)
Tax Gross-up		71.890%
Amortization Revenue Requirement	$	99,348
Replace Existing Flowthroughs	$	124,715.25
Grossed-up To Revenue Requirement	$	173,480.67
Net Change for Going to Full Normalization	$	(74,132.51)

Washington Gas Light Company
District of Columbia
FC 1027 Impairment amortization write off

	EDIT @ 1/1/2018	W/O EDIT - 1027 Impairment	Amortization for the W/O
DC/CM EDIT at 1/1/2018 p/Jurisdictional Exhibits			15 years
Federal Unprotected	27,146,225.89	(4,860,918.03)	
VA Unprotected	(812,296.97)	50,696.31	
MD Unprotected	559,440.66	(106,728.52)	
DC Unprotected	1,597,905.54	(159,705.66)	
WV Unprotected	380,834.59	5,604.27	
PA Unprotected	(629,706.81)	(81,790.51)	
NY Unprotected	23,181.40	(478.00)	
Total Unprotected	28,265,584.29	(5,153,320.15)	(343,554.68) 5

Adjustment No. 32

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 32 - NOLC Deferred Tax Asset (DTA) - Tax Normalization - Private Letter Ruling

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	System Amount C	DC Amount D
	Jurisdictional Realignment			
1	NOL Carryforward Federal Change	Workpaper 1 Ln. 14	$ 2/ 33,558,317	$ 2/ 6,403,501
2	NOL Carryforward State Change	Workpaper 1 Ln. 16	4,492,597	857,264
3	NOL Federal Benefit of State	Workpaper 1 Ln. 15	(943,445)	(180,026)
4	**Total NOL Change**	**Ln. 1 + Ln. 2 + Ln. 3**	**$ 37,107,469**	**$ 7,080,740**
5	Other Tax Credits - FED Change	Workpaper 1 Ln.	$ (32,614,872)	$ (5,451,639)
6	Other Tax Credits - STATE Change	Workpaper 1 Ln. 18	(4,492,597)	(750,946)
7	**Total Other Tax Credits Change**	**Ln. 5 + Ln. 6**	**$ (37,107,469)**	**$ (6,202,585)**
8	Net Change to Rate Base Deductions	Ln. 4 + Ln. 7	$ -	$ 878,155
9	**NOLC DTA**			
10	System Federal NOLC Depreciation	Workpaper 2	3/ 828,320,426	
11	Statutory Tax Rate		21%	
12	System Federal DTA- NOLC Depreciation	Ln. 10 * Ln. 11	173,947,289	
13	Test Year Amount	Analysis	$ 2/ (31,146,839)	
14	Increase in Federal DTA	Ln. 12 - Ln. 13	142,800,451	
15	District of Columbia Net Rate Base as of 03/31/2024	AL 3:6		6/ 19.08%
16	**Increase in DC DTA-NOLC Depreciation**	**Ln. 14 * Ln. 15**		**$ (27,248,768)**
	EDIT			
17	PLR effect on EDIT	Analysis	5/ (815,594)	
18	District of Columbia Net Rate Base as of 9/30/2017	AL 3:6		8/ 17.24%
19	**Income Tax Expense**	**Ln. 17 * Ln. 18**		**$ (140,599)**

20 **Adjustment Description:** To adjust rate base and expenses to comply with the IRS PLR and correct per book NOL and other tax
21 credit balances.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 32 - Work Paper 1 - NOL and Other Credits Per Book Realignment

Twelve Months Ended March 31, 2024

Line	Description A	Refernce B		System (Average) C	Factor D	DC Amount E
1	**COSA (as reflected in WG (F)-2)**					
2	NOL - FED	RB 1:18	(36,941,084)	9/ (78,173,336)	6/ 19.08%	(14,916,809)
3	NOL Contra State	RB 1:19	13,741,710	14,411,625	19.08%	2,749,985
4	NOL - STATE	RB 1:20	(65,436,714)	(68,626,785)	19.08%	(13,095,164)
5			(88,636,088)	(132,388,496)		(25,261,989)
6	Other Tax Credits - FED	RB 11:10	18,738	10/ 42,018,160	16.72%	7,023,417
7	Other Tax Credits - STATE	RB 11:10	(25,967,369)	(14,924,046)	16.72%	(2,494,583)
8	Total Other Tax Credits	Ln. 6 + Ln. 7	(25,948,631)	27,094,114		4,528,834
9	**COSA (corrected balances)**					
10	NOL - FED	Ln. 25 + Ln. 12 * 21%	(50,246,115)	(44,615,018)	19.08%	(8,513,309)
11	NOL Contra State	-Ln. 12 * 21%	13,726,965	13,468,179	19.08%	2,569,959
12	NOL - STATE	Ln. 26	(65,366,501)	(64,134,187)	19.08%	(12,237,900)
13	Total NOL	Ln. 10 + Ln. 11 + Ln. 12	(101,885,651)	(95,281,026)		(18,181,249)
14	NOL - FED Difference	Ln. 10 - Ln. 2	(13,305,031)	1 33,558,317	19.08%	6,403,501 1
15	NOL Contra State Difference	Ln. 11 - Ln. 3	(14,745)	(943,445)	19.08%	(180,026)
16	NOL - STATE Difference	Ln. 12 - Ln. 4	70,213	4,492,597	19.08%	857,264
17	Total NOL Difference	Ln. 14 + Ln. 15 + Ln. 16	(13,249,563)	37,107,469		7,080,740
18	Other Tax Credits - FED	Ln. 6 - Ln. 14 - Ln. 15	13,338,514	9,403,288	7/ 16.72%	1,571,778
19	Other Tax Credits - STATE	Ln. 7 - Ln. 15 - Ln. 16	(26,037,582)	(19,416,643)	16.72%	(3,245,529)
20	Total Other Tax Credits	Ln. 18 + Ln. 19	(12,699,068)	(10,013,355)		(1,673,752)
21	Other Tax Credits - FED Difference	Ln. 18 - Ln. 6	13,319,776	(32,614,872) 1	7/ 16.72%	(5,451,639) 1
22	Other Tax Credits - STATE Difference	Ln. 19 - Ln. 7	(70,213)	(4,492,597)	16.72%	(750,946)
23	Total Other Tax Credits Difference	Ln. 21 + Ln. 22	13,249,563	(37,107,469)		(6,202,585)
24	**GL Balance for NOLC Accounts**					
25	190867 - ADIT- Federal NOL	Account 190867	(36,519,150)	(31,146,839) 1	6/ 19.08%	(5,943,350)
26	190868 - ADIT - State NOL	Account 190886	(65,366,501)	(64,134,187)	19.08%	(12,237,900)
27	Total ADIT for NOL (per GL)	Ln. 25 + Ln. 26	(101,885,651)	(95,281,026)		(18,181,249)

NOTE: A portion of the NOL depreciation is included in "Other Tax Credits" (RB 11:18) rather as NOLC in the jurisdictional allocation study (Exhibit WG (F)-2). This workpaper realigns the NOLC to tie to the general ledger balance by moving the NOLC-related amounts that are

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 32 - Workpaper 2 - NOLC DTA Balance By Period

Twelve Months Ended March 31, 2024

Date	Annualized 2024 NOL	NOLC subject to Normalization Balance
12/31/2022		4/(737,954,503)
1/31/2023	4/ (10,583,396)	(748,537,899)
2/28/2023	(10,583,396)	(759,121,296)
3/31/2023	(10,583,396)	A (769,704,692)
4/30/2023	(10,583,396)	(780,288,089)
5/31/2023	(10,583,396)	(790,871,485)
6/30/2023	(10,583,396)	(801,454,881)
7/31/2023	(10,583,396)	(812,038,278)
8/31/2023	(10,583,396)	(822,621,674)
9/30/2023	(10,583,396)	(833,205,071)
10/31/2023	(10,583,396)	(843,788,467)
11/30/2023	(10,583,396)	(854,371,863)
12/31/2023	(10,583,396)	(864,955,260)
1/31/2024	-	(864,955,260)
2/29/2024	-	(864,955,260)
3/31/2024	-	(864,955,260)
Test Year 13 month Average at March 2024	average of A =	(828,320,426) 1

Filing Year	Tax Year	Carryback provision	Tax Depreciation Per Tax Return	Tax Depreciation Per 481 (a)	Tax Repairs Deduction 481(a)	Original WGL Taxable Income (Loss) Before carryback	WGL Taxable Income (Loss) Before carryback with 481(a) Adjustment	2009 Carryback	2012 Carryback	2015 Carryback	2016 Carryback	WGL Taxable Income (Loss) After carryback	exclude loss in excess of tax depreciation		Loss carryforward subject to normalization	
FYE 09/30/07	2006	2 year	115,460,748	(10,025,966)	8,803,197	119,933,779	121,156,548	(112,669,386)				8,487,162				
FYE 09/30/08	2007	2 year	156,285,517	7,408,151	(7,408,151)	90,070,214	90,070,214	(90,070,214)				-				
FYE 09/30/09	2008	2 year	148,732,453	9,522,771	(9,812,232)	(203,029,061)	(202,739,600)	202,739,600				-				
FYE 09/30/10	2009	2 year	144,701,820	4,266,697	(4,681,476)	113,673,879	114,088,658		(8,134,363)			105,954,295				
FYE 09/30/11	2010	2 year	161,016,485	6,266,561	(7,351,666)	13,026,937	14,112,042					14,112,042				
FYE 09/30/12	2011	2 year	152,142,399	2,758,389	(2,756,610)	(8,132,584)	(8,134,363)		8,134,363			-				
FYE 09/30/13	2012	2 year	134,368,426	(1,960,393)	2,927,546	93,063,605	92,096,452			(7,493,252)		84,603,200				
FYE 09/30/14	2013	2 year	159,584,096	846,062	(2,439,217)	35,265,686	36,858,841				(36,858,841)	-				
FYE 09/30/15	2014	2 year	167,166,009	(7,721,913)	10,259,757	(4,955,408)	(7,493,252)			7,493,252		-		A		
FYE 09/30/16	2015	2 year	169,793,731	(12,907,373)	25,475,642	(62,259,928)	(74,828,197)				36,858,841	(37,969,356)			(37,969,356)	
FYE 09/30/17	2016	2 year	204,405,259	(1,807,521)	1,829,704	(102,470,471)	(102,492,654)					(102,492,654)			(102,492,654)	
2018 SP 1 Ended 07/06/2018	2017	2 year	154,353,100	5,975,801	(16,011,266)	(13,996,735)	(3,961,270)					(3,961,270)			(3,961,270)	
2018 SP2 Ended 12/31/2018	2018	5 year	55,237,261	(18,082,643)	33,871,987	(298,352,237)	(314,141,581)					(314,141,581)	(120,619,332)		(193,522,249)	Cares Act
CYE 12/31/19	2019	5 year	121,585,022	(17,324,408)	54,079,045	(65,778,016)	(102,532,653)					(102,532,653)			(102,532,653)	Cares Act
CYE 12/31/20	2020	5 year	104,276,429	(10,347,536)	46,655,411	(106,019,384)	(142,327,259)					(142,327,259)	(48,398,366)		(93,928,893)	Cares Act
CYE 12/31/21	2021	none	102,938,551	396,982	(6,362,730)	(261,561,366)	(255,595,618)					(255,595,618)	(152,262,085)		(103,333,533)	
CYE 12/31/22	2022	none	103,418,702	(3,204,807)	96,047,882	(63,816,389)	(156,659,464)					(156,659,464)	(56,445,569)		(100,213,895)	
CYE 12/31/23	2023	none	127,000,757				(144,067,337)					(144,067,337)	(17,066,580)	B	(127,000,757)	Note A
Total			2,482,464,765	(45,941,146)	223,126,823	(725,337,479)	(1,046,590,493)	-	-	-	-	(1,259,747,192)	(394,791,932)		(864,955,260)	

Total tax deprec in carryforward period (2015-2022)	1,016,006,055	(1,152,538,696)
number of tax years included in period	8	8
avg annual tax deprec during carryforward period	127,000,757	(144,067,337)

Note A: These amounts represent an estimate based on the year end provision calculation. These amounts will be updated after completion of the tax year 2023 federal income tax return.

Sum of A = (737,954,503) 3

B/12 = (10,583,396) 3

Calculation of Deferred Tax Asset:

	(120,154,521)	35%	42,054,082	DTA on NOL carryforward at 35%	(based upon TCJA filing)
	(744,800,739)	21%	156,408,155	DTA on NOL carryforward at 21%	
	(864,955,260)		198,462,238	Total DTA before ASC740 adjustment to statutory rate	
	(864,955,260)	21%	181,640,605	DTA on NOL carryforward at statutory rate	
			16,821,633	Excess DTA on NOL Carryback - Agrees to previous filings for TCJA	
			21,293,206	grossed up regulatory asset for Excess DTA resulting from TCJA	
			(4,471,573)	deferred tax liability	
		annual	16,821,633	net APB11 regulatory asset amount recorded	
15 year Amort		1,121,442	6,728,653	previously amortized per rate orders(6years - 15 year amortization)	
est. ARAM amort		305,848	10,092,980	remaining amount required to be amortized using ARAM	
annual difference		815,594 1			
			181,640,605	deferred tax asset required to be restored per PLR	

Washington Gas Light Company
Allocation Factors Based on Gas Plant in Service

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Actual Construction Supplies Issued**									
2 **from Stores Stock**	Analysis	Stores _Stock	$ 781,698	$ 21,833	$ 269,494	$ 490,372	0.027930	0.344754	0.627316
3 **Adjusted Net Rate Base**									
4 Net Rate Base	RB:1:26		$ 4,256,466,925	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862			
5 Less: Chalk Point			-	-	-	-			
6 Adjusted Net Rate Base	= 4 - 5	Net_Rate_Base	$ 4,256,466,925	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	0.190817 1	2 0.372501	0.436682
7 **Net Gas Plant in Service**									
8 Gas Plant in Service	RB:1:1		$ 7,219,457,709	$ 1,317,182,832	$ 2,711,617,252	$ 3,190,657,625			
9 Gas Plant Held for Future Use	RB:1:2		-	-	-	-			
10 Construction Work In Progress	RB:1:4	CWIP	397,111,025	79,322,274	134,339,566	183,449,185	0.199748	0.338292	0.461959
11 Less: Reserve for Depreciation	RB:1:13		2,368,477,029	449,057,859	864,931,885	1,054,487,285			
12 Less: Accumulated Deferred Income taxes	RB:1:14		1,298,608,831	212,149,665	532,439,389	554,019,777			
13 Net Gas Plant in Service	= (8 > 10)-11-12	Net_GPIS	$ 3,949,482,875	$ 735,297,583	$ 1,448,585,543	$ 1,765,599,748	0.186176	0.366779	0.447046
14 Adjusted Construction Work In Progress	RB:5:29	ADJ_CWIP	$ 213,661,840	$ 79,322,274	$ 134,339,566	$ -	0.371251	0.628749	0.000000

		PBCOSA Dec-2023 Avg Study#288 Tot_GPIS_X_Chalk Point		Ratebase MACRS Plant Allocation Factor
Fed				
CMWG	93,017,678			
DCWG	155,232,386	0.184257	172,371,533.65	0.1671519 2
MDWG	377,255,272	0.372029	411,860,505.40	0.3993889
VAWG	405,721,347	0.443715	446,994,643.20	0.4334592
	1,031,226,682		1,031,226,682.25	
State				
CMWG	21,035,910			
DCWG	37,310,308	0.184257	41,186,319.68	0.1754048
MDWG	84,063,716	0.372029	91,889,675.62	0.3913409
VAWG	92,397,280	0.443715	101,731,219.11	0.4332542
	234,807,214		234,807,214.41	

Washington Gas Light Company
Allocation Factors Based on Gas Plant in Service

Twelve Months Ended September 2017 - EOP
Excluding FERC Portion

Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Actual Construction Supplies Issued**									
2 **from Stores Stock**	Analysis	Stores _Stock	$ 3,248,293	419,993.98	1,524,326.86	1,303,972.41	0.129297	0.469270	0.401433
3 **Adjusted Net Rate Base**									
4 Net Rate Base	RB:1:25		$ 2,539,480,732	$ 437,781,413	$ 996,792,808	$ 1,104,906,511			
5 Less: Chalk Point			(34,286)	-	(34,286)	-			
6 Adjusted Net Rate Base	=4-5	Net_Rate_Base	$ 2,539,515,018	$ 437,781,413	$ 996,827,094	$ 1,104,906,511	0.172388 1	0.392527	0.435086
7 **Net Gas Plant in Service**									
8 Gas Plant in Service	RB:1:1		$ 5,041,487,843	$ 880,522,480	$ 1,973,798,764	$ 2,187,166,599			
9 Gas Plant Held for Future Use	RB:1:2		-	-	-	-			
10 Construction Work In Progress	RB:1:3	CWIP	262,091,560	60,743,023	88,145,670	113,202,867	0.231763	0.336316	0.431921
11 Less: Reserve for Depreciation	RB:1:14		2,023,350,500	393,130,436	763,514,163	866,705,901			
12 Less: Accumulated Deferred Income taxes	RB:1:16		220,936,064	148,794,839	359,177,689	375,437,178			
13 Net Gas Plant in Service	=(8>10)-11-12	Net_GPIS	$ 2,396,819,197	$ 399,340,227	$ 939,252,583	$ 1,058,226,387	0.166613	0.391875	0.441513
14 Adjusted Construction Work In Progress	RB:5:17	ADJ_CWIP	$ 148,888,693	$ 60,743,023	$ 88,145,670	$ -	0.407976	0.592024	0.000000

Washington Gas Light Company
Rate Base Summary
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Gas Plant in Service	RB:3:17		$ 7,249,016,177	$ 1,317,182,832	$ 2,711,617,252	$ 3,190,657,625	$ 29,558,468
2	Gas Plant Held for Future Use	RB:4:13		-	-	-	-	-
3	Unrecovered Plant - Peaking Facility		Total_Weather_All_NW	-	-	-	-	-
4	Construction Work in Progress	RB:5:29		397,111,025	79,322,274	134,339,566	183,449,185	-
5	Materials & Supplies	RB:6:12		123,327,981	19,836,447	52,379,031	51,112,503	-
6	Non Plant - ADIT	RB:12:18	Financial Stmt.	(34,509,521)	(3,062,666)	(21,491,098)	(9,955,757)	0
7	FC 1027 - Rate Base CWIP (Reg Asset)			(0)	(0)			
8	Unamortized East Station Cost (Net of Deferred Taxes)		Financial Stmt.	1,075,846	1,075,846	-	-	-
9	Sub-Total	= 1>10		$ 7,736,021,508	$ 1,414,354,734	$ 2,876,844,750	$ 3,415,263,556	$ 29,558,468
10	Cash Working Capital	RB:7>9		$ 121,292,100	$ 39,219,091	$ 67,230,077	$ 14,826,433	$ 16,500
11	Total Rate Base Additions	= 9+10		$ 7,857,313,609	$ 1,453,573,825	$ 2,944,074,827	$ 3,430,089,989	$ 29,574,968
12	LESS:							
13	Reserve for Depreciation	RB:10:35		$ 2,370,279,045	$ 449,057,859	$ 864,931,885	$ 1,054,487,285	$ 1,802,016
14	Accumulated DIT re Depreciation	RB:11:21		1,298,608,831	212,149,665	532,439,389	554,019,777	0
15	Accumulated DIT re Gains/Losses On Reacquired Debt							
16	Federal	RB:11:9	Net_Rate_Base	175,290	29,300	70,009	75,981	-
17	State	RB:11:9	Net_Rate_Base	57,829	10,143	22,631	25,055	-
18	NOL Carryforward Federal		Net_Rate_Base	(78,173,336) 2	(14,916,809)	(29,119,631)	(34,136,895)	-
19	NOL Carryforward State		Net_Rate_Base	(68,626,785)	(13,095,164)	(25,563,533)	(29,968,088)	-
20	NOL Federal Benefit of State		Net_Rate_Base	14,411,625	2,749,985	5,368,342	6,293,298	-
21	Customer Advances for Construction		Financial Stmt.	2,698,381	305,769	244,862	2,147,750	-
22	Customer Deposits		Financial Stmt.	12,871,928	1,432,785	2,467,234	8,971,908	-
23	Supplier Refunds		Financial Stmt.	4,509,391	626,315	1,675,549	2,207,527	-
24	Deferred Tenant Allowance		Non_Genl_Plnt	16,261,534	3,017,287	6,000,718	7,243,529	-
25	Total Rate Base Deductions	= 13>24		$ 3,573,073,733	$ 641,367,135	$ 1,358,537,454	$ 1,571,367,128	$ 1,802,016
26	Net Rate Base	= 11 - 25		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952

Washington Gas Light Company
Accumulated Deferred Income Taxes
Modified Accelerated Cost Recovery System (MACRS)
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	---------Reference------ Sc-Pg-Ln	Allocator			WG	DC	MD	VA	FERC
	A	B	C			D	E	F	G	H
1	Avoided Cost of Interest		Macrs APB 11			$ (17,061,547)	$ (2,886,713)	$ (6,780,216)	$ (7,394,618)	$ -
2	Capitalized OPEB		Macrs APB 11			222,938	37,720	88,595	96,623	-
3	Capitalized Pension		Macrs APB 11			495,257	83,796	196,813	214,649	-
4	CIAC Contribs in Aid of Construct		Macrs APB 11			(7,068,198)	(1,195,915)	(2,808,866)	(3,063,416)	-
5	Cost of Removal - Net of Salvage		Macrs APB 11			30,921,154	5,231,613	12,288,049	13,401,491	-
6	Tax Depreciation - Utility		Macrs APB 11			394,484,673	66,618,859	156,889,706	170,976,108	-
7	Tax Depreciation - UTP		Macrs APB 11			-	-	-	-	-
8	Bk/Tx Unit of Property		Macrs APB 11			579,061,891	97,972,844	230,118,709	250,970,339	-
9	Amortization of Reacquisition Debt		Macrs APB 11			233,118	39,443	92,640	101,035	-
10	Other Tax Credits		Macrs APB 11			26,746,386	4,347,544	10,802,318	11,596,524	-
0			Macrs APB 11	Other Tax Credits - FED		42,018,160	7,023,417	16,761,587	18,213,156	-
0			Macrs APB 11	Other Tax Credits - STATE		(14,924,046)	(2,617,750)	(5,840,390)	(6,465,906)	-
			Macrs APB 11	R&D Credit - FED		(347,728)	(58,123)	(138,879)	(150,726)	-
			Macrs APB 11	R&D Credit - STATE		-	-	-	-	-
11	Disposition of Assets		Macrs APB 11			2,338,729	395,702	929,402	1,013,625	-
12	Repairs Deduction		Macrs APB 11			50,617,548	8,564,320	20,115,159	21,938,070	-
13	Excess Deferred Gross Up (Direct)		Financial Statement	254001 Balance	Excess Deferred Gross Up	324,983,819	44,401,403	153,046,134	127,536,283	-
14	Excess Deferred Gross Up (Allocable)		Macrs APB 11	254001 Balance	Excess Deferred Gross Up	26,884,429	4,493,784	10,737,343	11,653,302	-
15	Amortization of Excess Deferred (Direct)		Financial Statement	190225 Balance	FASB 109 Adjustment-Federal	(76,775,043)	(10,462,048)	(36,555,897)	(29,757,097)	-
16	Amortization of Excess Deferred (Allocable)		Macrs APB 11	190225 Balance	FASB 109 Adjustment-Federal	(8,364,813)	(1,398,195)	(3,340,814)	(3,625,805)	-
17	Amort of Excess Deferred Asset		Macrs APB 11			447,844	75,745	177,999	194,100	-
18	Other Adjustments		Macrs APB 11			(3,352,825)	(567,173)	(1,332,507)	(1,453,145)	-
19	Deferred Income Taxes (Direct)		Financial Statement		Subtotal	(23,908,456)	(3,218,460)	(11,307,818)	(9,382,179)	-
20	Deferred Income Taxes (Allocable)		Macrs APB 11		Subtotal	(2,064,955)	(345,161)	(824,720)	(895,074)	-
21	Total Plant ADIT	≡ 1 > 20				$ 1,298,841,949	$ 212,169,108	$ 532,532,029	$ 554,120,813	$ -

Washington Gas Light Company
District of Columbia Jurisdiction

Credit Metrics

Twelve Months Ended March 31, 2024

Line		Source	Book	Ratemaking
1	Net Income	RMPF DC Income Statement Exh WG (D)-1 Pg. 1 (Ln. 18 - Ln.	15,140,649	9,776,066
2	Depreciation & Amortization	RMPF DC Income Statement Exh WG (D)-1 Pg. 1 (Lns. 5 to 7)	29,542,876	37,367,719
3	Deferred Taxes	RMPF DC Income Statement Exh WG (D)-1 Pg. 1 (Ln. 14)	3,537,493	614,762
4	Accrued/deferred pension and other post-retirement benefit cost	Adjustments 7 & 8 Exh WG (D)-5	(6,626,956)	(7,822,986)
5	Compensation expense related to stock-based awards	Adjustment 6 Exh WG (D)-5	(3,390,371)	-
6	Regulatory Asset Amortizations	Sum Total	1,133,740	3,971,664
7	**Funds from Operations ("FFO")**	**Sum (Ln. 1 to Ln. 6)**	**39,337,430**	**43,907,225**
8	Net Rate Base	RMPF DC Income Statement Exh WG (D)-1 Pg. 1 (Ln. 20)	$ 812,206,690	$ 760,992,964
9	Debt Ratio	Utility Cost of Capital Exh WG (D)-1 Pg. 4	47.51%	47.51%
10	Debt	Ln. 8 * Ln. 9	$ 385,915,111	$ 361,581,218
11	FFO / Debt Ratio	Ln. 7 / Ln. 10	10.2%	12.1%
12	FFO	Ln. 7	39,337,430	43,907,225
13	Interest Expense:	RMPF DC Income Statement Exh WG (E)-1 Pg. 1 (Ln. 23)	19,142,496	17,980,262
14	FFO / Interest Ratio	Ln. 12 / Ln. 13	2.05	2.44

Washington Gas Light Company
District of Columbia Jurisdiction

Cash Flows

Twelve Months Ended March 31, 2024

Line		Source	Book	Ratemaking
1	Funds from Operations	FFO Schedule	39,337,430	43,907,225
2	Working Capital	RMPF Rate Base Exh WG (D)-1 Pg. 2 (Ln. 8)	(39,219,091)	(40,826,325)
3	Net Cash Provided by (Used in) Operating Activities	Ln. 1 + Ln. 2	118,340	3,080,899
4	**Capital Investments (Project*pipes* included in book amount only)**	**1/, 2/, 3/**	**(121,640,470)**	**(99,454,230)**
5	Net Cash Provided by (Used in) Investing Activities	Ln. 4	(121,640,470)	(99,454,230)
6	Cash Financing Requirements	Ln. 3 + Ln. 5	(121,522,130)	(96,373,331)

1/ Book amount from query of 107100 and 108xxx accounts excluding plant completions (resource type 3127). Ratemaking amount based projected 2025 expenditures.

2/ This amount includes expenditures for cost of removal, which are recorded at the time of the plant expenditure, as a use of funds from investing activity here. In contrast, the Company's cash flow statement includes cost of removal as a use of funds from operating activities (Line 16 "Other").

3/ Expenditures for accelerated replacement projects are included in both the Book and Ratemaking amounts.

Washington Gas Light Company
District of Columbia Jurisdiction
Reconciliation of the Cost of Service

Line No.	Reference			Amount
1	**Cost of Service Formal Case No. 1169**		**$**	**204,202,284**
	Changes in Rate Base Components			
2	Formal Case No. 1169 Average to End of Period ("EOP")			895,805
3	Rate Base Net Additions (January 2022-March 2023) EOP			8,604,593
4	Test Year Rate Base Net Additions (Average)			4,718,804
5	Total Rate Base Changes		$	14,219,202
	Changes in Net Operating Income Components			
6	Operation and Maintenance Expenses		$	9,690,324
7	Proposed New Depreciation Rates			7,691,665
8	Other Depreciation and Amortization Changes			3,858,781
9	General Taxes			8,383,293
10	Income Taxes			4,379,698
11	Miscellaneous			326,345
12	Net Operating Income Changes		$	34,330,107
	Changes in Cost of Capital Components			
13	Cost of Debt		$	1,719,193
14	Cost of Equity			2,577,722
15	Capital Structure			151,434
16	Cost of Capital Changes		$	4,448,349
17	**Total Increase in Cost of Service**		**$**	**52,997,658**
18	**Cost of Service Current Case**	**(Ln 1 + Ln 17)**	**$**	**257,199,942**

Exhibit WG (D)-8 Index

Washington Gas Light Company
District of Columbia Jurisdiction

Change in Cash Working Capital Requirement from Last Case

Twelve Months Ended March 31, 2024

	FC No. 1169 Final			Current			Change		
	DC RM Amount	DC Lag Days	DC Dollar Days	DC RM Amount	DC Lag Days	DC Dollar Days	DC RM Amount	DC Lag Days	DC Dollar Days
	A	B	C	D	E	F	G=D-A	H=E-B	I=F-C
Composite Revenue Lag		86.96			89.00			2.05	
Gas Purchased	$ 89,708,040	39.21	$ 3,517,499,543	$ 73,743,787	38.19	$ 2,816,268,422	$ (15,964,253)	(1.02)	$ (701,231,121)
Payroll	22,813,235	11.71	267,177,464	23,184,216	11.71	271,522,214	370,981	-	4,344,750
Other Operations and Maintenance Expenses				-					
Employee Health Benefits	4,343,696	30.37	131,904,144	4,873,579	30.37	147,994,982	529,883	-	16,090,838
Property and Public Liability Insurance	3,409,755	(163.46)	(557,372,917)	4,025,733	(163.46)	(658,063,186)	615,977	-	(100,690,269)
Other O&M	42,686,232	25.47	1,087,152,666	48,179,153	25.47	1,227,048,919	5,492,921	-	139,896,253
Less: Pension Benefit (Non Cash)	(16,464)	25.47	(419,317)	42,494	25.47	1,082,247	58,958	-	1,501,564
Less: OPEB Benefit (Non Cash)	5,672,405	25.47	144,467,439	6,584,462	25.47	167,696,128	912,057	-	23,228,689
Property Taxes	1,779,292	71.02	126,372,414	2,013,868	71.02	143,032,994	234,577	-	16,660,580
Delivery Tax	26,695,878	26.13	697,589,987	25,692,953	26.13	671,382,563	(1,002,925)	-	(26,207,424)
Rights-of-Way Fee	9,789,500	(54.53)	(533,821,441)	9,909,880	(54.53)	(540,385,729)	120,379	-	(6,564,288)
FICA Taxes	1,892,622	9.97	18,868,100	2,125,875	9.97	21,193,472	233,253	-	2,325,372
Unemployment Tax	63,139	9.99	630,965	(6,961)	9.99	(69,562)	(70,100)	-	(700,527)
Environmental Tax	-	-	-	-	-	-	-	-	-
Federal Excise Tax	17,898	(17.51)	(313,343)	(21,714)	(17.51)	380,156	(39,613)	-	693,499
Sustainable Trust Fund	12,485,762	26.13	326,265,451	21,338,896	26.13	557,606,691	8,853,134	-	231,341,240
Energy Assistance Fund	2,305,207	26.13	60,237,357	2,366,985	26.13	61,851,688	61,778	-	1,614,331
Firm Storage Service	5,161	308.86	1,594,096	29	308.86	8,840	(5,133)	-	(1,585,256)
Other Taxes - Direct Assignment	18,579	79.00	1,467,752	16,520	79.00	1,305,080	(2,059)	-	(162,672)
Income Taxes	2,084,860	-	-	(4,820,177)	-	-	(6,905,037)	-	-
Subtotal	$ 225,754,798	23.43	$ 5,289,300,359	$ 219,249,578	22.30	$ 4,889,855,917	$ (6,505,220)	(1.13)	$ (399,444,442)
Lead Lag Requirement	$ 618,506	63.53	39,291,138	$ 600,684	66.70	40,066,410	$ (17,823)	3.18	775,272
Other Lead-Lag Items									
Interest on Long-Term Debt	(170,720)	91.25	(170,720)	(1,162,234)	91.25	7,152	177,872	-	177,872
Economic Evaluation of Facility Extenstion (GSP 14)	13,700	-	13,700	752,764	-	752,764	739,064	-	739,064
Cash Working Capital - Ratemaking			$ 39,134,118			$ 40,826,325			$ 1,692,208

Cash Working Capital Formal Case No. 1169	$ 39,134,118
Increase in Revenue Lag	$ (319,097)
Decrease in Expenses	$ 1,094,368
Change in Other Lead/Lag Items	$ 916,936
Total Change in Cash Working Capital	$ 1,692,208
Requested Cash Working Capital	$ 40,826,325

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 29 - Cash Working Capital (Ratemaking)

Twelve Months Ended December 31, 2021

Line No.	Description	Reference	DC Dist. Amount	DC RM Adjustment	DC RM Amount	DC Lag Days	DC Dollar Days
	A	B	C	D	E	F	G = E x F
1	Composite Revenue Lag					86.96	
2	Gas Purchased	Adj 1 & Adj 6	$ 77,443,107	$ 12,264,933	$ 89,708,040	39.21	$ 3,517,499,543
3	Payroll	Adj 7 & Adj 8	24,080,658	(1,267,422)	22,813,235	11.71	267,177,464
4	Other Operations and Maintenance Expenses						
5	Employee Health Benefits	Adj 11	4,284,415	59,281	4,343,696	30.37	131,904,144
6	Property and Public Liability Insurance	Adj 17	2,750,282	659,474	3,409,755	(163.46)	(557,372,917)
7	Other O&M	Various	40,296,316	2,389,916	42,686,232	25.47	1,087,152,666
8	Less: Pension Benefit (Non Cash)		(16,464)	-	(16,464)	25.47	(419,317)
9	Less: OPEB Benefit (Non Cash)		5,672,405	-	5,672,405	25.47	144,467,439
10	Property Taxes		1,779,292	-	1,779,292	71.02	126,372,414
11	Delivery Tax	Adj 1 & Adj 6	22,881,236	3,814,642	26,695,878	26.13	697,589,987
12	Rights-of-Way Fee	Adj 1 & Adj 6	9,400,392	389,108	9,789,500	(54.53)	(533,821,441)
13	FICA Taxes	Adj 13	1,866,596	26,025	1,892,622	9.97	18,868,100
14	Unemployment Tax		63,139	-	63,139	9.99	630,965
15	Environmental Tax		-	-	-	-	-
16	Federal Excise Tax		17,898	-	17,898	(17.51)	(313,343)
17	Sustainable Trust Fund	Adj 1 & Adj 6	12,308,472	177,290	12,485,762	26.13	326,265,451
18	Energy Assistance Fund	Adj 1 & Adj 6	2,272,468	32,739	2,305,207	26.13	60,237,357
19	Firm Storage Service		5,161	-	5,161	308.86	1,594,096
20	Other Taxes - Direct Assignment		18,579	-	18,579	79.00	1,467,752
21	Income Taxes	Adj. 29	(2,199,588)	4,284,447	2,084,860	-	-
22	Subtotal	Sum of Lns. 2 > 21	$ 202,924,364	$ 22,830,433	$ 225,754,798	23.43	$ 5,289,300,359
23	Lead Lag Requirement	Ln. 22, Col. E / 365			$ 618,506	63.53	$ 39,291,138
24	Other Lead-Lag Items						
25	Interest on Long-Term Debt	Adj 27	819,672	(990,392)	(170,720)	91.25	(170,720)
26	Economic Evaluation of Facility Extenstion (GSP 14)	Accts. 186.200 & 174.400	13,700	-	13,700	-	13,700
27	Cash Working Capital - Ratemaking						$ 39,134,118
28	Cash Working Capital - Distribution Amount						36,069,502
29	Cash Working Capital Ratemaking Adjustment	RB:1:10					$ 3,064,615

Exhibit WG (D)-8
Summary of Changes

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 30 - Cash Working Capital (Ratemaking)

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	DC Dist. Amount	DC RM Adjustment	DC RM Amount	DC Lag Days	DC Dollar Days
	A	B	C	D	E	F	G = E x F
1	Composite Revenue Lag					89.00	
2	Gas Purchased	Adj 1	$ 66,068,873	$ 7,674,914	$ 73,743,787	38.19	$ 2,816,268,422
3	Payroll	Adj 5 & Adj 6	25,573,530	(2,389,314)	23,184,216	11.71	271,522,214
4	Other Operations and Maintenance Expenses						
5	Employee Health Benefits	Adj 9	4,793,783	79,796	4,873,579	30.37	147,994,982
6	Property and Public Liability Insurance	Adj 18	3,677,954	347,779	4,025,733	(163.46)	(658,063,186)
7	Other O&M	Various	48,736,805	(557,652)	48,179,153	25.47	1,227,048,919
8	Less: Pension Benefit (Non Cash)		42,494	-	42,494	25.47	1,082,247
9	Less: OPEB Benefit (Non Cash)		6,584,462	-	6,584,462	25.47	167,696,128
10	Property Taxes		2,013,868	-	2,013,868	71.02	143,032,994
11	Delivery Tax	Adj 1	23,451,041	2,241,912	25,692,953	26.13	671,382,563
12	Rights-of-Way Fee	Adj 1	12,518,268	(2,608,388)	9,909,880	(54.53)	(540,385,729)
13	FICA Taxes	Adj 12	2,103,553	22,322	2,125,875	9.97	21,193,472
14	Unemployment Tax		(6,961)	-	(6,961)	9.99	(69,562)
15	Environmental Tax		-	-	-	-	-
16	Federal Excise Tax		(21,714)	-	(21,714)	(17.51)	380,156
17	Sustainable Trust Fund	Adj 1	16,761,017	4,577,879	21,338,896	26.13	557,606,691
18	Energy Assistance Fund	Adj 1	2,156,914	210,071	2,366,985	26.13	61,851,688
19	Firm Storage Service		29	-	29	308.86	8,840
20	Other Taxes - Direct Assignment		16,520	-	16,520	79.00	1,305,080
21	Income Taxes	Adj. 31	(4,986,924)	166,747	(4,820,177)	-	-
22	Subtotal	Sum of Lns. 2 > 21	$ 209,483,512	$ 9,766,066	$ 219,249,578	22.30	$ 4,889,855,917
23	Lead Lag Requirement	Ln. 22, Col. E / 365			$ 600,684	66.70	$ 40,066,410
24	Other Lead-Lag Items						
25	Interest on Long-Term Debt	Adj 29	(330,939)	(831,295)	(1,162,234)	91.25	7,152
26	Economic Evaluation of Facility Extenstion (GSP 14)	Accts. 186.200 & 174.400	752,764	-	752,764	-	752,764
27	Cash Working Capital - Ratemaking						$ 40,826,325
28	Cash Working Capital - Distribution Amount						39,871,701
29	Cash Working Capital Ratemaking Adjustment	RB:1:10					$ 954,625

WASHINGTON GAS LIGHT COMPANY
District of Columbia
Description of the Lead-Lag Study

General

This exhibit discusses the development of the cash working capital allowance needed for Washington Gas Light Company (Company) for its District of Columbia operations using the lead-lag method. The objective of the lead-lag study is to determine the amount of investor funds needed to support utility operations from the time expenditures are made for goods and services in providing gas service to its customers to the time when the Company is reimbursed for those services by its customers.

Generally, a lag is the time between the date that a customer receives service from the Company and the date the customer makes payment for those services. A lead is generally the time between the date that employees and vendors provide labor, goods, and services to the Company and the date that the Company pays for those services. Leads and lags are measured in days with the dollar weighted net lag days multiplied by the average daily expense amount to determine the amount of working capital required.

The lead/lag calculations discussed below are as of December 31, 2020 except for the Operating Revenues Lag and the Gas Purchased Lag which are as of March 31, 2024.

Excel versions of the calculations and detailed workpapers supporting each lead/lag calculation are included in Exhibit WG (D)-5.

Operating Revenues (WG (D)-5, Adjustment 30, Line 1, Column F)

The total lag days in operating revenues of 89.00 days represents the average number of days between the time the Company provides service and the time it receives payment for that service.

This lag is developed in three parts. The first part measures the average number of days from the time the customer receives gas service to the time his meter is read. On average it is estimated that a customer would have 15.21 days of service at the time their meter is read, that is {(365/12) =30.42/2=15.21}.

The second part determines the average number of days from the meter reading date to the billing date. This computes to 4.34 days. This was calculated by applying the meter read schedule for the twelve months beginning April 1, 2023 which assumes a two business day lag between meter read date and bill preparation date and a one business day lag between bill preparation date and mailing date.

The third part of the revenue lag is the remaining 69.46 days, which reflect the lag from the time of billing customers to the receipt of payment of such bills. This is the result of dividing the 13 month average accounts receivable balance of $48,686,527 by the average daily amounts billed of $700,972. The 13 month average accounts receivable balance is developed from the monthly balances of the aging of accounts receivable adjusted to reflect (1) the cash in collection banks not yet recorded on the books of the Company; (2) the net differences in the amounts billed to customers on the budget plan versus their actual consumption; and (3) balances from customers that have elected to buy gas from third-party marketers who are being provided a single gas bill for gas and delivery service from Washington Gas. The average daily amount billed is determined by dividing the total amount debited to Account 142.101 – "Accounts Receivable – Gas" during the period [$255,854,652] by 365 days. The sum of the revenue lag days as determined above is 89.00 days and represents the composite lag days in operating revenues.

Operating Expenses

Gas Purchased (WG (D)-5, Adjustment 30, Line 2, Column F)

The gas purchased expense lead of 38.19 days was developed on a system basis as purchases and payments for gas from suppliers are made to serve the entire system. The total lead days in the payment of gas purchased was determined by netting the leads in payments to all suppliers for each month during the twelve months ended March 31, 2024. The lead payment for each month is the sum of the average number of days in the service period (i.e. one month) and the number of days from the end of the service period to the date paid. The computed lead days of 38.19 is applied to cost of gas allocated to the District of Columbia.

Payroll (WG (D)-5, Adjustment 30, Line 3, Column F)

Total payroll is represented by the net pay received by employees, plus taxes and other employee deductions. To determine the number of days, the Company examined separately each element of employee pay. As shown in the following table, the result of this analysis is a total payroll lead of 11.71 days. This figure was obtained by dividing the dollar days of payroll by the sum of the total payroll dollars.

The calculation of the net payroll lead days consists of two parts. First, the service period for the biweekly payroll of 14 days is divided by 2 to obtain the midpoint of the period. These 7 days are then added to the lead from the end of the service period until payday, which is 4.96 days. The result is a total of 11.96 lead days for net payroll.

Each payroll deduction was analyzed to determine the number of days from the end of the service period to the day that the deduction was remitted to the appropriate institution. As in the case of net payroll, each calculated lead day was increased by 7 days to account for the days from the mid-point of the service period to the end of the service period.

	Amount	Lead Days	Dollar Days
Payroll, Net of Deductions	$ 91,064,761	11.96	$1,089,404,361
Payroll deductions	52,839,306	11.28	595,929,747
Total Payroll-Operating	$143,904,067	11.71	$1,685,334,107

Employee Health Benefits (WG (D)-5, Adjustment 30, Lines 5, Column F)

The employee health benefit payments have a lead of 30.37 days. A representative sample of payments was reviewed to calculate the average service to payment date lead.

Property and Public Liability Insurance (WG (D)-5, Adjustment 30, Line 6, Column F)

The property and public liability insurance lag was obtained by reviewing the insurance coverage the Company has with various vendors and calculating the lag period for each category. The categories reviewed included Automobile, General Liability, Excess Liability, Directors & Officers, Crime, Property, and Workers Compensation. In each case the number of lag days was calculated for each vendor invoice by adding one-half the number of days in the service period to the number of days from the end of the service period to the paid date. The amount paid was multiplied by total lag days to determine dollar days associated with a particular payment. Dollar days were then totaled and divided by the DC allocated total insurance expense for the test period, giving a final lag of (163.46) days.

<u>Other O&M (WG (D)-5, Adjustment 30, Line 7-9, Column F)</u>

Lead days for Other O&M was calculated to be 25.47 days and excludes expenditures on payroll, employer-provided health benefits, insurance, and pension and other post-retirement benefits. A representative sample of payments was reviewed to calculate the average service to payment date lead.

<u>Property Taxes (WG (D)-5, Adjustment 30, Line 10, Column F)</u>

The District of Columbia property tax lead of 71.02 days was obtained by determining the amount of property tax for each jurisdiction. The total property tax for each jurisdiction was then multiplied by the average lead/lag days for that jurisdiction to obtain the associated dollar days. These were then totaled and divided by the total of District of Columbia taxes to obtain the 71.02 average lead for District of Columbia property tax.

The process used to obtain the lead/lag days for each jurisdiction was similar to that described above. For each tax installment, the period covered by the tax was determined along with the tax payment date. The lead/lag days were then computed by adding the average of the service period to the number of days from the end of the service period to the paid date. Total lead/lag days were then multiplied by total taxes paid to obtain the dollar days, which were then totaled and divided by the total of taxes paid to determine the average lead days for each jurisdiction.

<u>Delivery Tax Other Tax (WG (D)-5, Adjustment 30, Line 11, 17, and 18, Column F)</u>

The District of Columbia Delivery Tax and Other Tax lead of 26.13 days was obtained by determining the amount of delivery tax paid in District of Columbia during the period. The total delivery tax was then multiplied by the lead days for each payment to obtain the associated dollar days. These were then totaled and divided by the total of District of Columbia delivery taxes to calculate the lead. This lag is also used for the Sustainable Energy and Energy Assistance Trust Funds.

<u>Rights of Way Fee (WG (D)-5, Adjustment 30, Line 12, Column F)</u>

The final figure of (54.53) lag days was calculated using the same process described above for delivery taxes. For each of the installments paid during the test year, the period covered by the installment was noted along with the date paid. Total lead/lag days were subsequently calculated and dollar days obtained. The total of the dollar days was then divided by total paid taxes to determine the average days of lag.

<u>FICA Taxes (WG (D)-5, Adjustment 30, Line 13 Column F)</u>

The Federal Insurance Contributions Act (FICA) is a tax levied on both employer and employee and consists of both a social security tax and a medicare tax. The lead days for the employer portion of the tax is 9.97 days and was calculated by determining the amount of FICA tax paid during the period. The payments were then multiplied by the days of lag for each payment to obtain the associated dollar days. These were then totaled and divided by the total District of Columbia employer-paid FICA taxes to calculate the lead.

<u>Unemployment Tax (WG (D)-5, Adjustment 30, Line 14, Column F)</u>

The average lag for unemployment tax is 9.99 days. This is a payroll-related tax and the lag days were calculated in the same manner as the previously described FICA tax lag.

<u>Federal Excise Tax (WG (D)-5, Adjustment 30, Line 16, Column F)</u>

The final average lag days for federal excise tax were (17.51). This lag was calculated in the same manner as the previously described delivery tax lag.

Other Taxes (WG (D)-5, Adjustment 30, Lines 19 and 20, Column F)

This category consists of two taxes: (1) federal firm storage service and (2) arena fees. Total taxes and dollar days were calculated for each tax and then totaled. The final average lead days are 308.86 and 79.00, respectively.

Other Income taxes (WG (D)-5, Adjustment 30, Column F)

The Company currently has no income tax payment obligation because of a net operating loss carryforward. Therefore, the lead/lag days for this line are 0.

Other

Interest on Long-term debt (WG (D)-5, Adjustment 30, Line 25, Column F)

Interest is paid twice a year. The lead is calculated based on an average service period of 91.25 days (365/2/2).

Washington Gas Light Company
District of Columbia Jurisdiction

Summary of Lead / Lag Studies

For 12 Months Ended March 31, 2024

Line No.	Description	Lead / Lag Days
1	Revenue Lag	89.00
2	Gas Purchase Lag	38.19
3	Payroll Lead	11.71
4	Employee Health Benefits	30.37
5	Other O&M	25.47
6	FICA Taxes	9.97
7	Public Insurance Liability	(163.46)
8	Property Tax Lag	71.02
9	Federal Unemployment Tax Lag	9.99
10	Federal Excise Tax Lag	(17.51)
11	Other Tax Lag	308.86
12	Interest on Long-term Debt	91.25
13	Arena Fee (Other Taxes - Direct Assignment)	79.00
14	Delivery Tax	26.13
15	Rights-of-Way Fee	(54.53)

1/ Lead/Lags 1 and 2 are based on the Twelve Months Ended March 31, 2024.
2/ Lead/Lags 3 - 15 are base on the Twelve Months Ended December 31, 2020

WASHINGTON GAS LIGHT COMPANY
DISTRICT OF COLUMBIA JURISDICTION
DETERMINATION OF OPERATING REVENUES COMPOSITE DAYS LAG
T.M.E. March 31, 2024

LINE NO.	DESCRIPTION	AMOUNT
1	AVERAGE ACCOUNTS RECEIVABLE	
2	SCHEDULE B, PAGE 2, COL. I	4/ $48,686,527
3	AVERAGE AMOUNT BILLED PER DAY a/	700,972 A
4	DAYS LAG (LINE 2/ LINE 3)	69.46
5	DAYS LAG TO METER READ DATE b/	15.21 B
6	DAYS LAG - METER READ TO BILL DATE c/	4.34
7	TOTAL OPERATING REVENUES	
8	COMPOSITE DAYS LAG	89.00

a/ AMOUNTS BILLED TO CUSTOMERS DURING THE ABOVE TEST PERIOD	7/ $255,854,652
DIVIDED BY NUMBER OF DAYS IN BILLING PERIOD	365
AVERAGE AMOUNT BILLED PER DAY	$700,972 A

b/ BASED ON THE ASSUMPTION THAT THERE ARE 30.42 DAYS OF SERVICE ON AVERAGE PER MONTH i.e. 365/12 = 30.42/2 = 15.21 DAYS. B

c/ BASED ON SCHEDULED BILL PREPARATION DATE WITHIN 3 BUSINESS DAYS AND BILL MAILED THE FOLLOWING BUSINESS DAY.

WASHINGTON GAS LIGHT COMPANY
MARYLAND JURISDICTION
DETERMINATION OF OPERATING REVENUES COMPOSITE DAYS LAG
T.M.E. March 31, 2024

LINE NO.	DESCRIPTION	AMOUNT
1	AVERAGE ACCOUNTS RECEIVABLE	
2	SCHEDULE B, PAGE 2, COL. I	5/ $86,568,470
3	AVERAGE AMOUNT BILLED PER DAY a/	1,631,637 A
4	DAYS LAG (LINE 2/ LINE 3)	53.06
5	DAYS LAG TO METER READ DATE b/	15.21 B
6	DAYS LAG - METER READ TO BILL DATE c/	4.34
7	TOTAL OPERATING REVENUES	
8	COMPOSITE DAYS LAG	72.60

a/ AMOUNTS BILLED TO CUSTOMERS DURING THE ABOVE TEST PERIOD	7/ $595,547,397
DIVIDED BY NUMBER OF DAYS IN BILLING PERIOD	365
AVERAGE AMOUNT BILLED PER DAY	$1,631,637 A

b/ BASED ON THE ASSUMPTION THAT THERE ARE 30.42 DAYS OF SERVICE ON AVERAGE PER MONTH i.e. 365/12 = 30.42/2 = 15.21 DAYS. B

c/ BASED ON SCHEDULED BILL PREPARATION DATE WITHIN 3 BUSINESS DAYS AND BILL MAILED THE FOLLOWING BUSINESS DAY.

WASHINGTON GAS LIGHT COMPANY
VIRGINIA JURISDICTION
DETERMINATION OF OPERATING REVENUES COMPOSITE DAYS LAG
T.M.E. March 31, 2024

LINE NO.	DESCRIPTION	AMOUNT	
1	AVERAGE ACCOUNTS RECEIVABLE		
2	SCHEDULE B, PAGE 2, COL. I	6/ $50,617,702	
3	AVERAGE AMOUNT BILLED PER DAY a/	1,635,523	A
4	DAYS LAG (LINE 2/ LINE 3)	30.95	
5	DAYS LAG TO METER READ DATE b/	15.21	B
6	DAYS LAG - METER READ TO BILL DATE c/	4.34	
7	TOTAL OPERATING REVENUES		
8	COMPOSITE DAYS LAG	50.50	

a/ AMOUNTS BILLED TO CUSTOMERS DURING THE ABOVE TEST PERIOD	7/ $596,965,918	
DIVIDED BY NUMBER OF DAYS IN BILLING PERIOD	365	
AVERAGE AMOUNT BILLED PER DAY	$1,635,523	A

b/ BASED ON THE ASSUMPTION THAT THERE ARE 30.42 DAYS OF SERVICE ON AVERAGE PER MONTH i.e. 365/12 = 30.42/2 = 15.21 DAYS. B

c/ BASED ON SCHEDULED BILL PREPARATION DATE WITHIN 3 BUSINESS DAYS AND BILL MAILED THE FOLLOWING BUSINESS DAY.

WASHINGTON GAS LIGHT COMPANY
DISTRICT OF COLUMBIA
DETERMINATION OF 13 MONTH AVERAGE ACCOUNTS RECEIVABLE BY JURISDICTION

LINE NO.	MONTH	CASH IN COLLECTION BANKS	ACCOUNTS RECEIVABLE AGING ACTIVE	3rd Party Billings A/C 142915	ACCOUNTS RECEIVABLE TOTAL	ACCOUNTS RECEIVABLE 13 MO. AVG.
	A	B a/	C b/	D	E = C + D - B	F = E/13
1	Mar-2023	7/ 6,667	8/ 53,520,010	13/ 1,690,817	55,204,160	
2	Apr-2023	2,911	54,476,508	1,729,255	56,202,852	
3	May-2023	1,264	46,206,402	1,790,642	47,995,780	
4	Jun-2023	3,417	42,870,924	1,823,565	44,691,072	
5	Jul-2023	639	40,891,718	1,814,306	42,705,385	
6	Aug-2023	370	37,391,240	1,983,387	39,374,257	
7	Sep-2023	4,176	37,917,274	2,009,596	39,922,694	
8	Oct-2023	303	33,656,138	1,919,731	35,575,566	
9	Nov-2023	269	38,457,382	1,927,328	40,384,441	
10	Dec-2023	24,675	48,070,303	1,956,570	50,002,198	
11	Jan-2024	100,605	55,987,604	1,934,783	57,821,782	
12	Feb-2024	153,464	60,626,383	2,076,238	62,549,157	
13	Mar-2024	2,726	58,404,396	2,093,839	60,495,509	
14		$301,486	$608,476,283	$24,750,055	632,924,852	**$48,686,527** 1

a/ SCHEDULE C, COLUMN K
b/ SCHEDULE D, COLUMN D

WASHINGTON GAS LIGHT COMPANY
MARYLAND
DETERMINATION OF 13 MONTH AVERAGE ACCOUNTS RECEIVABLE BY JURISDICTION

LINE NO.	MONTH	CASH IN COLLECTION BANKS	ACCOUNTS RECEIVABLE AGING ACTIVE	3rd Party Billings A/C 142915	ACCOUNTS RECEIVABLE TOTAL	13 MO. AVG.
	A	B a/	C b/	D	E = C + D - B	F = E/13
1	Mar-2023	7/ 16,431	9/ 109,872,738	13/ 3,471,126	113,327,432	
2	Apr-2023	7,386	114,835,361	3,645,234	118,473,209	
3	May-2023	2,933	89,499,462	3,468,383	92,964,912	
4	Jun-2023	8,515	78,502,929	3,339,214	81,833,628	
5	Jul-2023	1,591	73,177,291	3,246,771	76,422,471	
6	Aug-2023	862	61,564,820	3,265,654	64,829,612	
7	Sep-2023	10,562	60,655,492	3,214,710	63,859,639	
8	Oct-2023	768	55,004,122	3,137,410	58,140,764	
9	Nov-2023	687	68,135,505	3,414,674	71,549,492	
10	Dec-2023	59,682	83,763,682	3,409,371	87,113,371	
11	Jan-2024	231,397	97,172,953	3,358,039	100,299,595	
12	Feb-2024	331,956	102,062,248	3,495,269	105,225,561	
13	Mar-2024	5,449	88,194,053	3,161,819	91,350,424	
14		$678,219	$1,082,440,656	$43,627,672	$1,125,390,108	**$86,568,470** 2

a/ SCHEDULE C, COLUMN L
b/ SCHEDULE D, COLUMN D

WASHINGTON GAS LIGHT COMPANY
VIRGINIA
DETERMINATION OF 13 MONTH AVERAGE ACCOUNTS RECEIVABLE BY JURISDICTION

LINE NO.	MONTH	CASH IN COLLECTION BANKS	ACCOUNTS RECEIVABLE AGING ACTIVE	3rd Party Billings A/C 142915	ACCOUNTS RECEIVABLE TOTAL	ACCOUNTS RECEIVABLE 13 MO. AVG.
	A	B a/	C b/	D	E = C + D - B	F = E/13
1	Mar-2023	7/ 16,117	10/ 64,230,408	13/ 2,029,182	66,243,473	
2	Apr-2023	7,032	65,005,754	2,063,486	67,062,208	
3	May-2023	3,043	45,145,417	1,749,525	46,891,900	
4	Jun-2023	7,971	39,840,280	1,694,653	41,526,962	
5	Jul-2023	1,624	37,540,668	1,665,625	39,204,669	
6	Aug-2023	1,029	29,730,076	1,577,007	31,306,053	
7	Sep-2023	12,882	33,639,931	1,782,899	35,409,948	
8	Oct-2023	924	31,557,442	1,800,022	33,356,540	
9	Nov-2023	566	36,718,644	1,840,189	38,558,267	
10	Dec-2023	53,955	52,098,880	2,120,542	54,165,467	
11	Jan-2024	222,907	64,155,346	2,217,038	66,149,477	
12	Feb-2024	337,884	70,959,112	2,430,097	73,051,326	
13	Mar-2024	5,964	62,856,355	2,253,445	65,103,835	
14		$671,898	$633,478,312	$25,223,710	$658,030,124	**$50,617,702** 3

a/ SCHEDULE C, COLUMN M
b/ SCHEDULE D, COLUMN D

WASHINGTON GAS LIGHT COMPANY
DETERMINATION OF CASH IN COLLECTION BANKS BY JURISDICTION
T.M.E. March 31, 2024

		AMOUNTS BILLED CUSTOMERS a/				FACTOR				CASH IN COLLECTION BANKS			
LINE NO.	MONTH	D.C.	MD.	VA.	TOTAL	D.C.	MD.	VA.	TOTAL	SYSTEM	D.C.	MD.	VA.
	A	B	C	D	E = B + C + D	F = B/E	G = C/E	H = D/E	I = E/E	J	K=F X J	L=G X J	M=H X J
1	Mar-2023	14/ 27,402,286	67,541,302	66,263,887	161,207,475	0.1700	0.4190	0.4110	1.000	15/ 39,215	6,667 4	16,431 5	16,117 6
2	Apr-2023	24,778,911	62,859,359	59,861,034	147,499,304	0.1680	0.4262	0.4058	1.000	17,329	2,911	7,386	7,032
3	May-2023	14,971,287	34,738,473	36,040,901	85,750,661	0.1746	0.4051	0.4203	1.000	7,239	1,264	2,933	3,043
4	Jun-2023	11,439,448	28,507,328	26,696,796	66,643,572	0.1717	0.4278	0.4005	1.000	19,904	3,417	8,515	7,971
5	Jul-2023	10,092,565	25,147,981	25,657,997	60,898,543	0.1657	0.4129	0.4214	1.000	3,854	639	1,591	1,624
6	Aug-2023	9,509,856	22,158,823	26,449,131	58,117,810	0.1636	0.3813	0.4551	1.000	2,260	370	862	1,029
7	Sep-2023	9,263,137	23,418,278	28,562,787	61,244,202	0.1512	0.3824	0.4664	1.000	27,620	4,176	10,562	12,882
8	Oct-2023	10,558,670	26,711,853	32,130,750	69,401,272	0.1521	0.3849	0.4630	1.000	1,995	303	768	924
9	Nov-2023	18,421,597	47,061,439	38,735,804	104,218,840	0.1768	0.4516	0.3716	1.000	1,522	269	687	566
10	Dec-2023	29,628,264	71,668,902	64,779,953	166,077,119	0.1784	0.4315	0.3901	1.000	138,312	24,675	59,682	53,955
11	Jan-2024	40,764,537	93,755,322	90,318,998	224,838,857	0.1813	0.4170	0.4017	1.000	554,908	100,605	231,397	222,907
12	Feb-2024	41,172,087	89,058,740	90,631,170	220,861,998	0.1864	0.4032	0.4104	1.000	823,304	153,464	331,956	337,884
13	Mar-2024	35,254,292	70,460,900	77,100,597	182,815,789	0.1928	0.3854	0.4218	1.000	14,138	2,726	5,449	5,964
14	13 MO TOTAL	$283,256,938	$663,088,699	$663,229,805	$1,609,575,442					$1,651,600	$301,486	$678,219	$671,898
15	TOTALS TME												
16	Mar-2024	$255,854,652 1	$595,547,397 2	$596,965,918 3	$1,448,367,967								

a/ AMOUNT PER BOOKS, A/C 142.101

Washington Gas - District of Columbia Division
Accounts Receivable - Active

Accounts Receivable Aging - Active

Line No.	Month		Active	Adjustment		Active-Adj	
	A		B	C a/		D = B - C	
1	Mar-2023	11/	53,520,010	$	12/ -	$	53,520,010 (4)
2	Apr-2023		54,476,508		-		54,476,508
3	May-2023		46,206,402		-		46,206,402
4	Jun-2023		42,870,924		-		42,870,924
5	Jul-2023		40,891,718		-		40,891,718
6	Aug-2023		37,391,240		-		37,391,240
7	Sep-2023		37,917,274		-		37,917,274
8	Oct-2023		33,656,138		-		33,656,138
9	Nov-2023		38,457,382		-		38,457,382
10	Dec-2023		48,070,303		-		48,070,303
11	Jan-2024		55,987,604		-		55,987,604
12	Feb-2024		60,626,383		-		60,626,383
13	Mar-2024		58,404,396		-		58,404,396
			$608,476,283		-		$608,476,283

a/ Represents credits in the AR account that have been reclassed to a liability account for financial statement presenation. These credits are added back in this analysis to more accurately reflect the AR balance (net monthly activity).

Washington Gas - Maryland Division
Accounts Receivable - Active/Final

Accounts Receivable Aging - Active

Line No.	Month	Active	Adjustment	Active-Adj
	A	B	C a/	D = B - C
1	Mar-2023	11/109,872,738	$ 12/ -	$ 109,872,738 5
2	Apr-2023	114,835,361	-	114,835,361
3	May-2023	89,499,462	-	89,499,462
4	Jun-2023	78,502,929	-	78,502,929
5	Jul-2023	73,177,291	-	73,177,291
6	Aug-2023	61,564,820	-	61,564,820
7	Sep-2023	60,655,492	-	60,655,492
8	Oct-2023	55,004,122	-	55,004,122
9	Nov-2023	68,135,505	-	68,135,505
10	Dec-2023	83,763,682	-	83,763,682
11	Jan-2024	97,172,953	-	97,172,953
12	Feb-2024	102,062,248	-	102,062,248
13	Mar-2024	88,194,053	-	88,194,053
		$1,082,440,656	-	$1,082,440,656

a/ Represents credits in the AR account that have been reclassed to a liability account for financial statement presenation. These credits are added back in this analysis to more accurately reflect the AR balance (net monthly activity).

Washington Gas - Virginia Division
Accounts Receivable - Active/Final

Accounts Receivable Aging - Active

Line No.	Month	Active	Adjustment	Active-Adj
	A	B	C a/	D = B - C
1	Mar-2023	11/ 64,230,408	$ 12/ -	$ 64,230,408 6
2	Apr-2023	65,005,754	-	65,005,754
3	May-2023	45,145,417	-	45,145,417
4	Jun-2023	39,840,280	-	39,840,280
5	Jul-2023	37,540,668	-	37,540,668
6	Aug-2023	29,730,076	-	29,730,076
7	Sep-2023	33,639,931	-	33,639,931
8	Oct-2023	31,557,442	-	31,557,442
9	Nov-2023	36,718,644	-	36,718,644
10	Dec-2023	52,098,880	-	52,098,880
11	Jan-2024	64,155,346	-	64,155,346
12	Feb-2024	70,959,112	-	70,959,112
13	Mar-2024	62,856,355	-	62,856,355
		$633,478,312	-	$633,478,312

a/ Represents credits in the AR account that have been reclassed to a liability account for financial statement presenation. These credits are added back in this analysis to more accurately reflect the AR balance (net monthly activity).

Sch. D, Col. B - Accounts Receivable Aging Accounts (GL account 142101)

Date	DC	MD	MD 3rd Party	VA	Total
Mar-2023	53,520,009.61 8	109,872,737.51 9		64,230,407.75 10	227,623,154.87
Apr-2023	54,476,508.26	114,835,360.72		65,005,754.14	234,317,623.12
May-2023	46,206,401.90	89,499,461.90		45,145,417.10	180,851,280.90
Jun-2023	42,870,923.76	78,502,928.59		39,840,279.62	161,214,131.97
Jul-2023	40,891,718.06	73,177,291.39		37,540,668.05	151,609,677.50
Aug-2023	37,391,240.16	61,564,820.37		29,730,075.59	128,686,136.12
Sep-2023	37,917,273.74	60,655,491.54		33,639,930.70	132,212,695.98
Oct-2023	33,656,138.23	55,004,122.01		31,557,441.80	120,217,702.04
Nov-2023	38,457,382.35	68,135,504.52		36,718,644.27	143,311,531.14
Dec-2023	48,070,303.27	83,763,682.43		52,098,880.02	183,932,865.72
Jan-2024	55,987,604.25	97,172,953.07		64,155,345.77	217,315,903.09
Feb-2024	60,626,382.80	102,062,248.14		70,959,112.37	233,647,743.31
Mar-2024	58,404,396.27	88,194,053.31		62,856,354.62	209,454,804.20
	608,476,282.66	**1,082,440,655.50**	**-**	**633,478,311.80**	**2,324,395,249.96**
13 Months Avg	46,805,867.90	83,264,665.81		48,729,100.91	178,799,634.61
Avg %	26.18%	46.57%		27.25%	100%

Sch. D, Col. C - Reclass of Credit Balances to Liability

	DC Col. C. 8	MD Col. C. 9	MD Col. C.	VA Col. C. 10	Total
Mar-2023	-	-		-	-
Apr-2023	-	-		-	-
May-2023	-	-		-	-
Jun-2023	-	-		-	-
Jul-2023	-	-		-	-
Aug-2023	-	-		-	-
Sep-2023	-	-		-	-
Oct-2023	-	-		-	-
Nov-2023	-	-		-	-
Dec-2023	-	-		-	-
Jan-2024	-	-		-	-
Feb-2024	-	-		-	-
Mar-2024	-	-		-	-
	-	-	-	-	-

Sch. B, Col. D --- Supplier Accounts Receivable Aging (GL account 142915)

	DC -- pg 1 Col.D	MD -- pg 2 of 3 Col.D	VA -- pg 3 of 3 Col.D	MANUAL INPUT	Total
Mar-2023	1,690,817 4	3,471,126 5	2,029,182 6	7,191,125	7,191,125
Apr-2023	1,729,255	3,645,234	2,063,486	7,437,975	7,437,975
May-2023	1,790,642	3,468,383	1,749,525	7,008,550	7,008,550
Jun-2023	1,823,565	3,339,214	1,694,653	6,857,432	6,857,432
Jul-2023	1,814,306	3,246,771	1,665,625	6,726,702	6,726,702
Aug-2023	1,983,387	3,265,654	1,577,007	6,826,047	6,826,047
Sep-2023	2,009,596	3,214,710	1,782,899	7,007,205	7,007,205
Oct-2023	1,919,731	3,137,410	1,800,022	6,857,162	6,857,162
Nov-2023	1,927,328	3,414,674	1,840,189	7,182,191	7,182,191
Dec-2023	1,956,570	3,409,371	2,120,542	7,486,482	7,486,482
Jan-2024	1,934,783	3,358,039	2,217,038	7,509,859	7,509,859
Feb-2024	2,076,238	3,495,269	2,430,097	8,001,604	8,001,604
Mar-2024	2,093,839	3,161,819	2,253,445	7,509,103	7,509,103
	24,750,055	**43,627,672**	**25,223,710**	**93,601,437**	**93,601,437**

Sch. C

FOR ALLOCATION OF CASH IN COLLECTION BANKS BY JURISDICTION

	Col B (DC)	Col C (MD)	Col D (VA)	Total
Mar-2023	27,402,286 7	67,541,302 7	66,263,887 7	161,207,475
Apr-2023	24,778,911	62,859,359	59,861,034	147,499,304
May-2023	14,971,287	34,738,473	36,040,901	85,750,661
Jun-2023	11,439,448	28,507,328	26,696,796	66,643,572
Jul-2023	10,092,565	25,147,981	25,657,997	60,898,543
Aug-2023	9,509,856	22,158,823	26,449,131	58,117,810
Sep-2023	9,263,137	23,418,278	28,562,787	61,244,202
Oct-2023	10,558,670	26,711,853	32,130,750	69,401,272
Nov-2023	18,421,597	47,061,439	38,735,804	104,218,840
Dec-2023	29,628,264	71,668,902	64,779,953	166,077,119
Jan-2024	40,764,537	93,755,322	90,318,998	224,838,857
Feb-2024	41,172,087	89,058,740	90,631,170	220,861,998
Mar-2024	35,254,292	70,460,900	77,100,597	182,815,789
	283,256,938	**663,088,699**	**663,229,805**	**1,609,575,442**

Sch. C, Col. J

CASH IN COLLECTION BANKS

	Western Union	Government	PMD & Fairfax	Total
Mar-2023	3,614	-	35,601	39,215 7
Apr-2023	2,543	-	14,787	17,329
May-2023	3,371	-	3,868	7,239
Jun-2023	1,056	-	18,848	19,904
Jul-2023	639	-	3,215	3,854
Aug-2023	1,510	-	750	2,260
Sep-2023	920	-	26,699	27,620
Oct-2023	974	-	1,021	1,995
Nov-2023	515	-	1,007	1,522
Dec-2023	1,656	-	136,656	138,312
Jan-2024	5,592	-	549,317	554,908
Feb-2024	1,903	-	821,401	823,304
Mar-2024	1,777	-	12,361	14,138
	26,071	**-**	**1,625,529**	**1,651,600**

Washington Gas Light
Gas Supplier Lead Calculation Twelve Months Ended March 31, 2024

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
ARM Energy	-	15,000	-	34,525	(34,525)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	1,398,263	1,398,263
Ascent	-	1,550,000	-	3,108,060	(3,108,060)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	125,876,430	125,876,430
BPEnergy	116,000	305,262	345,044	632,535	(287,491)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	11,643,402	25,617,663
CarbonBetter	-	19,600	-	45,434	(45,434)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	1,840,077	1,840,077
Castleton	5,000	122,045	11,350	266,762	(255,412)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	10,344,194	10,803,869
Chesapeake Energy	-	1,835,534	-	3,824,560	(3,824,560)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	154,894,676	154,894,676
Chevron	620,000	71,900	1,289,600	145,228	1,144,372	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(46,347,056)	5,881,744
CIMA	-	41,300	-	86,060	(86,060)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	3,485,420	3,485,420
Citadel	54,500	197,900	120,830	422,546	(301,716)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	12,219,478	17,113,093
CNX	-	359,500	-	783,893	(783,893)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	31,747,646	31,747,646
Columbia Gas of VA	5,000	-	10,875	-	10,875	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(440,438)	-
Columbia of Ohio	20,000	59,700	42,675	132,694	(90,019)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	3,645,770	5,374,107
Columbia PA	-	40,500	-	91,793	(91,793)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	3,717,596	3,717,596
Conoco	32,000	3,500	72,459	7,516	64,943	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(2,630,181)	304,408
Constellation	636,800	1,200	1,323,200	2,184	1,321,016	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(53,501,128)	88,452
Coterra	-	1,550,000	-	3,193,000	(3,193,000)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	129,316,500	129,316,500
Diversified	-	15,000	-	29,900	(29,900)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	1,210,950	1,210,950
DTE	329,541	91,092	786,738	184,419	602,320	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(24,393,945)	7,468,952
Duke Energy Carol	170,800	-	471,342	-	471,342	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(19,089,351)	-
EDF	5,000	6,500	12,675	16,900	(4,225)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	171,113	684,450
Emera	24,000	6,300	48,810	10,551	38,259	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(1,549,490)	427,316
Energy Authority	10,000	-	25,600	-	25,600	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(1,036,800)	-
Enterprise	-	9,000	-	16,200	(16,200)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	656,100	656,100
EQT Energy	264,200	1,911,487	658,065	3,669,834	(3,011,769)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	121,976,642	148,628,274
Equinor	465,000	-	952,088	-	952,088	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(38,559,544)	-
ETC Marketing Ltd	-	200	-	372	(372)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	15,066	15,066
Freepoint	-	31,200	-	62,039	(62,039)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	2,512,590	2,512,590
Greylock	-	92,500	-	193,610	(193,610)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	7,841,215	7,841,215
Hartree Partners LP	5,000	7,500	10,150	16,219	(6,069)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	245,784	656,859
IGS	-	28,500	-	57,805	(57,805)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	2,341,103	2,341,103
J Aron	106,000	34,800	277,793	75,812	201,981	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(8,180,231)	3,070,366
Koch	-	32,300	-	63,318	(63,318)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	2,564,359	2,564,359
Macq. Energy	232,700	28,400	540,365	58,070	482,295	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(19,532,937)	2,351,835
Mercuria	125,800	141,900	261,092	310,724	(49,632)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	2,010,106	12,584,322
MIECO	-	1,700	-	3,043	(3,043)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	123,242	123,242
Mitsui Marketing	-	23,500	-	45,919	(45,919)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	1,859,720	1,859,720
MorganCG	-	292,700	-	652,803	(652,803)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	26,438,522	26,438,522
MU Marketing	-	6,200,000	-	13,020,000	(13,020,000)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	527,310,000	527,310,000
NextEra	137,500	308,800	323,263	671,275	(348,012)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	14,094,496	27,186,627
NGX	3,156,887	989,400	7,409,822	2,032,808	5,377,014	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(217,769,065)	82,328,725
NJNG	72,700	-	140,562	-	140,562	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(5,692,771)	-
NJR Energy	300	-	700	-	700	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(28,340)	-
NOVEC Energy	-	6,000	-	13,560	(13,560)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	549,180	549,180
NRG Business	2,171,100	102,300	4,736,467	221,618	4,514,849	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(182,851,374)	8,975,519
PacificSE	629,600	23,300	1,507,379	477,532	1,029,847	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(41,708,814)	19,340,046
Petrochina	38,700	49,900	93,909	101,771	(7,863)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	318,431	4,121,726
Radiate Energy	-	5,400	-	13,037	(13,037)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	528,009	528,009
Range	-	2,500	-	4,965	(4,965)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	201,083	201,083
Repsol Energy	-	2,100	-	5,040	(5,040)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	204,120	204,120
S. Jersey Resources	60,000	61,900	129,163	133,387	(4,224)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	171,072	5,402,153
Sequent	687,500	185,361	1,462,688	368,362	1,094,325	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(44,320,175)	14,918,669
SGPM	-	800	-	1,488	(1,488)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	60,264	60,264
Shell	1,213,230	95,110	3,094,469	164,365	2,930,104	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(118,669,195)	6,656,802
SnyderBros	-	629,700	-	1,203,379	(1,203,379)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	48,736,850	48,736,850
Southern Co Svcs Inc	1,548,686	-	3,950,698	-	3,950,698	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(160,003,269)	-
Southwest	-	25,221	-	53,098	(53,098)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	2,150,468	2,150,468
Spark	-	100	-	180	(180)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	7,270	7,270
Spire	-	16,000	-	37,322	(37,322)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	1,511,541	1,511,541
Spotlight Energy	84,300	15,800	226,079	27,893	198,186	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(8,026,533)	1,129,646
Sprague	232,500	-	477,400	-	477,400	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(19,334,700)	-
SWN Energy Services	-	811,000	-	1,586,741	(1,586,741)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	64,262,990	64,262,990
TCEM	111,900	40,900	251,976	85,144	166,832	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(6,756,696)	3,448,332
Tenaska Marketing	143,100	279,900	350,331	583,498	(233,167)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	9,443,274	23,631,669
Tennessee Valley Aut	6,000	-	15,300	-	15,300	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(619,650)	-
TotalEnergies	-	63,800	-	149,518	(149,518)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	6,055,479	6,055,479
Trailstone	-	8,300	-	15,106	(15,106)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	611,793	611,793
TWIN EAGLE	123,800	1,381,900	321,887	3,666,790	(3,344,903)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	135,468,551	148,504,975
UGI Energy	278,840	72,800	631,843	158,233	473,611	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(19,181,239)	6,408,416
United Energy	65,600	43,700	139,526	97,460	42,066	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	(1,703,653)	3,947,130
Vitol	355,800	485,700	797,661	3,240,641	(2,442,980)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	98,940,670	131,245,940
XTO	-	17,000	-	35,869	(35,869)	3/1/2023	3/31/2023	4/25/2023	15.5	25	40.5	1,452,695	1,452,695

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
Allied/DTE	-	715,260	-	1,174,815	(1,174,815)	4/1/2023	4/30/2023	5/25/2023	15	25	40	46,992,582	46,992,582
ARM Energy	-	64,400	-	118,352	(118,352)	4/1/2023	4/30/2023	5/25/2023	15	25	40	4,734,080	4,734,080
Ascent	-	1,050,000	-	1,654,800	(1,654,800)	4/1/2023	4/30/2023	5/25/2023	15	25	40	66,192,000	66,192,000
BPEnergy	17,700	528,500	36,282	909,110	(872,828)	4/1/2023	4/30/2023	5/25/2023	15	25	40	34,913,130	36,364,410
Brooklyn Union Gas	20,221	-	44,486	-	44,486	4/1/2023	4/30/2023	5/25/2023	15	25	40	(1,779,448)	-
CarbonBetter	-	121,200	-	204,879	(204,879)	4/1/2023	4/30/2023	5/25/2023	15	25	40	8,195,150	8,195,150
Castleton	173,500	131,600	375,774	235,983	139,791	4/1/2023	4/30/2023	5/25/2023	15	25	40	(5,591,620)	9,439,330
Chesapeake Energy	-	984,000	-	1,632,383	(1,632,383)	4/1/2023	4/30/2023	5/25/2023	15	25	40	65,295,300	65,295,300
Chevron	197,500	94,000	431,031	185,668	245,363	4/1/2023	4/30/2023	5/25/2023	15	25	40	(9,814,530)	7,426,720
CIMA	-	60,600	-	100,292	(100,292)	4/1/2023	4/30/2023	5/25/2023	15	25	40	4,011,680	4,011,680
Citadel	-	247,200	-	396,728	(396,728)	4/1/2023	4/30/2023	5/25/2023	15	25	40	15,869,130	15,869,130
CitiEnergy	-	346,000	-	628,334	(628,334)	4/1/2023	4/30/2023	5/25/2023	15	25	40	25,133,340	25,133,340
Clearwater	-	15,600	-	33,811	(33,811)	4/1/2023	4/30/2023	5/25/2023	15	25	40	1,352,440	1,352,440
CNX	-	306,500	-	546,850	(546,850)	4/1/2023	4/30/2023	5/25/2023	15	25	40	21,873,980	21,873,980
Columbia KY	-	5,400	-	10,206	(10,206)	4/1/2023	4/30/2023	5/25/2023	15	25	40	408,240	408,240
Columbia MD	-	4,500	-	8,090	(8,090)	4/1/2023	4/30/2023	5/25/2023	15	25	40	323,600	323,600
Columbia of Ohio	-	167,800	-	291,791	(291,791)	4/1/2023	4/30/2023	5/25/2023	15	25	40	11,671,630	11,671,630
Columbia PA	-	364,700	-	591,015	(591,015)	4/1/2023	4/30/2023	5/25/2023	15	25	40	23,640,580	23,640,580
Conoco	-	81,504	-	133,164	(133,164)	4/1/2023	4/30/2023	5/25/2023	15	25	40	5,326,542	5,326,542
Constellation	162,000	41,000	259,200	76,501	182,699	4/1/2023	4/30/2023	5/25/2023	15	25	40	(7,307,960)	3,060,040
Coterra	-	3,000,000	-	4,800,000	(4,800,000)	4/1/2023	4/30/2023	5/25/2023	15	25	40	192,000,000	192,000,000
Delmarva Power	-	5,000	-	9,600	(9,600)	4/1/2023	4/30/2023	5/25/2023	15	25	40	384,000	384,000
Diversified	-	333,200	-	543,290	(543,290)	4/1/2023	4/30/2023	5/25/2023	15	25	40	21,731,610	21,731,610
Dominion	42,000	15,400	110,400	27,258	83,142	4/1/2023	4/30/2023	5/25/2023	15	25	40	(3,325,680)	1,090,320
DTE	142,800	22,900	311,581	45,732	265,849	4/1/2023	4/30/2023	5/25/2023	15	25	40	(10,633,960)	1,829,280
Duke Energy Carol	50,000	-	113,325	-	113,325	4/1/2023	4/30/2023	5/25/2023	15	25	40	(4,533,000)	-
Eco-Energy	-	25,200	-	46,137	(46,137)	4/1/2023	4/30/2023	5/25/2023	15	25	40	1,845,470	1,845,470
EDF	-	179,460	-	325,353	(325,353)	4/1/2023	4/30/2023	5/25/2023	15	25	40	13,014,126	13,014,126
Emera	7,700	20,000	15,650	31,800	(16,150)	4/1/2023	4/30/2023	5/25/2023	15	25	40	645,990	1,272,000
EQT Energy	143,000	1,984,238	229,213	2,618,796	(2,389,583)	4/1/2023	4/30/2023	5/25/2023	15	25	40	95,583,334	104,751,834
Equinor	-	2,500	-	4,381	(4,381)	4/1/2023	4/30/2023	5/25/2023	15	25	40	175,250	175,250
Freepoint	-	30,500	-	56,793	(56,793)	4/1/2023	4/30/2023	5/25/2023	15	25	40	2,271,700	2,271,700
Greylock	-	80,000	-	135,075	(135,075)	4/1/2023	4/30/2023	5/25/2023	15	25	40	5,403,000	5,403,000
Gunvor	-	312,523	-	537,352	(537,352)	4/1/2023	4/30/2023	5/25/2023	15	25	40	21,494,092	21,494,092
Hartree Partners LP	10,700	75,000	23,980	142,220	(118,240)	4/1/2023	4/30/2023	5/25/2023	15	25	40	4,729,600	5,688,800
IGS	-	42,100	-	72,909	(72,909)	4/1/2023	4/30/2023	5/25/2023	15	25	40	2,916,360	2,916,360
J Aron	-	112,600	-	197,292	(197,292)	4/1/2023	4/30/2023	5/25/2023	15	25	40	7,891,690	7,891,690
KeySpan Gas East	-	24,600	-	38,622	(38,622)	4/1/2023	4/30/2023	5/25/2023	15	25	40	1,544,880	1,544,880
Koch	-	124,500	-	214,705	(214,705)	4/1/2023	4/30/2023	5/25/2023	15	25	40	8,588,200	8,588,200
Macq. Energy	200	99,400	396	190,734	(190,338)	4/1/2023	4/30/2023	5/25/2023	15	25	40	7,613,500	7,629,340
Mercuria	435,736	111,971	924,920	204,453	720,466	4/1/2023	4/30/2023	5/25/2023	15	25	40	(28,818,657)	8,178,136
Mitsui Marketing	60,000	25,900	113,850	38,666	75,185	4/1/2023	4/30/2023	5/25/2023	15	25	40	(3,007,380)	1,546,620
MorganCG	9,200	50,900	17,572	90,816	(73,244)	4/1/2023	4/30/2023	5/25/2023	15	25	40	2,929,740	3,632,620
MU Marketing	-	6,000,000	-	10,440,000	(10,440,000)	4/1/2023	4/30/2023	5/25/2023	15	25	40	417,600,000	417,600,000
NextEra	747,838	770,342	1,190,932	1,366,008	(175,076)	4/1/2023	4/30/2023	5/25/2023	15	25	40	7,003,046	54,640,328
NGX	2,892,500	1,337,489	6,089,458	2,295,897	3,793,561	4/1/2023	4/30/2023	5/25/2023	15	25	40	(151,742,435)	91,835,897
NJNG	-	14,400	-	27,504	(27,504)	4/1/2023	4/30/2023	5/25/2023	15	25	40	1,100,160	1,100,160
NJR Energy	-	6,900	-	10,264	(10,264)	4/1/2023	4/30/2023	5/25/2023	15	25	40	410,550	410,550
NRG Business	1,765,000	533,600	2,858,075	834,117	2,023,958	4/1/2023	4/30/2023	5/25/2023	15	25	40	(80,958,320)	33,364,680
Old Dominion Electr	28,200	-	62,100	-	62,100	4/1/2023	4/30/2023	5/25/2023	15	25	40	(2,484,000)	-
PacificSE	542,700	691,300	1,151,334	1,148,825	2,509	4/1/2023	4/30/2023	5/25/2023	15	25	40	(100,360)	45,952,990
Petrochina	-	89,700	-	153,304	(153,304)	4/1/2023	4/30/2023	5/25/2023	15	25	40	6,132,160	6,132,160
Range	-	17,000	-	25,458	(25,458)	4/1/2023	4/30/2023	5/25/2023	15	25	40	1,018,300	1,018,300
Repsol Energy	-	25,000	-	49,481	(49,481)	4/1/2023	4/30/2023	5/25/2023	15	25	40	1,979,250	1,979,250
S. Jersey Resources	33,800	321,900	70,416	519,735	(449,319)	4/1/2023	4/30/2023	5/25/2023	15	25	40	17,972,760	20,789,380
Sequent	557,400	1,131,500	1,052,219	1,810,578	(758,359)	4/1/2023	4/30/2023	5/25/2023	15	25	40	30,334,360	72,423,120
Shell	3,228,873	164,100	6,503,806	262,004	6,241,802	4/1/2023	4/30/2023	5/25/2023	15	25	40	(249,672,088)	10,480,160
SnyderBros	-	374,800	-	637,395	(637,395)	4/1/2023	4/30/2023	5/25/2023	15	25	40	25,495,800	25,495,800
Southern Co Svcs Inc	1,498,899	-	3,134,198	-	3,134,198	4/1/2023	4/30/2023	5/25/2023	15	25	40	(125,367,912)	-
Spark	-	1,300	-	2,146	(2,146)	4/1/2023	4/30/2023	5/25/2023	15	25	40	85,840	85,840
Spire	-	5,000	-	11,300	(11,300)	4/1/2023	4/30/2023	5/25/2023	15	25	40	452,000	452,000
Spotlight Energy	474,700	6,500	994,294	10,138	984,156	4/1/2023	4/30/2023	5/25/2023	15	25	40	(39,366,250)	405,500
Sprague	225,000	-	357,750	-	357,750	4/1/2023	4/30/2023	5/25/2023	15	25	40	(14,310,000)	-
SWN Energy Services	-	794,100	-	1,099,965	(1,099,965)	4/1/2023	4/30/2023	5/25/2023	15	25	40	43,998,600	43,998,600
TCEM	343,300	122,200	568,045	220,141	347,904	4/1/2023	4/30/2023	5/25/2023	15	25	40	(13,916,160)	8,805,640
Tenaska Marketing	510,458	609,800	1,214,856	1,018,493	196,363	4/1/2023	4/30/2023	5/25/2023	15	25	40	(7,854,516)	40,739,720
TotalEnergies	-	49,900	-	88,534	(88,534)	4/1/2023	4/30/2023	5/25/2023	15	25	40	3,541,340	3,541,340
TWIN EAGLE	374,775	190,800	677,449	303,393	374,056	4/1/2023	4/30/2023	5/25/2023	15	25	40	(14,962,230)	12,135,730
UGI Energy	259,798	190,600	496,717	314,777	181,940	4/1/2023	4/30/2023	5/25/2023	15	25	40	(7,277,600)	12,591,080
United Energy	300,000	144,500	516,750	293,933	222,818	4/1/2023	4/30/2023	5/25/2023	15	25	40	(8,912,700)	11,757,300
Vitol	13,900	6,700	30,996	9,686	21,311	4/1/2023	4/30/2023	5/25/2023	15	25	40	(852,420)	387,420
XTO	-	89,200	-	156,257	(156,257)	4/1/2023	4/30/2023	5/25/2023	15	25	40	6,250,280	6,250,280
Allied/DTE	-	527,000	-	938,060	(938,060)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	38,929,490	38,929,490

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
ARM Energy	-	5,900	-	10,593	(10,593)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	439,610	439,610
Ascent	-	1,084,900	-	1,787,641	(1,787,641)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	74,187,093	74,187,093
BPEnergy	122,900	637,674	213,022	999,405	(786,383)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	32,634,903	41,475,316
Brooklyn Union Gas	-	15,000	-	21,850	(21,850)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	906,775	906,775
CarbonBetter	-	19,000	-	29,063	(29,063)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	1,206,094	1,206,094
Castleton	499,600	329,493	1,064,787	483,247	581,540	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(24,133,890)	20,054,771
Chesapeake Energy	-	988,000	-	1,740,798	(1,740,798)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	72,243,096	72,243,096
Chevron	93,500	14,900	157,902	29,680	128,222	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(5,321,213)	1,231,720
CIMA	-	146,400	-	230,982	(230,982)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	9,585,732	9,585,732
Citadel	48,200	119,700	90,756	184,290	(93,534)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	3,881,651	7,648,035
CitiEnergy	-	67,900	-	97,248	(97,248)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	4,035,792	4,035,792
Clearwater	-	15,000	-	32,600	(32,600)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	1,352,900	1,352,900
CNX	-	122,600	-	230,781	(230,781)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	9,577,412	9,577,412
Columbia Gas of VA	33,000	-	61,235	-	61,235	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(2,541,232)	-
Columbia KY	91,500	-	162,305	-	162,305	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(6,735,658)	-
Columbia of Ohio	232,400	-	402,360	-	402,360	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(16,697,919)	-
Columbia PA	5,000	10,000	8,250	18,800	(10,550)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	437,825	780,200
Conoco	25,000	122,815	45,413	214,821	(169,409)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	7,030,463	8,915,082
Constellation	7,700	7,600	15,489	10,908	4,581	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(190,122)	452,682
Coterra	-	3,099,443	-	4,866,126	(4,866,126)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	201,944,209	201,944,209
Coyanosa/Chevron	-	620,000	-	1,103,600	(1,103,600)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	45,799,400	45,799,400
Crooked/UET	-	620,000	-	1,103,600	(1,103,600)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	45,799,400	45,799,400
Diversified	-	268,600	-	396,390	(396,390)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	16,450,195	16,450,195
Dominion	35,000	-	65,400	-	65,400	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(2,714,100)	-
DTE	340,800	33,800	696,304	37,890	658,413	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(27,324,150)	1,572,445
Duke Energy Carol	4,700	7,400	11,468	16,317	(4,849)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	201,234	677,156
Eco-Energy	-	16,200	-	36,324	(36,324)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	1,507,446	1,507,446
EDF	28,800	59,100	54,660	89,427	(34,768)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	1,442,862	3,711,231
Emera	6,000	17,000	13,253	25,154	(11,901)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	493,892	1,043,870
Energy Authority	66,400	-	144,298	-	144,298	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(5,988,367)	-
EQT Energy	174,900	2,625,358	366,587	3,234,594	(2,868,007)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	119,022,292	134,235,631
EVI/DTE	-	739,102	-	1,143,391	(1,143,391)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	47,450,718	47,450,718
Freepoint	-	62,500	-	76,825	(76,825)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	3,188,238	3,188,238
Greylock	-	27,200	-	44,491	(44,491)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	1,846,366	1,846,366
Gunvor	-	14,500	-	20,606	(20,606)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	855,149	855,149
Hartree Partners LP	500	19,600	1,220	37,925	(36,705)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	1,523,258	1,573,888
IGS	14,000	12,500	24,898	21,125	3,773	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(156,559)	876,688
J Aron	154,861	57,700	331,325	97,129	234,196	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(9,719,139)	4,030,854
KeySpan Gas East	-	52,000	-	66,820	(66,820)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	2,773,030	2,773,030
Koch	330,384	113,700	695,430	202,050	493,380	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(20,475,265)	8,385,065
Macq. Energy	145,600	47,690	247,038	100,520	146,518	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(6,080,514)	4,171,563
Mercuria	161,800	398,200	294,635	564,910	(270,275)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	11,216,413	23,443,775
MIECO	16,800	-	22,680	-	22,680	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(941,220)	-
Mitsui Marketing	-	14,300	-	15,090	(15,090)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	626,235	626,235
MorganCG	15,000	5,800	27,450	9,945	17,505	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(726,468)	412,707
MU Marketing	200,000	6,200,000	294,800	11,098,000	(10,803,200)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	448,332,800	460,567,000
NextEra	782,243	223,000	1,224,722	293,497	931,225	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(38,645,856)	12,180,126
NGX	2,429,500	1,139,400	4,756,822	1,788,555	2,968,267	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(123,183,092)	74,225,028
NJNG	305,417	5,000	474,923	7,900	467,023	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(19,381,473)	327,850
NJR Energy	400	6,200	679	11,624	(10,945)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	454,218	482,396
NRG Business	1,974,000	633,000	3,183,758	790,587	2,393,171	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(99,316,607)	32,809,340
PacificSE	184,900	476,300	345,390	687,319	(341,929)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	14,190,064	28,523,728
Petrochina	5,000	15,000	11,450	21,350	(9,900)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	410,850	886,025
Rainbow Energy Markg	-	6,500	-	14,366	(14,366)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	596,199	596,199
Range	-	20,100	-	22,855	(22,855)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	948,472	948,472
Repsol Energy	5,000	18,300	11,650	38,064	(26,414)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	1,096,181	1,579,656
S. Jersey Resources	54,000	120,427	124,838	182,763	(57,925)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	2,403,891	7,584,658
Sequent	347,700	446,400	750,001	659,269	90,732	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(3,765,388)	27,359,653
Shell	2,862,006	166,955	5,755,705	305,976	5,449,729	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(226,163,750)	12,697,994
SnyderBros	-	877,500	-	1,192,011	(1,192,011)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	49,468,457	49,468,457
Southern Co Svcs Inc	1,550,000	-	3,436,350	-	3,436,350	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(142,608,525)	-
Spark	-	100	-	132	(132)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	5,457	5,457
Spire	12,500	-	24,038	-	24,038	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(997,556)	-
Spotlight Energy	255,100	33,000	557,367	72,759	484,608	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(20,111,242)	3,019,488
Sprague	232,500	-	362,700	-	362,700	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(15,052,050)	-
SWN Energy Services	20,000	696,000	37,600	971,705	(934,105)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	38,765,358	40,325,758
Symmetry	-	77,500	-	200,493	(200,493)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	8,320,439	8,320,439
TCEM	359,979	154,400	679,117	227,015	452,102	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(18,762,250)	9,421,123
Tenaska Marketing	542,226	502,993	1,258,131	843,468	414,663	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(17,208,523)	35,003,903
Texican	-	23,400	-	43,310	(43,310)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	1,797,344	1,797,344
TotalEnergies	-	43,000	-	79,060	(79,060)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	3,280,990	3,280,990
TWIN EAGLE	34,199	135,600	75,290	199,531	(124,241)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	5,155,984	8,280,516
UGI Energy	114,300	65,800	228,513	83,222	145,291	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(6,029,587)	3,453,713

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
United Energy	353,500	62,000	621,179	119,402	501,777	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(20,823,756)	4,955,162
Vitol	43,800	51,600	100,043	89,941	10,102	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	(419,212)	3,732,552
XTO	-	171,300	-	255,645	(255,645)	5/1/2023	5/31/2023	6/26/2023	15.5	26	41.5	10,609,257	10,609,257
Allied/DTE	0	517,877	0	643,980.05	-643,980.05	6/1/2023	6/30/2023	7/25/2023	15	25	40	25,759,202	25,759,202
ARM Energy	0	8,900	0	21,182.00	-21,182.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	847,280	847,280
Ascent	0	1,050,000	0	1,569,300.00	-1,569,300.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	62,772,000	62,772,000
BPEnergy	879,300	655,500	1,570,676.00	942,696.25	627,979.75	6/1/2023	6/30/2023	7/25/2023	15	25	40	(25,119,190)	37,707,850
Brooklyn Union Gas	9,000	53,800	10,237.50	77,221.00	-66,983.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	2,679,340	3,088,840
Castleton	261,800	125,314	604,964.50	185,647.35	419,317.15	6/1/2023	6/30/2023	7/25/2023	15	25	40	(16,772,686)	7,425,894
Chesapeake Energy	0	919,924	0	1,695,959.33	-1,695,959.33	6/1/2023	6/30/2023	7/25/2023	15	25	40	67,838,373	67,838,373
Chevron	100,000	5,000	150,946.75	8,950.00	141,996.75	6/1/2023	6/30/2023	7/25/2023	15	25	40	(5,679,870)	358,000
CIMA	0	139,500	0	224,990.50	-224,990.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	8,999,620	8,999,620
Citadel	39,500	47,100	61,318.75	68,791.75	-7,473.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	298,920	2,751,670
CitiEnergy	0	257,700	0	347,423.75	-347,423.75	6/1/2023	6/30/2023	7/25/2023	15	25	40	13,896,950	13,896,950
Clearwater	0	1,400	0	3,192.00	-3,192.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	127,680	127,680
Columbia Gas of VA	181,900	0	268,156.25	0	268,156.25	6/1/2023	6/30/2023	7/25/2023	15	25	40	(10,726,250)	-
Columbia KY	149,900	0	229,251.50	0	229,251.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	(9,170,060)	-
Columbia MD	0	2,500	0	3,593.75	-3,593.75	6/1/2023	6/30/2023	7/25/2023	15	25	40	143,750	143,750
Columbia of Ohio	12,800	6,700	18,980.00	10,231.50	8,748.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	(349,940)	409,260
Columbia PA	0	20,000	0	30,600.00	-30,600.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	1,224,000	1,224,000
Conoco	603,600	20,000	751,849.50	53,050.00	698,799.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	(27,951,980)	2,122,000
Constellation	378,900	33,100	577,002.75	55,379.50	521,623.25	6/1/2023	6/30/2023	7/25/2023	15	25	40	(20,864,930)	2,215,180
Coterra	0	2,999,953	0	3,749,941.25	-3,749,941.25	6/1/2023	6/30/2023	7/25/2023	15	25	40	149,997,650	149,997,650
Diversified	0	46,700	0	56,604.00	-56,604.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	2,264,160	2,264,160
Dominion	56,500	0	156,197.50	0	156,197.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	(6,247,900)	-
DTE	391,200	22,300	822,014.25	33,805.00	788,209.25	6/1/2023	6/30/2023	7/25/2023	15	25	40	(31,528,370)	1,352,200
Duke Energy Carol	49,775	0	137,005.50	0	137,005.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	(5,480,220)	-
Eco-Energy	0	4,600	0	10,166.00	-10,166.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	406,640	406,640
EDF	197,000	36,600	305,750.00	63,730.00	242,020.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	(9,680,800)	2,549,200
Emera	159,900	20,157	248,471.75	27,840.66	220,631.09	6/1/2023	6/30/2023	7/25/2023	15	25	40	(8,825,244)	1,113,626
EQT Energy	48,800	1,685,289	69,910.50	1,494,580.57	-1,424,670.07	6/1/2023	6/30/2023	7/25/2023	15	25	40	56,986,803	59,783,223
ETC Marketing Ltd	0	6,500	0	13,455.00	-13,455.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	538,200	538,200
EVI/DTE	0	711,930	0	871,046.36	-871,046.36	6/1/2023	6/30/2023	7/25/2023	15	25	40	34,841,854	34,841,854
Exxon	0	32,800	0	55,098.50	-55,098.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	2,203,940	2,203,940
Freepoint	0	18,500	0	22,887.50	-22,887.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	915,500	915,500
Greylock	0	13,000	0	17,027.50	-17,027.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	681,100	681,100
Gunvor	0	76,400	0	110,259.25	-110,259.25	6/1/2023	6/30/2023	7/25/2023	15	25	40	4,410,370	4,410,370
Hartree Partners LP	30,000	6,200	68,400.00	8,444.00	59,956.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	(2,398,240)	337,760
IGS	10,000	21,000	14,000.00	29,655.00	-15,655.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	626,200	1,186,200
KeySpan Gas East	0	39,600	0	51,543.50	-51,543.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	2,061,740	2,061,740
Koch	15,000	40,200	17,850.00	66,141.00	-48,291.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	1,931,640	2,645,640
Macq. Energy	8,800	109,777	13,425.50	172,583.10	-159,157.60	6/1/2023	6/30/2023	7/25/2023	15	25	40	6,366,304	6,903,324
Mercuria	402,000	190,900	747,704.00	241,781.25	505,922.75	6/1/2023	6/30/2023	7/25/2023	15	25	40	(20,236,910)	9,671,250
MIECO	0	37,400	0	47,962.50	-47,962.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	1,918,500	1,918,500
Mitsui Marketing	0	45,100	0	56,040.25	-56,040.25	6/1/2023	6/30/2023	7/25/2023	15	25	40	2,241,610	2,241,610
MorganCG	0	265,900	0	309,947.25	-309,947.25	6/1/2023	6/30/2023	7/25/2023	15	25	40	12,397,890	12,397,890
MU Marketing	1,200,000	6,000,000	1,729,000.00	9,300,000.00	-7,571,000.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	302,840,000	372,000,000
NextEra	833,353	348,200	1,052,043.35	447,097.75	604,945.60	6/1/2023	6/30/2023	7/25/2023	15	25	40	(24,197,824)	17,883,910
NGX	1,876,690	579,800	3,580,338.10	913,898.43	2,666,439.67	6/1/2023	6/30/2023	7/25/2023	15	25	40	(106,657,587)	36,555,937
NJNG	0	13,800	0	19,786.00	-19,786.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	791,440	791,440
NJR Energy	64,800	150,000	99,663.25	241,500.00	-141,836.75	6/1/2023	6/30/2023	7/25/2023	15	25	40	5,673,470	9,660,000
NRG Business	1,706,700	246,900	2,145,500.25	310,890.75	1,834,609.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	(73,384,380)	12,435,630
PacificSE	1,440,800	947,789	3,006,740.00	1,183,233.78	1,823,506.22	6/1/2023	6/30/2023	7/25/2023	15	25	40	(72,940,249)	47,329,351
Petrochina	162,500	178,400	245,750.00	236,626.75	9,123.25	6/1/2023	6/30/2023	7/25/2023	15	25	40	(364,930)	9,465,070
Range	0	525,530	0	1,053,558.46	-1,053,558.46	6/1/2023	6/30/2023	7/25/2023	15	25	40	42,142,338	42,142,338
S. Jersey Resources	8,000	79,700	15,111.00	111,173.50	-96,062.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	3,842,500	4,446,940
Sequent	1,006,000	969,800	2,078,909.00	1,280,382.25	798,526.75	6/1/2023	6/30/2023	7/25/2023	15	25	40	(31,941,070)	51,215,290
Shell	1,553,315	134,589	2,679,762.42	282,590.47	2,397,171.95	6/1/2023	6/30/2023	7/25/2023	15	25	40	(95,886,878)	11,303,619
SnyderBros	0	73,600	0	97,342.75	-97,342.75	6/1/2023	6/30/2023	7/25/2023	15	25	40	3,893,710	3,893,710
Southern Co Svcs Inc	1,519,968	0	3,487,522.01	0	3,487,522.01	6/1/2023	6/30/2023	7/25/2023	15	25	40	(139,500,880)	-
Southwest	0	14,543	0	32,649.04	-32,649.04	6/1/2023	6/30/2023	7/25/2023	15	25	40	1,305,962	1,305,962
Spark	0	900	0	1,134.00	-1,134.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	45,360	45,360
Spire	9,200	0	12,604.00	0	12,604.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	(504,160)	-
Spotlight Energy	212,900	20,400	503,917.75	47,273.25	456,644.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	(18,265,780)	1,890,930
Sprague	224,567	0	278,463.08	0	278,463.08	6/1/2023	6/30/2023	7/25/2023	15	25	40	(11,138,523)	-
SWN Energy Services	0	791,700	0	1,134,237.25	-1,134,237.25	6/1/2023	6/30/2023	7/25/2023	15	25	40	45,369,490	45,369,490
Symmetry	0	74,000	0	196,174.00	-196,174.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	7,846,960	7,846,960
TCEM	144,900	126,700	328,976.00	177,306.75	151,669.25	6/1/2023	6/30/2023	7/25/2023	15	25	40	(6,066,770)	7,092,270
Tenaska Marketing	550,021	174,094	1,320,954.00	272,686.50	1,048,267.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	(41,930,700)	10,907,460
TWIN EAGLE	167,200	32,385	421,634.25	48,068.33	373,565.92	6/1/2023	6/30/2023	7/25/2023	15	25	40	(14,942,637)	1,922,733
UGI Energy	7,100	32,500	11,034.50	49,482.25	-38,447.75	6/1/2023	6/30/2023	7/25/2023	15	25	40	1,537,910	1,979,290
United Energy	22,800	28,000	40,254.00	49,800.00	-9,546.00	6/1/2023	6/30/2023	7/25/2023	15	25	40	381,840	1,992,000
Vitol	214,800	59,500	362,076.50	96,375.00	265,701.50	6/1/2023	6/30/2023	7/25/2023	15	25	40	(10,628,060)	3,855,000

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
ARM Energy	0	10,900	0	24,762.00	-24,762.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	1,002,861	1,002,861
Ascent	0	1,085,000	0	1,798,930.00	-1,798,930.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	72,856,665	72,856,665
BPEnergy	181,000	472,900	449,040.50	768,982.75	-319,942.25	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	12,957,661	31,143,801
Brooklyn Union Gas	10,000	0	15,950.00	0	15,950.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(645,975)	-
CarbonBetter	0	1,400	0	2,097.75	-2,097.75	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	84,959	84,959
Castleton	58,800	315,800	167,751.50	577,437.25	-409,685.75	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	16,592,273	23,386,209
Chesapeake Energy	0	927,697	0	2,108,655.28	-2,108,655.28	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	85,400,539	85,400,539
Chevron	0	7,300	0	17,595.00	-17,595.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	712,598	712,598
CIMA	0	93,900	0	200,782.50	-200,782.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	8,131,691	8,131,691
Citadel	527,000	188,300	832,574.75	341,113.50	491,461.25	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(19,904,181)	13,815,097
CitiEnergy	0	256,800	0	421,872.25	-421,872.25	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	17,085,826	17,085,826
Clearwater	25,000	0	71,925.00	0	71,925.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(2,912,963)	-
CNX	0	42,500	0	70,337.50	-70,337.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	2,848,669	2,848,669
Columbia MD	0	18,000	0	31,635.00	-31,635.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	1,281,218	1,281,218
Columbia of Ohio	0	37,900	0	68,036.00	-68,036.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	2,755,458	2,755,458
Columbia PA	0	51,400	0	79,459.00	-79,459.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	3,218,090	3,218,090
Conoco	10,000	118,400	29,200.00	274,749.00	-245,549.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	9,944,735	11,127,335
Constellation	430,600	15,900	834,206.50	29,143.00	805,063.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(32,605,072)	1,180,292
Coterra	0	2,919,701	0	3,649,626.25	-3,649,626.25	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	147,809,863	147,809,863
Crooked/UET	0	735,661	0	932,818.15	-932,818.15	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	37,779,135	37,779,135
Diversified	0	257,200	0	385,448.25	-385,448.25	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	15,610,654	15,610,654
Dominion	74,600	0	253,830.00	0	253,830.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(10,280,115)	-
DTE	775,661	124,200	1,808,087.00	170,367.00	1,637,720.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(66,327,660)	6,899,864
Duke Energy Carol	148,000	0	503,850.00	0	503,850.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(20,405,925)	-
Eco-Energy	0	32,500	0	79,387.50	-79,387.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	3,215,194	3,215,194
EDF	0	26,300	0	59,857.00	-59,857.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	2,424,209	2,424,209
Emera	92,200	4,000	161,794.25	11,670.00	150,124.25	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(6,080,032)	472,635
EQT Energy	5,000	2,577,427	8,750.00	2,810,797.06	-2,802,047.06	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	113,482,906	113,837,281
ETC Marketing Ltd	0	6,500	0	18,655.00	-18,655.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	755,528	755,528
Exxon	0	81,000	0	141,785.75	-141,785.75	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	5,742,323	5,742,323
Freepoint	0	87,300	0	192,596.00	-192,596.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	7,800,138	7,800,138
Greylock	0	30,700	0	53,502.75	-53,502.75	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	2,166,861	2,166,861
Gunvor	0	40,065	0	55,792.25	-55,792.25	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	2,259,586	2,259,586
Hartree Partners LP	1,800	32,800	5,364.00	52,354.50	-46,990.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	1,903,115	2,120,357
IGS	19,600	0	34,048.00	0	34,048.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(1,378,944)	-
J Aron	0	14,200	0	22,152.00	-22,152.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	897,156	897,156
Koch	500	15,000	725	36,937.50	-36,212.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	1,466,606	1,495,969
Macq. Energy	565,000	111,400	891,165.00	219,630.50	671,534.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(27,197,147)	8,895,035
Mercuria	922,085	244,826	2,705,856.93	352,913.01	2,352,943.92	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(95,294,229)	14,292,977
MIECO	0	37,200	0	50,220.00	-50,220.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	2,033,910	2,033,910
Mitsui Marketing	196,000	7,000	579,587.50	10,787.00	568,800.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(23,036,420)	436,874
MorganCG	6,100	173,400	10,980.00	244,595.50	-233,615.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	9,461,428	9,906,118
MU Marketing	883,572	6,200,000	1,497,672.40	9,982,000.00	-8,484,327.60	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	343,615,268	404,271,000
NextEra	775,060	123,500	967,262.05	224,146.50	743,115.55	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(30,096,180)	9,077,933
NGX	2,218,900	2,393,260	5,023,022.00	3,493,234.85	1,529,787.15	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(61,956,380)	141,476,011
NJNG	0	5,000	0	8,100.00	-8,100.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	328,050	328,050
NJR Energy	0	129,400	0	360,489.50	-360,489.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	14,599,825	14,599,825
NRG Business	2,153,407	524,900	2,956,592.89	738,924.25	2,217,668.64	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(89,815,580)	29,926,432
Old Dominion Electr	20,000	0	41,500.00	0	41,500.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(1,680,750)	-
PacificSE	828,600	286,000	1,979,751.00	406,627.50	1,573,123.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(63,711,502)	16,468,414
Petrochina	5,700	75,000	16,587.00	207,200.00	-190,613.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	7,719,827	8,391,600
Radiate Energy	0	20,200	0	57,695.00	-57,695.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	2,336,648	2,336,648
Range	0	40,111	0	102,427.42	-102,427.42	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	4,148,311	4,148,311
Repsol Energy	0	1,000	0	2,810.00	-2,810.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	113,805	113,805
S. Jersey Resources	45,800	147,500	124,509.00	237,256.25	-112,747.25	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	4,566,264	9,608,878
Sequent	345,400	597,300	982,363.50	850,874.00	131,489.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(5,325,325)	34,460,397
Shell	2,973,238	413,915	7,612,729.43	1,134,285.18	6,478,444.25	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(262,376,992)	45,938,550
SnyderBros	0	40,400	0	64,139.50	-64,139.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	2,597,650	2,597,650
Southern Co Svcs Inc	1,550,000	0	4,189,650.00	0	4,189,650.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(169,680,825)	-
Southwest	0	12,000	0	33,240.00	-33,240.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	1,346,220	1,346,220
Spire	20,000	2,200	57,880.00	6,204.00	51,676.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(2,092,878)	251,262
Spotlight Energy	26,000	58,600	76,690.00	112,954.75	-36,264.75	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	1,468,722	4,574,667
Sprague	232,097	0	287,800.28	0	287,800.28	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(11,655,911)	-
SWN Energy Services	0	700,000	0	1,290,960.00	-1,290,960.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	52,283,880	52,283,880
Symmetry	0	77,500	0	238,157.50	-238,157.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	9,645,379	9,645,379
TCEM	776,225	82,500	984,950.00	199,473.50	785,476.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(31,811,798)	8,078,677
Tenaska Marketing	2,344,975	404,358	6,814,019.25	1,011,220.75	5,802,798.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(235,013,339)	40,954,440
TotalEnergies	0	62,100	0	85,934.00	-85,934.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	3,480,327	3,480,327
TWIN EAGLE	142,679	115,441	405,522.21	300,768.65	104,753.56	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(4,242,519)	12,181,130
UGI Energy	0	17,700	0	39,060.00	-39,060.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	1,581,930	1,581,930
United Energy	400,000	104,500	641,582.50	271,324.00	370,258.50	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(14,995,469)	10,988,622
Vitol	44,700	36,400	117,840.00	99,310.00	18,530.00	7/1/2023	7/31/2023	8/25/2023	15.5	25	40.5	(750,465)	4,022,055
Allied/DTE	0	735,661	0	788,996.42	-788,996.42	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	31,954,355	31,954,355

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
Ascent	0	1,085,000	0	1,578,520.00	-1,578,520.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	63,930,060	63,930,060
BPEnergy	64,200	337,400	128,941.00	476,436.50	-347,495.50	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	14,073,568	19,295,678
Brooklyn Union Gas	0	62,000	0	76,232.00	-76,232.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	3,087,396	3,087,396
CarbonBetter	0	10,700	0	13,341.75	-13,341.75	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	540,341	540,341
Castleton	513,100	127,700	1,418,083.50	152,491.50	1,265,592.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(51,256,476)	6,175,906
Chesapeake Energy	0	934,924	0	2,016,645.69	-2,016,645.69	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	81,674,150	81,674,150
Chevron	17,000	24,896	22,805.50	64,909.22	-42,103.72	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	1,705,201	2,628,823
CIMA	300	85,700	421.25	125,921.25	-125,500.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	5,082,750	5,099,811
Citadel	5,000	211,090	13,612.50	313,015.88	-299,403.38	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	12,125,837	12,677,143
CitiEnergy	0	69,600	0	93,871.50	-93,871.50	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	3,801,796	3,801,796
Clearwater	0	8,500	0	24,990.00	-24,990.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	1,012,095	1,012,095
CNX	20,000	451,600	26,850.00	933,845.75	-906,995.75	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	36,733,328	37,820,753
Columbia MD	0	45,300	0	55,887.00	-55,887.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	2,263,424	2,263,424
Columbia of Ohio	10,000	43,500	13,000.00	56,700.00	-43,700.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	1,769,850	2,296,350
Columbia PA	0	24,700	0	27,473.00	-27,473.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	1,112,657	1,112,657
Conoco	10,000	33,800	29,900.00	60,081.25	-30,181.25	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	1,222,341	2,433,291
Constellation	1,382,000	15,700	1,860,427.50	30,239.75	1,830,187.75	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(74,122,604)	1,224,710
Coterra	0	3,099,720	0	3,285,703.20	-3,285,703.20	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	133,070,980	133,070,980
Diversified	0	45,400	0	51,379.00	-51,379.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	2,080,850	2,080,850
Dominion	73,500	4,000	226,745.00	5,300.00	221,445.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(8,968,523)	214,650
DTE	157,379	101,900	433,398.75	152,987.50	280,411.25	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(11,356,656)	6,195,994
Duke Energy Carol	340,000	19,000	926,445.00	56,110.00	870,335.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(35,248,568)	2,272,455
Eco-Energy	0	44,200	0	119,177.00	-119,177.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	4,826,669	4,826,669
EDF	0	56,697	0	74,803.14	-74,803.14	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	3,029,527	3,029,527
Emera	24,724	17,800	58,428.40	53,222.00	5,206.40	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(210,859)	2,155,491
EQT Energy	0	3,577,043	0	3,398,647.50	-3,398,647.50	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	137,645,224	137,645,224
Exxon	0	95,100	0	128,436.75	-128,436.75	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	5,201,688	5,201,688
Freepoint	0	5,000	0	12,860.00	-12,860.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	520,830	520,830
Greylock	0	10,000	0	10,625.00	-10,625.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	430,313	430,313
Gunvor	0	36,100	0	45,923.75	-45,923.75	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	1,859,912	1,859,912
Hartree Partners LP	22,200	13,400	51,036.50	15,979.00	35,057.50	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(1,419,829)	647,150
IGS	0	22,500	0	28,125.00	-28,125.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	1,139,063	1,139,063
J Aron	24,800	18,600	56,959.50	23,630.25	33,329.25	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(1,349,835)	957,025
KeySpan Gas East	0	22,500	0	21,625.00	-21,625.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	875,813	875,813
Koch	0	14,500	0	18,886.25	-18,886.25	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	764,893	764,893
Macq. Energy	1,320,000	115,600	2,144,290.00	196,637.75	1,947,652.25	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(78,879,916)	7,963,829
Mercuria	151,817	286,740	417,154.50	464,973.75	-47,819.25	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	1,936,680	18,831,437
MIECO	0	117,500	0	136,012.50	-136,012.50	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	5,508,506	5,508,506
Mitsui Marketing	68,100	54,700	194,316.75	114,031.25	80,285.50	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(3,251,563)	4,618,266
MorganCG	0	312,600	0	734,774.50	-734,774.50	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	29,758,367	29,758,367
MU Marketing	625,000	6,200,000	844,175.00	8,494,000.00	-7,649,825.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	309,817,913	344,007,000
NextEra	781,720	245,485	825,192.80	361,852.36	463,340.44	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(18,765,288)	14,655,021
NGX	1,703,500	672,200	4,561,562.50	913,693.45	3,647,869.05	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(147,738,697)	37,004,585
NJNG	0	14,800	0	18,418.00	-18,418.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	745,929	745,929
NJR Energy	0	34,800	0	103,928.25	-103,928.25	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	4,209,094	4,209,094
NRG Business	2,448,900	320,100	3,595,544.50	396,259.75	3,199,284.75	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(129,571,032)	16,048,520
PacificSE	1,160,300	1,252,100	3,255,366.00	1,453,179.75	1,802,186.25	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(72,988,543)	58,853,780
Petrochina	35,100	20,000	102,542.00	50,975.00	51,567.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(2,088,464)	2,064,488
Radiate Energy	0	2,000	0	5,840.00	-5,840.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	236,520	236,520
Rainbow Energy Markg	0	1,100	0	3,168.00	-3,168.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	128,304	128,304
Range	0	668,800	0	1,624,461.40	-1,624,461.40	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	65,790,687	65,790,687
Repsol Energy	0	5,000	0	14,350.00	-14,350.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	581,175	581,175
S. Jersey Resources	109,300	65,600	308,407.50	137,203.25	171,204.25	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(6,933,772)	5,556,732
Sequent	902,759	276,800	2,599,317.07	394,026.50	2,205,290.57	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(89,314,268)	15,958,073
SGPM	4,500	0	6,390.00	0	6,390.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(258,795)	-
Shell	2,979,209	276,154	7,040,011.63	641,523.29	6,398,488.34	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(259,138,778)	25,981,693
SnyderBros	0	34,500	0	42,220.75	-42,220.75	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	1,709,940	1,709,940
Southern Co Svcs Inc	1,547,291	0	4,010,578.27	0	4,010,578.27	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(162,428,420)	-
Spotlight Energy	26,500	27,300	51,671.50	76,875.00	-25,203.50	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	1,020,742	3,113,438
Sprague	232,319	0	243,934.95	0	243,934.95	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(9,879,365)	-
SWN Energy Services	0	862,000	0	1,158,773.50	-1,158,773.50	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	46,930,327	46,930,327
Symmetry	0	77,460	0	229,436.52	-229,436.52	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	9,292,179	9,292,179
TCEM	345,800	112,000	371,520.71	158,977.50	212,543.21	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(8,608,000)	6,438,589
Tenaska Marketing	1,122,479	113,846	3,636,897.60	259,392.11	3,377,505.49	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(136,788,972)	10,505,380
Texican	0	2,500	0	6,900.00	-6,900.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	279,450	279,450
TotalEnergies	0	9,600	0	23,310.00	-23,310.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	944,055	944,055
TWIN EAGLE	37,900	37,200	123,579.75	47,850.50	75,729.25	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(3,067,035)	1,937,945
UGI Energy	19,700	0	54,823.00	0	54,823.00	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(2,220,332)	-
United Energy	7,900	11,000	18,217.25	19,775.00	-1,557.75	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	63,089	800,888
Vitol	264,000	54,400	724,339.75	76,600.25	647,739.50	8/1/2023	8/31/2023	9/25/2023	15.5	25	40.5	(26,233,450)	3,102,310
Allied/DTE	0	12,200	0	12,596.50	-12,596.50	9/1/2023	9/30/2023	10/25/2023	15	25	40	503,860	503,860
Ascent	0	1,050,000	0	1,344,300.00	-1,344,300.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	53,772,000	53,772,000
BPEnergy	134,100	190,100	322,985.00	326,841.75	-3,856.75	9/1/2023	9/30/2023	10/25/2023	15	25	40	154,270	13,073,670

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
Castleton	526,000	108,000	1,427,410.00	163,082.00	1,264,328.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	(50,573,120)	6,523,280
Chesapeake Energy	0	998,700	0	2,153,765.00	-2,153,765.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	86,150,600	86,150,600
Chevron	20,000	2,600	55,825.00	6,188.00	49,637.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	(1,985,480)	247,520
CIMA	0	3,000	0	3,825.00	-3,825.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	153,000	153,000
Citadel	23,400	227,100	68,113.50	368,955.25	-300,841.75	9/1/2023	9/30/2023	10/25/2023	15	25	40	12,033,670	14,758,210
CitiEnergy	0	217,800	0	311,425.25	-311,425.25	9/1/2023	9/30/2023	10/25/2023	15	25	40	12,457,010	12,457,010
Clearwater	66,373	0	188,366.12	0	188,366.12	9/1/2023	9/30/2023	10/25/2023	15	25	40	(7,534,645)	-
CNX	0	414,700	0	886,640.00	-886,640.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	35,465,600	35,465,600
Columbia KY	7,200	10,000	9,198.00	15,400.00	-6,202.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	248,080	616,000
Columbia MD	0	27,900	0	33,528.75	-33,528.75	9/1/2023	9/30/2023	10/25/2023	15	25	40	1,341,150	1,341,150
Columbia of Ohio	4,900	86,100	6,370.00	118,141.50	-111,771.50	9/1/2023	9/30/2023	10/25/2023	15	25	40	4,470,860	4,725,660
Columbia PA	0	10,000	0	11,500.00	-11,500.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	460,000	460,000
Conoco	3,500	95,355	9,642.50	164,995.25	-155,352.75	9/1/2023	9/30/2023	10/25/2023	15	25	40	6,214,110	6,599,810
Constellation	957,200	37,200	1,095,579.00	54,581.00	1,040,998.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	(41,639,920)	2,183,240
Coterra	0	2,998,361	0	2,878,426.56	-2,878,426.56	9/1/2023	9/30/2023	10/25/2023	15	25	40	115,137,062	115,137,062
Diversified	0	56,400	0	73,402.50	-73,402.50	9/1/2023	9/30/2023	10/25/2023	15	25	40	2,936,100	2,936,100
Dominion	0	143,200	0	142,188.75	-142,188.75	9/1/2023	9/30/2023	10/25/2023	15	25	40	5,687,550	5,687,550
DTE	156,600	107,300	464,270.50	196,891.00	267,379.50	9/1/2023	9/30/2023	10/25/2023	15	25	40	(10,695,180)	7,875,640
Duke Energy Carol	63,000	0	180,790.00	0	180,790.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	(7,231,600)	-
Eco-Energy	0	13,000	0	33,300.00	-33,300.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	1,332,000	1,332,000
EDF	5,000	36,900	13,812.50	93,839.50	-80,027.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	3,201,080	3,753,580
Emera	35,400	48,700	97,345.00	142,274.00	-44,929.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	1,797,160	5,690,960
EQT Energy	304,000	1,930,734	290,950.00	1,349,260.52	-1,058,310.52	9/1/2023	9/30/2023	10/25/2023	15	25	40	42,332,421	53,970,421
Equinor	200	30,000	258	44,550.00	-44,292.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	1,771,680	1,782,000
ETC Marketing Ltd	0	7,500	0	22,500.00	-22,500.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	900,000	900,000
Exxon	0	247,800	0	317,518.00	-317,518.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	12,700,720	12,700,720
Freepoint	0	193,523	0	310,234.84	-310,234.84	9/1/2023	9/30/2023	10/25/2023	15	25	40	12,409,394	12,409,394
Greylock	0	23,500	0	36,180.00	-36,180.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	1,447,200	1,447,200
Gunvor	0	97,097	0	100,592.15	-100,592.15	9/1/2023	9/30/2023	10/25/2023	15	25	40	4,023,686	4,023,686
Hartree Partners LP	19,789	77,000	59,362.46	110,586.50	-51,224.04	9/1/2023	9/30/2023	10/25/2023	15	25	40	2,048,962	4,423,460
IGS	0	55,000	0	84,500.00	-84,500.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	3,380,000	3,380,000
J Aron	300	800	383.25	976	-592.75	9/1/2023	9/30/2023	10/25/2023	15	25	40	23,710	39,040
KeySpan Gas East	2,300	0	4,209.00	0	4,209.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	(168,360)	-
Koch	33,600	55,200	44,234.00	87,487.00	-43,253.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	1,730,120	3,499,480
Macq. Energy	760,000	172,500	965,175.00	311,542.50	653,632.50	9/1/2023	9/30/2023	10/25/2023	15	25	40	(26,145,300)	12,461,700
Mercuria	549,997	180,100	1,030,924.95	279,828.00	751,096.95	9/1/2023	9/30/2023	10/25/2023	15	25	40	(30,043,878)	11,193,120
Mitsui Marketing	90,400	15,800	255,204.75	21,564.75	233,640.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	(9,345,600)	862,590
MorganCG	0	156,200	0	207,333.50	-207,333.50	9/1/2023	9/30/2023	10/25/2023	15	25	40	8,293,340	8,293,340
MU Marketing	460,000	6,000,000	686,100.00	6,600,000.00	-5,913,900.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	236,556,000	264,000,000
NextEra	748,961	300,100	713,707.85	382,511.50	331,196.35	9/1/2023	9/30/2023	10/25/2023	15	25	40	(13,247,854)	15,300,460
NGX	688,296	1,394,600	1,890,803.88	2,074,327.08	-183,523.20	9/1/2023	9/30/2023	10/25/2023	15	25	40	7,340,928	82,973,083
NJR Energy	0	9,900	0	22,449.50	-22,449.50	9/1/2023	9/30/2023	10/25/2023	15	25	40	897,980	897,980
NRG Business	2,052,200	428,700	2,647,255.50	607,585.00	2,039,670.50	9/1/2023	9/30/2023	10/25/2023	15	25	40	(81,586,820)	24,303,400
Old Dominion Electr	3,700	0	7,215.00	0	7,215.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	(288,600)	-
PacificSE	586,900	255,130	1,671,404.50	298,642.75	1,372,761.75	9/1/2023	9/30/2023	10/25/2023	15	25	40	(54,910,470)	11,945,710
Petrochina	19,452	100,000	29,372.52	154,486.00	-125,113.48	9/1/2023	9/30/2023	10/25/2023	15	25	40	5,004,539	6,179,440
Radiate Energy	0	6,300	0	6,678.00	-6,678.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	267,120	267,120
Range	0	726,469	0	1,860,613.39	-1,860,613.39	9/1/2023	9/30/2023	10/25/2023	15	25	40	74,424,536	74,424,536
Repsol Energy	0	10,000	0	30,750.00	-30,750.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	1,230,000	1,230,000
S. Jersey Resources	73,800	252,200	203,302.00	238,515.75	-35,213.75	9/1/2023	9/30/2023	10/25/2023	15	25	40	1,408,550	9,540,630
Sequent	1,034,700	348,400	2,963,898.50	511,531.50	2,452,367.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	(98,094,680)	20,461,260
SGPM	7,900	0	9,141.00	0	9,141.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	(365,640)	-
Shell	1,985,763	332,043	4,492,018.07	507,130.60	3,984,887.47	9/1/2023	9/30/2023	10/25/2023	15	25	40	(159,395,499)	20,285,224
SnyderBros	0	673,300	0	958,897.25	-958,897.25	9/1/2023	9/30/2023	10/25/2023	15	25	40	38,355,890	38,355,890
Southern Co Svcs Inc	1,500,000	0	3,984,000.00	0	3,984,000.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	(159,360,000)	-
Southwest	0	5,000	0	14,700.00	-14,700.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	588,000	588,000
Spire	0	9,957	0	30,567.99	-30,567.99	9/1/2023	9/30/2023	10/25/2023	15	25	40	1,222,720	1,222,720
Spotlight Energy	138,100	32,700	375,087.75	58,257.00	316,830.75	9/1/2023	9/30/2023	10/25/2023	15	25	40	(12,673,230)	2,330,280
Sprague	224,971	0	213,722.45	0	213,722.45	9/1/2023	9/30/2023	10/25/2023	15	25	40	(8,548,898)	-
SWN Energy Services	0	668,900	0	1,204,987.00	-1,204,987.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	48,199,480	48,199,480
Symmetry	0	79,796	0	234,365.90	-234,365.90	9/1/2023	9/30/2023	10/25/2023	15	25	40	9,374,636	9,374,636
TCEM	0	223,389	0	285,311.27	-285,311.27	9/1/2023	9/30/2023	10/25/2023	15	25	40	11,412,451	11,412,451
Tenaska Marketing	2,094,545	265,642	7,076,865.00	644,631.46	6,432,233.54	9/1/2023	9/30/2023	10/25/2023	15	25	40	(257,289,342)	25,785,258
TotalEnergies	20,442	0	59,128.49	0	59,128.49	9/1/2023	9/30/2023	10/25/2023	15	25	40	(2,365,140)	-
TWIN EAGLE	15,000	92,900	39,875.00	124,810.00	-84,935.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	3,397,400	4,992,400
UGI Energy	41,138	11,500	109,196.67	16,017.50	93,179.17	9/1/2023	9/30/2023	10/25/2023	15	25	40	(3,727,167)	640,700
Vitol	27,100	87,600	77,254.00	161,367.50	-84,113.50	9/1/2023	9/30/2023	10/25/2023	15	25	40	3,364,540	6,454,700
VPSE	0	125,000	0	236,550.00	-236,550.00	9/1/2023	9/30/2023	10/25/2023	15	25	40	9,462,000	9,462,000
Allied/DTE	0	374,800	0	552,549.50	-552,549.50	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	23,483,354	23,483,354
Ascent	0	1,085,000	0	1,686,090.00	-1,686,090.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	71,658,825	71,658,825
BPEnergy	102,800	395,300	173,935.00	497,457.75	-323,522.75	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	13,749,717	21,141,954
CarbonBetter	0	200	0	244	-244	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	10,370	10,370
Castleton	144,500	165,400	405,730.00	210,407.00	195,323.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(8,301,228)	8,942,298

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
Chesapeake Energy	0	945,100	0	2,284,161.00	-2,284,161.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	97,076,843	97,076,843
Chevron	109,500	0	304,997.50	0	304,997.50	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(12,962,394)	-
CIMA	0	165,700	0	278,277.75	-278,277.75	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	11,826,804	11,826,804
Citadel	35,000	104,400	44,100.00	201,823.00	-157,723.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	6,703,228	8,577,478
CitiEnergy	15,400	333,400	19,669.50	434,552.75	-414,883.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	17,632,538	18,468,492
Clearwater	48,500	0	131,303.75	0	131,303.75	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(5,580,409)	-
CNX	0	342,100	0	715,304.50	-715,304.50	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	30,400,441	30,400,441
Columbia Gas of VA	10,000	0	14,100.00	0	14,100.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(599,250)	-
Columbia MD	0	4,200	0	4,011.00	-4,011.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	170,468	170,468
Columbia of Ohio	48,000	55,700	70,220.00	73,518.25	-3,298.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	140,176	3,124,526
Columbia PA	0	30,000	0	27,750.00	-27,750.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	1,179,375	1,179,375
Conoco	12,300	150,142	32,835.75	370,270.46	-337,434.71	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	14,340,975	15,736,495
Constellation	963,100	67,900	1,362,413.50	82,016.00	1,280,397.50	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(54,416,894)	3,485,680
Coterra	0	3,092,966	0	4,330,152.40	-4,330,152.40	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	184,031,477	184,031,477
Delmarva Power	1,000	0	1,245.00	0	1,245.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(52,913)	-
Diversified	0	213,500	0	263,327.25	-263,327.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	11,191,408	11,191,408
Dominion	29,100	0	54,738.00	0	54,738.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(2,326,365)	-
DTE	290,200	49,200	863,114.50	52,523.00	810,591.50	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(34,450,139)	2,232,228
Duke Energy Carol	32,500	0	106,975.00	0	106,975.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(4,546,438)	-
Eco-Energy	0	22,600	0	62,397.25	-62,397.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	2,651,883	2,651,883
EDF	31,200	9,500	52,422.00	27,231.00	25,191.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(1,070,618)	1,157,318
Emera	24,200	5,200	37,483.00	12,704.25	24,778.75	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(1,053,097)	539,931
Energy Authority	30,900	0	95,172.00	0	95,172.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(4,044,810)	-
EQT Energy	7,400	2,745,374	23,613.00	2,708,348.77	-2,684,735.77	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	114,101,270	115,104,823
Freepoint	0	330,400	0	471,048.75	-471,048.75	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	20,019,572	20,019,572
Greylock	0	54,600	0	67,553.25	-67,553.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	2,871,013	2,871,013
Gunvor	0	155,763	0	169,057.01	-169,057.01	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	7,184,923	7,184,923
Hartree Partners LP	14,300	24,600	45,125.00	35,278.50	9,846.50	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(418,476)	1,499,336
IGS	15,000	61,300	23,700.00	70,394.50	-46,694.50	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	1,984,516	2,991,766
J Aron	258,300	61,600	654,016.75	69,145.00	584,871.75	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(24,857,049)	2,938,663
Koch	0	252,894	0	350,468.66	-350,468.66	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	14,894,918	14,894,918
Macq. Energy	1,055,000	447,400	1,310,300.00	613,257.75	697,042.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(29,624,296)	26,063,454
Mercuria	332,866	252,000	717,967.75	377,089.50	340,878.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(14,487,326)	16,026,304
MIECO	0	300	0	963	-963	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	40,928	40,928
Mitsui Marketing	0	14,600	0	18,130.00	-18,130.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	770,525	770,525
MorganCG	6,600	114,718	13,564.00	167,638.93	-154,074.93	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	6,548,185	7,124,655
MU Marketing	200,000	6,325,000	270,200.00	8,828,875.00	-8,558,675.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	363,743,688	375,227,188
NextEra	877,425	314,200	1,273,000.07	402,882.50	870,117.57	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(36,979,997)	17,122,506
NGX	1,896,100	689,400	4,249,953.25	861,026.08	3,388,927.17	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(144,029,405)	36,593,608
NJR Energy	20,300	10,400	19,684.50	31,018.00	-11,333.50	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	481,674	1,318,265
NRG Business	2,023,857	367,300	3,014,213.99	389,593.75	2,624,620.24	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(111,546,360)	16,557,734
PacificSE	509,529	490,900	1,543,247.72	597,040.00	946,207.72	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(40,213,828)	25,374,200
Petrochina	2,500	49,800	3,250.00	83,394.00	-80,144.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	3,406,120	3,544,245
Radiate Energy	0	15,302	0	37,547.04	-37,547.04	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	1,595,749	1,595,749
Range	0	774,025	0	1,430,423.10	-1,430,423.10	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	60,792,982	60,792,982
RDAF/Rainbow	0	465,000	0	669,135.00	-669,135.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	28,438,238	28,438,238
Repsol Energy	0	8,000	0	22,900.00	-22,900.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	973,250	973,250
S. Jersey Resources	57,000	118,200	156,480.50	161,801.75	-5,321.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	226,153	6,876,574
Sequent	1,000,400	245,347	2,919,090.25	328,255.40	2,590,834.85	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(110,110,481)	13,950,855
SGPM	0	9,300	0	29,016.00	-29,016.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	1,233,180	1,233,180
Shell	1,970,162	95,269	4,101,964.26	148,887.40	3,953,076.86	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(168,005,767)	6,327,715
SnyderBros	0	666,700	0	911,768.25	-911,768.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	38,750,151	38,750,151
Southern Co Svcs Inc	1,547,977	0	4,433,406.12	0	4,433,406.12	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(188,419,760)	-
Spark	0	1,600	0	2,091.00	-2,091.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	88,868	88,868
Spire	18,700	800	29,115.00	2,504.00	26,611.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(1,130,968)	106,420
Spotlight Energy	136,500	52,300	349,810.00	73,826.50	275,983.50	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(11,729,299)	3,137,626
Sprague	232,275	0	322,862.25	0	322,862.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(13,721,646)	-
SWN Energy Services	0	842,000	0	1,317,523.75	-1,317,523.75	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	55,994,759	55,994,759
Symmetry	0	77,500	0	250,635.00	-250,635.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	10,651,988	10,651,988
TCEM	10,000	88,000	31,100.00	163,501.25	-132,401.25	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	5,627,053	6,948,803
Tenaska Marketing	95,300	101,777	274,163.00	243,622.73	30,540.27	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(1,297,961)	10,353,966
TotalEnergies	0	9,000	0	26,550.00	-26,550.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	1,128,375	1,128,375
TWIN EAGLE	35,800	77,700	82,022.75	94,553.50	-12,530.75	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	532,557	4,018,524
UGI Energy	512,641	39,100	910,843.50	54,441.50	856,402.00	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	(36,397,085)	2,313,764
Vitol	38,900	140,600	57,468.00	179,121.50	-121,653.50	10/1/2023	10/31/2023	11/27/2023	15.5	27	42.5	5,170,274	7,612,664
Allied/DTE	0	114,200	0	208,946.50	-208,946.50	11/1/2023	11/30/2023	12/26/2023	15	26	41	8,566,807	8,566,807
Ascent	0	1,050,000	0	2,179,200.00	-2,179,200.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	89,347,200	89,347,200
BPEnergy	621,400	936,098	1,268,800.00	1,968,226.22	-699,426.22	11/1/2023	11/30/2023	12/26/2023	15	26	41	28,676,475	80,697,275
Brooklyn Union Gas	5,500	0	17,325.00	0	17,325.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	(710,325)	-
Castleton	116,291	86,300	271,662.58	185,720.00	85,942.58	11/1/2023	11/30/2023	12/26/2023	15	26	41	(3,523,646)	7,614,520
Chesapeake Energy	0	911,300	0	2,569,496.00	-2,569,496.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	105,349,336	105,349,336
Chevron	170,500	26,900	333,178.75	65,684.00	267,494.75	11/1/2023	11/30/2023	12/26/2023	15	26	41	(10,967,285)	2,693,044
CIMA	0	114,400	0	244,077.00	-244,077.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	10,007,157	10,007,157

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
Citadel	281,900	421,838	576,327.00	942,179.66	-365,852.66	11/1/2023	11/30/2023	12/26/2023	15	26	41	14,999,959	38,629,366
CitiEnergy	264,100	480,500	798,422.50	1,024,713.75	-226,291.25	11/1/2023	11/30/2023	12/26/2023	15	26	41	9,277,941	42,013,264
Clearwater	0	79,430	0	193,420.55	-193,420.55	11/1/2023	11/30/2023	12/26/2023	15	26	41	7,930,243	7,930,243
CNX	10,000	781,000	16,000.00	1,551,525.00	-1,535,525.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	62,956,525	63,612,525
Columbia Gas of VA	16,100	0	35,742.00	0	35,742.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	(1,465,422)	-
Columbia KY	0	100	0	210	-210	11/1/2023	11/30/2023	12/26/2023	15	26	41	8,610	8,610
Columbia MD	1,800	0	4,234.50	0	4,234.50	11/1/2023	11/30/2023	12/26/2023	15	26	41	(173,615)	-
Columbia of Ohio	10,000	36,100	15,000.00	72,605.00	-57,605.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	2,361,805	2,976,805
Conoco	8,600	379,100	20,578.00	764,575.50	-743,997.50	11/1/2023	11/30/2023	12/26/2023	15	26	41	30,503,898	31,347,596
Constellation	429,300	62,000	1,211,977.00	104,195.00	1,107,782.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	(45,419,062)	4,271,995
Coterra	0	2,999,263	0	5,728,592.33	-5,728,592.33	11/1/2023	11/30/2023	12/26/2023	15	26	41	234,872,286	234,872,286
Delmarva Power	53,700	0	121,098.25	0	121,098.25	11/1/2023	11/30/2023	12/26/2023	15	26	41	(4,965,028)	-
Diversified	0	288,700	0	557,402.75	-557,402.75	11/1/2023	11/30/2023	12/26/2023	15	26	41	22,853,513	22,853,513
Dominion	113,000	0	662,730.00	0	662,730.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	(27,171,930)	-
DTE	211,330	138,267	734,735.25	310,827.87	423,907.38	11/1/2023	11/30/2023	12/26/2023	15	26	41	(17,380,203)	12,743,943
Duke Energy Carol	10,000	0	24,000.00	0	24,000.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	(984,000)	-
Eco-Energy	0	24,100	0	67,793.00	-67,793.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	2,779,513	2,779,513
EDF	224,280	34,446	442,166.75	77,086.46	365,080.29	11/1/2023	11/30/2023	12/26/2023	15	26	41	(14,968,292)	3,160,545
Emera	31,700	43,200	80,452.25	109,040.50	-28,588.25	11/1/2023	11/30/2023	12/26/2023	15	26	41	1,172,118	4,470,661
Energy Authority	5,000	0	11,650.00	0	11,650.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	(477,650)	-
Enspire Energy, LLC	0	40,000	0	56,425.00	-56,425.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	2,313,425	2,313,425
EQT Energy	36,400	1,555,601	81,938.25	2,488,672.26	-2,406,734.01	11/1/2023	11/30/2023	12/26/2023	15	26	41	98,676,094	102,035,563
Equinor	0	8,000	0	17,680.00	-17,680.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	724,880	724,880
ETC Marketing Ltd	0	15,000	0	44,150.00	-44,150.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	1,810,150	1,810,150
EVI/DTE	0	711,930	0	1,283,253.83	-1,283,253.83	11/1/2023	11/30/2023	12/26/2023	15	26	41	52,613,407	52,613,407
Freepoint	0	98,500	0	245,840.00	-245,840.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	10,079,440	10,079,440
Greylock	0	153,400	0	304,613.75	-304,613.75	11/1/2023	11/30/2023	12/26/2023	15	26	41	12,489,164	12,489,164
Gunvor	107,500	30,600	399,262.50	41,967.00	357,295.50	11/1/2023	11/30/2023	12/26/2023	15	26	41	(14,649,116)	1,720,647
Hartree Partners LP	900	186,700	1,305.00	394,908.84	-393,603.84	11/1/2023	11/30/2023	12/26/2023	15	26	41	16,137,757	16,191,262
IGS	0	80,100	0	171,717.50	-171,717.50	11/1/2023	11/30/2023	12/26/2023	15	26	41	7,040,418	7,040,418
J Aron	158,900	180,400	393,134.50	391,359.50	1,775.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	(72,775)	16,045,740
KeySpan Gas East	9,600	0	15,024.00	0	15,024.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	(615,984)	-
Koch	100	58,600	360	119,134.25	-118,774.25	11/1/2023	11/30/2023	12/26/2023	15	26	41	4,869,744	4,884,504
Macq. Energy	20,000	116,500	30,850.00	232,815.00	-201,965.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	8,280,565	9,545,415
Mercuria	52,600	563,600	139,576.00	1,165,708.75	-1,026,132.75	11/1/2023	11/30/2023	12/26/2023	15	26	41	42,071,443	47,794,059
MIECO	0	11,200	0	26,656.00	-26,656.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	1,092,896	1,092,896
Mitsui Marketing	0	62,500	0	98,471.25	-98,471.25	11/1/2023	11/30/2023	12/26/2023	15	26	41	4,037,321	4,037,321
MorganCG	0	46,600	0	96,843.00	-96,843.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	3,970,563	3,970,563
MU Marketing	0	6,000,000	0	11,820,000.00	-11,820,000.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	484,620,000	484,620,000
NextEra	35,550	388,991	75,759.75	795,438.89	-719,679.14	11/1/2023	11/30/2023	12/26/2023	15	26	41	29,506,845	32,612,994
NGX	2,869,800	825,600	6,881,017.00	1,805,838.10	5,075,178.90	11/1/2023	11/30/2023	12/26/2023	15	26	41	(208,082,335)	74,039,362
NJNG	77,900	0	155,628.25	0	155,628.25	11/1/2023	11/30/2023	12/26/2023	15	26	41	(6,380,758)	-
NJR Energy	0	7,600	0	17,867.00	-17,867.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	732,547	732,547
NOVEC Energy	0	7,000	0	13,917.50	-13,917.50	11/1/2023	11/30/2023	12/26/2023	15	26	41	570,618	570,618
NRG Business	1,161,100	189,300	3,079,131.75	435,056.25	2,644,075.50	11/1/2023	11/30/2023	12/26/2023	15	26	41	(108,407,096)	17,837,306
Old Dominion Electr	24,700	0	184,200.00	0	184,200.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	(7,552,200)	-
PacificSE	1,455,118	277,100	4,039,980.70	584,016.75	3,455,963.95	11/1/2023	11/30/2023	12/26/2023	15	26	41	(141,694,522)	23,944,687
Petrochina	500	172,900	1,875.00	377,759.00	-375,884.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	15,411,244	15,488,119
PSEG ERT LLC	95,000	0	170,425.00	0	170,425.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	(6,987,425)	-
Radiate Energy	0	5,000	0	13,050.00	-13,050.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	535,050	535,050
Range	0	154,800	0	294,124.00	-294,124.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	12,059,084	12,059,084
Repsol Energy	150,000	134,000	479,625.00	340,345.75	139,279.25	11/1/2023	11/30/2023	12/26/2023	15	26	41	(5,710,449)	13,954,176
S. Jersey Resources	72,400	277,678	166,285.50	541,586.46	-375,300.96	11/1/2023	11/30/2023	12/26/2023	15	26	41	15,387,339	22,205,045
Sequent	577,300	157,300	1,379,541.00	315,741.50	1,063,799.50	11/1/2023	11/30/2023	12/26/2023	15	26	41	(43,615,780)	12,945,402
SGPM	0	15,000	0	39,300.00	-39,300.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	1,611,300	1,611,300
Shell	2,435,087	498,061	6,712,220.59	1,331,505.65	5,380,714.94	11/1/2023	11/30/2023	12/26/2023	15	26	41	(220,609,313)	54,591,732
SnyderBros	0	1,270,900	0	2,548,998.75	-2,548,998.75	11/1/2023	11/30/2023	12/26/2023	15	26	41	104,508,949	104,508,949
Southern Co Svcs Inc	1,496,039	0	4,883,071.30	0	4,883,071.30	11/1/2023	11/30/2023	12/26/2023	15	26	41	(200,205,923)	-
Spire	0	5,000	0	15,150.00	-15,150.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	621,150	621,150
Spotlight Energy	60,600	13,700	183,622.00	42,736.75	140,885.25	11/1/2023	11/30/2023	12/26/2023	15	26	41	(5,776,295)	1,752,207
SWN Energy Services	0	622,700	0	1,499,571.50	-1,499,571.50	11/1/2023	11/30/2023	12/26/2023	15	26	41	61,482,432	61,482,432
Symmetry	0	22,500	0	49,843.75	-49,843.75	11/1/2023	11/30/2023	12/26/2023	15	26	41	2,043,594	2,043,594
TCEM	165,000	348,500	323,400.00	724,835.25	-401,435.25	11/1/2023	11/30/2023	12/26/2023	15	26	41	16,458,845	29,718,245
Tenaska Marketing	1,521,557	218,300	4,600,688.73	434,867.25	4,165,821.48	11/1/2023	11/30/2023	12/26/2023	15	26	41	(170,798,681)	17,829,557
TotalEnergies	0	30,000	0	48,679.00	-48,679.00	11/1/2023	11/30/2023	12/26/2023	15	26	41	1,995,839	1,995,839
TWIN EAGLE	585,800	256,300	1,619,506.53	691,870.50	927,636.03	11/1/2023	11/30/2023	12/26/2023	15	26	41	(38,033,077)	28,366,691
UGI Energy	706,247	87,000	1,517,581.66	230,208.00	1,287,373.66	11/1/2023	11/30/2023	12/26/2023	15	26	41	(52,782,320)	9,438,528
Vitol	191,700	1,135,794	327,331.50	2,448,965.10	-2,121,633.60	11/1/2023	11/30/2023	12/26/2023	15	26	41	86,986,978	100,407,569
Allied/DTE	0	81,900	0	168,438.50	-168,438.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	6,821,759	6,821,759
Ascent	0	1,085,000	0	2,164,110.00	-2,164,110.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	87,646,455	87,646,455
BPEnergy	1,340,100	476,084	2,679,371.25	812,076.87	1,867,294.38	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(75,625,422)	32,889,113
CarbonBetter	0	89,200	0	167,524.00	-167,524.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	6,784,722	6,784,722
Castleton	212,266	68,900	574,468.52	140,396.00	434,072.52	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(17,579,937)	5,686,038

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
Chesapeake Energy	0	1,130,700	0	2,564,652.00	-2,564,652.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	103,868,406	103,868,406
Chevron	620,000	43,800	1,250,850.00	73,651.00	1,177,199.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(47,676,560)	2,982,866
CIMA	0	108,200	0	200,733.75	-200,733.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	8,129,717	8,129,717
Citadel	58,700	1,137,900	108,431.00	2,086,565.00	-1,978,134.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	80,114,427	84,505,883
CitiEnergy	8,400	96,200	18,648.00	192,719.00	-174,071.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	7,049,876	7,805,120
Clearwater	700	0	2,345.00	0	2,345.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(94,973)	-
CNX	0	846,000	0	1,776,392.50	-1,776,392.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	71,943,896	71,943,896
Columbia Gas of VA	14,500	0	28,456.25	0	28,456.25	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(1,152,478)	-
Columbia KY	0	5,000	0	8,250.00	-8,250.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	334,125	334,125
Columbia of Ohio	0	22,300	0	41,147.00	-41,147.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	1,666,454	1,666,454
Columbia PA	0	20,000	0	39,937.50	-39,937.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	1,617,469	1,617,469
Conoco	0	313,300	0	591,435.50	-591,435.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	23,953,138	23,953,138
Constellation	629,400	143,700	1,262,258.00	282,468.25	979,789.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(39,681,485)	11,439,964
Coterra	0	3,090,000	0	6,705,300.00	-6,705,300.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	271,564,650	271,564,650
Delmarva Power	5,000	0	9,525.00	0	9,525.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(385,763)	-
Diversified	0	145,800	0	269,851.00	-269,851.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	10,928,966	10,928,966
Dominion	387,600	0	1,374,159.00	0	1,374,159.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(55,653,440)	-
DTE	115,176	875,543	355,847.86	2,778,195.54	-2,422,347.68	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	98,105,081	112,516,919
Duke Energy Carol	45,000	0	147,937.50	0	147,937.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(5,991,469)	-
Eco-Energy	0	30,000	0	66,832.75	-66,832.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	2,706,726	2,706,726
EDF	216,646	34,000	478,190.16	64,558.50	413,631.66	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(16,752,082)	2,614,619
Emera	60,500	8,700	165,850.00	20,991.00	144,859.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(5,866,790)	850,136
Enspire Energy, LLC	0	186,000	0	368,466.00	-368,466.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	14,922,873	14,922,873
EQT Energy	23,500	1,940,922	81,812.50	4,884,807.14	-4,802,994.64	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	194,521,283	197,834,689
Equinor	0	43,200	0	81,682.50	-81,682.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	3,308,141	3,308,141
Freepoint	0	11,100	0	23,691.75	-23,691.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	959,516	959,516
Greylock	0	34,500	0	64,751.25	-64,751.25	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	2,622,426	2,622,426
GRP/BP	0	783,836	0	1,579,429.54	-1,579,429.54	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	63,966,896	63,966,896
Gunvor	342,500	49,100	1,135,750.00	189,147.00	946,603.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(38,337,422)	7,660,454
Hartree Partners LP	0	83,200	0	167,112.75	-167,112.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	6,768,066	6,768,066
IGS	0	84,700	0	162,647.50	-162,647.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	6,587,224	6,587,224
J Aron	94,100	249,100	285,705.25	817,047.00	-531,341.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	21,519,341	33,090,404
KeySpan Gas East	4,000	0	7,960.00	0	7,960.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(322,380)	-
Koch	600	67,900	1,159.50	125,144.75	-123,985.25	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	5,021,403	5,068,362
Macq. Energy	17,700	60,900	65,423.25	141,552.00	-76,128.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	3,083,214	5,732,856
Mercuria	12,800	798,952	30,304.00	1,601,454.30	-1,571,150.30	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	63,631,587	64,858,899
MIECO	0	11,300	0	25,799.75	-25,799.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	1,044,890	1,044,890
Mitsui Marketing	0	26,400	0	50,729.00	-50,729.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	2,054,525	2,054,525
MorganCG	0	729,400	0	2,535,515.75	-2,535,515.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	102,688,388	102,688,388
MU Marketing	200,000	6,200,000	1,464,000.00	12,648,000.00	-11,184,000.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	452,952,000	512,244,000
NextEra	9,000	692,300	26,049.00	1,287,680.75	-1,261,631.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	51,096,086	52,151,070
NGX	2,338,577	751,900	5,570,362.06	1,445,546.25	4,124,815.81	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(167,055,040)	58,544,623
NJNG	12,600	5,300	25,128.00	10,861.25	14,266.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(577,803)	439,881
NJR Energy	0	10,100	0	20,230.50	-20,230.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	819,335	819,335
NRG Business	1,612,000	304,300	3,827,310.50	555,702.00	3,271,608.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(132,500,144)	22,505,931
PacificSE	2,208,350	681,416	8,327,277.25	1,221,083.92	7,106,193.33	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(287,800,830)	49,453,899
Petrochina	17,400	42,100	36,463.50	71,916.50	-35,453.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	1,435,847	2,912,618
Radiate Energy	0	27,100	0	70,560.25	-70,560.25	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	2,857,690	2,857,690
Range	0	120,000	0	234,497.25	-234,497.25	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	9,497,139	9,497,139
Repsol Energy	0	32,800	0	64,796.50	-64,796.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	2,624,258	2,624,258
S. Jersey Resources	90,500	601,173	243,742.50	1,235,227.87	-991,485.37	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	40,155,157	50,026,729
Sequent	62,900	633,500	150,129.00	1,548,566.50	-1,398,437.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	56,636,719	62,716,943
Shell	2,366,054	977,742	7,270,302.66	2,248,002.88	5,022,299.78	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(203,403,141)	91,044,117
SnyderBros	0	549,661	0	1,121,308.44	-1,121,308.44	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	45,412,992	45,412,992
Southern Co Svcs Inc	1,540,273	0	4,322,006.04	0	4,322,006.04	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(175,041,245)	-
Southwest	0	29,964	0	79,104.96	-79,104.96	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	3,203,751	3,203,751
Spark	0	1,500	0	2,739.75	-2,739.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	110,960	110,960
Spire	10,000	10,000	29,000.00	27,400.00	1,600.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(64,800)	1,109,700
Spotlight Energy	245,500	40,200	554,362.50	88,795.50	465,567.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(18,855,464)	3,596,218
SWN Energy Services	0	551,700	0	1,138,012.50	-1,138,012.50	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	46,089,506	46,089,506
Symmetry	0	2,000	0	3,300.00	-3,300.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	133,650	133,650
TCEM	0	585,600	0	1,138,682.00	-1,138,682.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	46,116,621	46,116,621
Tenaska Marketing	1,088,100	270,300	2,304,019.75	527,662.75	1,776,357.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(71,942,459)	21,370,341
TotalEnergies	0	49,300	0	93,748.75	-93,748.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	3,796,824	3,796,824
TWIN EAGLE	398,600	1,002,700	1,106,132.50	3,813,978.75	-2,707,846.25	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	109,667,773	154,466,139
UGI Energy	1,057,217	81,400	2,256,208.78	134,574.50	2,121,634.28	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(85,926,188)	5,450,267
United Energy	77,500	0	156,550.00	0	156,550.00	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(6,340,275)	-
Vitol	176,500	143,500	300,934.75	289,024.00	11,910.75	12/1/2023	12/31/2023	1/25/2024	15.5	25	40.5	(482,385)	11,705,472
Allied/DTE	0	50,600	0	110,702.00	-110,702.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	4,594,133	4,594,133
ARM Energy	0	15,100	0	39,968.50	-39,968.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	1,658,693	1,658,693
Ascent	0	1,162,500	0	2,415,675.00	-2,415,675.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	100,250,513	100,250,513
BPEnergy	270,036	324,900	918,644.50	1,311,923.00	-393,278.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	16,321,058	54,444,805
CarbonBetter	0	30,400	0	52,923.00	-52,923.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	2,196,305	2,196,305

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
Castleton	160,600	90,442	830,607.50	454,042.34	376,565.16	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(15,627,454)	18,842,757
Chesapeake Energy	0	1,064,500	0	2,402,832.75	-2,402,832.75	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	99,717,559	99,717,559
Chevron	105,100	5,600	776,399.50	10,776.00	765,623.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(31,773,375)	447,204
CIMA	0	76,000	0	154,129.75	-154,129.75	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	6,396,385	6,396,385
Citadel	72,700	702,000	789,000.00	2,503,842.00	-1,714,842.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	71,165,943	103,909,443
CitiEnergy	40,000	157,600	617,400.00	1,425,102.25	-807,702.25	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	33,519,643	59,141,743
Clearwater	18,500	0	55,681.25	0	55,681.25	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(2,310,772)	-
CNX	35,000	949,100	463,750.00	2,039,356.75	-1,575,606.75	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	65,387,680	84,633,305
Columbia KY	0	12,000	0	224,220.00	-224,220.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	9,305,130	9,305,130
Columbia of Ohio	0	30,000	0	55,500.00	-55,500.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	2,303,250	2,303,250
Columbia PA	0	5,000	0	8,375.00	-8,375.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	347,563	347,563
Conoco	0	184,976	0	910,215.93	-910,215.93	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	37,773,961	37,773,961
Constellation	50,000	6,000	614,800.00	13,600.00	601,200.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(24,949,800)	564,400
Coterra	0	3,100,000	0	6,634,000.00	-6,634,000.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	275,311,000	275,311,000
Delmarva Power	10,000	0	27,700.00	0	27,700.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(1,149,550)	-
Diversified	0	172,600	0	733,175.50	-733,175.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	30,426,783	30,426,783
Dominion	557,000	0	2,234,140.00	0	2,234,140.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(92,716,810)	-
DTE	198,628	819,600	990,283.00	4,087,766.25	-3,097,483.25	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	128,545,555	169,642,299
Duke Energy Carol	10,000	0	35,000.00	0	35,000.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(1,452,500)	-
Eco-Energy	0	20,400	0	41,255.50	-41,255.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	1,712,103	1,712,103
EDF	206,646	163,500	450,488.28	1,714,646.25	-1,264,157.97	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	52,462,556	71,157,819
Emera	103,100	15,600	816,193.50	43,430.25	772,763.25	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(32,069,675)	1,802,355
EQT Energy	170,000	2,110,294	1,158,708.00	6,670,551.53	-5,511,843.53	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	228,741,506	276,827,888
Equinor	0	98,400	0	1,665,402.00	-1,665,402.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	69,114,183	69,114,183
Freepoint	0	46,800	0	109,579.25	-109,579.25	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	4,547,539	4,547,539
Greylock	0	28,900	0	65,720.50	-65,720.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	2,727,401	2,727,401
GRP/BP	0	425,692	0	914,413.08	-914,413.08	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	37,948,143	37,948,143
Gunvor	395,000	0	1,365,800.00	100,000.00	1,265,800.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(52,530,700)	4,150,000
Hartree Partners LP	0	600	0	1,572.25	-1,572.25	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	65,248	65,248
IGS	0	10,700	0	21,493.50	-21,493.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	891,980	891,980
J Aron	51,600	36,800	665,825.75	59,370.50	606,455.25	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(25,167,893)	2,463,876
KeySpan Gas East	26,200	0	212,030.00	0	212,030.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(8,799,245)	-
Koch	2,100	127,700	4,935.00	598,198.75	-593,263.75	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	24,620,446	24,825,248
Macq. Energy	176,600	51,400	680,702.50	219,450.00	461,252.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(19,141,979)	9,107,175
Mercuria	529,175	518,043	3,219,956.61	2,581,172.45	638,784.16	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(26,509,543)	107,118,657
MIECO	0	35,900	0	429,381.00	-429,381.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	17,819,312	17,819,312
Mitsui Marketing	0	29,000	0	65,670.00	-65,670.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	2,725,305	2,725,305
MorganCG	0	102,295	0	1,298,891.50	-1,298,891.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	53,903,997	53,903,997
MU Marketing	0	6,200,000	0	13,206,000.00	-13,206,000.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	548,049,000	548,049,000
NextEra	0	302,500	0	1,629,781.75	-1,629,781.75	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	67,635,943	67,635,943
NGX	2,563,394	340,400	8,745,382.21	951,290.88	7,794,091.33	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(323,454,790)	39,478,572
NJNG	0	11,400	0	102,885.00	-102,885.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	4,269,728	4,269,728
NJR Energy	0	29,300	0	65,950.00	-65,950.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	2,736,925	2,736,925
NRG Business	2,801,200	462,300	6,900,747.00	932,621.50	5,968,125.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(247,677,208)	38,703,792
PacificSE	362,000	507,000	2,365,188.25	967,059.25	1,398,129.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(58,022,354)	40,132,959
Petrochina	0	23,600	0	54,202.00	-54,202.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	2,249,383	2,249,383
Radiate Energy	0	16,100	0	36,711.50	-36,711.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	1,523,527	1,523,527
Range	0	6,800	0	15,899.25	-15,899.25	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	659,819	659,819
Repsol Energy	0	23,800	0	61,507.75	-61,507.75	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	2,552,572	2,552,572
S. Jersey Resources	315,100	174,500	944,021.50	336,746.50	607,275.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(25,201,913)	13,974,980
Sequent	252,500	348,000	1,698,650.00	906,555.00	792,095.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(32,871,943)	37,622,033
Shell	1,691,117	881,454	6,424,452.29	5,137,430.20	1,287,022.09	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(53,411,417)	213,203,353
SnyderBros	0	295,400	0	1,412,899.00	-1,412,899.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	58,635,309	58,635,309
Southern Co Svcs Inc	1,549,491	0	4,213,066.02	0	4,213,066.02	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(174,842,240)	-
Southwest	0	5,000	0	18,700.00	-18,700.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	776,050	776,050
Spark	0	200	0	307.5	-307.5	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	12,761	12,761
Spire	25,000	30,000	106,250.00	83,605.00	22,645.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(939,768)	3,469,608
Spotlight Energy	23,600	22,100	225,680.00	53,722.00	171,958.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(7,136,257)	2,229,463
SWN Energy Services	13,500	524,500	34,740.00	1,193,320.00	-1,158,580.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	48,081,070	49,522,780
Symmetry	0	10,700	0	26,820.00	-26,820.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	1,113,030	1,113,030
TCEM	900	330,500	1,710.00	2,772,339.75	-2,770,629.75	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	114,981,135	115,052,100
Tenaska Marketing	1,140,200	44,355	3,481,314.00	121,255.55	3,360,058.45	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(139,442,426)	5,032,105
TotalEnergies	0	162,500	0	343,499.50	-343,499.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	14,255,229	14,255,229
TWIN EAGLE	618,177	1,000,479	2,170,753.60	7,255,673.75	-5,084,920.15	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	211,024,186	301,110,461
UGI Energy	1,359,600	49,400	2,984,939.00	89,326.50	2,895,612.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(120,167,919)	3,707,050
United Energy	620,000	0	1,308,200.00	0	1,308,200.00	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	(54,290,300)	-
Vitol	106,100	208,600	689,645.00	1,759,977.50	-1,070,332.50	1/1/2024	1/31/2024	2/26/2024	15.5	26	41.5	44,418,799	73,039,066
ARM Energy	0	22,700	0	27,874.50	-27,874.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	1,101,043	1,101,043
Ascent	0	1,087,500	0	2,162,312.50	-2,162,312.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	85,411,344	85,411,344
BPEnergy	25,000	153,300	32,700.00	211,168.00	-178,468.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	7,049,486	8,341,136
Brooklyn Union Gas	5,000	0	8,750.00	0	8,750.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(345,625)	-
CarbonBetter	0	22,800	0	29,082.00	-29,082.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	1,148,739	1,148,739
Castleton	175,600	128,500	330,784.26	169,108.00	161,676.26	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(6,386,212)	6,679,766

Legal Entity	Debit Vol	Credit Vol	Debit	Credit	Net Amount	Service Date From	Service Date To	Paid Date	Midpoint of Service Period Days	Date Paid Days From	Days Total	Dollar Days Total (Net)	Dollar Days Total (Credit Only)
Chesapeake Energy	0	889,600	0	1,904,688.00	-1,904,688.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	75,235,176	75,235,176
Chevron	0	3,600	0	5,778.50	-5,778.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	228,251	228,251
CIMA	0	79,200	0	115,188.75	-115,188.75	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	4,549,956	4,549,956
Citadel	20,000	111,800	40,275.50	164,823.50	-124,548.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	4,919,646	6,510,528
CitiEnergy	0	159,200	0	241,795.50	-241,795.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	9,550,922	9,550,922
CNX	0	765,800	0	1,559,201.50	-1,559,201.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	61,588,459	61,588,459
Columbia MD	0	12,500	0	21,162.50	-21,162.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	835,919	835,919
Columbia of Ohio	20,000	114,300	30,600.00	154,181.75	-123,581.75	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	4,881,479	6,090,179
Columbia PA	0	36,500	0	59,543.75	-59,543.75	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	2,351,978	2,351,978
Conoco	0	103,500	0	144,312.00	-144,312.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	5,700,324	5,700,324
Constellation	435,000	48,100	841,362.50	62,559.00	778,803.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(30,762,738)	2,471,081
Coterra	0	2,900,000	0	5,307,000.00	-5,307,000.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	209,626,500	209,626,500
Diversified	0	232,700	0	289,130.50	-289,130.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	11,420,655	11,420,655
Dominion	696,300	0	1,385,845.00	0	1,385,845.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(54,740,878)	-
DTE	236,100	645,600	438,263.75	2,514,094.50	-2,075,830.75	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	81,995,315	99,306,733
Duke Energy Carol	826,900	0	1,661,579.75	0	1,661,579.75	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(65,632,400)	-
Eco-Energy	0	78,900	0	111,024.00	-111,024.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	4,385,448	4,385,448
EDF	193,314	80,500	361,497.18	124,892.50	236,604.68	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(9,345,885)	4,933,254
Emera	52,000	20,000	86,382.75	28,075.00	58,307.75	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(2,303,156)	1,108,963
EQT Energy	40,000	1,715,449	89,675.00	4,682,150.45	-4,592,475.45	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	181,402,780	184,944,943
Equinor	0	27,900	0	34,279.50	-34,279.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	1,354,040	1,354,040
Freepoint	0	6,500	0	10,270.00	-10,270.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	405,665	405,665
Greylock	0	110,200	0	139,254.00	-139,254.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	5,500,533	5,500,533
Gunvor	190,000	31,400	416,700.00	143,050.50	273,649.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(10,809,155)	5,650,495
Hartree Partners LP	0	44,600	0	69,360.00	-69,360.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	2,739,720	2,739,720
IGS	0	29,300	0	36,582.25	-36,582.25	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	1,444,999	1,444,999
J Aron	45,000	181,600	64,375.00	553,705.00	-489,330.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	19,328,535	21,871,348
KeySpan Gas East	0	10,000	0	20,500.00	-20,500.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	809,750	809,750
Koch	15,300	139,000	19,910.00	197,434.00	-177,524.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	7,012,198	7,798,643
Macq. Energy	0	87,000	0	128,040.00	-128,040.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	5,057,580	5,057,580
Mercuria	218,358	53,400	415,521.84	79,416.50	336,105.34	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(13,276,161)	3,136,952
Mitsui Marketing	0	165,000	0	216,907.50	-216,907.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	8,567,846	8,567,846
MorganCG	0	90,300	0	118,471.75	-118,471.75	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	4,679,634	4,679,634
MU Marketing	0	5,800,000	0	11,948,000.00	-11,948,000.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	471,946,000	471,946,000
NextEra	0	116,800	0	189,013.00	-189,013.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	7,466,014	7,466,014
NGX	2,573,600	528,700	4,865,880.25	766,456.98	4,099,423.27	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(161,927,219)	30,275,051
NJNG	12,000	0	16,540.00	0	16,540.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(653,330)	-
NRG Business	2,299,800	437,500	4,481,764.00	592,927.00	3,888,837.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(153,609,062)	23,420,617
PacificSE	2,217,500	723,800	4,282,298.50	962,707.50	3,319,591.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(131,123,845)	38,026,946
Petrochina	0	10,000	0	13,500.00	-13,500.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	533,250	533,250
Radiate Energy	0	1,500	0	1,972.50	-1,972.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	77,914	77,914
Range	0	800	0	1,042.00	-1,042.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	41,159	41,159
S. Jersey Resources	87,800	129,900	165,437.00	190,671.50	-25,234.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	996,763	7,531,524
Sequent	381,479	186,400	718,926.25	262,217.00	456,709.25	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(18,040,015)	10,357,572
Shell	1,290,928	364,000	2,554,409.35	498,137.25	2,056,272.10	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(81,222,748)	19,676,421
SnyderBros	0	539,900	0	736,433.00	-736,433.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	29,089,104	29,089,104
Southern Co Svcs Inc	1,450,000	0	3,755,500.00	0	3,755,500.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(148,342,250)	-
Spark	0	3,000	0	3,981.00	-3,981.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	157,250	157,250
Spire	0	100	0	127.5	-127.5	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	5,036	5,036
Spotlight Energy	473,814	40,000	893,378.46	65,000.00	828,378.46	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(32,720,949)	2,567,500
SWN Energy Services	0	564,000	0	985,495.25	-985,495.25	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	38,927,062	38,927,062
Symmetry	0	3,000	0	5,687.50	-5,687.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	224,656	224,656
TCEM	0	109,600	0	155,285.00	-155,285.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	6,133,758	6,133,758
Tenaska Marketing	1,203,200	93,100	2,447,157.50	174,693.00	2,272,464.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(89,762,348)	6,900,374
TotalEnergies	0	6,000	0	7,605.00	-7,605.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	300,398	300,398
TWIN EAGLE	265,900	1,016,200	492,568.00	4,152,075.26	-3,659,507.26	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	144,550,537	164,006,973
UGI Energy	595,500	25,000	1,111,790.00	33,500.00	1,078,290.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(42,592,455)	1,323,250
United Energy	580,000	0	1,183,200.00	0	1,183,200.00	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	(46,736,400)	-
Vitol	0	1,700	0	3,595.50	-3,595.50	2/1/2024	2/29/2024	3/25/2024	14.5	25	39.5	142,022	142,022

Totals	539,961,711	21,991,527,400 A
Calculated Lead		40.73
Total Pipeline	278,947,305	16/ 9,282,532,556 A
Total Supplier and Pipeline	818,909,017	Sum of A = 31,274,059,956
Calculated Combined Lead		38.19

Washington Gas Light
Pipeline Supplier Lead Calculation Twelve Months Ended March 31, 2024

Company Name	Date From Service	Date To Service	Date Paid	Amount	Midpoint Days From	Date Paid Days From	Days Total	Dollar Days Total
(A)	(B)	(C)	(D)	(E)	(F)=Midpoint	(G)=(D)-(C)	(H)=(F)+(G)	(I)=(E)*(H)
TCO - Demand	Mar 01, 2023	Mar 31, 2023	Apr 24, 2023	13,310,815	15.50	24	39.50	525,777,205
TCO - Commodity	Mar 01, 2023	Mar 31, 2023	Apr 24, 2023	251,404	15.50	24	39.50	9,930,462
Transco - Demand	Mar 01, 2023	Mar 31, 2023	Apr 10, 2023	4,243,796	15.50	10	25.50	108,216,786
Transco - Commodity	Mar 01, 2023	Mar 31, 2023	Apr 20, 2023	346,375	15.50	20	35.50	12,296,324
Pine Needle - Demand	Mar 01, 2023	Mar 31, 2023	Apr 10, 2023	56,858	15.50	10	25.50	1,449,872
Pine Needle - Commodity	Mar 01, 2023	Mar 31, 2023	Apr 20, 2023	59	15.50	20	35.50	2,107
Hardy - Demand	Mar 01, 2023	Mar 31, 2023	Apr 24, 2023	781,951	15.50	24	39.50	30,887,075
Hardy - Commodity	Mar 01, 2023	Mar 31, 2023	Apr 24, 2023	6,085	15.50	24	39.50	240,352
EGTS - Demand	Mar 01, 2023	Mar 31, 2023	Apr 13, 2023	3,184,611	15.50	13	28.50	90,761,413
EGTS - Commodity	Mar 01, 2023	Mar 31, 2023	Apr 17, 2023	83,478	15.50	17	32.50	2,713,040
Cove Point - Demand	Mar 01, 2023	Mar 31, 2023	Apr 13, 2023	1,215,610	15.50	13	28.50	34,644,885
Cove Point - Commodity	Mar 01, 2023	Mar 31, 2023	Apr 17, 2023	271,640	15.50	17	32.50	8,828,305
East Tennessee - Demand	Mar 01, 2023	Mar 31, 2023	Apr 24, 2023	610,400	15.50	24	39.50	24,110,800
East Tennessee - Commodity	Mar 01, 2023	Mar 31, 2023	Apr 24, 2023	512	15.50	24	39.50	20,242
Saltville - Demand	Mar 01, 2023	Mar 31, 2023	Apr 20, 2023	204,050	15.50	20	35.50	7,243,775
Saltville - Commodity	Mar 01, 2023	Mar 31, 2023	Apr 20, 2023	16,381	15.50	20	35.50	581,517
CGV- Demand Manassas Park	Mar 01, 2023	Mar 31, 2023	Apr 28, 2023	3,700	15.50	28	43.50	160,950
TCO - Demand	Apr 01, 2023	Apr 30, 2023	May 22, 2023	10,903,977	15.00	22	37.00	403,447,167
TCO - Commodity	Apr 01, 2023	Apr 30, 2023	May 22, 2023	195,338	15.00	22	37.00	7,227,521
Transco - Demand	Apr 01, 2023	Apr 30, 2023	May 10, 2023	4,312,928	15.00	10	25.00	107,823,195
Transco - Commodity	Apr 01, 2023	Apr 30, 2023	May 22, 2023	336,459	15.00	22	37.00	12,448,966
Pine Needle - Demand	Apr 01, 2023	Apr 30, 2023	May 10, 2023	55,024	15.00	10	25.00	1,375,590
Hardy - Demand	Apr 01, 2023	Apr 30, 2023	May 22, 2023	781,951	15.00	22	37.00	28,932,197
Hardy - Commodity	Apr 01, 2023	Apr 30, 2023	May 22, 2023	7,868	15.00	22	37.00	291,112
EGTS - Demand	Apr 01, 2023	Apr 30, 2023	May 11, 2023	2,926,181	15.00	11	26.00	76,080,701
EGTS - Commodity	Apr 01, 2023	Apr 30, 2023	May 12, 2023	105,477	15.00	12	27.00	2,847,888
Cove Point - Demand	Apr 01, 2023	Apr 30, 2023	May 11, 2023	1,212,840	15.00	11	26.00	31,533,840
Cove Point - Commodity	Apr 01, 2023	Apr 30, 2023	May 12, 2023	450,961	15.00	12	27.00	12,175,951
East Tennessee - Demand	Apr 01, 2023	Apr 30, 2023	May 22, 2023	683,360	15.00	22	37.00	25,284,320
East Tennessee - Commodity	Apr 01, 2023	Apr 30, 2023	May 22, 2023	83	15.00	22	37.00	3,074
Saltville - Demand	Apr 01, 2023	Apr 30, 2023	May 19, 2023	212,891	15.00	19	34.00	7,238,294
Saltville - Commodity	Apr 01, 2023	Apr 30, 2023	May 19, 2023	2,853	15.00	19	34.00	97,004
CGV- Demand Manassas Park	Apr 01, 2023	Apr 30, 2023	May 26, 2023	3,700	15.00	26	41.00	151,700
TCO - Demand	May 01, 2023	May 31, 2023	Jun 22, 2023	10,898,825	15.50	22	37.50	408,705,954
TCO - Commodity	May 01, 2023	May 31, 2023	Jun 22, 2023	181,670	15.50	22	37.50	6,812,609
Transco - Demand	May 01, 2023	May 31, 2023	Jun 12, 2023	4,460,371	15.50	12	27.50	122,660,189
Transco - Commodity	May 01, 2023	May 31, 2023	Jun 20, 2023	359,328	15.50	20	35.50	12,756,143
Pine Needle - Demand	May 01, 2023	May 31, 2023	Jun 12, 2023	68,537	15.50	12	27.50	1,884,767
Hardy - Demand	May 01, 2023	May 31, 2023	Jun 22, 2023	781,951	15.50	22	37.50	29,323,173
Hardy - Commodity	May 01, 2023	May 31, 2023	Jun 22, 2023	480	15.50	22	37.50	17,982
EGTS - Demand	May 01, 2023	May 31, 2023	Jun 12, 2023	2,931,289	15.50	12	27.50	80,610,444
EGTS - Commodity	May 01, 2023	May 31, 2023	Jun 12, 2023	112,774	15.50	12	27.50	3,101,272
Cove Point - Demand	May 01, 2023	May 31, 2023	Jun 12, 2023	1,212,840	15.50	12	27.50	33,353,100
Cove Point - Commodity	May 01, 2023	May 31, 2023	Jun 12, 2023	268,753	15.50	12	27.50	7,390,718
East Tennessee - Demand	May 01, 2023	May 31, 2023	Jun 23, 2023	683,360	15.50	23	38.50	26,309,360
East Tennessee - Commodity	May 01, 2023	May 31, 2023	Jun 23, 2023	200	15.50	23	38.50	7,693
Saltville - Demand	May 01, 2023	May 31, 2023	Jun 20, 2023	212,891	15.50	20	35.50	7,557,631
Saltville - Commodity	May 01, 2023	May 31, 2023	Jun 20, 2023	3,569	15.50	20	35.50	126,692

Company Name	Date From Service	Date To Service	Date Paid	Amount	Midpoint Days From	Date Paid Days From	Days Total	Dollar Days Total
(A)	(B)	(C)	(D)	(E)	(F)=Midpoint	(G)=(D)-(C)	(H)=(F)+(G)	(I)=(E)*(H)
CGV- Demand Manassas Park	May 01, 2023	May 31, 2023	Jun 28, 2023	3,700	15.50	28	43.50	160,950
TCO - Demand	Jun 01, 2023	Jun 30, 2023	Jul 24, 2023	10,955,491	15.00	24	39.00	427,264,146
TCO - Commodity	Jun 01, 2023	Jun 30, 2023	Jul 24, 2023	82,131	15.00	24	39.00	3,203,120
Transco - Demand	Jun 01, 2023	Jun 30, 2023	Jul 10, 2023	4,225,427	15.00	10	25.00	105,635,678
Transco - Commodity	Jun 01, 2023	Jun 30, 2023	Jul 20, 2023	314,750	15.00	20	35.00	11,016,258
Pine Needle - Demand	Jun 01, 2023	Jun 30, 2023	Jul 10, 2023	66,326	15.00	10	25.00	1,658,153
Hardy - Demand	Jun 01, 2023	Jun 30, 2023	Jul 24, 2023	781,951	15.00	24	39.00	30,496,100
Hardy - Commodity	Jun 01, 2023	Jun 30, 2023	Jul 24, 2023	3,376	15.00	24	39.00	131,673
EGTS - Demand	Jun 01, 2023	Jun 30, 2023	Jul 13, 2023	2,931,426	15.00	13	28.00	82,079,932
EGTS - PENALTY REFUND	Jun 01, 2023	Jun 30, 2023	Jul 13, 2023	(63,346)	15.00	13	28.00	(1,773,689)
EGTS - Commodity	Jun 01, 2023	Jun 30, 2023	Jul 14, 2023	79,676	15.00	14	29.00	2,310,602
Cove Point - Demand	Jun 01, 2023	Jun 30, 2023	Jul 13, 2023	1,212,840	15.00	13	28.00	33,959,520
CVPT - PENALTY REFUND	Jun 01, 2023	Jun 30, 2023	Jul 13, 2023	(326,545)	15.00	13	28.00	(9,143,271)
Cove Point - Commodity	Jun 01, 2023	Jun 30, 2023	Jul 13, 2023	223,894	15.00	13	28.00	6,269,024
East Tennessee - Demand	Jun 01, 2023	Jun 30, 2023	Jul 24, 2023	683,360	15.00	24	39.00	26,651,040
East Tennessee - Commodity	Jun 01, 2023	Jun 30, 2023	Jul 24, 2023	194	15.00	24	39.00	7,561
Saltville - Demand	Jun 01, 2023	Jun 30, 2023	Jul 20, 2023	212,891	15.00	20	35.00	7,451,185
Saltville - Commodity	Jun 01, 2023	Jun 30, 2023	Jul 20, 2023	6,671	15.00	20	35.00	233,502
CGV- Demand Manassas Park	Jun 01, 2023	Jun 30, 2023	Jul 28, 2023	3,700	15.00	28	43.00	159,100
TCO - Demand	Jul 01, 2023	Jul 31, 2023	Aug 21, 2023	10,977,621	15.50	21	36.50	400,683,180
TCO - Commodity	Jul 01, 2023	Jul 31, 2023	Aug 21, 2023	111,705	15.50	21	36.50	4,077,240
Transco - Demand	Jul 01, 2023	Jul 31, 2023	Aug 10, 2023	4,363,097	15.50	10	25.50	111,258,978
Transco - Commodity	Jul 01, 2023	Jul 31, 2023	Aug 21, 2023	375,238	15.50	21	36.50	13,696,186
Pine Needle - Demand	Jul 01, 2023	Jul 31, 2023	Aug 10, 2023	68,537	15.50	10	25.50	1,747,693
Hardy - Demand	Jul 01, 2023	Jul 31, 2023	Aug 21, 2023	781,951	15.50	21	36.50	28,541,221
Hardy - Commodity	Jul 01, 2023	Jul 31, 2023	Aug 21, 2023	3,042	15.50	21	36.50	111,051
EGTS - Demand	Jul 01, 2023	Jul 31, 2023	Aug 11, 2023	2,934,183	15.50	11	26.50	77,755,852
EGTS - Commodity	Jul 01, 2023	Jul 31, 2023	Aug 14, 2023	69,381	15.50	14	29.50	2,046,726
Cove Point - Demand	Jul 01, 2023	Jul 31, 2023	Aug 01, 2023	1,212,840	15.50	1	16.50	20,011,860
Cove Point - Commodity	Jul 01, 2023	Jul 31, 2023	Aug 14, 2023	340,824	15.50	14	29.50	10,054,293
East Tennessee - Demand	Jul 01, 2023	Jul 31, 2023	Aug 21, 2023	683,360	15.50	21	36.50	24,942,640
East Tennessee - Commodity	Jul 01, 2023	Jul 31, 2023	Aug 21, 2023	1,114	15.50	21	36.50	40,649
Saltville - Demand	Jul 01, 2023	Jul 31, 2023	Aug 18, 2023	212,891	15.50	18	33.50	7,131,849
Saltville - Commodity	Jul 01, 2023	Jul 31, 2023	Aug 18, 2023	38,645	15.50	18	33.50	1,294,616
CGV- Demand Manassas Park	Jul 01, 2023	Jul 31, 2023	Aug 28, 2023	3,700	15.50	28	43.50	160,950
TCO - Demand	Aug 01, 2023	Aug 31, 2023	Sep 25, 2023	10,945,467	15.50	25	40.50	443,291,427
TCO - PENALTY REFUND	Aug 01, 2023	Aug 31, 2023	Sep 25, 2023	136,183	15.50	25	40.50	5,515,420
Transco - Demand	Aug 01, 2023	Aug 31, 2023	Sep 11, 2023	4,373,110	15.50	11	26.50	115,887,411
Transco - Commodity	Aug 01, 2023	Aug 31, 2023	Sep 20, 2023	364,599	15.50	20	35.50	12,943,259
Pine Needle - Demand	Aug 01, 2023	Aug 31, 2023	Sep 11, 2023	68,537	15.50	11	26.50	1,816,230
Hardy - Demand	Aug 01, 2023	Aug 31, 2023	Sep 25, 2023	781,951	15.50	25	40.50	31,669,026
Hardy - Commodity	Aug 01, 2023	Aug 31, 2023	Sep 25, 2023	2,569	15.50	25	40.50	104,051
EGTS - Demand	Aug 01, 2023	Aug 31, 2023	Sep 11, 2023	2,927,965	15.50	11	26.50	77,591,074
EGTS - Commodity	Aug 01, 2023	Aug 31, 2023	Sep 15, 2023	50,888	15.50	15	30.50	1,552,089
Cove Point - Demand	Aug 01, 2023	Aug 31, 2023	Sep 11, 2023	1,180,911	15.50	11	26.50	31,294,139
Cove Point - Commodity	Aug 01, 2023	Aug 31, 2023	Sep 15, 2023	451,306	15.50	15	30.50	13,764,845
East Tennessee - Demand	Aug 01, 2023	Aug 31, 2023	Sep 25, 2023	683,360	15.50	25	40.50	27,676,080
East Tennessee - Commodity	Aug 01, 2023	Aug 31, 2023	Sep 25, 2023	928	15.50	25	40.50	37,589
Saltville - Demand	Aug 01, 2023	Aug 31, 2023	Sep 20, 2023	212,891	15.50	20	35.50	7,557,631
Saltville - Commodity	Aug 01, 2023	Aug 31, 2023	Sep 20, 2023	26,429	15.50	20	35.50	938,246
CGV- Demand Manassas Park	Aug 01, 2023	Aug 31, 2023	Sep 29, 2023	3,700	15.50	29	44.50	164,650
TCO - Demand	Sep 01, 2023	Sep 30, 2023	Oct 23, 2023	10,816,887	15.00	23	38.00	411,041,704
TCO - Commodity	Sep 01, 2023	Sep 30, 2023	Oct 23, 2023	151,351	15.00	23	38.00	5,751,345

Company Name	Date From Service	Date To Service	Date Paid	Amount	Midpoint Days From	Date Paid Days From	Days Total	Dollar Days Total
(A)	(B)	(C)	(D)	(E)	(F)=Midpoint	(G)=(D)-(C)	(H)=(F)+(G)	(I)=(E)*(H)
Transco - Demand	Sep 01, 2023	Sep 30, 2023	Oct 10, 2023	4,335,651	15.00	10	25.00	108,391,283
Transco - Commodity	Sep 01, 2023	Sep 30, 2023	Oct 20, 2023	336,216	15.00	20	35.00	11,767,550
Pine Needle - Demand	Sep 01, 2023	Sep 30, 2023	Oct 10, 2023	66,326	15.00	10	25.00	1,658,153
Hardy - Demand	Sep 01, 2023	Sep 30, 2023	Oct 23, 2023	781,951	15.00	23	38.00	29,714,148
Hardy - Commodity	Sep 01, 2023	Sep 30, 2023	Oct 23, 2023	8,466	15.00	23	38.00	321,696
EGTS - Demand	Sep 01, 2023	Sep 30, 2023	Oct 12, 2023	2,932,112	15.00	12	27.00	79,167,035
EGTS - Commodity	Sep 01, 2023	Sep 30, 2023	Oct 13, 2023	76,673	15.00	13	28.00	2,146,836
Cove Point - Demand	Sep 01, 2023	Sep 30, 2023	Oct 12, 2023	1,212,840	15.00	12	27.00	32,746,680
Cove Point - Commodity	Sep 01, 2023	Sep 30, 2023	Oct 13, 2023	352,476	15.00	13	28.00	9,869,334
East Tennessee - Demand	Sep 01, 2023	Sep 30, 2023	Oct 23, 2023	683,360	15.00	23	38.00	25,967,680
East Tennessee - Commodity	Sep 01, 2023	Sep 30, 2023	Oct 23, 2023	1,676	15.00	23	38.00	63,693
Saltville - Demand	Sep 01, 2023	Sep 30, 2023	Oct 20, 2023	212,891	15.00	20	35.00	7,451,185
Saltville - Commodity	Sep 01, 2023	Sep 30, 2023	Oct 20, 2023	50,472	15.00	20	35.00	1,766,512
CGV- Demand Manassas Park	Sep 01, 2023	Sep 30, 2023	Oct 27, 2023	3,700	15.00	27	42.00	155,400
TCO - Demand	Oct 01, 2023	Oct 31, 2023	Nov 20, 2023	13,624,782	15.50	20	35.50	483,679,759
TCO - Commodity	Oct 01, 2023	Oct 31, 2023	Nov 20, 2023	143,925	15.50	20	35.50	5,109,333
Transco - Demand	Oct 01, 2023	Oct 31, 2023	Nov 13, 2023	4,445,132	15.50	13	28.50	126,686,275
Transco - Commodity	Oct 01, 2023	Oct 31, 2023	Nov 20, 2023	308,817	15.50	20	35.50	10,962,992
Pine Needle - Demand	Oct 01, 2023	Oct 31, 2023	Nov 13, 2023	68,537	15.50	13	28.50	1,953,304
Hardy - Demand	Oct 01, 2023	Oct 31, 2023	Nov 20, 2023	781,951	15.50	20	35.50	27,759,270
Hardy - Commodity	Oct 01, 2023	Oct 31, 2023	Nov 20, 2023	9,963	15.50	20	35.50	353,694
EGTS - Demand	Oct 01, 2023	Oct 31, 2023	Nov 13, 2023	2,921,252	15.50	13	28.50	83,255,675
EGTS - Commodity	Oct 01, 2023	Oct 31, 2023	Nov 13, 2023	92,394	15.50	13	28.50	2,633,224
Cove Point - Demand	Oct 01, 2023	Oct 31, 2023	Nov 13, 2023	1,212,840	15.50	13	28.50	34,565,940
Cove Point - Commodity	Oct 01, 2023	Oct 31, 2023	Nov 13, 2023	335,704	15.50	13	28.50	9,567,564
East Tennessee - Demand	Oct 01, 2023	Oct 31, 2023	Nov 22, 2023	683,360	15.50	22	37.50	25,626,000
East Tennessee - Commodity	Oct 01, 2023	Oct 31, 2023	Nov 22, 2023	510	15.50	22	37.50	19,124
Saltville - Demand	Oct 01, 2023	Oct 31, 2023	Nov 20, 2023	212,891	15.50	20	35.50	7,557,631
Saltville - Commodity	Oct 01, 2023	Oct 31, 2023	Nov 20, 2023	17,079	15.50	20	35.50	606,317
TCO - Demand	Nov 01, 2023	Nov 30, 2023	Dec 22, 2023	13,762,846	15.00	22	37.00	509,225,287
TCO - PENALTY REFUND	Nov 01, 2023	Nov 30, 2023	Dec 22, 2023	(1,217,880)	15.00	22	37.00	(45,061,551)
TCO - Commodity	Nov 01, 2023	Nov 30, 2023	Dec 22, 2023	187,274	15.00	22	37.00	6,929,145
Transco - Demand	Nov 01, 2023	Nov 30, 2023	Dec 11, 2023	4,066,977	15.00	11	26.00	105,741,402
Transco - Commodity	Nov 01, 2023	Nov 30, 2023	Dec 20, 2023	310,627	15.00	20	35.00	10,871,939
Pine Needle - Demand	Nov 01, 2023	Nov 30, 2023	Dec 11, 2023	66,326	15.00	11	26.00	1,724,479
Hardy - Demand	Nov 01, 2023	Nov 30, 2023	Dec 22, 2023	781,951	15.00	22	37.00	28,932,197
Hardy - Commodity	Nov 01, 2023	Nov 30, 2023	Dec 22, 2023	2,408	15.00	22	37.00	89,107
EGTS - Demand	Nov 01, 2023	Nov 30, 2023	Dec 11, 2023	3,155,519	15.00	11	26.00	82,043,497
EGTS - Outage Demand REFUN	Nov 01, 2023	Nov 30, 2023	Dec 11, 2023	(241,085)	15.00	11	26.00	(6,268,200)
EGTS - Commodity	Nov 01, 2023	Nov 30, 2023	Dec 14, 2023	70,430	15.00	14	29.00	2,042,464
Cove Point - Demand	Nov 01, 2023	Nov 30, 2023	Dec 11, 2023	1,212,840	15.00	11	26.00	31,533,840
Cove Point - Commodity	Nov 01, 2023	Nov 30, 2023	Dec 14, 2023	433,583	15.00	14	29.00	12,573,912
East Tennessee - Demand	Nov 01, 2023	Nov 30, 2023	Dec 26, 2023	683,360	15.00	26	41.00	28,017,760
East Tennessee - Commodity	Nov 01, 2023	Nov 30, 2023	Dec 26, 2023	691	15.00	26	41.00	28,347
Saltville - Demand	Nov 01, 2023	Nov 30, 2023	Dec 20, 2023	212,891	15.00	20	35.00	7,451,185
Saltville - Commodity	Nov 01, 2023	Nov 30, 2023	Dec 20, 2023	24,401	15.00	20	35.00	854,049
TCO - Demand	Dec 01, 2023	Dec 31, 2023	Jan 22, 2024	13,439,449	15.50	22	37.50	503,979,339
TCO - Commodity	Dec 01, 2023	Dec 31, 2023	Jan 22, 2024	211,019	15.50	22	37.50	7,913,216
Transco - Demand	Dec 01, 2023	Dec 31, 2023	Jan 10, 2024	3,866,616	15.50	10	25.50	98,598,709
Transco - Commodity	Dec 01, 2023	Dec 31, 2023	Jan 22, 2024	281,008	15.50	22	37.50	10,537,794
Pine Needle - Demand	Dec 01, 2023	Dec 31, 2023	Jan 10, 2024	68,537	15.50	10	25.50	1,747,693
Hardy - Demand	Dec 01, 2023	Dec 31, 2023	Jan 22, 2024	781,951	15.50	22	37.50	29,323,173
Hardy - Commodity	Dec 01, 2023	Dec 31, 2023	Jan 22, 2024	7,694	15.50	22	37.50	288,534

Company Name	Date From Service	Date To Service	Date Paid	Amount	Midpoint Days From	Date Paid Days From	Days Total	Dollar Days Total
(A)	(B)	(C)	(D)	(E)	(F)=Midpoint	(G)=(D)-(C)	(H)=(F)+(G)	(I)=(E)*(H)
EGTS - Demand	Dec 01, 2023	Dec 31, 2023	Jan 12, 2024	3,119,443	15.50	12	27.50	85,784,670
EGTS - Commodity	Dec 01, 2023	Dec 31, 2023	Jan 16, 2023	80,242	15.50	-349	(333.50)	(26,760,780)
Cove Point - Demand	Dec 01, 2023	Dec 31, 2023	Jan 12, 2024	1,212,840	15.50	12	27.50	33,353,100
Cove Point - Commodity	Dec 01, 2023	Dec 31, 2023	Jan 16, 2024	504,673	15.50	16	31.50	15,897,193
East Tennessee - Demand	Dec 01, 2023	Dec 31, 2023	Jan 22, 2024	683,360	15.50	22	37.50	25,626,000
East Tennessee - Commodity	Dec 01, 2023	Dec 31, 2023	Jan 22, 2024	701	15.50	22	37.50	26,288
Saltville - Demand	Dec 01, 2023	Dec 31, 2023	Jan 22, 2024	212,891	15.50	22	37.50	7,983,413
Saltville - Commodity	Dec 01, 2023	Dec 31, 2023	Jan 22, 2024	24,348	15.50	22	37.50	913,042
TCO - Demand	Jan 01, 2024	Jan 31, 2024	Feb 22, 2024	13,543,397	15.50	22	37.50	507,877,371
TCO - Commodity	Jan 01, 2024	Jan 31, 2024	Feb 22, 2024	352,261	15.50	22	37.50	13,209,795
Transco - Demand	Jan 01, 2024	Jan 31, 2024	Feb 12, 2024	3,779,741	15.50	12	27.50	103,942,887
Transco - Commodity	Jan 01, 2024	Jan 31, 2024	Feb 20, 2024	321,056	15.50	20	35.50	11,397,496
Pine Needle - Demand	Jan 01, 2024	Jan 31, 2024	Feb 12, 2024	68,537	15.50	12	27.50	1,884,767
Hardy - Demand	Jan 01, 2024	Jan 31, 2024	Feb 22, 2024	781,951	15.50	22	37.50	29,323,173
Hardy - Commodity	Jan 01, 2024	Jan 31, 2024	Feb 22, 2024	12,676	15.50	22	37.50	475,367
EGTS - Demand	Jan 01, 2024	Jan 31, 2024	Feb 12, 2024	3,148,118	15.50	12	27.50	86,573,251
EGTS - Commodity	Jan 01, 2024	Jan 31, 2024	Feb 12, 2024	174,804	15.50	12	27.50	4,807,103
Cove Point - Demand	Jan 01, 2024	Jan 31, 2024	Feb 12, 2024	1,212,840	15.50	12	27.50	33,353,100
Cove Point - Commodity	Jan 01, 2024	Jan 31, 2024	Feb 12, 2024	535,502	15.50	12	27.50	14,726,318
East Tennessee - Demand	Jan 01, 2024	Jan 31, 2024	Feb 23, 2024	683,360	15.50	23	38.50	26,309,360
East Tennessee - Commodity	Jan 01, 2024	Jan 31, 2024	Feb 23, 2024	1,070	15.50	23	38.50	41,180
Saltville - Demand	Jan 01, 2024	Jan 31, 2024	Feb 20, 2024	212,891	15.50	20	35.50	7,557,631
Saltville - Commodity	Jan 01, 2024	Jan 31, 2024	Feb 20, 2024	39,295	15.50	20	35.50	1,394,977
TCO - Demand	Feb 01, 2024	Feb 29, 2024	Mar 22, 2024	13,495,460	14.50	22	36.50	492,584,275
TCO - Commodity	Feb 01, 2024	Feb 29, 2024	Mar 22, 2024	332,307	14.50	22	36.50	12,129,200
Transco - Demand	Feb 01, 2024	Feb 29, 2024	Mar 11, 2024	3,483,698	14.50	11	25.50	88,834,301
Transco - Commodity	Feb 01, 2024	Feb 29, 2024	Mar 20, 2024	297,386	14.50	20	34.50	10,259,812
Pine Needle - Demand	Feb 01, 2024	Feb 29, 2024	Mar 11, 2024	64,115	14.50	11	25.50	1,634,938
Hardy - Demand	Feb 01, 2024	Feb 29, 2024	Mar 22, 2024	781,951	14.50	22	36.50	28,541,221
Hardy - Commodity	Feb 01, 2024	Feb 29, 2024	Mar 22, 2024	11,309	14.50	22	36.50	412,789
EGTS - Demand	Feb 01, 2024	Feb 29, 2024	Mar 11, 2024	3,144,489	14.50	11	25.50	80,184,473
EGTS - Commodity	Feb 01, 2024	Feb 29, 2024	Mar 14, 2024	135,745	14.50	14	28.50	3,868,735
Cove Point - Demand	Feb 01, 2024	Feb 29, 2024	Mar 11, 2024	1,212,840	14.50	11	25.50	30,927,420
Cove Point - Commodity	Feb 01, 2024	Feb 29, 2024	Mar 14, 2024	545,451	14.50	14	28.50	15,545,349
East Tennessee - Demand	Feb 01, 2024	Feb 29, 2024	Mar 25, 2024	683,360	14.50	25	39.50	26,992,720
East Tennessee - Commodity	Feb 01, 2024	Feb 29, 2024	Mar 25, 2024	1,227	14.50	25	39.50	48,485
Saltville - Demand	Feb 01, 2024	Feb 29, 2024	Mar 20, 2024	212,891	14.50	20	34.50	7,344,740
Saltville - Commodity	Feb 01, 2024	Feb 29, 2024	Mar 20, 2024	44,164	14.50	20	34.50	1,523,663
Totals				**$ 278,947,305**				**$ 9,282,532,556** 12
Gas Lead Days - TME March 31, 2024								**33.28**

Washington Gas Light Company
System

Payroll Lead / Lag Calculation

For the Year Ending December 31, 2020

Line No.	Description A	Reference B	Amount C
1	Gross Payroll	HRIS	$ 3/ 185,109,624
2	Payroll Deductions	HRIS	2/ 67,969,337
3	Net Payroll	Line 1 - Line 2	$ 117,140,287
4	Percentage of Payroll Deductions to Gross Payroll	Line 2 / Line 1	36.72%
5	*Payroll Charges to Operations*		
6	Gross Payroll	Line 1 x 5/ 0.7774	$ 143,904,067
7	Payroll Deductions	Line 6 x Line 4	52,839,306
8	Net Payroll - Operations Only	Line 6 - Line 7	$ 91,064,761
9	*Lead / Lag Calculation*		
10	Net Payroll - Operations Only	Line 8	$ 91,064,761
11	Payroll Lead Days	Analysis	4/ 11.96
12	Net Payroll Dollar Days	Line 10 x Line 11	$ 1,089,404,361
13	Payroll Deductions - Operations Only	Line 7	52,839,306
14	Payroll Lead Days	Analysis	2/ 11.28
15	Net Payroll Dollar Days	Line 13 x Line 14	$ 595,929,747
16	Total Payroll - Operations Only	Line 10 + Line 13	$ 143,904,067
17	Total Payroll Dollar Days	Line 12 + Line 15	1,685,334,107
18	Days of Lead	Line 17 / Line 16	11.71

Deduction	Source	Total Amount Paid	Weighted Dollar Days	Average Lead/Lag Days
401K 50+	HRIS Report (Deductions)	$ 498,002.87	$ 4,964,100.61	9.97
401K AT	HRIS Report (Deductions)	335,671.45	3,344,474.72	9.96
401K BT	HRIS Report (Deductions)	10,243,066.96	102,129,850.67	9.97
401K Loan for Management	HRIS Report (Deductions)	703,231.49	7,006,796.62	9.96
401K Loan for Union	HRIS Report (Deductions)	1,349,892.65	13,447,798.63	9.96
AFLAC	HRIS Report (Deductions)	305,988.47	3,671,861.64	12.00
Benevity	HRIS Report (Deductions)	7,942.63	480,319.12	60.47
Blue Cross/Shield Medical	HRIS Report (Deductions)	3,776,958.35	101,830,764.46	26.96
CAIC Accident/Cancer Ins.	HRIS Report (Deductions)	8,250.12	82,501.20	10.00
Child Life Optional	HRIS Report (Deductions)	6,664.98	179,737.64	26.97
Dental	HRIS Report (Deductions)	36,853.90	992,763.23	26.94
Employee Giving Campaign	HRIS Report (Deductions)	87,095.66	870,956.60	10.00
Flex Spending Depend Care	HRIS Report (Deductions)	185,620.96	2,227,451.52	12.00
Flex Spending Health Care	HRIS Report (Deductions)	313,497.42	3,761,969.04	12.00
Fred Clerical Union Dues	HRIS Report (Deductions)	6,018.00	60,180.00	10.00
Fred IBEW P&M Union Dues	HRIS Report (Deductions)	13,301.40	132,851.60	9.99
Health Savings Account	HRIS Report (Deductions)	153,094.95	1,837,139.40	12.00
HSA Compatible FSA	HRIS Report (Deductions)	6,717.50	80,610.00	12.00
ING Supplemental Life Insur	HRIS Report (Deductions)	7,336.99	73,369.90	10.00
Kaiser Medical Employee	HRIS Report (Deductions)	302,958.23	8,182,009.68	27.01
Local 2 Union Dues	HRIS Report (Deductions)	37,319.70	373,197.00	10.00
Long Term Care	HRIS Report (Deductions)	14,059.34	377,143.78	26.83
Metro Check After Tax	HRIS Report (Deductions)	-	1,120.00	0.00
Metro Check Before Tax	HRIS Report (Deductions)	20,967.09	684,387.30	32.64
Net Pay Adjustment	HRIS Report (Deductions)	353,859.48	4,226,450.76	11.94
Parking/Trans After-Tax	HRIS Report (Deductions)	160.00	5,440.00	34.00
Parking/Trans Pre-Tax	HRIS Report (Deductions)	45,005.00	1,543,830.00	34.30
Roth	HRIS Report (Deductions)	427,914.55	4,267,418.21	9.97
Roth 50+	HRIS Report (Deductions)	29,186.63	291,435.92	9.99
Shenandoah Union Dues	HRIS Report (Deductions)	21,546.28	215,462.80	10.00
Spousal Optional Life	HRIS Report (Deductions)	52,668.03	1,421,337.08	26.99
Supplemental AD/D	HRIS Report (Deductions)	63,496.60	1,711,441.79	26.95
Supplemental Life	HRIS Report (Deductions)	533,209.83	14,365,362.39	26.94
UN Added Basic LF 6/1/89 - A	HRIS Report (Deductions)	12,082.88	325,024.52	26.90
Union Int Fee - IBEW	HRIS Report (Deductions)	118.00	1,180.00	10.00
Union Int Fee - Local 2	HRIS Report (Deductions)	160.00	1,600.00	10.00
Union Int Fee - SHN L96	HRIS Report (Deductions)	150.00	1,500.00	10.00
Union Int Fee - WG L96	HRIS Report (Deductions)	1,950.00	19,500.00	10.00
Vision Care	HRIS Report (Deductions)	169,714.85	4,572,441.85	26.94
Washington Gas PAC	HRIS Report (Deductions)	98,452.94	981,033.89	9.96
WG Teamster Union Dues	HRIS Report (Deductions)	537,823.61	5,378,236.10	10.00
Withholding Order (Bankruptcy)	HRIS Report (Deductions)	15,147.13	151,176.38	9.98
Withholding Order (Creditor)	HRIS Report (Deductions)	6,699.06	66,457.03	9.92
Withholding Order (Federal Tax Levy)	HRIS Report (Deductions)	5,645.00	56,180.00	9.95
Withholding Order (State Tax Levy)	HRIS Report (Deductions)	39,490.65	393,738.32	9.97
Withholding Order (Student Loan)	HRIS Report (Deductions)	8,372.17	83,721.70	10.00
Withholding Order (Support)	HRIS Report (Deductions)	791,305.30	7,882,518.94	9.96
Withholding Order (Wage Assignment)	HRIS Report (Deductions)	2,074.04	20,740.40	10.00
Additional Medicare Tax	HRIS Report (Payroll Taxes)	245,901.93	2,454,187.01	9.98
Federal Withholding	HRIS Report (Payroll Taxes)	23,327,070.64	232,499,776.69	9.97
OASDI	HRIS Report (Payroll Taxes)	9,585,611.26	95,561,756.32	9.97
Local City Withholding (Resident)	HRIS Report (Payroll Taxes)	9,389.44	93,430.33	9.95
Medicare	HRIS Report (Payroll Taxes)	2,770,678.21	27,615,207.68	9.97
State Withholding (Resident)	HRIS Report (Payroll Taxes)	4,045,051.33	40,313,067.93	9.97
State Withholding (Work)	HRIS Report (Payroll Taxes)	6,348,891.39	63,254,540.31	9.96
		$ 67,969,337.34	$ 766,568,548.71	11.28
		①		①

Annual - Lag/Lead Payroll Gross to Net Summary

Pay Run Groups and/or Pa	Active: Regular (Biweekly)
Periods	12/14/2020 - 12/27/2020 (Bi-Weekly) 11/30/2020 - 12/13/2020 (Bi-Weekly) 11/16/2020 - 11/29/2020 (Bi-Weekly) 11/02/2020 - 11/15/2020 (Bi-Weekly) 10/19/2020 - 11/01/2020 (Bi-Weekly) 10/05/2020 - 10/18/2020 (Bi-Weekly) 09/21/2020 - 10/04/2020 (Bi-Weekly) 09/07/2020 - 09/20/2020 (Bi-Weekly) 08/24/2020 - 09/06/2020 (Bi-Weekly) 08/10/2020 - 08/23/2020 (Bi-Weekly) 07/27/2020 - 08/09/2020 (Bi-Weekly)
Company	Washington Gas Light Company

Company	Pay Component Group	Amount
WG	1 - Gross Pay	185,109,624.31
WG	2 - Deductions	-21,652,731.11
WG	3 - Taxes	-46,682,032.88
WG	4 - Net Pay	-116,774,860.32

Period Start Date	Period End Date	Check Date	Payment Date - CD -2BD	Days in Pay Period	Payment Lag	Average Payroll Period	F + H
12/14/2020	12/27/2020	12/31/2020	12/29/2020	14	4	7	11
12/28/2020	1/10/2021	1/15/2021	1/13/2021	14	5	7	12
11/30/2020	12/13/2020	12/18/2020	12/16/2020	14	5	7	12
11/16/2020	11/29/2020	12/4/2020	12/2/2020	14	5	7	12
11/2/2020	11/15/2020	11/20/2020	11/18/2020	14	5	7	12
10/19/2020	11/1/2020	11/6/2020	11/4/2020	14	5	7	12
10/5/2020	10/18/2020	10/23/2020	10/21/2020	14	5	7	12
9/21/2020	10/4/2020	10/9/2020	10/7/2020	14	5	7	12
9/7/2020	9/20/2020	9/25/2020	9/23/2020	14	5	7	12
8/24/2020	9/6/2020	9/11/2020	9/9/2020	14	5	7	12
8/10/2020	8/23/2020	8/28/2020	8/26/2020	14	5	7	12
7/27/2020	8/9/2020	8/14/2020	8/12/2020	14	5	7	12
7/13/2020	7/26/2020	7/31/2020	7/29/2020	14	5	7	12
6/29/2020	7/12/2020	7/17/2020	7/15/2020	14	5	7	12
6/15/2020	6/28/2020	7/3/2020	7/1/2020	14	5	7	12
6/1/2020	6/14/2020	6/19/2020	6/17/2020	14	5	7	12
5/18/2020	5/31/2020	6/5/2020	6/3/2020	14	5	7	12
5/4/2020	5/17/2020	5/22/2020	5/20/2020	14	5	7	12
4/20/2020	5/3/2020	5/8/2020	5/6/2020	14	5	7	12
4/6/2020	4/19/2020	4/24/2020	4/22/2020	14	5	7	12
3/23/2020	4/5/2020	4/10/2020	4/8/2020	14	5	7	12
3/9/2020	3/22/2020	3/27/2020	3/25/2020	14	5	7	12
2/24/2020	3/8/2020	3/13/2020	3/11/2020	14	5	7	12
2/10/2020	2/23/2020	2/28/2020	2/26/2020	14	5	7	12
1/27/2020	2/9/2020	2/14/2020	2/12/2020	14	5	7	12
1/13/2020	1/26/2020	1/31/2020	1/29/2020	14	5	7	12
12/30/2019	1/12/2020	1/17/2020	1/15/2020	14	5	7	12
12/16/2019	12/29/2019	1/3/2020	1/1/2020				
12/2/2019	12/15/2019	12/20/2019	12/18/2019			Average	11.96 ①

Washington Gas Light Company
All Jurisdictions

Operations & Maintenance (O&M) Factor Caluclation & Classification of Payroll

Twelve Months December 31, 2020

Utility Labor (Direct)

Res Type	(All)
Source	TLI

Sum of Sum Amount		Unit Year Period													Payroll Classification			
		01	01	01	01	01	01	01	01	01	01	01	01	Grand Total				
		20	20	20	20	20	20	20	20	20	20	20	20					
Exp Type	Account	1	2	3	4	5	6	7	8	9	10	11	12		O&M	Capital	Other	Affiliates
Capital		138,093	180,110	221,116	326,754	276,994	288,508	289,327	326,998	426,428	339,855	244,847	266,673	3,325,704	-	3,325,704	-	-
Non-Utility		2,312	10,595	9,577	7,569	13,251	9,299	33,709	10,861	21,889	16,248	16,485	11,647	163,443	-	-	163,443	-
O&M		7,374,199	9,032,116	8,627,835	13,089,368	8,965,540	7,929,919	7,694,811	8,187,384	11,500,576	8,366,370	7,479,042	7,328,738	105,575,898	105,575,898	-	-	-
Other		157,594	191,665	175,942	273,018	184,270	173,734	158,662	246,342	280,442	187,745	167,685	150,270	2,347,369	-	-	2,347,369	-
Pool	163101	19,485	29,661	26,805	57,508	41,509	37,002	37,917	43,469	52,703	28,536	30,810	38,401	443,806	14,894	428,803	106	3
Pool	184105	5,098	8,508	10,177	9,159	6,910	8,553	8,898	8,312	13,328	14,185	42,928	13,358	149,416	116,167	-	4,178	29,070
Pool	184107	19,878	25,204	30,603	57,140	38,816	36,103	34,872	35,857	47,667	51,621	186,785	46,441	610,987	592,672	-	6,894	11,422
Pool	184110	4,341	9,187	5,029	1,159	386	-	515	-	386	-	258	-	21,261	16,530	-	595	4,137
Pool	184112	-	954	477	-	954	954	477	477	954	477	-	1,385	7,107	7,107	-	0	-
Pool	184122	35,334	52,498	53,611	96,613	60,636	61,198	73,697	112,013	93,324	67,585	60,289	56,194	822,993	802,384	18,135	2,474	-
Pool	184123	54,145	75,494	73,674	102,272	78,602	79,413	141,447	246,115	143,309	106,481	98,021	87,472	1,288,446	1,251,415	32,585	4,445	-
Pool	184126	-	-	-	-	-	-	-	-	-	368	1,638	-	2,006	2,006	-	-	-
Pool	184131	2,193	2,649	1,646	2,588	2,059	2,069	7,274	49,340	11,149	7,679	5,819	6,798	101,262	98,429	2,205	628	-
Pool	184181	-	-	93	-	-	-	-	-	-	-	335	-	428	395	13	8	11
Pool	184201	44,476	56,861	55,077	88,860	62,818	59,900	78,570	80,074	116,728	80,877	66,717	74,810	865,768	-	865,768	-	-
Pool	184211	20,995	32,123	28,140	42,368	33,501	29,414	29,416	21,757	41,432	24,853	74,427	27,047	405,476	-	405,476	-	-
Pool	184212	61,412	78,249	74,848	101,972	67,469	62,036	56,094	54,051	82,704	57,188	60,866	49,646	806,532	-	806,532	-	-
Pool	184213	47,468	72,457	73,362	100,697	66,755	57,134	51,201	27,109	67,923	50,971	73,695	43,748	732,519	-	732,519	-	-
Pool	184215	258,817	357,017	364,010	617,766	434,134	395,834	384,590	420,065	599,127	432,594	554,552	355,395	5,173,923	-	5,173,923	-	-
Pool	184218	114,425	155,005	157,474	231,275	151,287	140,362	144,249	143,805	204,617	149,891	130,629	125,252	1,848,672	369,734	1,478,938	-	-
Pool	184227	28,775	38,868	38,299	60,448	38,494	37,632	35,260	40,076	52,401	37,337	36,172	34,104	477,866	-	477,866	-	-
Pool	184231	705,603	942,372	968,027	1,490,282	998,360	920,845	886,039	952,939	1,366,532	947,661	744,886	793,179	11,716,725	-	11,716,725	-	-
Pool	184411	-	-	-	-	-	-	844	-	-	-	-	-	844	796	39	8	-
Grand Total		9,094,642	11,351,592	10,995,824	16,756,837	11,522,745	10,329,909	10,147,871	11,007,045	15,123,820	10,970,524	10,077,085	9,510,557	136,888,451	108,848,429	25,465,231	2,530,148	44,643

Affiliate Labor (Direct)

Res Type	(All)
Source	TLI

Sum of Sum Amount		Year Period																
		20	20	20	20	20	20	20	20	20	20	20	20	Grand Total				
Exp Type	Unit	1	2	3	4	5	6	7	8	9	10	11	12					
Non-Utility	00	3,101	2,831	3,388	4,638	3,691	2,775	2,386	2,743	4,335	2,767	3,266	2,028	37,948	-	-	-	37,948
Non-Utility	07	-	1,433	54	533	-	-	-	287	-	162	81	486	3,035	-	-	-	3,035
Non-Utility	15	71,341	114,033	117,158	192,057	130,568	112,429	123,938	120,492	152,304	95,532	83,865	70,942	1,384,658	-	-	-	1,384,658
Non-Utility	16	-	109	136	679	543	-	-	-	-	-	-	-	1,466	-	-	-	1,466
Non-Utility	18	751	1,670	1,128	2,663	2,087	657	905	714	1,381	952	428	823	14,358	-	-	-	14,358
Non-Utility	20	57,168	72,806	64,311	109,586	61,730	43,207	47,630	38,049	45,230	26,632	17,774	10,870	594,992	-	-	-	594,992
Non-Utility	25	50,522	59,199	57,116	99,381	69,388	68,684	102,099	68,513	109,391	74,238	70,328	67,969	897,029	-	-	-	897,029
Non-Utility	26	-	-	-	1,613	-	-	-	-	-	-	-	-	1,613	-	-	-	1,613
Non-Utility	27	343	2,160	945	-	86	-	86	-	-	-	-	-	3,620	-	-	-	3,620
Non-Utility	28	1,200	172	102	223	213	-	172	858	-	555	-	-	3,494	-	-	-	3,494
Non-Utility	300	8,542	11,630	3,857	16,523	11,940	8,989	16,466	13,590	7,568	6,605	6,330	4,557	116,596	-	-	-	116,596
Non-Utility	302	1,108	337	337	506	337	337	253	169	365	365	91	-	4,208	-	-	-	4,208
Non-Utility	305	3,493	4,146	4,465	9,202	9,883	8,587	1,815	955	-	1,956	1,279	1,644	47,445	-	-	-	47,445
Non-Utility	312	709	337	337	506	337	337	253	169	365	-	-	-	3,353	-	-	-	3,353
Non-Utility	318	930	-	-	-	-	-	-	1,856	914	-	-	-	3,700	-	-	-	3,700
Non-Utility	320	999	1,666	1,332	1,666	1,332	1,332	-	-	-	-	-	-	8,328	-	-	-	8,328
Non-Utility	321	465	-	-	-	-	-	-	-	365	-	-	-	831	-	-	-	831
Non-Utility	99	-	-	-	217	-	-	-	-	-	490	307	-	1,014	-	-	-	1,014
Grand Total		200,673	272,530	254,689	439,991	292,137	247,736	296,001	248,394	322,218	210,253	183,748	159,319	3,127,688	-	-	-	3,127,688
Total		9,295,315	11,624,122	11,250,513	17,196,828	11,814,882	10,577,645	10,443,872	11,255,439	15,446,038	11,180,777	10,260,833	9,669,876	140,016,139	108,848,429	25,465,231	2,530,148	3,172,331
Percentage															77.74% ①	18.19%	1.81%	2.27%

Washington Gas Light Company
Employee Benefits Lead/Lag Calculation
as of December 2020

Line No.	Supplier	Description	Total Amount Paid	Weighted Dollar Days	Average Lead/ Lag Days
	A	B	C	D	E = D / C
1	CARE FIRST BLUECROSS BLUE SHIELD	Carefirst Claims	2/ 11,343,590	2/ 616,108,719	54.31
2	DELTA DENTAL PLAN OF VIRGINIA	Delta Dental Claims	3/ 1,021,028	3/ 35,964,341	35.22
3	KAISER PERMANENTE	Kaiser Claims	4/ 1,501,080	4/ 35,419,749	23.60
4	PCS HEALTH SYSTEMS, INC.	CVS Caremark Claims	5/ 4,198,669	5/ 54,520,394	12.99
5	401(K) Match & Enhanced Benefit	401(K) Match & Enhanced Benefit	6/ 9,482,618	6/ 94,500,539	9.97
			27,546,985	836,513,742	30.37

Supplier CARE FIRST BLUECROSS BLUE SHIELD

Date	Payment Date	Descr	Sum of Sum Amour	Service Start Date	Service End Date	Average Service Day	Lead (Lag) Days	Weighted Dollar Days
1/16/2019	**1/22/2020**	Carefirst November Claims 2019	1,792,969.34	11/1/2019	11/30/2019	11/15/2019	68	121,921,915.12
1/24/2020	**1/28/2020**	Carefirst Dec 2019 Claims	993,989.93	12/1/2019	12/31/2019	12/16/2019	43	42,741,566.99
3/1/2020	**3/20/2020**	Carefirst January 2020 Claims	1,060,936.71	1/1/2020	1/31/2020	1/16/2020	64	67,899,949.44
3/1/2020	**4/13/2020**	Carefirst February 2020 Claims	672,728.93	2/1/2020	2/28/2020	2/14/2020	59	39,691,006.87
4/23/2020	**4/29/2020**	CareFirst Admin and Adjustment March Claims	954,889.32	3/1/2020	3/31/2020	3/16/2020	44	42,015,130.08
6/1/2020	**6/17/2020**	Carefirst April 2020 Claims	793,020.14	4/1/2020	4/30/2020	4/15/2020	63	49,960,268.82
6/1/2020	**6/26/2020**	Carefirst May Claims 2020	904,774.67	5/1/2020	5/31/2020	5/16/2020	41	37,095,761.47
7/3/2020	**8/10/2020**	Carefirst June 2020 Claims	675,054.61	6/1/2020	6/30/2020	6/15/2020	56	37,803,058.16
8/1/2020	**9/2/2020**	Carefirst Claims July 2020	923,164.45	7/1/2020	7/31/2020	7/16/2020	48	44,311,893.60
10/2/2020	**10/6/2020**	Carefirst August Claims 2020	789,599.12	8/1/2020	8/31/2020	8/16/2020	51	40,269,555.12
11/9/2020	**11/12/2020**	Carefirst September 2020 Claim	684,042.00	9/1/2020	9/30/2020	9/15/2020	58	39,674,436.00
11/24/2020	**12/3/2020**	Carefirst October Claims 2020	1,098,420.37	10/1/2020	10/31/2020	10/16/2020	48	52,724,177.76
Grand Total			**11,343,589.59**					616,108,719.43
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RA NOTE: Carefirst lead/lags are calculated based on claims .

Supplier PLAN OF

Date	Payment Date	Descr	Sum of Sum Amour	Service Start Date	Service End Date	Average Service Day	Lead (Lag) Days	Weighted Dollar Days
1/1/2020	**1/9/2020**	Delta Dental - Active DEC 2019	98,087.98	12/1/2019	12/31/2019	12/16/2019	24	2,354,111.52
2/6/2020	**2/11/2020**	Delta Dental - Active Jan 2020	121,997.54	1/1/2020	1/31/2020	1/16/2020	26	3,171,936.04
2/6/2020	**3/19/2020**	Delta Dental - Active FEB 2020	117,860.97	2/1/2020	2/28/2020	2/14/2020	34	4,007,272.98
4/1/2020	**4/10/2020**	Delta Dental - Active MAR 2020	104,896.54	3/1/2020	3/31/2020	3/16/2020	25	2,622,413.50
6/1/2020	**6/17/2020**	Delta Dental April 2020	22,263.88	4/1/2020	4/30/2020	4/15/2020	63	1,402,624.44
6/1/2020	**6/17/2020**	Delta Dental May 2020	40,616.56	5/1/2020	5/31/2020	5/16/2020	32	1,299,729.92
7/1/2020	**8/4/2020**	Delta Dental - Active June 202	84,609.28	6/1/2020	6/30/2020	6/15/2020	50	4,230,464.00
8/25/2020	**8/31/2020**	Delta Dental - Active July 202	93,119.43	7/1/2020	7/31/2020	7/16/2020	46	4,283,493.78
9/1/2020	**9/21/2020**	Delta Dental - Active August 2	117,182.87	8/1/2020	8/31/2020	8/16/2020	36	4,218,583.32
10/1/2020	**10/22/2020**	Delta Dental - Active Septembe	110,799.29	9/1/2020	9/30/2020	9/15/2020	37	4,099,573.73
11/15/2020	**11/24/2020**	Delta Dental October 2020	109,593.27	10/1/2020	10/31/2020	10/16/2020	39	4,274,137.53
Grand Total			**1,021,027.61**					35,964,340.76

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Supplier PERMANENT

Date	Payment Date	Descr	Sum of Sum Amoui	Service Start Date	Service End Date	Average Service Day	Lead (Lag) Days	Weighted Dollar Days
2/25/2020	**2/26/2020**	Kaiser Mid ATL 01.01.2020	132,990.41	1/1/2020	1/31/2020	1/16/2020	41	5,452,606.81
3/16/2020	**3/18/2020**	Kaiser 02.01.2020	133,272.62	2/1/2020	2/28/2020	2/14/2020	33	4,397,996.46
4/16/2020	**4/16/2020**	Kaiser 03.2020	133,264.59	3/1/2020	3/31/2020	3/16/2020	31	4,131,202.29
5/5/2020	**5/7/2020**	Kaiser Mid atlantic April 2020	133,281.35	4/1/2020	4/30/2020	4/15/2020	22	2,932,189.70
6/4/2020	**6/5/2020**	Kaiser Mid ATL May 2020	136,392.10	5/1/2020	5/31/2020	5/16/2020	20	2,727,842.00
6/30/2020	**7/2/2020**	Kaiser Mid ATL 06.2020	136,617.13	6/1/2020	6/30/2020	6/15/2020	17	2,322,491.21
8/4/2020	**8/7/2020**	Kaiser Mid ATL 07.2020	137,570.90	7/1/2020	7/31/2020	7/16/2020	22	3,026,559.80
9/2/2020	**9/8/2020**	Kaiser Mid ATL 08.2020	137,567.76	8/1/2020	8/31/2020	8/16/2020	23	3,164,058.48
9/2/2020	**10/8/2020**	Kaiser Mid ATL 09.2020	139,767.71	9/1/2020	9/30/2020	9/15/2020	23	3,214,657.33
10/19/2020	**10/22/2020**	Kaiser Mid ATL 10.2020	141,060.75	10/1/2020	10/31/2020	10/16/2020	6	846,364.50
12/4/2020	**12/8/2020**	Kaiser Mid ATL 11.2020	139,294.79	11/1/2020	11/30/2020	11/15/2020	23	3,203,780.17
Grand Total			**1,501,080.11**					35,419,748.75
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Supplier PCS HEALTH SYSTEMS, INC.

Date	Payment Date	Descr	Sum of Sum Amour	Service Start Date	Service End Date	Average Service Day	Lead (Lag) Days	Weighted Dollar Days
1/1/2020	1/8/2020	CVS CAREMARK 12.16.19-12.31.19	149,804.11	12/16/2019	12/31/2019	12/23/2019	16	2,321,963.71
1/16/2020	1/23/2020	CVS CAREMARK 1.1.20-1.15.20	195,923.28	1/1/2020	1/15/2020	1/8/2020	15	2,938,849.20
2/1/2020	2/5/2020	CVS CAREMARK 1.16.20-1.31.20	174,633.75	1/16/2020	1/31/2020	1/23/2020	13	2,182,921.88
2/16/2020	2/20/2020	CVS CAREMARK 2.1.20-2.15.20	147,764.09	2/1/2020	2/15/2020	2/8/2020	12	1,773,169.08
3/1/2020	3/6/2020	CVS CAREMARK 2.16.20-2.29.20	142,747.67	2/16/120	2/29/2020	2/29/2020	6	856,486.02
3/15/2020	3/18/2020	CVS CAREMARK 3.1.20-3.15.20	237,586.47	3/1/2020	3/15/2020	3/8/2020	10	2,375,864.70
4/1/2020	4/8/2020	CVS CAREMARK 3.16.20-3.31.20	200,223.94	3/16/2020	3/31/2020	3/23/2020	16	3,103,471.07
4/15/2020	4/22/2020	CVS CAREMARK 4.1.20-4.15.20	208,808.09	4/1/2020	4/15/2020	4/8/2020	14	2,923,313.26
5/1/2020	5/7/2020	CVS CAREMARK 4.16.20-4.30.20	125,097.26	4/16/2020	4/30/2020	4/23/2020	14	1,751,361.64
5/16/2020	5/21/2020	CVS CAREMARK 5.1.20-5.15.20	154,700.98	5/1/2020	5/15/2020	5/8/2020	13	2,011,112.74
6/1/2020	6/5/2020	CVS CAREMARK 5.16.20-5.31.20	178,457.21	5/16/2020	5/31/2020	5/23/2020	13	2,230,715.13
6/16/2020	6/18/2020	CVS CAREMARK 6.1.20-6.15.20	223,421.79	6/1/2020	6/15/2020	6/8/2020	10	2,234,217.90
7/1/2020	7/9/2020	CVS CAREMARK 6.16.20-6.30.20	205,144.43	6/16/2020	6/30/2020	6/23/2020	16	3,282,310.88
7/16/2020	7/22/2020	CVS CAREMARK 7.1.20-7.15.20	187,791.91	7/1/2020	7/15/2020	7/8/2020	14	2,629,086.74
8/1/2020	8/6/2020	CVS CAREMARK 7.16.20-7.31.20	150,289.28	7/16/2020	7/31/2020	7/23/2020	14	2,028,905.28
8/15/2020	8/31/2020	CVS CAREMARK 8.1.20-8.15.20	132,262.85	8/1/2020	8/15/2020	8/8/2020	23	3,042,045.55
9/1/2020	9/8/2020	CVS CAREMARK 8.16.20-8.31.20	202,567.07	8/16/2020	8/31/2020	8/23/2020	16	3,139,789.59
9/16/2020	9/18/2020	CVS CAREMARK 9.16.20-9.31.20	167,917.39	9/16/2020	9/30/2020	9/23/2020	(5)	(839,586.95)
10/1/2020	10/8/2020	CVS CAREMARK 9.16.20-9.30.20	132,520.92	9/16/2020	9/30/2020	9/23/2020	15	1,987,813.80
10/16/2020	10/22/2020	CVS CAREMARK 10.1.20-10.15.20	182,462.99	10/1/2020	10/15/2020	10/8/2020	14	2,554,481.86
11/1/2020	11/10/2020	CVS CAREMARK 10.16.20-10.31.20	144,912.47	10/16/2020	10/31/2020	10/23/2020	18	2,535,968.23
11/16/2020	11/18/2020	CVS CAREMARK 11.1.20-11.15.20	184,955.53	11/1/2020	11/15/2020	11/8/2020	10	1,849,555.30
12/1/2020	12/10/2020	CVS CAREMARK 11.16.20-11.30.20	148,371.43	11/16/2020	11/30/2020	11/23/2020	17	2,522,314.31
12/16/2020	12/22/2020	CVS CAREMARK 12.1.20-12.15.20	220,304.52	12/1/2020	12/15/2020	12/8/2020	14	3,084,263.28
Grand Total			4,198,669.43					54,520,394.18
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Company	Washington Gas Light Company

Sum of Current Period Result	Deduction Code	Deduction							
	401K Match	SPWEB	Grand Total						
Check Date	401K Match	Saving Plan w/Enhanced Benefit		Payment Date	Service Start Date	Service End Date	Average Service Day	Lead (Lag) Days	Weighted Dollar Days
1/3/2020	211,157	138,263	349,420	1/1/2020	12/16/2019	12/29/2019	12/22/2019	10	3,494,203.40
1/17/2020	214,476	138,863	353,340	1/15/2020	12/30/2019	1/12/2020	1/5/2020	10	3,533,397.20
1/31/2020	225,686	144,828	370,515	1/29/2020	1/13/2020	1/26/2020	1/19/2020	10	3,705,146.50
2/14/2020	218,411	141,861	360,272	2/12/2020	1/27/2020	2/9/2020	2/2/2020	10	3,602,724.10
2/28/2020	211,654	141,960	353,614	2/26/2020	2/10/2020	2/23/2020	2/16/2020	10	3,536,143.90
3/13/2020	263,340	170,153	433,493	3/11/2020	2/24/2020	3/8/2020	3/1/2020	10	4,334,934.00
3/27/2020	210,594	141,569	352,164	3/25/2020	3/9/2020	3/22/2020	3/15/2020	10	3,521,638.80
4/10/2020	216,239	142,578	358,817	4/8/2020	3/23/2020	4/5/2020	3/29/2020	10	3,588,165.30
4/24/2020	208,394	140,682	349,076	4/22/2020	4/6/2020	4/19/2020	4/12/2020	10	3,490,757.70
5/8/2020	209,424	141,492	350,917	5/6/2020	4/20/2020	5/3/2020	4/26/2020	10	3,509,169.20
5/22/2020	215,592	146,101	361,694	5/20/2020	5/4/2020	5/17/2020	5/10/2020	10	3,616,937.50
6/5/2020	210,264	141,667	351,930	6/3/2020	5/18/2020	5/31/2020	5/24/2020	10	3,519,303.50
6/19/2020	210,055	143,026	353,081	6/17/2020	6/1/2020	6/14/2020	6/7/2020	10	3,530,812.00
7/3/2020	208,939	142,086	351,025	7/1/2020	6/15/2020	6/28/2020	6/21/2020	10	3,510,245.10
7/17/2020	210,639	143,573	354,213	7/15/2020	6/29/2020	7/12/2020	7/5/2020	10	3,542,125.40
7/31/2020	209,113	140,368	349,481	7/29/2020	7/13/2020	7/26/2020	7/19/2020	10	3,494,811.10
8/14/2020	207,991	141,427	349,417	8/12/2020	7/27/2020	8/9/2020	8/2/2020	10	3,494,172.40
8/28/2020	206,800	140,669	347,469	8/26/2020	8/10/2020	8/23/2020	8/16/2020	10	3,474,686.60
9/11/2020	207,994	140,851	348,845	9/9/2020	8/24/2020	9/6/2020	8/30/2020	10	3,488,447.50
9/25/2020	202,965	141,752	344,717	9/23/2020	9/7/2020	9/20/2020	9/13/2020	10	3,447,172.10
10/9/2020	201,856	141,798	343,654	10/7/2020	9/21/2020	10/4/2020	9/27/2020	10	3,436,537.10
10/23/2020	200,025	140,565	340,590	10/21/2020	10/5/2020	10/18/2020	10/11/2020	10	3,405,901.50
11/6/2020	197,906	139,442	337,348	11/4/2020	10/19/2020	11/1/2020	10/25/2020	10	3,373,478.80
11/20/2020	193,121	139,083	332,204	11/18/2020	11/2/2020	11/15/2020	11/8/2020	10	3,322,038.20
12/4/2020	192,049	140,795	332,844	12/2/2020	11/16/2020	11/29/2020	11/22/2020	10	3,328,436.80
12/18/2020	186,816	140,022	326,838	12/16/2020	11/30/2020	12/13/2020	12/6/2020	10	3,268,381.30
12/31/2020	182,714	142,928	325,641	12/29/2020	12/14/2020	12/27/2020	12/20/2020	9	2,930,771.79
Grand Total	5,634,215	3,848,403	9,482,618						94,500,538.79

RA NOTES: Removed small dollar items from the check date since those are immaterial.

Payroll is funded 2 days prior ("Payment Date") to the check/pay date ("Invoice Date"). Check/pay date is 5 days after the end of each 14-day pay period. The employer matching portion of 401(k) expense is remitted by the Company's payroll processing vendor (Alight) on the check/pay date.

Washington Gas Light Company
Other O&M Lead/Lag Calculation
as of December 2020

Sample #	Population #	Fiscal Year	Accounting Period	GL Business Unit	Supplier	Descr	Sum Monetary Amount	Department	Process	Account	Res Type	Voucher ID	Invoice Date	Payment Date	Beginning Service Date	Ending Service Date	Average Service Day	Service Day vs. Payment Date	Dollar Days
1	90	20	1	01	FANEUIL, INC.	Faneuil Call Center	689,038.88	681	25701	903200	2205	00909611	12/31/2019	1/24/2020	12/1/2019	12/31/2019	12/31/2019	24	3.91715
2	2915	20	9	01	ACCENTURE INTERNATIONAL LIMITED	Accenture AO Monthly Base Char	312,831.62	602	42104	923000	2203	00936569	9/3/2020	10/2/2020	9/1/2020	9/30/2020	9/15/2020	17	1.22267
3	3768	20	11	01	COGNIZANT TECHNOLOGY SOLUTIONS	Cognizant WG - ITO Support Ser	123,544.66	680	42115	923000	2203	00943306	11/5/2020	11/25/2020	10/1/2020	10/31/2020	10/16/2020	40	1.17058
4	3105	20	9	01	PRICE WATERHOUSE COOPERS LLP	June and July SIO Review Commi	310,000.00	105	27001	921000	2205	00934841	8/7/2020	9/9/2020	6/1/2020	7/31/2020	7/1/2020	70	5.14014
5	3859	20	11	01	KUBRA DATA TRANSFER LTD	KUBRA Invoices	154,048.49	413	25701	903200	2205	00941071	10/31/2020	12/4/2020	10/1/2020	10/31/2020	10/16/2020	49	1.78801
6	4200	20	12	01	ERNST & YOUNG LLP	Professional Services	573,286.00	045	26801	923000	2201	00945432	12/8/2020	1/6/2021	1/1/2020	12/31/2020	7/1/2020	38	5.11951
7	272	20	1	01	THE SQUIRES GROUP INC.	Squires_INV0000003121	27,281.86	060	25104	921000	2203	00909022	10/18/2019	1/17/2020	9/1/2019	9/30/2019	9/15/2019	124	0.7981
8	3991	20	11	01	UTILLI, LLC	COVID-19 Email Blast	49,407.54	750	70707	903210	2203	00940992	8/31/2020	11/9/2020	8/31/2020	8/31/2020	8/31/2020	70	0.81923
10	4195	20	12	01	EPLUS TECHNOLOGY, INC.	Eplus NETAPP	130,976.77	680	42135	923000	3053	00946551	12/14/2020	1/12/2021	10/1/2020	9/30/2021	4/1/2021	(79)	-2.45096
11	2393	20	7	01	IBM CORPORATION	IBM 7/1/2020	9,852.48	802	90001	921000	2205	00927686	7/1/2020	7/30/2020	7/1/2020	6/30/2021	12/30/2020	(153)	-0.35707
12	2811	20	8	01	TEMPORARY SOLUTIONS, INC.	Temporary Services	9,769.60	033	27001	921000	2205	00931967	8/1/2020	8/31/2020	7/25/2020	8/8/2020	8/1/2020	30	0.06942
13	3385	20	10	01	BEVERIDGE & DIAMOND PC	BEVERIDGE & DIAMOND - INV. 201	84,697.51	014	30109	923000	2202	00939438	8/24/2020	10/22/2020	7/1/2020	7/31/2020	7/16/2020	98	1.96613
14	4273	20	12	01	MASTER PRINT, INC.	Professional Services	106,462.43	475	75302	909000	2204	00947985	12/21/2020	1/19/2021	10/15/2020	11/14/2020	10/30/2020	81	2.04266
15	1620	20	5	01	ALIGHT SOLUTIONS LLC	Alight May 2020 Svcs	47,016.15	038	90001	921000	2205	00921353	4/23/2020	5/8/2020	5/1/2020	5/31/2020	5/16/2020	(8)	-0.08909
16	2045	20	6	01	HEIDRICK & STRUGGLES, INC.	March 2020 Reg/Legal Retainer	81,885.00	105	27001	921000	2205	00925401	3/30/2020	6/16/2020	3/1/2020	3/31/2020	3/16/2020	92	1.78446
17	592	20	2	01	OPERATIONS TECHNOLOGY DEVELOPMENT	OTD VA Membership 2020	263,313.00	601	75102	930200	2205	00909718	12/2/2019	1/28/2020	1/1/2020	12/31/2020	7/1/2020	(156)	-9.6988
18	2367	20	7	01	EQUIFAX INFORMATION SVCS LLC	Equifax Services	70,619.08	413	70707	903210	2205	00927901	7/7/2020	8/4/2020	7/1/2020	7/31/2020	7/16/2020	19	0.31783
19	3977	20	11	01	TOWERS WATSON WORLDWIDE	09-2020 OOS WTW	65,500.00	037	55603	926208	2205	00942027	9/15/2020	11/17/2020	9/1/2020	9/30/2020	9/15/2020	63	0.9697
20	546	20	2	01	KLEINFELDER,INC	Chillum - investigation 2019	255,672.10	400	81501	921000	2205	00910313	1/17/2020	1/29/2020	12/1/2019	1/6/2020	12/19/2019	41	2.48303
21	1367	20	4	01	HURON CONSULTING SERVICES, LLC	Huron_Task 3_1135232	80,128.85	060	25104	921000	2203	00918060	6/20/2019	4/10/2020	4/1/2019	4/30/2019	4/15/2019	361	6.84242
22	1703	20	5	01	FISERV INC	Fiserv E-Bill Fees	36,985.90	413	40427	903300	2203	00922393	4/14/2020	5/18/2020	3/1/2020	3/31/2020	3/16/2020	63	0.55194
23	1789	20	5	01	NSOLN, LLC	nSoln_Support Service	33,480.00	602	42132	923000	2203	00921154	4/24/2020	5/6/2020	3/1/2020	3/31/2020	3/16/2020	51	0.40446
24	100	20	1	01	HCL America Inc.	HCL-WGL Management Services-#9	114,234.41	051	42105	923000	2203	00907262	12/12/2019	12/31/2019	12/1/2019	12/31/2019	12/16/2019	15	0.40589
25	3199	20	9	01	UTILIQUEST	UtiliQuest HTL Mapping	47,960.00	518	92155	892300	2205	00934190	8/3/2020	9/3/2020	7/1/2020	7/31/2020	7/16/2020	49	0.55666
26	4403	20	12	01	THOMSON REUTERS	OneSource Direct Tax Complianc	86,548.98	033	26410	921000	2205	00944302	10/4/2020	12/8/2020	12/1/2020	11/30/2021	6/1/2021	(175)	-3.58769
27	2695	20	8	01	GROOM LAW GROUP, CHARTERED	Prof Services Rendered Through	33,615.00	013	30010	921000	2202	00931887	4/28/2020	8/12/2020	2/3/2020	2/29/2020	2/16/2020	178	1.41732
28	2752	20	8	01	MCDERMOTT WILL & EMERY LLP	Billing for services rendered	66,558.50	033	26410	921000	2205	00931078	4/24/2020	8/6/2020	1/1/2020	3/31/2020	2/15/2020	173	2.7275
29	3889	20	11	01	MYTA TECHNOLOGIES LLC	MYTA Technologies Consulting S	21,120.00	608	42132	923000	2203	00940905	11/3/2020	12/1/2020	10/1/2020	10/31/2020	10/16/2020	46	0.23013
31	2765	20	8	01	NAGLE & ZALLER, P.C.	Law Firm Collections	65,514.56	750	70707	903210	2202	00931153	7/27/2020	8/25/2020	4/1/2020	4/30/2020	4/15/2020	132	2.0407
32	332	20	1	01	XEROX CORPORATION	Xerox Monthly Printing Fees (U	30,968.87	680	42125	923000	3087	00908239	7/26/2019	1/13/2020	7/1/2019	7/31/2019	7/16/2019	181	1.32776
33	3453	20	12	01	HP SECURE INC.	HP Secure Maintenance	16,805.00	368	27905	923000	2105	00944863	11/24/2020	12/23/2020	1/1/2020	12/31/2020	7/1/2020	175	0.69482
34	2593	20	8	01	AEROTEK, INC.	Contractor Services	3,036.00	750	70707	903210	2205	00933837	8/20/2020	9/2/2020	8/2/2020	8/8/2020	8/5/2020	28	0.02014
35	4142	20	12	01	CDW DIRECT	CDW FireEye	162,824.92	368	42135	923000	3053	00943831	11/30/2020	12/28/2020	11/24/2020	11/25/2021	5/26/2021	(149)	-5.74675
36	653	20	2	01	STINSON MORRISON HECKER LLP	Internal Investigation - B. Wi	36,450.00	013	30010	921000	2202	00913020	2/12/2020	2/25/2020	1/1/2020	1/31/2020	1/16/2020	40	0.34536
37	1731	20	5	01	INSIGHT GLOBAL INC.	Employee placement services -	20,240.00	518	90113	921000	2205	00921241	5/4/2020	5/7/2020	2/6/2020	5/4/2020	3/21/2020	47	0.22533
							4,221,874.16										Total Other O&M Lag Days		25.47

RA NOTE: The invoice below was selected for testing, but determined to be an outlier for purposes of the population. See below for further detail. Payment date out of range.

9	882	20	3	01	COVINGTON & BURLING LLP	CONVINGTON - INV. 60863604 DAT	573,530.74	015	30109	923000	2203	00914245	9/20/2019	3/4/2020	8/1/2019	8/31/2019	8/16/2019	201	27.3066

RA NOTE: The invoice below was selected for testing. Upon review, the invoice is a non recurring expense activity.

30	3462	20	10	01	KORN FERRY (US)	VP Customer Experience, First	41,230.00	105	27001	921000	2205	00939156	7/27/2020	10/20/2020	7/1/2020	12/1/2020	9/15/2020	35	0.11231

Account	(Multiple Items)

Sum of Sum Monetary Amount		
Supplier	Total	
FANEUIL, INC.	$	7,850,914
ACCENTURE INTERNATIONAL LIMITED	$	7,014,258
COGNIZANT TECHNOLOGY SOLUTIONS	$	5,942,371
KUBRA DATA TRANSFER LTD	$	1,982,419
PRICE WATERHOUSE COOPERS LLP	$	1,961,931
ERNST & YOUNG LLP	$	1,770,164
THE SQUIRES GROUP INC.	$	1,059,906
UTILLI, LLC	$	859,053
COVINGTON & BURLING LLP	$	847,016
EPLUS TECHNOLOGY, INC.	$	735,731
IBM CORPORATION	$	672,276
TEMPORARY SOLUTIONS, INC.	$	620,993
BEVERIDGE & DIAMOND PC	$	531,668
MASTER PRINT, INC.	$	525,948
ALIGHT SOLUTIONS LLC	$	520,321
HEIDRICK & STRUGGLES, INC.	$	512,619
OPERATIONS TECHNOLOGY DEVELOPMENT	$	483,756
EQUIFAX INFORMATION SVCS LLC	$	466,781
TOWERS WATSON WORLDWIDE	$	450,518
KLEINFELDER,INC	$	445,107
HURON CONSULTING SERVICES, LLC	$	434,394
FISERV INC	$	408,417
NSOLN, LLC	$	324,994
HCL America Inc.	$	315,319
UTILIQUEST	$	312,466
THOMSON REUTERS	$	294,182
GROOM LAW GROUP, CHARTERED	$	283,961
MCDERMOTT WILL & EMERY LLP	$	276,553
AMAZON WEB SERVICES	$	262,730
MYTA TECHNOLOGIES LLC	$	240,160
KORN FERRY (US)	$	239,698
NAGLE & ZALLER, P.C.	$	239,698
XEROX CORPORATION	$	234,903
HP SECURE INC.	$	225,084
AEROTEK, INC.	$	209,284
CDW DIRECT	$	200,377
FOSTER ASSOCIATES CONSULTANTS, LLC	$	199,535
STINSON MORRISON HECKER LLP	$	184,154
VISION TECHNOLOGIES, INC.	$	179,692
EVERSHEDS SUTHERLAND US [LLP]	$	161,033
INSIGHT GLOBAL INC.	$	161,008
GOMOCHA USA LLC	$	150,563
EOP GROUP INC	$	150,000
DCI UIS, LLC	$	146,000
KPMG LLP	$	145,663
MORGAN LEWIS & BOCKIUS	$	140,661
OCTANE LLC	$	132,434
REGULATED CAPITAL CONSULTANTS, LLC	$	132,183
PA CONSULTING GROUP, INC.	$	131,271
MARY ELISE HYLAND	$	131,250
LINDA R. GOODEN	$	131,250
JAMES W. DYKE, JR.	$	131,250
HARRIS, JONES & MALONE LLC	$	130,000
SCOTTMADDEN, INC.	$	128,200
J.D. POWER AND ASSOCIATES	$	127,000
RANDSTAD NORTH AMERICA, INC.	$	126,130
DELOITTE & TOUCHE LLP	$	125,534
NATIONWIDE CREDIT CORPORATION	$	124,153
OUTSIDE GC LLC	$	123,833
ENGINEERING SYSTEMS INC.	$	121,839
SOFTWAREONE US	$	121,664
PERRY WHITE ROSS & JACOBSON LLC	$	120,600
REVCO SOLUTIONS, INC	$	119,028
DIXON HUGHES GOODMAN LLP	$	116,089
KIRKLAND & ELLIS LLP	$	116,070
PRECISION PIPELINE SOLUTIONS	$	116,060
ESRI, INC.	$	114,450
TROUTMAN PEPPER HAMILTON SANDERS LLP	$	111,999
ERWIN,INC	$	109,916
SKD KNICKERBOCKER LLC	$	108,000
ORACLE AMERICA, INC	$	103,170
AON CONSULTING, INC	$	100,652
MONTGOMERY COUNTY MARYLAND	$	99,000
ITRON INC	$	97,127
ELSTER AMERICAN METER COMPANY	$	96,409
EN ENGINEERING LLC	$	94,604
PAUL H RAAB	$	93,275
E GROUP, INC	$	92,174
PARADIGM ALLIANCE, INC	$	90,445
WORKDAY, INC	$	88,887
ZILLION TECHNOLOGIES INC	$	88,111
NBCUNIVERSAL MEDIA, LLC	$	85,097
SRB COMMUNICATIONS, LLC	$	78,634
ARC DOCUMENT SOLUTIONS, LLC	$	78,241
IRON MOUNTAIN INC.	$	77,546
DC TREASURER	$	76,533
SALESFORCE.COM INC.	$	75,536
CIRCLE SAFETY & HEALTH CONSULTANTS, LLC	$	69,218
GARTNER INC.	$	68,582
SOFTWARE AG USA, INC.	$	67,362
BROMLEY'S UTILITY CONSULTING SERVICES,	$	64,724
CITRIX SYSTEMS, INC.	$	63,111
SKYCREEK C/O LIBERTY BELL BANK	$	59,363
SUCCESS FACTORS, INC	$	58,758
LAPSON ADVISORY	$	58,513
EVERBRIDGE, INC.	$	57,375
SCREEN THEM	$	56,836
SYSTEM IMPROVEMENTS, INC	$	55,895
SAPIENTRAZORFISH	$	52,224
WOLTERS KLUWER FINANCIAL SERVICES	$	52,000
RISKSENSE, INC.	$	51,450
APEX COMPANIES, LLC	$	50,509
AMERICAN INNOVATIONS	$	50,000

RA NOTE: The pivot table to the left outlines the total payments made by supplier during FY20. RA noted that approximately $39.8M represents 80% of the population. The vendors highlighted with payments greater than $200K, represent approximately 80% of the population. Given the assumption that vendors bill using a similar service period methodology, RA then selected the highest dollar value payment for each vendor highlighted in light "orange" within the pivot table. See the "Sample Selection" tab for further detail.

80% of Population (calculated)	=	$	39,768,166
Sum of amounts coded in "Orange" **80% of Population (selected)**	=	$	40,101,130

MICROSOFT CORPORATION	$	49,653
DATABANK IMX LLC	$	47,254
LINKED IN CORPORATION	$	45,960
MARKLOGIC CORPORATION	$	45,688
DNV GL NOBLE DENTON USA LLC	$	44,824
PRINCE GEORGE'S COUNTY MARYLAND	$	44,000
BLUESTONE INSOURCING SOLUTIONS	$	42,860
FRONTEO USA INC.	$	40,003
HUMAN CAPITAL, INC.	$	40,000
GLOBAL GOVERNMENT AND INDUSTRY	$	40,000
WSP USA INC.	$	39,438
MULESOFT, INC.	$	39,201
BLOOMFIELD & COMPANY	$	39,114
ASMAR, SCHOR & MCKENNA, PLLC	$	38,895
HUNTON ANDREWS KURTH LLP	$	38,297
ACUMEN SOLUTIONS	$	38,250
KYRIBA CORP.	$	38,240
SAP AMERICA, INC	$	37,574
COVEO SOFTWARE CORP	$	37,500
RSA SECURITY, LLC	$	37,407
ONLINE COLLECTIONS	$	37,255
LEE HECHT HARRISON LLC	$	37,000
MIDTOWN PERSONNEL, INC.	$	36,869
SPATIAL BUSINESS SYSTEMS, INC.	$	36,303
REDWOOD SOFTWARE INC.	$	35,790
VIRGINIA URGENT & PRIMARY CARE,LLC "VUPC	$	35,407
AERSTONE	$	34,966
ZIP MAILING SERVICES, INC.	$	34,918
CVM SOLUTIONS, LLC.	$	34,438
PREDICTIVE SOLUTIONS CORPORATION	$	34,107
CHA INTEGRATED SOLUTIONS, LLC	$	33,472
QUEBIT CONSULTING, LLC	$	33,082
SAFETEC COMPLIANCE SYSTEMS, INC	$	32,892
CORVEL CORPORATION	$	31,800
CURVATURE LLC	$	31,673
BEYONDTRUST CORPORATION	$	29,880
CULLEN AND DYKMAN LLP	$	29,836
VIRGINIA MEDICAL ALLIANCE, P.C.	$	28,810
WORKSITE HEALTH & SAFETY CONSULTANTS	$	28,761
ATMAN SOLUTIONS	$	28,730
CLICKSOFTWARE, INC	$	27,959
GRANT THORNTON, LLP	$	27,631
ADVOCO INC.	$	27,514
PAYSCALE INC	$	27,400
MERIDIAN COMPENSATION PARTNERS, LLC	$	26,928
ROFFMAN HORVITZ, PLC	$	26,784
WILLIAMS CONSTRUCTION & METER SERVICE	$	25,642
RICHARD D. HURIAUX, P.E. LLC	$	25,215
WILD WELL CONTROL, INC.	$	25,143
THE WASHINGTON INFORMER	$	25,000
CONCENTRIC ENERGY ADVISORS, INC	$	24,028
ROTHFUSS ENGINEERING COMPANY	$	23,664
SITECORE USA, INC.	$	23,430
ROUTESMART TECHNOLOGIES INC.	$	23,000
MCG ENERGY SOLUTIONS, LLC	$	22,399
INTRADO DIGITAL MEDIA, LLC	$	21,325
WINDROCK INCORPORATED	$	21,250
MONTICELLO CONSULTING GROUP, LIMITED	$	21,200
CERTENT, INC	$	21,195
THE ECONOMIC CLUB OF WASHINGTON, D.C.	$	21,075
BSL - GEM LASER EXPRESS LLC	$	20,797
WHITE WHALE SOLUTIONS LLC.	$	20,480
LOCUSVIEW SOLUTIONS INCORPORATED	$	20,400
EMPOWER RETIREMENT	$	20,000
JPMORGAN CHASE	$	20,000
EL TIEMPO LATINO	$	20,000
ENERGY SOLUTIONS CENTER,INC	$	19,380
KFORCE, INC	$	19,331
PAVA APPLICATIONS INTERNATIONAL CORP	$	19,250
JEFF LABONTE	$	19,177
CRITICAL MENTION, INC.	$	18,750
PROGRESS SOFTWARE CORPORATION	$	18,166
TABLEAU SOFTWARE, INC.	$	18,000
FLAGGER FORCE, LLC	$	17,555
PETERSEN ENGINEERING	$	17,506
DUNHAM COBB & ASSOCIATES, INC.	$	16,965
EXIT CERTIFIED CORP	$	16,650
ENERGYTOOLS, L.L.C.	$	16,000
ALL STAR INCENTIVE MARKETING	$	15,490
HARRELL & CHAMBLISS LLP	$	15,339
LUMMUS CONSULTANTS INTERNATIONAL, INC.	$	15,261
MILLER CHEVALIER	$	14,944
COVENANT HOLDINGS GROUP, LLC	$	14,316
WILSON, ELSER, MOSKOWITZ, EDELMAN &	$	14,291
THYCOTIC SOFTWARE LTD	$	13,865
PARKER POE ADAMS & BERNSTEIN LLP	$	13,515
C & E SERVICES, INC.	$	13,471
BASIS TECHNOLOGIES INC.	$	11,900
MERCURY INSTRUMENTS	$	11,384
RIMKUS CONSULTING GROUP,INC	$	11,088
KING-MOORE, INC.	$	11,030
HURT & PROFFITT, INC.	$	10,901
MCNEES WALLACE & NURICK LLC	$	10,855
LATHAM & WATKINS LLP	$	10,827
AVAYA, INC	$	10,752
TOTAL BOILER CONTROL INC	$	10,750
DOCUSIGN, INC.	$	10,598
MORRISON & FOERSTER	$	10,500
GEOSYNTEC CONSULTANTS, INC.	$	10,102
EMPLOYMENT SCREENING ASSOCIATES	$	10,030
ONELOGIN INC.	$	10,000
LOCAL JOB NETWORK	$	9,858
CLEAN HARBORS ENVIRO SER INC	$	9,759
JUSTIN BRADLEY, INC.	$	9,729
KNOWBE4, INC.	$	9,205
MILLER ENVIRONMENTAL GROUP, INC.	$	8,959
KAREN HASTIE WILLIAMS, ESQ.	$	8,500
SCHWARTZ HANNUM PC	$	8,350

THOMSON REUTERS-WEST PUBLISHING CORP.	$	7,856
RES SERVICES, LLC	$	7,800
MERCER (CANADA) LIMITED	$	7,758
MILLER'S OFFICE PRODUCTS	$	7,445
DEPARTMENT OF ENERGY AND ENVIROMENT	$	7,136
MORNINGSTAR COMMODITY DATA, INC	$	7,129
FINCAD USA INC.	$	6,750
OPVANTEK, INC.	$	6,545
NATIONAL COMPLIANCE MANAGEMENT SERVICES	$	6,250
SEAM GROUP LLC	$	5,996
INOVA 360 SERVICES	$	5,915
COMPUTERSHARE, INC	$	5,906
TOWN OF UNIVERSITY PARK	$	5,895
GAWTHROP GREENWOOD, PC	$	5,692
GETTING HIRED	$	5,208
MGM COMMUNICATIONS	$	4,963
INTEGRAL CONSULTING INC.	$	4,643
NEAL R. GROSS & CO., INC.	$	4,635
LEXIS-NEXIS	$	4,503
CLARK LEGAL SOLUTIONS, LLC.	$	4,500
APPEXTREMES, INC.	$	4,320
ROSEMCKENNA, PLLC	$	4,100
UNEX CORPORATION, DBA HYTORC	$	4,010
WEST INTERACTIVE SERVICES CORPORATION.	$	3,978
CAPITOL BOILER WORKS, INC.	$	3,948
CARON EAST INC.	$	3,791
THE MATHWORKS, INC.	$	3,784
CALERO SOFTWARE, LLC	$	3,660
AMERICAS SAP USERS GROUP	$	3,625
MARK CASON,J.D.,C.P.A.ATTORNEY AT LAW	$	3,590
CCH INCORPORATED	$	3,567
SHELBY JONES COMPANY INC	$	3,567
RAILROAD MANAGEMENT COMPANY IV, LLC	$	3,513
CENTER FOR ENERGY WORKFORCE DEVELOPMENT	$	3,500
NEW HORIZONS COMPUTER LEARNING INC	$	3,500
PANTHER-PS,LLC	$	3,400
OPPORTUNE ID. LTD	$	3,225
GROUNDWATER & ENVIRONMENTAL SERVICES,	$	3,217
THOMAS G MCCONNELL JR	$	3,159
DOUGLAS STAEBLER	$	3,060
METZ LEWIS BRODMAN MUST O'KEEFE, LLC	$	3,022
KONECRANES, INC.	$	2,962
HURLEY COMPANY	$	2,877
CARMICHAEL HILL & ASSOCIATES, INC	$	2,693
MVRCHECK.COM	$	2,641
PANAMETRICS LLC	$	2,629
ARC WATER TREATMENT COMPANY	$	2,500
OPEN TEXT INC	$	2,481
P & P EXCELSIOR UPDATES, INC.	$	2,475
WELLS FARGO BANK	$	2,435
LEFTWICH, LLC.	$	2,393
SOFTCHOICE	$	2,262
VIRGINIA ENERGY EFFICIENCY COUNCIL	$	2,100
LAW OFFICE OF MIDGETT S. PARKER, P.A.	$	2,065
JHU DEPARTMENT OF MEDICINE	$	2,040
PHILLIP G. WOODYARD	$	2,000
AMHERST FAMILY PRACTICE	$	1,980
ZENMAR POWER TOOL AND HOIST SYSTEMS	$	1,764
DEX MEDIA, INC.	$	1,722
CROWN CASTLE USA, INC	$	1,700
INFORMATICA LLC	$	1,622
NATURAL GAS SOLUTIONS NORTH AMERICA, LLC	$	1,610
MARYLAND FIRE EQUIPMENT CORPORATION	$	1,601
EXPLICO ENGINEERING CO.	$	1,542
DH INFRASTRUCTURE, LLC	$	1,488
DATAWATCH SYSTEMS	$	1,474
CHUBB & SON	$	1,473
CLERK OF COURT, FAIRFAX GENERAL	$	1,376
FREDERICK HEALTH EMPLOYER SOLUTIONS	$	1,300
TRINITY CONSULTANTS INC	$	1,215
SPERRY SOFTWARE, INC.	$	1,148
CRC-SALOMON, INC.	$	1,134
JACKSON WALKER LLP	$	1,042
FISHER & PHILLIPS, LLP	$	957
MIDPOINT TECHNOLOGY GROUP, LLC	$	900
OMNITRAX HOLDINGS COMBINED, INC.	$	828
JOE BARTOLETTA	$	800
TESTAMERICA LABORATORIES, INC	$	710
LAW OFFICES OF FREDERICK W. PETERS	$	666
GREGORY RHEAULT	$	643
PGLS LLC	$	534
ROBERTS CORROSION SERVICES, LLC	$	500
DEVELOPMENT DIMENSIONS INTERNATIONAL,	$	500
DATAWATCH SYSTEMS, INC.	$	491
SMARTYSTREETS	$	474
HEATH CONSULTANTS INC	$	418
MARK A. LOWE	$	375
JAMES FUHS	$	315
HOLTZMAN OIL CORP.	$	314
MERCER (US) INC.	$	300
TREASURER OF VIRGINIA - VDOT	$	300
KELLY GENERATOR & EQUIPMENT, INC.	$	300
CLICKATELL, INC	$	280
CITY OF ROCKVILLE	$	270
CLERK DISTRICT COURT OF MARYLAND FOR	$	252
ITRON NETWORKED SOLUTIONS, INC.	$	250
SAME DAY PROCESS SERVICE, INC.	$	228
INBODEN ENVIROMENTAL SERV INC	$	218
PRINCE GEORGES SHERIFF'S DEPARTMENT	$	200
TO BACKFLOW LLC	$	160
SHERIFF MONTGOMERY COUNTY DEPARTMENT	$	120
COMMONWEALTH OF VIRGINIA	$	80
SHERIFF DEPARTMENT ANNE ARUNDEL COUNTY	$	80
CLERK FAIRFAX COUNTY DISTRICT COURT	$	58
DISTRICT COURT OF MARYLAND	$	40
DIRECTOR OF FINANCE	$	40
MARYLAND PUBLIC SERVICE COMMISSION	$	25
Grand Total	$	49,710,207

Washington Gas Light Company
System

FICA

For the Year Ending December 31, 2020

Line No.	Beg. Period	Ending Period	Total Tax	Payment Date	Average Service Period	Payment lead	Total Lead	Weighted Days
	A	B	C	D	E = (B - A)/2	F = D - B	G = E + F	H = G x C
	3/		2/	3/				
1	12/30/2019	1/12/2020	$ 410,389.54	1/15/2020	7	3	10	$ 4,103,895.40
2	1/13/2020	1/26/2020	412,316.00	1/29/2020	7	3	10	4,123,160.00
3	1/27/2020	2/9/2020	408,090.22	2/12/2020	7	3	10	4,080,902.20
4	2/10/2020	2/23/2020	387,024.33	2/26/2020	7	3	10	3,870,243.30
5	2/24/2020	3/8/2020	932,527.93	3/11/2020	7	3	10	9,325,279.30
6	3/9/2020	3/22/2020	366,291.45	3/25/2020	7	3	10	3,662,914.50
7	3/23/2020	4/5/2020	365,494.04	4/8/2020	7	3	10	3,654,940.40
8	4/6/2020	4/19/2020	346,404.20	4/22/2020	7	3	10	3,464,042.00
9	4/20/2020	5/3/2020	344,999.85	5/6/2020	7	3	10	3,449,998.50
10	5/4/2020	5/17/2020	367,526.67	5/20/2020	7	3	10	3,675,266.70
11	5/18/2020	5/31/2020	347,323.15	6/3/2020	7	3	10	3,473,231.50
12	6/1/2020	6/14/2020	346,016.86	6/17/2020	7	3	10	3,460,168.60
13	6/15/2020	6/28/2020	345,455.86	7/1/2020	7	3	10	3,454,558.60
14	6/29/2020	7/12/2020	350,326.85	7/15/2020	7	3	10	3,503,268.50
15	7/13/2020	7/26/2020	336,058.86	7/29/2020	7	3	10	3,360,588.60
16	7/27/2020	8/9/2020	338,034.03	8/12/2020	7	3	10	3,380,340.30
17	8/10/2020	8/23/2020	334,327.41	8/26/2020	7	3	10	3,343,274.10
18	8/24/2020	9/6/2020	336,294.13	9/9/2020	7	3	10	3,362,941.30
19	9/7/2020	9/20/2020	330,909.53	9/23/2020	7	3	10	3,309,095.30
20	9/21/2020	10/4/2020	359,414.74	10/7/2020	7	3	10	3,594,147.40
21	10/5/2020	10/18/2020	315,993.40	10/21/2020	7	3	10	3,159,934.00
22	10/19/2020	11/1/2020	310,202.31	11/4/2020	7	3	10	3,102,023.10
23	11/2/2020	11/15/2020	301,336.05	11/18/2020	7	3	10	3,013,360.50
24	11/16/2020	11/29/2020	297,937.10	12/2/2020	7	3	10	2,979,371.00
25	11/30/2020	12/13/2020	300,622.81	12/16/2020	7	3	10	3,006,228.10
26	12/14/2020	12/27/2020	294,357.95	12/29/2020	7	2	9	2,649,221.55
27	Total		$ 9,585,675.27					$95,562,394.75
28	Average lead days for FICA				9.97			

Company	WG
Deduction	OASDI (ER)

Row Labels	Sum of Amount
12/20/2019	(212.35)
12/23/2019	(119.22)
12/29/2019	(389,691.45)
1/12/2020	(410,389.54) ①
1/17/2020	(206.81)
1/21/2020	(36.07)
1/22/2020	(0.24)
1/24/2020	(7,529.85)
1/26/2020	(412,316.00) ①
1/31/2020	(240.62)
2/3/2020	(374.59)
2/7/2020	(8,537.40)
2/9/2020	(408,090.22) ①
2/13/2020	(4,340.00)
2/14/2020	(245.28)
2/23/2020	(387,024.33) ①
3/3/2020	(155.68)
3/8/2020	(932,527.93) ①
3/22/2020	(366,291.45)
4/5/2020	(365,494.04)
4/10/2020	(115.78)
4/19/2020	(346,404.20) ①
5/3/2020	(344,999.85)
5/17/2020	(367,526.67)
5/22/2020	(41.90)
5/31/2020	(347,323.15) ①
6/14/2020	(346,016.86)
6/24/2020	(40.91)
6/28/2020	(345,455.86) ①
7/12/2020	(350,326.85)
7/26/2020	(336,058.86)
7/30/2020	(20.67)
7/31/2020	(1,205.29)
8/4/2020	(119.56)
8/9/2020	(338,034.03) ①
8/14/2020	(96.62)
8/23/2020	(334,327.41) ①
9/6/2020	(336,294.13)
9/20/2020	(330,909.53)
10/4/2020	(359,414.74)
10/18/2020	(315,993.40)
11/1/2020	(310,202.31)
11/6/2020	(331.00)
11/15/2020	(301,336.05) ①
11/24/2020	(342.84)
11/29/2020	(297,937.10) ①
12/13/2020	(300,622.81)
12/27/2020	(294,357.95)
12/31/2020	37.20
Grand Total	**(9,999,642.20)**

Period Start Date	Period End Date	Check Date	Payment Date - CD -2BD
12/14/2020	12/27/2020	12/31/2020	12/29/2020
12/28/2020	1/10/2021	1/15/2021	1/13/2021
11/30/2020	12/13/2020	12/18/2020	12/16/2020
11/16/2020	11/29/2020	12/4/2020	12/2/2020
11/2/2020	11/15/2020	11/20/2020	11/18/2020
10/19/2020	11/1/2020	11/6/2020	11/4/2020
10/5/2020	10/18/2020	10/23/2020	10/21/2020
9/21/2020	10/4/2020	10/9/2020	10/7/2020
9/7/2020	9/20/2020	9/25/2020	9/23/2020
8/24/2020	9/6/2020	9/11/2020	9/9/2020
8/10/2020	8/23/2020	8/28/2020	8/26/2020
7/27/2020	8/9/2020	8/14/2020	8/12/2020
7/13/2020	7/26/2020	7/31/2020	7/29/2020
6/29/2020	7/12/2020	7/17/2020	7/15/2020
6/15/2020	6/28/2020	7/3/2020	7/1/2020
6/1/2020	6/14/2020	6/19/2020	6/17/2020
5/18/2020	5/31/2020	6/5/2020	6/3/2020
5/4/2020	5/17/2020	5/22/2020	5/20/2020
4/20/2020	5/3/2020	5/8/2020	5/6/2020
4/6/2020	4/19/2020	4/24/2020	4/22/2020
3/23/2020	4/5/2020	4/10/2020	4/8/2020
3/9/2020	3/22/2020	3/27/2020	3/25/2020
2/24/2020	3/8/2020	3/13/2020	3/11/2020
2/10/2020	2/23/2020	2/28/2020	2/26/2020
1/27/2020	2/9/2020	2/14/2020	2/12/2020
1/13/2020	1/26/2020	1/31/2020	1/29/2020
12/30/2019	1/12/2020	1/17/2020	1/15/2020
12/16/2019	12/29/2019	1/3/2020	1/1/2020
12/2/2019	12/15/2019	12/20/2019	12/18/2019

NOTE: Payroll is funded two days prior to the check date

Exhibit WG (D)-8
Lead-Lag No. 7
Page 1 of 3

Washington Gas Light Company
Property and Public Liability Insurance Lead Lag Study
For Twelve Months Ended December 31, 2020

Coverage	Current Carrier	Policy Renewal	Policy Expiration	Policy Period	Annual Premium	Paid Date	Service Period Average	Payment (Lead) / Lag	Total Lag	Dollar Days	WGL Factors	WGL Dollar Days
Automobile Liability												
WGL w/$250,000 ded	Liberty Mutual	10/1/2020	10/1/2021	365	$ 228,896	10/27/2020	182.50	(339.00)	(156.50)	(35,822,224)		
FGC	Liberty Mutual	10/1/2020	10/1/2021	365	$ 22,517	10/27/2020	182.50	(339.00)	(156.50)	(3,523,911)		
SGC	Liberty Mutual	10/1/2020	10/1/2021	365	$ 31,328	10/27/2020	182.50	(339.00)	(156.50)	(4,902,832)		
					$ 282,741				(156.50)	(44,248,967)	3/ 99.09%	$ (43,844,451)
General Liability												
WGL w/$250,000 ded	Liberty Mutual	10/1/2020	10/1/2021	365	$ 374,089	10/27/2020	182.50	(339.00)	(156.50)	(58,544,929)		
SGC	Liberty Mutual	10/1/2020	10/1/2021	365	$ 11,000	10/27/2020	182.50	(339.00)	(156.50)	(1,721,500)		
					$ 385,089				(156.50)	(60,266,429)	100.00%	$ (60,266,429)
Excess Liability [A]												
First Layer	AEGIS	10/1/2020	10/1/2021	365	$ 4,019,242	10/14/2020	182.50	(352.00)	(169.50)	(681,261,519)		
Second Layer	EIM	10/1/2020	10/1/2021	365	$ 1,395,159	10/14/2020	182.50	(352.00)	(169.50)	(236,479,451)		
Second Layer	EIM	10/1/2020	10/1/2021	365	$ 449,770	10/14/2020	182.50	(352.00)	(169.50)	(76,236,015)		
Third Layer	XL Bermuda	10/1/2020	10/1/2021	365	$ 322,000	10/23/2020	182.50	(343.00)	(160.50)	(51,681,000)		
Fourth Layer	Argo	10/1/2020	10/1/2021	365	$ 244,000	10/23/2020	182.50	(343.00)	(160.50)	(39,162,000)		
Fifth Layer	SCOR	10/1/2020	10/1/2021	365	$ 142,520	10/23/2020	182.50	(343.00)	(160.50)	(22,874,460)		
Sixth Layer	Everest/HDI	10/1/2020	10/1/2021	365	$ 216,000	10/19/2020	182.50	(347.00)	(164.50)	(35,532,000)		
Seventh Layer	Mercer	10/1/2020	10/1/2021	365	$ 29,988	10/14/2020	182.50	(352.00)	(169.50)	(5,082,966)		
Eight Layer	OCIL	10/1/2020	10/1/2021	365	$ 465,000	10/19/2020	182.50	(347.00)	(164.50)	(76,492,500)		
Ninth Layer	Chubb/Arch	10/1/2020	10/1/2021	365	$ 360,000	10/19/2020	182.50	(347.00)	(164.50)	(59,220,000)		
Tenth Layer	Hamilton/Great Ls	10/1/2020	10/1/2021	365	$ 422,400	10/23/2020	182.50	(343.00)	(160.50)	(67,795,200)		
Eleventh Layer	Starr/Hiscox	10/1/2020	10/1/2021	365	$ 310,335	10/14/2020	182.50	(352.00)	(169.50)	(52,601,783)		
					$ 8,376,414				(167.66)	(1,404,418,893)	2/ 94.44%	$ (1,326,382,593)
Professional Liability [E]												
Professional Liability	AEGIS	10/1/2020	10/1/2021	365	$ 43,246	10/14/2020	182.50	(352.00)	(169.50)	(7,330,197)	94.44%	$ (6,922,896)
Control of Well [E]												
Control of Well		10/1/2020	10/1/2021	365	$ 25,092	10/5/2020	182.50	(361.00)	(178.50)	(4,478,922)	94.44%	$ (4,230,051)
Pollution Wrap [A]												
Pollution Wrap	Ironshore	10/1/2020	10/1/2021	365	$ 280,336	10/5/2020	182.50	(361.00)	(178.50)	(50,039,976)	94.44%	$ (47,259,513)
D & O - Fiduciary - Special Crime [B]												
D & O	Allianz	10/1/2020	12/31/2020	92	$ 67,733	2/1/2021	46.00	32.00	78.00	5,283,168		
Fiduciary	Houston Cas.	10/1/2020	12/31/2020	92	$ 22,005	2/1/2021	46.00	32.00	78.00	1,716,362		
Special Crime [C]	Hiscox	10/1/2020	12/31/2020	92	$ 569	2/1/2021	46.00	32.00	78.00	44,354		
					$ 90,306				78.00	7,043,883	100.00%	$ 7,043,883
Commercial Crime [A]												
Commercial Crime	Travelers	10/1/2020	10/1/2021	365	$ 56,297	10/12/2020	182.50	(354.00)	(171.50)	(9,654,936)		
Excess Commercial Crime	Berkley	10/1/2020	10/1/2021	365	$ 15,200	10/12/2020	182.50	(354.00)	(171.50)	(2,606,800)		
					$ 71,497				(171.50)	(12,261,736)	2/ 94.44%	$ (11,580,414)
Cyber Liability [D]												
Cyber	Lloyds	10/1/2020	10/1/2021	365	$ 428,732	12/17/2020	182.50	(288.00)	(105.50)	(45,231,226)		
					$ 428,732				(105.50)	(45,231,226)	94.44%	$ (42,717,961)
Property [A]												
Boiler & Mach.	Travelers	10/1/2020	10/1/2021	365	$ 59,889	10/27/2020	182.50	(339.00)	(156.50)	(9,372,629)		
Property	AEGIS	10/1/2020	10/1/2021	365	$ 995,987	10/1/2020	182.50	(365.00)	(182.50)	(181,767,628)		
Sabotage & Terr.	AEGIS	10/1/2020	10/1/2021	365	$ 81,090	10/23/2020	182.50	(343.00)	(160.50)	(13,014,945)		
					$ 1,136,966				(179.56)	(204,155,201)	94.44%	$ (192,811,352)
Workers Compensation												
WGL	Liberty Mutual	10/1/2020	10/1/2021	365	$ 1,069,112	10/27/2020	182.50	(339.00)	(156.50)	(167,316,028)		
					$ 1,069,112				(156.50)	(167,316,028)	100.00%	$ (167,316,028)
Service Fees												
Aon Risk Services	Property & Casual	10/1/2020	10/1/2021	365	$ 303,530	11/9/2020	182.50	(326.00)	(143.50)	(43,556,555)		
					$ 303,530				(143.50)	(43,556,555)	2/ 94.44%	$ (41,136,342)
				Total Liability Premiums	$ 12,493,061				(149.60) $	(1,868,944,218)		
				Total Liability Premiums (WGL Only)	$ 10,828,720				(163.46)			$ (1,770,108,119)

[A] - Named Insured is WGL Holdings, Inc. and subsidiaries
[B] - Named Insured is AltaGas, Ltd and its subsidiaries. Premium shown is internal allocation
[C] - 3-Year Policy - Annual Premium Shown
[D] - Named Insured is AltaGas, Ltd and its subsidiaries. Premium shown is allocation from broker
[E] - Named Insured is WGL Holdings, Inc. and its subsidiaries and SEMCO Inc and its subsidiaries. Premium shown is allocation from broker

Sum of Amount	Column Labels					
Row Labels	417123	417903	417904	925101	Grand Total	Allocation Factor
00		79,045	378,716		457,761	4%
01				10,650,049	10,650,049	94%
07				14,526	14,526	0%
15	102,004	48,144			150,148	1%
16	3,988				3,988	0%
18	132				132	0%
20	30				30	0%
Grand Total	**106,153**	**127,189**	**378,716**	**10,664,575**	**11,276,633**	100%

	01	07	15	20	25		
	Washington Gas Light Company	Hampshire Gas Company	WGL Energy Services	WGL Energy Systems	WGL Midstream, Inc.	WGL RELATED TOTAL	
ASSETS							
Property, Plant and Equipment							
Property, plant and equipment, at cost	6,194,486,269	63,121,863	13,052,063	11,310,236	766,279		
Intangible assets, at cost	168,906,094	-	-	-	-		
Accumulated depreciation of PPE	(1,587,326,266)	(34,507,615)	(8,559,921)	(1,119,749)	(747,270)		
Accumulated amortization of intangible assets	(81,165,027)	-	-	-	-		
Net Property, Plant and Equipment	**4,694,901,070**	**28,614,247**	**4,492,142**	**10,190,487**	**19,009**	**4,738,216,955**	99% 1

Washington Gas Company
Lead / Lag Study of General Taxes
District of Columbia - Property Tax
For the 12 months ending December 31, 2020

LN	Nature Tax	Number of Installments Per Year	Period covered by Installment Calendar 2020		Check Mailed FY 20	1/2 No. of Days in Installment Period	Days form End of Period to Due date	Days of Lag	Average Days of Lag	Taxes Paid	Dollar Days
	A	B	C	D	E	F	G	H	I	J	K
	DC Property Tax & Cap BID Tax (236.351)										
		1	10/1/2019	9/30/2020	3/12/2020	183.00	(202.00)	(19.00)		45,514	(864,767)
		1	10/1/2019	9/30/2020	3/12/2020	183.00	(202.00)	(19.00)		41,255	(783,843)
		1	10/1/2019	9/30/2020	3/13/2020	183.00	(201.00)	(18.00)		3,118	(56,122)
		1	10/1/2019	9/30/2020	3/13/2020	183.00	(201.00)	(18.00)		1,240	(22,324)
		1	10/1/2019	9/30/2020	9/8/2020	183.00	(22.00)	161.00		45,514	7,327,760
		1	10/1/2019	9/30/2020	9/8/2020	183.00	(22.00)	161.00		41,255	6,642,034
		1	10/1/2019	9/30/2020	9/8/2020	183.00	(22.00)	161.00		3,118	501,979
		1	10/1/2019	9/30/2020	9/8/2020	183.00	(22.00)	161.00		1,240	199,677
		8							71.02	2/182,254.04	12,944,394

Account	236351

Sum of Merchandise Amt				
Descr	Beginning Period Covered	Ending Period Covered	Acctg Date	Total
DC BID - 1025E_801FY20	10/1/2019	9/30/2020	3/13/2020	1,240.23
DC BID - 1025E_801FY21	10/1/2019	9/30/2020	9/8/2020	1,240.23
DC BID -1025S_11FY20	10/1/2019	9/30/2020	3/13/2020	3,117.88
			9/8/2020	3,117.88
DC Prop - Sq 1025E-801	10/1/2019	9/30/2020	3/12/2020	41,254.87
DC Prop -1025S_11	10/1/2019	9/30/2020	3/12/2020	45,514.04
DC Prop-1025E-801-FY20	10/1/2019	9/30/2020	9/8/2020	41,254.87
DC Prop-1025S_11_ FY20	10/1/2019	9/30/2020	9/8/2020	45,514.04
Grand Total				182,254.04

Washington Gas Light Company
System

Unemployment Taxes

For the Year Ending December 31, 2020

Line No.	Beg. Period	Ending Period	Total Tax	Payment Date	Average Service Period	Payment lead	Total Lead	Weighted Days
	A	B	C	D	E = (B - A)/2	F = D - B	G = E + F	H = G x C
	3/		2/	3/				
1	12/30/2019	1/12/2020	$47,472.41	1/15/2020	7	3	10	$ 474,724.10
2	1/13/2020	1/26/2020	20,386.52	1/29/2020	7	3	10	203,865.20
3	1/27/2020	2/9/2020	4,489.43	2/12/2020	7	3	10	44,894.30
4	2/10/2020	2/23/2020	1,162.99	2/26/2020	7	3	10	11,629.90
5	2/24/2020	3/8/2020	1,041.20	3/11/2020	7	3	10	10,412.00
6	3/9/2020	3/22/2020	764.38	3/25/2020	7	3	10	7,643.80
7	3/23/2020	4/5/2020	367.32	4/8/2020	7	3	10	3,673.20
8	4/6/2020	4/19/2020	234.46	4/22/2020	7	3	10	2,344.60
9	4/20/2020	5/3/2020	155.39	5/6/2020	7	3	10	1,553.90
10	5/4/2020	5/17/2020	142.95	5/20/2020	7	3	10	1,429.50
11	5/18/2020	5/31/2020	208.26	6/3/2020	7	3	10	2,082.60
12	6/1/2020	6/14/2020	491.88	6/17/2020	7	3	10	4,918.80
13	6/15/2020	6/28/2020	429.00	7/1/2020	7	3	10	4,290.00
14	6/29/2020	7/12/2020	174.48	7/15/2020	7	3	10	1,744.80
15	7/13/2020	7/26/2020	218.17	7/29/2020	7	3	10	2,181.70
16	7/27/2020	8/9/2020	381.79	8/12/2020	7	3	10	3,817.90
17	8/10/2020	8/23/2020	353.31	8/26/2020	7	3	10	3,533.10
18	8/24/2020	9/6/2020	332.34	9/9/2020	7	3	10	3,323.40
19	9/7/2020	9/20/2020	479.03	9/23/2020	7	3	10	4,790.30
20	9/21/2020	10/4/2020	1,152.89	10/7/2020	7	3	10	11,528.90
21	10/5/2020	10/18/2020	267.11	10/21/2020	7	3	10	2,671.10
22	10/19/2020	11/1/2020	272.55	11/4/2020	7	3	10	2,725.50
23	11/2/2020	11/15/2020	266.04	11/18/2020	7	3	10	2,660.40
24	11/16/2020	11/29/2020	502.36	12/2/2020	7	3	10	5,023.60
25	11/30/2020	12/13/2020	681.17	12/16/2020	7	3	10	6,811.70
26	12/14/2020	12/27/2020	558.68	12/29/2020	7	2	9	5,028.12
27	Total		$82,986.11					$ 829,302.42
28	Average lead days for Unemployment Tax				9.99			

Company	WG
Deduction	(Multiple Items)

Row Labels	Sum of Amount
12/29/2019	(75,233)
1/12/2020	(47,472) ①
1/17/2020	(35)
1/21/2020	(5)
1/22/2020	(0)
1/24/2020	(81)
1/26/2020	(20,387) ①
2/3/2020	(65)
2/7/2020	(204)
2/9/2020	(4,489) ①
2/14/2020	(21)
2/23/2020	(1,163) ①
3/8/2020	(1,041)
3/22/2020	(764)
4/5/2020	(367)
4/19/2020	(234)
5/3/2020	(155)
5/17/2020	(143)
5/31/2020	(208)
6/14/2020	(492)
6/28/2020	(429)
7/12/2020	(174)
7/26/2020	(218)
8/9/2020	(382)
8/23/2020	(353)
9/6/2020	(332)
9/20/2020	(479)
10/4/2020	(1,153)
10/18/2020	(267)
11/1/2020	(273)
11/15/2020	(266)
11/29/2020	(502)
12/13/2020	(681)
12/27/2020	(559)
12/28/2020	1,601
12/31/2020	(2)
Grand Total	**(157,031)**

Period Start Date	Period End Date	Check Date	Payment Date - CD -2BD
12/14/2020 (1)	12/27/2020 (1)	12/31/2020	12/29/2020 (1)
12/28/2020	1/10/2021	1/15/2021	1/13/2021
11/30/2020 (1)	12/13/2020 (1)	12/18/2020	12/16/2020 (1)
11/16/2020	11/29/2020	12/4/2020	12/2/2020
11/2/2020	11/15/2020	11/20/2020	11/18/2020
10/19/2020	11/1/2020	11/6/2020	11/4/2020
10/5/2020	10/18/2020	10/23/2020	10/21/2020
9/21/2020	10/4/2020	10/9/2020	10/7/2020
9/7/2020	9/20/2020	9/25/2020	9/23/2020
8/24/2020	9/6/2020	9/11/2020	9/9/2020
8/10/2020	8/23/2020	8/28/2020	8/26/2020
7/27/2020	8/9/2020	8/14/2020	8/12/2020
7/13/2020	7/26/2020	7/31/2020	7/29/2020
6/29/2020	7/12/2020	7/17/2020	7/15/2020
6/15/2020	6/28/2020	7/3/2020	7/1/2020
6/1/2020	6/14/2020	6/19/2020	6/17/2020
5/18/2020	5/31/2020	6/5/2020	6/3/2020
5/4/2020	5/17/2020	5/22/2020	5/20/2020
4/20/2020	5/3/2020	5/8/2020	5/6/2020
4/6/2020	4/19/2020	4/24/2020	4/22/2020
3/23/2020	4/5/2020	4/10/2020	4/8/2020
3/9/2020	3/22/2020	3/27/2020	3/25/2020
2/24/2020	3/8/2020	3/13/2020	3/11/2020
2/10/2020	2/23/2020	2/28/2020	2/26/2020
1/27/2020	2/9/2020	2/14/2020	2/12/2020
1/13/2020	1/26/2020	1/31/2020	1/29/2020
12/30/2019	1/12/2020	1/17/2020	1/15/2020
12/16/2019	12/29/2019	1/3/2020	1/1/2020
12/2/2019	12/15/2019	12/20/2019	12/18/2019

NOTE: Payroll is funded two days prior to the check date

Washington Gas Company
Lead / Lag Study of General Taxes
Federal Excise Tax
For the 12 Months Ended December 31, 2020

LN	Nature Tax	Number of Installments Per Period	Period covered by Installment Calendar		Date Amount Wired	1/2 No. of Days in Installment Period	Days from End of Period to Date Paid	Days of Lag	Average Days of Lag	Taxes Paid	Dollar Days
	A	B	C	D	E	F	G	H	I	J	K
	Federal Excise Tax (236.390)		2/								
		1	1/1/2020	3/31/2020	5/1/2020	45.50	31.00	76.50	2/	720.29	55,102
		1	4/1/2020	6/30/2020	4/24/2020	45.50	(67.00)	(21.50)		49,000.00	(1,053,500)
		1	7/1/2020	9/30/2020	7/21/2020	46.00	(71.00)	(25.00)		20,000.00	(500,000)
		1	7/1/2020	9/30/2020	1/6/2020	46.00	(268.00)	(222.00)		2,354.55	(522,710)
		1	7/1/2020	9/30/2020	11/6/2020	46.00	37.00	83.00		847.32	70,328
		1	10/1/2020	12/31/2020	11/9/2020	46.00	(52.00)	(6.00)		28,302.06	(169,812)
		6							(16.48)	101,224.22	(1,668,210)
	Federal Heavy Vehicle Use Tax (236.390)										
		1	2/ 7/1/2020	6/30/2021	8/10/2020	182.50	(324.00)	(141.50)		2/ 838.00	(118,577)
					Total Excise Tax				(17.51)	102,062.22	(1,786,787)
	Total Federal Excise Tax		102,062.22								

DC	(17.51)	20,412.44	(357,367)
MD	(17.51)	40,824.89	(714,727)
VA	(17.51)	40,824.89	(714,727)
		102,062.22	(1,786,787)

DC Allocation Factor 20.00% (A)	
Total Federal Excise Tax attributable to DC	20,412.44
MD Allocation Factor 40.00% (A)	
Total Federal Excise Tax attributable to MD	40,824.89
VA Allocation Factor 40.00% (A)	
Total Federal Excise Tax attributable to VA	40,824.89

V:\Regulatory Accounting\01. COS Production Environment\Lead & Lag Schedules\FY20 Updates\[Lead-Lag #9-12 - General, Property Tax Lag Study TME Dec-2020.xls]Summary

Supplier	Invoice	Date	Short Name	Descr	Unit	Voucher	Acctg Date	Dept	Oper Unit	Account	Process	Res Type	Merchandise Amt	Payment Frequency	Beginning Period Covered	Ending Period Covered	Statutory Due Date	1/2 Number of Days in Installment Period	Days from End of Period Due Date	Days of Lag	Notes
0000113155	03304092057	4/24/2020	U.S. TREAS-002	Fed Excise Tax Q2 2020 PrePymn	01	00919950	4/24/2020	033	10	236390		3860	49,000.00 ①	Quarterly	4/1/2020	6/30/2020	4/24/2020	45	-67	-22	
0000113155	03307101549	7/15/2020	U.S. TREAS-002	Fed Excise Q3-2020 Prepayment	01	00929411	7/21/2020	033	10	236390		3860	20,000.00 ①	Quarterly	7/1/2020	9/30/2020	7/21/2020	45.5	-71	-25.5	
0000113155	03311061013	11/6/2020	U.S. TREAS-002	FET 720 Q4-2020 Deposit	01	00941093	11/9/2020	033	10	236390		3860	18,868.04 A	Quarterly	10/1/2020	12/31/2020	11/9/2020	45.5	-52	-6.5	
0000113155	03310270849	10/27/2020	U.S. TREAS-002	FET 720 Q4-2020 Deposit	01	00941010	11/6/2020	033	10	236390		3860	9,434.02 A	Quarterly	10/1/2020	12/31/2020	11/6/2020	45.5	-55	-9.5	
0000113155	03301060814	1/6/2020	U.S. TREAS-002	720 3rd Qtr 2019 pymnt	01	00907904	1/6/2020	033	10	236390		3860	2,354.55 ①	Quarterly	7/1/2020	9/30/2020	1/6/2020	45.5	-268	-222.5	
0000113155	03310251341	10/28/2020	U.S. TREAS-002	FET 720 Q3-2020	01	00941011	11/6/2020	033	10	236390		3860	847.32	Quarterly	7/1/2020	9/30/2020	11/6/2020	45.5	37	82.5	
0000113155	03304230815	4/27/2020	U.S. TREAS-002	Fed Excise Tax Q1 2020	01	00920244	5/1/2020	033	10	236390		3860	720.29	Quarterly	1/1/2020	3/31/2020	5/1/2020	45	31	76	

sum A = $28,302 ①

Supplier	Invoice	Date	Short Name	Descr	Unit	Voucher	Acctg Date	Dept	Oper Unit	Account	Process	Res Type	Merchandise Amt	Payment Frequency	Beginning Period Covered	Ending Period Covered	Statutory Due Date	1/2 Number of Days in Installment Period	Days from End of Period Due Date	Days of Lag	Notes
0000121382	03308051703	8/7/2020	UNITED STA-006	Heavy Highway Vehicle 2020-202	01	00931371	8/10/2020	033	10	236390		3860	838.00 ①	Annually	7/1/2020 ①	6/30/2021	8/10/2020	182	-324	-142	

Washington Gas Company
Lead / Lag Study of General Taxes
West Virginia - Franchise Tax
For the 12 Months Ended December 31, 2020

LN	Nature Tax	Number of Installment: Per Year	Period covered by Installment		Check Mailed Made	1/2 No. of Days in Installment Period	Days form End of Period tc Due date	Days of Lag	Average Day: of Lag		Taxes Paid	Dollar Days
	A	B	C	D	E	F	G	H	I		J	K
	Business Franchise Tax - WVa (236.393)											
	Payment made for Annually											
		1	2/ 7/1/2018	6/30/2019	2/3/2020	182.50	218.00	400.50		2/	349,683.63	140,048,294
		1	7/1/2019	6/30/2020	8/10/2020	183.00	41.00	224.00			377,633.01	84,589,794
		1	1/1/2019	12/31/2019	4/20/2020	182.50	111.00	293.50			150.00	44,025
		3							308.86		727,466.64	224,682,113
			727,466.64									

DC Allocation Factor 20.00% (A)	
Total WV Franchise Tax attributable to DC	145,493.33
MD Allocation Factor 40.00% (A)	
Total WV Franchise Tax attributable to ME	290,986.66
VA Allocation Factor 40.00% (A)	
Total WV Franchise Tax attributable to V/	290,986.66

DC	308.86	145,493.33	44,936,423
MD	308.86	290,986.66	89,872,846
VA	308.86	290,986.66	89,872,846
		727,466.65	224,682,115

(A) See Allocation Factor Tab

Descr	Unit	Voucher	Acctg Date	Dept	Oper Unit	Account	Process	Res Type	Merchandise Amt	Payment Frequency	Beginning Period Covered	Ending Period Covered	Statutory Due Date	1/2 Number of Days in Installment Period	Days from End of Period Due Date	Days of Lag
WV Prop Tax - Cal 20	01	00931769	8/10/2020	033	10	236393		3860	① 377,633.01	Annually	7/1/2019	6/30/2020	8/10/2020	182.5	41	223.5
WV Per Prop Tax - Cal 19	01	00910994	2/3/2020	033	10	236393		3860	349,683.63	Annually	7/1/2018	6/30/2019	2/3/2020	182	218	400
OH CAT - QTR Ended 03-31-20	01	00919388	4/20/2020	033	10	236393		3860	150.00	Annually	1/1/2019	12/31/2019	4/20/2020	182	111	293

①

Washington Gas Light Company
System

Computation of the Interest Expense Lead/(Lag)

Twelve Months Ended December 31, 2020

	Interest Period	Interest Lead
	A 1/	B = A / 2
CY 2020	182.5	91.25

1/ Interest is paid twice a year.

Washington Gas Company
Lead / Lag Study of General Taxes
District of Columbia - Annual Report and Ballpark Fee
For the 12 months ending December 31, 2020

LN	Nature Tax	Number of Installments Per Year	Period covered by Installment		Check Mailed	1/2 No. of Days in Installment Period	Days form End of Period to Due date	Days of Lag	Average Days of Lag	Taxes Paid	Dollar Days
	A	B	C	D	E	F	G	H	I	J	K
	Ann. Rept./Ballpark Fee - (236.371)	1	10/1/2019	9/30/2020	6/18/2020	183.00	(104.00)	79.00	79.00	16,500.00	1,303,500
											-
		1							79.00	2/ 16,500.00	1,303,500

Detail Summary of Tax Payments Remitted during Calendar Year 2020

Account 236371

Sum of Merchandise Amt				
Descr	**Beginning**	**Ending Pe**	**Acctg Date**	**Total**
Ballpark Fee FY 2019	**Oct**	Sep	18-Jun	16,500
Grand Total				**16,500**

Washington Gas Company
Lead / Lag Study of General Taxes
District of Columbia - Gross Receipts Tax
For the 12 months ending December 31, 2020

LN	Nature Tax	Number of Installments Per Year	Period covered by Installment		Wire Tranfer Made	1/2 No. of Days in Installment Period	Days from End of Period to Due date	Days of Lag	Average Days of Lag	Taxes Paid	Dollar Days
	A	B	C	D	E	F	G	H	I	J	K
	DC GRT (236.331)										
		1	12/01/19	12/31/19	01/10/20	15.50	10.00	25.50		1,950,792.29	49,745,203
		1	01/01/20	01/31/20	02/11/20	15.50	11.00	26.50		3,089,657.12	81,875,914
		1	02/01/20	02/29/20	03/16/20	14.50	16.00	30.50		2,918,830.16	89,024,320
		1	03/01/20	03/31/20	04/13/20	15.50	13.00	28.50		2,603,021.62	74,186,116
		1	04/01/20	04/30/20	05/08/20	15.00	8.00	23.00		1,775,232.09	40,830,338
		1	05/01/20	05/31/20	06/09/20	15.50	9.00	24.50		1,433,792.70	35,127,921
		1	06/01/20	06/30/20	07/09/20	15.00	9.00	24.00		950,395.99	22,809,504
		1	07/01/20	07/31/20	08/10/20	15.50	10.00	25.50		721,445.26	18,396,854
		1	08/01/20	08/31/20	09/08/20	15.50	8.00	23.50		802,184.18	18,851,328
		1	09/01/20	09/30/20	10/09/20	15.00	9.00	24.00		837,998.79	20,111,971
		1	10/01/20	10/31/20	11/10/20	15.50	10.00	25.50		879,461.60	22,426,271
		1	11/01/20	11/30/20	12/08/20	15.00	8.00	23.00		1,279,993.73	29,439,856
										2/	
		12							26.13	19,242,805.53	502,825,596

Account	236331

Sum of Merchandise Amt				
Descr	Beginning Period Covered	Ending Period Covered	Acctg Date	Total
DC GRT _ Apr 2020	4/1/2020	4/30/2020	5/8/2020	1,775,232.09
DC GRT _ Aug 2020	8/1/2020	8/31/2020	9/8/2020	802,184.18
DC GRT _ Dec 2019	12/1/2019	12/31/2019	1/10/2020	1,950,792.29
DC GRT _ Feb 2020	2/1/2020	2/29/2020	3/16/2020	2,918,830.16
DC GRT _ Jan 2020	1/1/2020	1/31/2020	2/11/2020	3,089,657.12
DC GRT _ July 2020	7/1/2020	7/31/2020	8/10/2020	721,445.26
DC GRT _ June 2020	6/1/2020	6/30/2020	7/9/2020	950,395.99
DC GRT _ Mar 2020	3/1/2020	3/31/2020	4/13/2020	2,603,021.62
DC GRT _ May 2020	5/1/2020	5/31/2020	6/9/2020	1,433,792.70
DC GRT _ Nov 2020	11/1/2020	11/30/2020	12/8/2020	1,279,993.73
DC GRT _ Oct 2020	10/1/2020	10/31/2020	11/10/2020	879,461.60
DC GRT _ Sep 2020	9/1/2020	9/30/2020	10/9/2020	837,998.79
Grand Total				19,242,805.53 ①

Washington Gas Company
Lead / Lag Study of General Taxes
Rights of Way Fee District of Columbia
For the 12 months ending December 31, 2020

LN	Nature Tax	Number of Installments Per Year	Period covered by installment		Funds wired to DC	1/2 No. of Days in Installment Period	Days from End of Period to Due date	Days of Lag	Average Days of Lag	Taxes Paid	Dollar Days
	A	B	C	D	E	F	G	H	I	J	K
	Rights of Way Fee (182,330)										
		1	4/1/2020	6/30/2020	3/19/2020	45.50	(103.00)	(57.50)		2,503,244.86	(143,936,579)
		1	4/1/2020	6/30/2020	7/1/2020	45.50	1.00	46.50		(61,380.31)	(2,854,184)
		1	7/1/2020	9/30/2020	7/1/2020	46.00	(91.00)	(45.00)		2,438,869.85	(109,749,143)
		1	10/1/2020	12/31/2020	9/22/2020	46.00	(100.00)	(54.00)		2,437,390.24	(131,619,073)
		1	1/1/2021	3/31/2021	12/17/2020	45.00	(104.00)	(59.00)		2,437,390.24	(143,806,024)
		5							$\boxed{(54.53)}$	2/ 9,755,514.88	(531,965,003)

Detail Summary of Tax Payments Remitted during Calendar Year 2020

Account 182330

Sum of Merchandise Amt

Descr	Beginning	Ending Pe	Acctg Date	Total
DC ROW - 3rd Qtr FY 20	Apr	Jun	19-Mar	2,503,244.86
DC ROW ADJ _ FY 20	Apr	Jun	1-Jul	(61,380.31)
DC ROW Fee _ FY 20	Jul	Sep	1-Jul	2,438,869.85
DC ROW Fee _ FY 21	Jan	Mar	17-Dec	2,437,390.24
	Oct	Dec	22-Sep	2,437,390.24
Grand Total				**9,755,514.88**

Washington Gas Light Company
District of Columbia
Revenue Adjustment for Weather Normalization (WNA)
For the WNA period April 2023 to March 2024

	District of Columbia			
	Billing Month	Normal (billing) HDDs /a	Actual (billing) HDDs /b	Act HDDs under / (over) Normal
	A	B	C	D=B-C
1	Mar-24	634	516	(118)
2	Feb-24	811	699	(112)
3	Jan-24	763	655	(108)
4	Dec-23	552	536	(16)
5	Nov-23	288	223	(65)
6	Oct-23	47	39	(8)
7	Sep-23	-	1	1
8	Aug-23	-	-	-
9	Jul-23	-	-	-
10	Jun-23	35	21	(14)
11	May-23	184	130	(54)
12	Apr-23	415	367	(48)
13	**Total**	**3,729**	**3,187**	**(542)**
13	**8 Month Total**	**3,694**	**3,165**	**(529)**

		Total DC WNA Revenue Adjustment /c					
	Customer Class	Average Annual Customers	Variation per Hdd	Act HDDs under / (over) Case	Volume Adjustment	Distribution Rate	Revenue Adjustment
	A	B	C	D	E=B*C*D	F	G=E*F
14	RES HTG / HC - Sales	135,615	See Detail	(542)	(10,276,186)	$ 0.5638	$ (5,793,714)
15	RES NON-HTG NON-CLG - IMA - Sales	10,924	See Detail	(542)	(44,959)	$ 0.6610	(29,718)
16	RES NON-HTG NON-CLG - OTH - Sales	3,566	See Detail	(542)	(187,021)	$ 0.6390	(119,507)
17	C&I HTG / HC - SYS LEV 1 - Sales	4,499	See Detail	(542)	(589,515)	$ 0.5821	(343,157)
18	C&I HTG / HC - SYS LEV 2 - Sales	3,390	See Detail	(542)	(5,688,769)	$ 0.4796	(2,728,332)
19	C&I CNG	1	See Detail	(542)	(163,922)	$ 0.1033	(16,934)
20	C&I NON-HTG NON-CLG - Sales	1,845	See Detail	(542)	(399,194)	$ 0.4811	(192,052)
21	GMA HTG / HC - SYS LEV 1 - Sales	598	See Detail	(542)	(82,548)	$ 0.4863	(40,145)
22	GMA HTG / HC - SYS LEV 2 - Sales	1,707	See Detail	(542)	(2,976,271)	$ 0.4930	(1,467,303)
23	GMA NON-HTG NON-CLG - Sales	869	See Detail	(542)	(225,529)	$ 0.4841	(109,178)
24	**Total Firm**	**163,013**			**(20,633,914)**		**$ (10,840,040)**

		8 Month DC WNA Revenue Adjustment /c					
	Customer Class	Average Annual Customers	Variation per Hdd	Act HDDs under / (over) Case	Volume Adjustment	Distribution Rate	Revenue Adjustment
	A	B	C	D	E=B*C*D	F	G=E*F
25	RES HTG / HC - Sales	135,694	Exhhibit WG (D)-9b	(529)	(10,030,327)	(1)	$ (5,655,099)
26	RES NON-HTG NON-CLG - IMA - Sales	10,908	Exhhibit WG (D)-9b	(529)	(43,877)	(1)	(29,003)
27	RES NON-HTG NON-CLG - OTH - Sales	3,573	Exhhibit WG (D)-9b	(529)	(182,579)	(1)	(116,668)
28	C&I HTG / HC - SYS LEV 1 - Sales	4,517	Exhhibit WG (D)-9c	(529)	(575,606)	(1)	(335,061)
29	C&I HTG / HC - SYS LEV 2 - Sales	3,400	Exhhibit WG (D)-9c	(529)	(5,553,689)	(0)	(2,663,548)
30	C&I CNG	1	Exhhibit WG (D)-9c	(529)	(159,990)	(0)	(16,528)
31	C&I NON-HTG NON-CLG - Sales	1,844	Exhhibit WG (D)-9c	(529)	(389,582)	(0)	(187,428)
32	GMA HTG / HC - SYS LEV 1 - Sales	601	Exhhibit WG (D)-9c	(529)	(80,582)	(0)	(39,188)
33	GMA HTG / HC - SYS LEV 2 - Sales	1,706	Exhhibit WG (D)-9c	(529)	(2,904,692)	(0)	(1,432,014)
34	GMA NON-HTG NON-CLG - Sales	870	Exhhibit WG (D)-9c	(529)	(220,135)	(0)	(106,567)
35	**Total Firm**	**163,114**			**(20,141,059)**		**$ (10,581,104)**

Foototes:
/a Information in the DC Normal (Billing) HDD is sourced from Exhibit WG (N)-3.
/b Information in the DC Actual (Billing) HDD is sourced from Exhibit WG (D)-9d.
/c Information in the DC WNA Revenue Calculation Table is sourced from the supporting schedules Exhibit WG (D)-9b and Exhibit WG (D)-9c.

DC WNA Sample Revenue Calculation
Rate Schedule No. 1 Customer Classes

DC Residential Heating and/or Cooling WNA Revenue Adjustment

	Month	(no. of customers billed) /a	Variation per HDD /b	HDD Variance /c	Volume Adjustment		Distribution Rate /d		Revenue Adjustment
	A	B	C	D	E=B*C*D		F		G=E*F
1	March-24	135,420	0.139774	(118)	(2,233,527)	$	0.5638	$	(1,259,263)
2	February-24	135,697	0.139774	(112)	(2,124,294)	$	0.5638	$	(1,197,677)
3	January-24	135,801	0.139774	(108)	(2,049,996)	$	0.5638	$	(1,155,788)
4	December-23	135,978	0.139774	(16)	(304,099)	$	0.5638	$	(171,451)
5	November-23	135,976	0.139774	(65)	(1,235,384)	$	0.5638	$	(696,509)
6	October-23	135,752	0.139774	(8)	(151,797)	$	0.5638	$	(85,583)
7	September-23	135,676	0.139774	1	18,964	$	0.5638	$	10,692
8	August-23	135,514	0.139774	-	-	$	0.5638	$	-
9	July-23	135,303	0.139774	-	-	$	0.5638	$	-
10	June-23	135,332	0.139774	(14)	(264,823)	$	0.5638	$	(149,307)
11	May-23	135,360	0.139774	(54)	(1,021,670)	$	0.5638	$	(576,018)
12	April-23	135,570	0.139774	(48)	(909,560)	$	0.5638	$	(512,810)
13	**Total**	**135,615**		**(542)**	**(10,276,186)**	**$**	**0.5638**	**$**	**(5,793,714)**
	WNA Months (October -May)	**135,694**		**(529)**	**(10,030,327)**	**$**	**(0.5638)**	**$**	**(5,655,099)**

DC WNA Sample Revenue Calculation
Rate Schedule No. 1 Customer Classes

DC Residential Non-Heating/Non-Cooling Individually Metered Apartments (IMA) - WNA Revenue Adjustment

	Month	Months Billed (no. of customers billed) /a	Variation per HDD /b	HDD Variance /c	Volume Adjustment	Distribution Rate /d	Revenue Adjustment
	A	B	C	D	E=B*C*D	F	G=E*F
14	March-24	10,820	0.007619	(118)	(9,728)	$ 0.6610	$ (6,430)
15	February-24	10,857	0.007619	(112)	(9,265)	$ 0.6610	$ (6,124)
16	January-24	10,890	0.007619	(108)	(8,961)	$ 0.6610	$ (5,923)
17	December-23	10,910	0.007619	(16)	(1,330)	$ 0.6610	$ (879)
18	November-23	10,962	0.007619	(65)	(5,429)	$ 0.6610	$ (3,589)
19	October-23	10,959	0.007619	(8)	(668)	$ 0.6610	$ (442)
20	September-23	10,964	0.007619	1	84	$ 0.6610	$ 56
21	August-23	10,957	0.007619	-	-	$ 0.6610	$ -
22	July-23	10,965	0.007619	-	-	$ 0.6610	$ -
23	June-23	10,935	0.007619	(14)	(1,166)	$ 0.6610	$ (771)
24	May-23	10,920	0.007619	(54)	(4,493)	$ 0.6610	$ (2,970)
25	April-23	10,945	0.007619	(48)	(4,003)	$ 0.6610	$ (2,646)
26	**Total**	**10,924**		**(542)**	**(44,959)**	**$ 0.6610**	**$ (29,718)**
	WNA Months (October -May)	**10,908**		**(529)**	**(43,877)**	**$ (0.6610)**	**$ (29,003)**

DC WNA Sample Revenue Calculation
Rate Schedule No. 1 Customer Classes

DC Residential Non-Heating/Non-Cooling Other - WNA Revenue Adjustment

	Month	Months Billed (no. of customers billed) /a	Variation per HDD /b	HDD Variance /c	Volume Adjustment		Distribution Rate /d		Revenue Adjustment
	A	B	C	D	E=B*C*D		F		G=E*F
27	March-24	3,586	0.096533	(118)	(40,848)	$	0.6390	$	(26,102)
28	February-24	3,581	0.096533	(112)	(38,717)	$	0.6390	$	(24,740)
29	January-24	3,586	0.096533	(108)	(37,386)	$	0.6390	$	(23,890)
30	December-23	3,589	0.096533	(16)	(5,543)	$	0.6390	$	(3,542)
31	November-23	3,589	0.096533	(65)	(22,520)	$	0.6390	$	(14,390)
32	October-23	3,591	0.096533	(8)	(2,773)	$	0.6390	$	(1,772)
33	September-23	3,570	0.096533	1	345	$	0.6390	$	220
34	August-23	3,548	0.096533	-	-	$	0.6390	$	-
35	July-23	3,547	0.096533	-	-	$	0.6390	$	-
36	June-23	3,542	0.096533	(14)	(4,787)	$	0.6390	$	(3,059)
37	May-23	3,550	0.096533	(54)	(18,505)	$	0.6390	$	(11,825)
38	April-23	3,515	0.096533	(48)	(16,287)	$	0.6390	$	(10,407)
39	**Total**	**3,566**		**(542)**	**(187,021)**	**$**	**0.6390**	**$**	**(119,507)**
	WNA Months (October -May)	**3,573**		**(529)**	**(182,579)**	**$**	**(0.6390)**	**$**	**(116,668)**

Footnotes:
/a Exhibit WG (N)-4, Pages 9 to 15 of 28, Schedule 2B, Column B,
/b Exhibit WG (N)-4, pages 9 to 15 of 28, Schedule 2B, Column D less Column C.
/c Exhibit WG (N)-4, pages 9 to 15 of 28, Schedule 2B, Column E.
/d Distribution rates are sourced from the Company's tariff pages. See Exhibit WG (D)-5, the workpapers for Adjustment 1, Page 5 of 46, Line 3.

DC WNA Sample Revenue Calculation
Rate Schedule No. 2, 3 and 7 Customer Classes

DC Commercial & Industrial (C&I) Heating and/or Cooling < 3075 therms - WNA Revenue Adjustment

	Month	Months Billed (no. of customers billed) /a	Variation per HDD /b	HDD Variance /c	Volume Adjustment	Distribution Rate /d	Revenue Adjustment
	A	B	C	D	E=B*C*D	F	G=E*F
1	March-24	4,584	0.239770	(118)	(129,694)	$ 0.5821	$ (75,495)
2	February-24	4,589	0.239770	(112)	(123,234)	$ 0.5821	$ (71,735)
3	January-24	4,537	0.239770	(108)	(117,486)	$ 0.5821	$ (68,389)
4	December-23	4,528	0.239770	(16)	(17,371)	$ 0.5821	$ (10,112)
5	November-23	4,509	0.239770	(65)	(70,273)	$ 0.5821	$ (40,906)
6	October-23	4,480	0.239770	(8)	(8,593)	$ 0.5821	$ (5,002)
7	September-23	4,447	0.239770	1	1,066	$ 0.5821	$ 621
8	August-23	4,471	0.239770	-	-	$ 0.5821	$ -
9	July-23	4,467	0.239770	-	-	$ 0.5821	$ -
10	June-23	4,461	0.239770	(14)	(14,975)	$ 0.5821	$ (8,717)
11	May-23	4,464	0.239770	(54)	(57,798)	$ 0.5821	$ (33,644)
12	April-23	4,445	0.239770	(48)	(51,157)	$ 0.5821	$ (29,778)
13	**Total**	**4,499**		**(542)**	**(589,515)**	**$ 0.5821**	**$ (343,157)**
	WNA Months (October -May)	**4,517**		**(529)**	**(575,606)**	**$ (0.5821)**	**$ (335,061)**

DC WNA Sample Revenue Calculation
Rate Schedule No. 2, 3 and 7 Customer Classes

DC C&I Heating and/or Cooling > 3075 therms - WNA Revenue Adjustment

	Month	Months Billed (no. of customers billed) /a	Variation per HDD /b	HDD Variance /c	Volume Adjustment	Distribution Rate /d	Revenue Adjustment
	A	B	C	D	E=B*C*D	F	G=E*F
14	March-24	3,419	3.081347	(118)	(1,243,145)	$ 0.4796	$ (596,212)
15	February-24	3,417	3.081347	(112)	(1,179,244)	$ 0.4796	$ (565,565)
16	January-24	3,428	3.081347	(108)	(1,140,789)	$ 0.4796	$ (547,122)
17	December-23	3,424	3.081347	(16)	(168,809)	$ 0.4796	$ (80,961)
18	November-23	3,387	3.081347	(65)	(678,374)	$ 0.4796	$ (325,348)
19	October-23	3,373	3.081347	(8)	(83,147)	$ 0.4796	$ (39,877)
20	September-23	3,384	3.081347	1	10,427	$ 0.4796	$ 5,001
21	August-23	3,363	3.081347	-	-	$ 0.4796	$ -
22	July-23	3,363	3.081347	-	-	$ 0.4796	$ -
23	June-23	3,373	3.081347	(14)	(145,507)	$ 0.4796	$ (69,785)
24	May-23	3,360	3.081347	(54)	(559,080)	$ 0.4796	$ (268,135)
25	April-23	3,388	3.081347	(48)	(501,101)	$ 0.4796	$ (240,328)
26	**Total**	**3,390**		**(542)**	**(5,688,769)**	**$ 0.4796**	**$ (2,728,332)**
	WNA Months (October -May)	**3,400**		**(529)**	**(5,553,689)**	**$ (0.4796)**	**$ (2,663,548)**

DC WNA Sample Revenue Calculation
Rate Schedule No. 2, 3 and 7 Customer Classes

DC C&I CHP - WNA Revenue Adjustment

	Month	Months Billed (no. of customers billed) /a	Variation per HDD /b	HDD Variance /c	Volume Adjustment	Distribution Rate /d	Revenue Adjustment
	A	B	C	D	E=B*C*D	F	G=E*F
27	March-24	1	302.437600	(118)	(35,688)	$ 0.1033	$ (3,687)
28	February-24	1	302.437600	(112)	(33,873)	$ 0.1033	$ (3,499)
29	January-24	1	302.437600	(108)	(32,663)	$ 0.1033	$ (3,374)
30	December-23	1	302.437600	(16)	(4,839)	$ 0.1033	$ (500)
31	November-23	1	302.437600	(65)	(19,658)	$ 0.1033	$ (2,031)
32	October-23	1	302.437600	(8)	(2,420)	$ 0.1033	$ (250)
33	September-23	1	302.437600	1	302	$ 0.1033	$ 31
34	August-23	1	302.437600	-	-	$ 0.1033	$ -
35	July-23	1	302.437600	-	-	$ 0.1033	$ -
36	June-23	1	302.437600	(14)	(4,234)	$ 0.1033	$ (437)
37	May-23	1	302.437600	(54)	(16,332)	$ 0.1033	$ (1,687)
38	April-23	1	302.437600	(48)	(14,517)	$ 0.1033	$ (1,500)
39	**Total**	**1**		**(542)**	**(163,922)**	**$ 0.1033**	**$ (16,934)**
	WNA Months (October -May)	**1**		**(529)**	**(159,990)**	**$ (0.1033)**	**$ (16,528)**

DC WNA Sample Revenue Calculation
Rate Schedule No. 2, 3 and 7 Customer Classes

DC C&I Non-Heating/Non-Cooling - WNA Revenue Adjustment

	Month	Months Billed (no. of customers billed) /a	Variation per HDD /b	HDD Variance /c	Volume Adjustment	Distribution Rate /d	Revenue Adjustment
	A	B	C	D	E=B*C*D	F	G=E*F
40	March-24	1,838	0.399846	(118)	(86,720)	$ 0.4811	$ (41,721)
41	February-24	1,837	0.399846	(112)	(82,266)	$ 0.4811	$ (39,578)
42	January-24	1,836	0.399846	(108)	(79,285)	$ 0.4811	$ (38,144)
43	December-23	1,839	0.399846	(16)	(11,765)	$ 0.4811	$ (5,660)
44	November-23	1,844	0.399846	(65)	(47,926)	$ 0.4811	$ (23,057)
45	October-23	1,846	0.399846	(8)	(5,905)	$ 0.4811	$ (2,841)
46	September-23	1,845	0.399846	1	738	$ 0.4811	$ 355
47	August-23	1,844	0.399846	-	-	$ 0.4811	$ -
48	July-23	1,844	0.399846	-	-	$ 0.4811	$ -
49	June-23	1,849	0.399846	(14)	(10,350)	$ 0.4811	$ (4,979)
50	May-23	1,856	0.399846	(54)	(40,074)	$ 0.4811	$ (19,280)
51	April-23	1,857	0.399846	(48)	(35,641)	$ 0.4811	$ (17,147)
52	**Total**	**1,845**		**(542)**	**(399,194)**	**$ 0.4811**	**$ (192,052)**
	WNA Months (October -May)	**1,844**		**(529)**	**(389,582)**	**$ (0.4811)**	**$ (187,428)**

DC WNA Sample Revenue Calculation
Rate Schedule No. 2, 3 and 7 Customer Classes

DC Group Metered Apartments (GMA) Heating and/or Cooling < 3075 therms - WNA Revenue Adjustment

	Month	Months Billed (no. of customers billed) /a	Variation per HDD /b	HDD Variance /c	Volume Adjustment	Distribution Rate /d	Revenue Adjustment
	A	B	C	D	E=B*C*D	F	G=E*F
53	March-24	605	0.252432	(118)	(18,021)	$ 0.4863	$ (8,764)
54	February-24	612	0.252432	(112)	(17,303)	$ 0.4863	$ (8,414)
55	January-24	597	0.252432	(108)	(16,276)	$ 0.4863	$ (7,915)
56	December-23	595	0.252432	(16)	(2,403)	$ 0.4863	$ (1,169)
57	November-23	602	0.252432	(65)	(9,878)	$ 0.4863	$ (4,804)
58	October-23	596	0.252432	(8)	(1,204)	$ 0.4863	$ (586)
59	September-23	583	0.252432	1	147	$ 0.4863	$ 71
60	August-23	590	0.252432	-	-	$ 0.4863	$ -
61	July-23	596	0.252432	-	-	$ 0.4863	$ -
62	June-23	598	0.252432	(14)	(2,113)	$ 0.4863	$ (1,028)
63	May-23	608	0.252432	(54)	(8,288)	$ 0.4863	$ (4,030)
64	April-23	595	0.252432	(48)	(7,209)	$ 0.4863	$ (3,506)
65	**Total**	**598**		**(542)**	**(82,548)**	**$ 0.4863**	**$ (40,145)**
	WNA Months (October -May)	**601**		**(529)**	**(80,582)**	**$ (0.4863)**	**$ (39,188)**

DC WNA Sample Revenue Calculation
Rate Schedule No. 2, 3 and 7 Customer Classes

DC GMA Heating and/or Cooling > 3075 therms - WNA Revenue Adjustment

	Month	Months Billed (no. of customers billed) /a	Variation per HDD /b	HDD Variance /c	Volume Adjustment	Distribution Rate /d	Revenue Adjustment
	A	B	C	D	E=B*C*D	F	G=E*F
66	March-24	1,709	3.218457	(118)	(649,040)	$ 0.4930	$ (319,977)
67	February-24	1,703	3.218457	(112)	(613,876)	$ 0.4930	$ (302,641)
68	January-24	1,711	3.218457	(108)	(594,732)	$ 0.4930	$ (293,203)
69	December-23	1,713	3.218457	(16)	(88,211)	$ 0.4930	$ (43,488)
70	November-23	1,699	3.218457	(65)	(355,430)	$ 0.4930	$ (175,227)
71	October-23	1,701	3.218457	(8)	(43,797)	$ 0.4930	$ (21,592)
72	September-23	1,714	3.218457	1	5,516	$ 0.4930	$ 2,719
73	August-23	1,709	3.218457	-	-	$ 0.4930	$ -
74	July-23	1,705	3.218457	-	-	$ 0.4930	$ -
75	June-23	1,711	3.218457	(14)	(77,095)	$ 0.4930	$ (38,008)
76	May-23	1,699	3.218457	(54)	(295,281)	$ 0.4930	$ (145,574)
77	April-23	1,711	3.218457	(48)	(264,325)	$ 0.4930	$ (130,312)
78	**Total**	**1,707**		**(542)**	**(2,976,271)**	**$ 0.4930**	**$ (1,467,303)**
	WNA Months (October -May)	**1,706**		**(529)**	**(2,904,692)**	**$ (0.4930)**	**$ (1,432,014)**

DC WNA Sample Revenue Calculation
Rate Schedule No. 2, 3 and 7 Customer Classes

DC GMA Non-Heating/Non-Cooling - Sales Customers WNA Revenue Adjustment

	Month	Months Billed (no. of customers billed) /a	Variation per HDD /b	HDD Variance /c	Volume Adjustment	Distribution Rate /d	Revenue Adjustment
	A	B	C	D	E=B*C*D	F	G=E*F
79	March-24	871	0.478026	(118)	(49,131)	$ 0.4841	$ (23,784)
80	February-24	875	0.478026	(112)	(46,847)	$ 0.4841	$ (22,679)
81	January-24	870	0.478026	(108)	(44,915)	$ 0.4841	$ (21,743)
82	December-23	869	0.478026	(16)	(6,646)	$ 0.4841	$ (3,217)
83	November-23	868	0.478026	(65)	(26,970)	$ 0.4841	$ (13,056)
84	October-23	869	0.478026	(8)	(3,323)	$ 0.4841	$ (1,609)
85	September-23	868	0.478026	1	415	$ 0.4841	$ 201
86	August-23	869	0.478026	-	-	$ 0.4841	$ -
87	July-23	868	0.478026	-	-	$ 0.4841	$ -
88	June-23	868	0.478026	(14)	(5,809)	$ 0.4841	$ (2,812)
89	May-23	869	0.478026	(54)	(22,432)	$ 0.4841	$ (10,859)
90	April-23	866	0.478026	(48)	(19,871)	$ 0.4841	$ (9,620)
91	**Total**	**869**		**(542)**	**(225,529)**	**$ 0.4841**	**$ (109,178)**
	WNA Months (October -May)	**870**		**(529)**	**(220,135)**	**$ (0.4841)**	**$ (106,567)**

Footnotes:
/a Exhibit WG (N)-4, Pages 9 to 15 of 28, Schedule 2B, Column B,
/b Exhibit WG (N)-4, pages 9 to 15 of 28, Schedule 2B, Column D less Column C.
/c Exhibit WG (N)-4, pages 9 to 15 of 28, Schedule 2B, Column E.
/d Distribution rates are sourced from the Company's tariff pages. See Exhibit WG (D)-5, the workpapers for Adjustment 1, Page 5 of 46, Line 3.

* This analysis uses actual meter reads per SAP to calculate actual HDDs.

CYCLE	Mar-2023	Apr-2023	May-2023	Jun-2023	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024
1	02/27/23	03/30/23	04/27/23	05/30/23	06/29/23	07/28/23	08/30/23	09/28/23	10/30/23	11/29/23	12/28/23	01/30/24	02/28/24
2	02/28/23	03/31/23	04/28/23	05/31/23	06/30/23	07/31/23	08/31/23	09/29/23	10/31/23	11/30/23	12/29/23	01/31/24	02/29/24
3	03/01/23	04/03/23	05/01/23	06/01/23	07/03/23	08/01/23	09/01/23	10/02/23	11/01/23	12/01/23	01/02/24	02/01/24	03/01/24
4	03/02/23	04/04/23	05/02/23	06/02/23	07/05/23	08/02/23	09/05/23	10/03/23	11/02/23	12/04/23	01/03/24	02/02/24	03/04/24
5	03/03/23	04/05/23	05/03/23	06/05/23	07/06/23	08/03/23	09/06/23	10/04/23	11/03/23	12/05/23	01/04/24	02/03/24	03/05/24
6	03/06/23	04/06/23	05/04/23	06/06/23	07/07/23	08/04/23	09/07/23	10/05/23	11/06/23	12/06/23	01/05/24	02/05/24	03/06/24
7	03/07/23	04/07/23	05/05/23	06/07/23	07/10/23	08/07/23	09/08/23	10/06/23	11/07/23	12/07/23	01/08/24	02/06/24	03/07/24
8	03/08/23	04/10/23	05/08/23	06/08/23	07/11/23	08/08/23	09/11/23	10/09/23	11/08/23	12/08/23	01/09/24	02/07/24	03/08/24
9	03/09/23	04/11/23	05/09/23	06/09/23	07/12/23	08/09/23	09/12/23	10/10/23	11/09/23	12/11/23	01/10/24	02/08/24	03/11/24
10	03/10/23	04/12/23	05/10/23	06/12/23	07/13/23	08/10/23	09/13/23	10/11/23	11/13/23	12/12/23	01/11/24	02/09/24	03/12/24
11	03/13/23	04/13/23	05/11/23	06/13/23	07/14/23	08/11/23	09/14/23	10/12/23	11/14/23	12/13/23	01/12/24	02/12/24	03/13/24
12	03/14/23	04/14/23	05/12/23	06/14/23	07/17/23	08/14/23	09/15/23	10/13/23	11/15/23	12/14/23	01/13/24	02/13/24	03/14/24
13	03/15/23	04/17/23	05/15/23	06/15/23	07/18/23	08/15/23	09/18/23	10/16/23	11/16/23	12/15/23	01/16/24	02/14/24	03/15/24
14	03/16/23	04/18/23	05/16/23	06/16/23	07/19/23	08/16/23	09/19/23	10/17/23	11/17/23	12/18/23	01/17/24	02/15/24	03/18/24
15	03/17/23	04/19/23	05/17/23	06/20/23	07/20/23	08/17/23	09/20/23	10/18/23	11/18/23	12/19/23	01/18/24	02/16/24	03/19/24
16	03/21/23	04/20/23	05/18/23	06/21/23	07/21/23	08/18/23	09/21/23	10/19/23	11/20/23	12/20/23	01/19/24	02/20/24	03/20/24
17	03/22/23	04/21/23	05/19/23	06/22/23	07/24/23	08/21/23	09/22/23	10/20/23	11/21/23	12/21/23	01/22/24	02/21/24	03/21/24
18	03/23/23	04/24/23	05/22/23	06/23/23	07/25/23	08/22/23	09/25/23	10/21/23	11/22/23	12/26/23	01/23/24	02/22/24	03/22/24
19	03/24/23	04/25/23	05/23/23	06/26/23	07/26/23	08/23/23	09/26/23	10/23/23	11/27/23	12/27/23	01/24/24	02/23/24	03/25/24
20		04/26/23	05/24/23	06/27/23		08/24/23	09/27/23	10/24/23	11/28/23	12/28/23	01/25/24	02/26/24	03/26/24
21								10/25/23			01/26/24	02/27/24	

CALCULATED CYCLE HDDs

	Mar-2023	Apr-2023	May-2023	Jun-2023	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024
1	486	490	154	80	-	-	-	7	109	418	588	794	604
2	492	489	138	77	-	-	-	9	107	451	565	807	592
3	504	501	132	59	-	-	-	9	124	456	623	751	591
4	492	493	133	50	-	-	-	9	143	485	600	748	617
5	472	486	144	39	-	-	-	9	164	479	609	742	605
6	424	440	156	27	-	-	-	9	195	468	614	762	571
7	420	424	165	18	-	-	-	9	203	484	670	704	561
8	412	446	135	9	-	-	-	21	191	509	666	707	544
9	422	438	123	9	-	-	-	30	189	553	631	714	567
10	430	423	122	7	-	-	-	34	235	526	624	718	563
11	448	354	125	4	-	-	-	37	252	532	620	732	533
12	451	334	125	4	-	-	-	38	265	540	619	729	519
13	461	308	125	4	-	-	-	53	264	552	674	670	500
14	477	288	123	4	-	-	-	63	263	594	662	655	487
15	481	277	119	4	-	-	-	70	262	604	688	637	482
16	490	202	115	4	-	-	-	78	281	604	695	702	404
17	495	186	119	-	-	-	-	83	296	610	779	616	390
18	486	187	111	-	-	-	3	83	309	695	713	605	389
19	484	198	100	-	-	-	3	94	386	625	723	599	428
20							7				730	645	379
21												647	
	8,827	6,964	2,464	399	-	-	13	745	4,238	10,185	13,093	14,684	10,326
Cycle HDDs	465	367	130	21	-	-	1	39	223	536	655	699	516
TME HDDs	3,250	3,209	3,164	3,160	3,160	3,160	3,161	3,111	3,115	3,134	3,056	3,136	3,187

ATTESTATION

I, ROBERT E. TUORINIEMI, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Robert E. Tuoriniemi

ROBERT E. TUORINIEMI

07/29/2024

DATE

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

FORMAL CASE NO. 1180

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY
FOR AUTHORITY TO INCREASE EXISTING RATES
AND CHARGES FOR GAS SERVICE

VOLUME 3 OF 3

PUBLIC

DIRECT TESTIMONY
WG (E) THROUGH WG (O)

(WITNESSES BANKS, SMITH, WHITE, BELL, MORROW, QUENUM, BLOCK, BARYENBRUCH, BURGUM, RAAB, AND LAWSON)

SUPPORTING EXHIBITS
WG (F)-1 THROUGH WG (F)-5, WG (G) -1 THROUGH WG (G)-2, WG (H)-1 THROUGH WG (H)-2, WG (I)-1 THROUGH WG (I)-3, WG (J)-1 THROUGH WG (J)-5, WG (K)-1, WG (L)-1 THROUGH WG (L)-2, WG (N)-1 THROUGH WG (N)-4 AND WG (O)-1 THROUGH WG (O)-4

KAREN M. HARDWICK
SENIOR VICE PRESIDENT AND
GENERAL COUNSEL

JOHN C. DODGE
CATHY THURSTON-SEIGNIOUS
MEERA AHAMED
SPENCER NICHOLS
PAUL BUCKLEY

ATTORNEYS FOR

WASHINGTON GAS LIGHT COMPANY
1000 MAINE AVENUE, SW, SUITE 700
WASHINGTON, DC 20024
(202) 624-6722

DATED: AUGUST 5, 2024

WITNESS BANKS
EXHIBIT WG (E)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF KATINA L. BANKS
Exhibit WG (E)

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EXHIBIT WG (E)

WASHINGTON GAS LIGHT COMPANY

District of Columbia

DIRECT TESTIMONY OF KATINA L. BANKS

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Katina L. Banks. I am the Manager of Utility Revenue Accounting for Washington Gas Light Company, ("Washington Gas" or the "Company"). My business address is 1000 Maine Avenue, SW, Washington, D.C., 20024.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I graduated from Strayer University in May 1998, with a Bachelor of Science in Accounting Degree. From September 1998 through July 2022, I worked at Washington Gas as a Senior Specialist Accountant in various areas within the Finance department, including Current Asset Management, Energy Accounting, and Utility Revenue Accounting. During that time, I was responsible for the recordation of the revenue normalization adjustments, the adjustments related to the revenue sharing mechanisms, and various other revenue transactions to complete the month-end close processes. I was also responsible for preparing responses to revenue-related data requests for rate cases, and for both internal and external audits.

From December 2014 to January 2017, I was a subject matter expert for the implementation of the SAP Billing application. In this role, I was responsible for applying functional knowledge to the design and customization of workflow systems that were integrated into the client/server application. My responsibilities included assisting with the design, functional documentation, and testing of finance and billing processes, reports, and interfaces in the SAP application. I also assisted with the identification and relevant updates of key audit controls related to the implementation.

I was promoted to Manager of Utility Revenue Accounting in August of 2022. In this role, I am responsible for overseeing the recordation of various revenue transactions, the completion of the monthly close process, providing responses to audit and rate case data requests, and the analyses and internal reporting of utility revenue results.

Q. HAVE YOU TESTIFIED PREVIOUSLY?

A. No, I have not previously testified before any commission.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to describe and support the Company's Test Year Revenue and Related Expense Adjustments, which removes the effect that variations in weather from normal levels had on test year revenues and therm deliveries. My testimony presents test year revenues and therms at levels the Company could expect to occur in the rate effective period.

III. SUMMARY OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. No. The detailed workpapers for Adjustment 1-Revenues that I support are included in Exhibits WG (D)-3 and WG (D)-5 attached to Company Witness Tuoriniemi's Direct Testimony.

IV. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony supports the revenue adjustments, as presented below, that are necessary so that the test year more accurately reflects revenues and costs that the Company will experience during the rate effective period. The revenue adjustments represent known and measurable adjustments to the test year.

V. REVENUE AND RELATED ADJUSTMENTS

Q. PLEASE IDENTIFY THE ADJUSTMENT PRESENTED BY WASHINGTON GAS IN THIS CASE NECESSARY TO REFLECT THE EFFECT OF NORMAL WEATHER.

A. Adjustment 1—Revenues reflects ratemaking adjustments associated with the effect of normal weather and includes the following components:

Revenues.

Uncollectible Gas Accounts.

Sustainable Energy and Energy Assistance Trust Funds.

District of Columbia Delivery Tax and Rights-of-Way Fees.

Test Year Revenues and Revenue Related Adjustments (Adjustment 1)

Q. PLEASE PROVIDE AN OVERVIEW OF THE APPROACH YOU USED IN PREPARING ADJUSTMENT 1—REVENUES.

A. Adjustment 1—Revenues sets forth $19.4 million of combined revenue-related adjustments, using methodologies that have been approved by the Public Service Commission of the District of Columbia ("Commission") in prior rate proceedings. In addition, it reflects the requirement of Commission Order No. 17132, in Formal Case No. 1093, to reflect the cost of service on a "distribution-only" basis. I applied these adjustments to the per book revenues for the test year ended March 31, 2024, to determine the ratemaking revenues. Adjustment 1—Revenues also includes $5.5 million of expense adjustments for other cost of service components that are affected by the normalization of test year revenues.

Revenues

Distribution Revenues[1]	$ 27,551,307
Revenue Taxes[2]	4,679,521
Late Payment Charges	332,243
PROJECT*pipes*	(13,157,184)

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[1]

Delivery Revenues	$18,877,467
Distribution Charge & Plant Rec Adjustments	8,444,784
Peak Usage Charge	229,056
Total	$27,551,307

[2]

Delivery Tax	$ 1,978,792
Rights-of-Way Fees	(2,457,862)
Sustainable Energy Trust Fund	4,900,753
Energy Assistance Trust Fund	257,838
Total	$ 4,679,521

Other Revenues[3]	9,050
Total Revenue Related Adjustments	$ 19,414,936
Expenses	
Uncollectible Gas Accounts	$ 1,038,168
Sustainable Energy and Energy Assistance Trust Funds	4,787,949
Delivery Tax and Rights-of Way Fees	(366,477)
Total Expense Adjustments	$ 5,459,640

Test Year Revenues

Q. PLEASE DISCUSS THE REVENUE COMPONENT OF ADJUSTMENT 1—REVENUES.

A. Exhibit WG (D)-5, the workpapers for Adjustment 1, page 1 of 46 presents two major categories of revenues that I discuss in my testimony: (1) Deliveries of Gas; and (2) Other Operating Revenues.

Q. PLEASE DESCRIBE THE REVENUES THAT YOU CATEGORIZE AS "BASE REVENUES" AND FURTHER DESCRIBE THE ADJUSTMENTS.

A. This category represents the revenues from the distribution of gas to all the Company's customers. Revenues from each major customer class are shown on Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 1 of 46, Lines 3, 4, and 5.

Q. PLEASE DESCRIBE THE ADJUSTMENTS THAT YOU MADE TO BASE REVENUES.

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[3]

Rents (East Station Sharing)	$ (41,088)
Non-District of Columbia	$ 50,138
Total	$ 9,050

A. In total, I propose to increase Deliveries of Gas Revenues by \$27.5[4] million as shown on Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 1 of 46, Lines 3, 4, and 5. This adjustment is necessary to incorporate the net effect of items including an increase for the revenue-related effect of 22.5 million[5] additional firm therm deliveries because test year weather was warmer than normal and changes in peak usage charges and related revenue taxes. The increase due to variations in weather from normal levels is reflected in the Company's Normal Weather Study sponsored by Company Witness Raab (Exhibit WG (N)-4). If this portion of the adjustment is not made, the revenues and therm deliveries presented in this filing would be lower than the Company could expect to occur in the rate effective period.

This adjustment is computed by calculating the Company's gross base revenues[6] for the delivery of gas, using the assumption that normal weather therm deliveries occurred during the test period. Based on this calculation, I was able to determine the ratemaking revenues for each delivery customer class, totaling \$151.1 million. I then subtracted the per book revenues of \$123.5 million, which reflect actual weather, from my calculated ratemaking revenues to compute the ratemaking adjustment for weather normalization as it relates to the delivery revenue, resulting in an adjustment to increase per book revenues by \$27.6 million. I have shown this adjustment on Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 1 of 46, Lines 3-5.

The calculations used to determine the Company's ratemaking revenue for gas deliveries follow the methodology accepted by this Commission in

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[4] Exhibit WG (D)-5 Page 1, Lines 3 through 5, Column F.

[5] Exhibit WG (N)-4 Page 1 Line 22 (206,081,756 Normal Weather Therms – 183,591,944 actual therms).

[6] Includes distribution charge, system charge, and peak usage charge revenues.

previous rate filings made by the Company and required by Commission Order No. 17132, in Formal Case No. 1093, and continue to be appropriate for this proceeding.

Q. HOW DID YOU DETERMINE THE LEVEL OF NORMAL WEATHER REVENUES?

A. Company Witness Raab provided the normal weather study for Washington Gas, which determined the total therm deliveries on a weather-normalized basis used in the calculation of normal weather revenues as described below.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPUTATION OF NORMAL WEATHER REVENUES USING THE INFORMATION FROM THE NORMAL WEATHER STUDY.

A. Exhibit WG (D)-5, Workpapers for Adjustment 1—Revenues, page 5 of 46 performs the computation of normal weather revenue by individual rate class. It comprises two components that rely on data from the Company's Normal Weather Study:

Distribution Charge Revenues

Customer Charge Revenues

Q. DISTRIBUTION CHARGE REVENUES AND CUSTOMER CHARGE REVENUES ARE DETERMINED BY MULTIPLYING THE NORMAL WEATHER THERMS AND METER COUNT AS DETERMINED BY THE NORMAL WEATHER STUDY FOR EACH CUSTOMER RATE CLASS BY THE RESPECTIVE FACTORS AND CHARGE RATES ACCORDING TO THE TARIFF. PLEASE DISCUSS THE COMPUTATION IN FURTHER DETAIL.

Exhibit WG (D)-5, Workpapers for Adjustment 1—Revenues, page 5 of 46, Line 1 shows the normal weather therms from Company Witness Raab's Normal Weather Study (Exhibit WG (N)-4, page 1 of 28, Schedule 1A Column H). Exhibit WG (D)-5, Workpapers for Adjustment 1—Revenues, page 5 of 46, Line 3, shows the approved District of Columbia tariff rates in Formal Case No. 1169 by customer class. I multiplied the normal weather therms by customer class (Exhibit WG (D)-5 Workpapers for Adjustment 1—Revenues, page 5 of 46, Line 1) by the tariff rates (Exhibit WG (D)-5 Workpapers for Adjustment 1—Revenues, page 8 of 46 normal weather distribution charge revenues for the test period (Exhibit WG (D)-5 Workpapers for Adjustment 1—Revenues, page 5 of 46, Line 4).

Q. PLEASE DISCUSS CUSTOMER CHARGE REVENUES.

A. Exhibit WG (D)-5, Workpapers for Adjustment 1—Revenues, page 5 of 46, Line 6 shows the number of customer bills (meters) by customer class from the Company's Normal Weather Study (Exhibit WG (N)-4, page 8 of 28, Schedule 2A, Column B). Exhibit WG (D)-5 Workpapers for Adjustment 1—Revenues, page 5 of 46, Line 7 shows the approved District of Columbia tariff rates by customer class in Formal Case No. 1169. I multiplied the customer bills (Exhibit WG (D)-5, Workpapers for Adjustment 1—Revenues, page 5 of 46, Line 6) by the tariff rates (Exhibit WG (D)-5, Workpapers for Adjustment 1—Revenues, page 5 of 46, Line 7) to develop revenue estimates, which reflect customer charge revenues for the test period (Exhibit WG (D)-5 Workpapers for Adjustment 1—Revenues, page 5 of 46, Line 8).

Q. PLEASE DESCRIBE THE PEAK USAGE CHARGE COMPONENTS OF GAS SALES AND DELIVERY REVENUES.

A. Peak usage is a measure of the amount of gas a customer uses on the coldest days of the year for which the Company must incur substantial costs for investment, operation, and maintenance of gas production and additional gas distribution facilities. Under the Company's District of Columbia tariff approved in FC 1169, non-residential customers are billed a monthly peak usage charge during the six months of November through April based on the customer's "maximum billing month's" usage during the preceding November through April. The "maximum billing month" is defined in the tariff as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs.

Exhibit WG (D)-5 Workpapers for Adjustment 1—Revenues, page 5 of 46, Line 13, shows the peak usage charges billed for the month of November 2023 and charges projected to be billed through April 2024 by customer class, based on customers' maximum billing month from November 2022 to April 2023. The peak usage charges are calculated by multiplying the applicable peak usage charge factor for each rate class by the "maximum billing month's" usage as determined by the normal weather study.

Q. IS THIS THE SAME APPROACH USED IN FORMAL CASE NOS. 1162 AND 1169?

A. Yes, it is.

Q. PLEASE DESCRIBE HOW YOU TREATED THE RECOVERY OF GAS COSTS IN YOUR REVENUE COMPUTATIONS.

A. In my computation of weather-normalized revenues, I have excluded the recovery of gas costs to reflect distribution-only amounts. This elimination is reflected on Exhibit WG (D)-5 Workpapers for Adjustment 1—Revenues, page 1 of 46, Line 6.[7]

Q. PLEASE DESCRIBE HOW YOU TREATED THE DISTRICT OF COLUMBIA DELIVERY TAX AND OTHER PASS-THROUGH TAXES IN YOUR DEVELOPMENT OF REVENUES.

A. I synchronized the amount of District of Columbia Delivery Tax and other pass-through taxes included in revenues with the related expense amounts discussed below[8] to ensure the amounts agree and are, therefore, eliminated from the overall cost of service.

Q. PLEASE DESCRIBE THE SUSTAINABLE ENERGY TRUST FUND ("SETF") AND ENERGY ASSISTANCE TRUST FUND ("EATF") ADJUSTMENTS.

A. I included the SETF and EATF revenues by multiplying normal weather therms times the applicable assessment rate. The Sustainable Energy and Energy Assistance Trust Fund revenue component of Adjustment 1 synchronizes with SETF and EATF expense to ensure the amounts agree and are, therefore, eliminated from the overall cost of service.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO DELIVERY REVENUES RELATING TO WEATHER.

A. I computed the ratemaking adjustment by comparing the distribution-only per book amounts to the normal weather revenue calculation, including delivery revenues, system charges, and peak-usage charges, District of Columbia

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[7] *See* Exhibit WG (D) and Exhibit WG (D)-5 Adjustments 1D, 2D, and 4D for explanation and detailed calculations of the fuel revenues elimination.

[8] *See* "Revenue Related Expense Adjustments"

delivery tax, and other pass-through taxes. This generated a ratemaking adjustment to increase delivery revenues by $19.1 million.[9]

Q. HAVE YOU MADE ADJUSTMENTS TO OTHER OPERATING REVENUES?

A. Yes, I have.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO LATE PAYMENT CHARGES.

A. Consistent with its tariff provisions and 15 DCMR § 305.3, Washington Gas charges customers whose bills are in arrears a late payment fee. Customers whose bills are in arrears for more than 20 days are assessed a one-percent late payment fee. Should the original arrearage continue 30 additional days, Washington Gas assesses an additional one and one-half-percent late payment charge on any total amount that remains unpaid at that time.

Generally, late payment charges increase or decrease in proportion to the Company's gross revenues. Therefore, it is necessary to align the late payment charges with the weather-normalized revenues that I previously discussed. In calculating this adjustment, I determined the ratio of per book non-Purchase Of Receivables late payment charges in the test year. I then applied this ratio to the total weather-normalized revenues to determine the associated late payment charges on a ratemaking basis. Because the adjusted late payment charges were higher than those reflected in the per book test year amounts, I computed a $332,243 increase to revenues as the ratemaking adjustment.[10]

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[9] Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 1 of 46, line 15. This adjustment is net of the elimination of PROJECT*pipes* revenues of $13.2 million.

[10] Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 1 of 46, line 16 and page 28 of 46.

Q. WHAT IS INCLUDED IN "MISCELLANEOUS SERVICE REVENUES" THAT IS SHOWN ON EXHIBIT WG (D)-5, THE WORKPAPERS FOR ADJUSTMENT 1—REVENUES, PAGE 1 OF 46, LINE 17?

A. This category includes miscellaneous revenues that have been outlined in the Revenue Study, Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 2 of 46. Examples of miscellaneous revenues include reconnection revenues and fees collected for dishonored checks. The test year level of these revenues is included in ratemaking revenues. I left reconnection revenues at test year levels because any change from test year levels of revenues would be offset by an equal change in the cost to perform the reconnection. Dishonored check costs for the test year are comparable to historic levels. Items included in the "Miscellaneous Service Revenues" category (Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 2 of 46, Lines 28-34) are set forth in the Company's tariffs. These revenues are reflected in ratemaking revenues at unadjusted, test year amounts. Refer to Exhibit WG (O) for discussion of the impact on changes in the miscellaneous services fees on rate year revenues.

Q. PLEASE EXPLAIN THE RENTS COMPONENT OF THE MISCELLANEOUS REVENUE ADJUSTMENT.

A. The rents component removes 50 percent of the rent received from the ground leases at the former East Station manufactured gas plant site. The Company is receiving revenues in connection with the real estate development of the East Station property. In the Opinion and Order on Remand in Formal Case No. 989 (Order No. 14104) the Commission affirmed that the 50/50 allocation of net revenues from the development of Maritime Plaza is reasonable and appropriate. This amount is computed in a supporting schedule to Adjustment 1—Revenues.[11]

Q. PLEASE DESCRIBE HOW THE SPECIAL CONTRACT REVENUES FOR THE ARCHITECT OF THE CAPITOL "AOC" AND GENERAL SERVICES ADMINISTRATION CENTRAL HEATING PLANT ("GSA CHP") ARE REFLECTED IN ADJUSTMENT 1—REVENUES.

A. AOC distribution revenues in the amount of $4.0 million[12] are treated as firm revenues for rate setting purposes. GSA CHP contract revenues of $3.8 million are treated as fully interrupted and returned to firm customers through the Distribution Charge Adjustment ("DCA") sharing mechanism and are therefore excluded from ratemaking revenues. Revenue taxes for both AOC and GSA CHP are also reflected in the adjustment. Below is a table of the special contract revenues and related expenses.

	AOC	GSA CHP	Total
Revenues			
Distribution Charge Revenues	$ 3,954,044	$ -	$ 3,954,044
Customer Charge Revenues	1,452	2,904	4,356
Total Firm Base Rate Revenues	$ 3,955,496	2,904	$ 3,958,400
DC Rights of Way Fee Revenues	481,639	852,265	1,333,904
Delivery Tax Revenues	1,073,238	1,899,159	2,972,427
Sustainable Energy Trust Fund	1,037,111	1,835,178	2,872,288
Energy Assistance Trust Fund	115,040	203,564	318,604
Total Non-gas Revenues	$ 6,662,553	$ 4,793,070	$11,455,623

[11] Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, Workpaper 5, page 29 of 46.
[12] Exhibit WG (D)-5, Adjustment 1, Page 5 of 46, Line 4, Column O.

Expenses

DC Rights of Way Fee Revenues	$ 481,639	$ 852,265	$ 1,333,904
Delivery Tax Revenues	1,073,238	1,899,159	2,972,427
Sustainable Energy Trust Fund	1,037,111	1,835,178	2,872,288
Energy Assistance Trust Fund	115,040	203,564	318,604
Total Expenses	$ 2,707,057	$ 4,790,166	$ 7,497,223

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO REVENUES.

A. The following is a summary of the ratemaking adjustments I made to revenues.[13]

Ratemaking Adjustments (Adjustment 1)	($ in Millions)
Sales and Deliveries	
Base Revenues	$ 27.6
Revenue Taxes	4.7
PROJECT*pipes*	(13.2)
Sales and Deliveries Subtotal	19.1
Other Operating Revenues	
Late Payment Fees	0.3
Other Book Ratemaking Adjustments	(0.04)[14]
Other Operating Revenue Subtotal	0.3
Total Ratemaking Adjustment	$ 19.4

[13] Refer to Exhibit WG (D) for a discussion of the distribution-only revenue adjustments.
[14] Maritime Plaza Rents ($41,088)

Revenue Related Expense Adjustments

Uncollectible Gas Accounts (Adjustment 1, Workpaper 9)

Q. PLEASE EXPLAIN WHY IT IS NECESSARY TO ADJUST THE COMPANY'S UNCOLLECTIBLE GAS ACCOUNTS EXPENSE.

A. Many factors influence the level of uncollectible gas accounts expense incurred by the Company during any given year, including the state of the economy and regional unemployment levels. By far, however, the factor that has the single greatest impact on the Company's level of uncollectible expenses is the level of revenues billed in any given year. As I discussed previously, the level of revenues billed by the Company is, in turn, dependent upon both weather and the cost of gas that is billed to consumers. Therefore, it is necessary to align the level of uncollectible gas accounts expense with weather-normalized revenues and to remove uncollectible gas accounts related to gas costs pursuant to the Commission-approved Gas Administrative Charge ("GAC") to present uncollectible account expense in distribution revenues only. Adjustment 2D—Gas Administrative Charges sponsored by Company Witness Tuoriniemi removes the GAC portion of uncollectible gas accounts expense.

Q. HOW DID YOU CALCULATE THE RATE MAKING ADJUSTMENT TO THE COMPANY'S UNCOLLECTIBLE GAS ACCOUNTS EXPENSE?

A. I began by calculating the accrual rate utilizing a five-year average percent of charge-offs to accrual base (2.7046 percent).[15] I then calculated the total ratemaking uncollectible gas accounts expense by applying this rate to the non-gas ratemaking revenues (2.7046 percent x $205,930,738 of revenues) which equals $5,569,603 non-gas ratemaking uncollectible gas accounts expense.

[15] Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 32 of 46.

The difference between the ratemaking calculation and the distribution-only per book balance reflects the need to increase the per book expense amounts by $1,038,168 ($5,569,603 ratemaking expense less $4,531,435 distribution-per book expense) to reflect ratemaking uncollectible gas accounts expense in the rate effective period.[16] The original per book revenues include uncollectible gas accounts expense related to both non-gas and gas revenues and the Purchase of Receivables ("POR"), while the ratemaking level reflects uncollectible gas accounts expense related to distribution revenues only.

Q. HOW DID YOU DEVELOP THE FIVE-YEAR ACCRUAL RATE?

A. To set a normal accrual rate, I used actual revenues for each of the five years ending March 31, 2024. I divided these amounts into monthly net charge-offs for the five-year period beginning April 2019 through March 2024, consistent with the methodology approved by the Commission in Formal Case Nos. 1016, 1093, and 1137.

<u>Sustainable Energy Trust Fund and Energy Assistance Trust Fund (Adjustment 1, Workpapers 12 and 13)</u>

Q. PLEASE DISCUSS THE SUSTAINABLE ENERGY TRUST FUND (SETF) AND ENERGY ASSISTANCE TRUST FUND (EATF) COMPONENT OF ADJUSTMENT 1—REVENUES.

A. Because the SETF and EATF are components of base rates discussed earlier, it is necessary to synchronize the related expense in the cost of service consistent with the treatment of the revenues. The ratemaking amount of SETF and EATF revenues, based on normal weather included in Adjustment 1—

[16] *See* Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 32 of 46.

Revenues, are $21,338,896 and $2,366,984 respectively.[17] SETF and EATF expenses during the test year were $16,761,017 and $2,156,914, respectively. The Sustainable Energy Trust Fund alignment increases expense by $4,577,879 ($21,338,896 - $16,761,017 = $4,577,879) and the Energy Assistance Trust Fund alignment decreases expense by $210,070 ($2,366,984 - $2,156,914 = $210,070) to synchronize the amounts with revenues.[18]

District of Columbia Delivery Tax and Rights-of Way Fees (Adjustment 1, Workpapers 10 and 11)

Q. PLEASE DEFINE THE TERM "PASS-THROUGH TAX" AND IDENTIFY THE PASS-THROUGH TAXES THAT AFFECT CUSTOMERS IN THE DISTRICT OF COLUMBIA.

A. A pass-through tax is a tax or fee that a utility is required to collect from customers by embedding an authorized surcharge in customers' bills. These tax and fee collections are then remitted to the appropriate authority. Because the Company's tax and fee payments offset the taxes collected in customers' bills, there is no permanent effect on utility operating income. Currently, there are two types of pass-through taxes that are embedded in customers' rates—the District of Columbia Delivery Tax and the Rights-of-Way fee.

Q. PLEASE EXPLAIN THE DISTRICT OF COLUMBIA DELIVERY TAXES COMPONENT.

A. Both the per book and ratemaking gross revenues shown in Exhibit WG (D)-1, include the District of Columbia delivery tax. This Adjustment is needed to offset the District of Columbia delivery tax embedded in

[17] Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, pages 37 and 38 of 46.
[18] CleanEnergy DC Omnibus Amendment Act of 2018 increased the rate per therm to $0.04515 for fiscal year 2020 through fiscal year 2023, and to $0.07515 thereafter. (D.C. Official Code § 8-1774.07)

Adjustment 1—Revenues discussed earlier. I calculated the ratemaking District of Columbia delivery tax by applying the District of Columbia's delivery tax rate per therm to the associated ratemaking weather-normalized sales and delivery therms. The current rate per therm applicable to residential and group metered apartment customers is \$0.07070 per therm. The applicable rate per therm for commercial, industrial, and interruptible customers is \$0.07777. The ratemaking adjustment is the difference between the ratemaking District of Columbia delivery tax of \$21,221,880 and the per book amount of \$18,979,968 or \$2,241,912.[19]

Q. PLEASE EXPLAIN THE DC RIGHTS-OF-WAY FEE.

A. The Rights-of-Way fee is collected from customers as a pass-through tax via a surcharge per therm that the Commission has authorized. Each year, the Company files a report with the Commission that reconciles revenue recovery to the taxes paid. The \$(2,608,389) adjustment included in the current case equals the current quarterly tax assessment annualized to arrive at the Company's ratemaking revenues of \$9,909,880, less the amount of per book Rights-of-Way fee for the twelve months ended March 31, 2024, of \$12,518,268.[20] This approach eliminates the effect of the Rights-of-Way fee from the revenue requirement.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

[19] Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 34 of 46.
[20] Exhibit WG (D)-5, the workpapers for Adjustment 1—Revenues, page 36 of 46.

ATTESTATION

I, KATINA BANKS, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Katina Banks

KATINA BANKS

07/18/2024

DATE

WITNESS SMITH
EXHIBIT WG (F)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

PUBLIC VERSION

DIRECT TESTIMONY OF TRACEY M. SMITH
Exhibit WG (F)
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DIRECT TESTIMONY OF TRACEY M. SMITH

Exhibit WG (F)
(Page 2 of 2)

Exhibits

WASHINGTON GAS LIGHT COMPANY

District of Columbia

DIRECT TESTIMONY OF TRACEY M. SMITH

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Tracey M. Smith. I am the Manager of Regulatory Accounting for Washington Gas Light Company ("Washington Gas" or the "Company"). My business address is 6801 Industrial Road, Springfield, VA 22151.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I graduated from the University of Oklahoma with a Bachelor of Arts degree in 1996. In 2001, I completed a Bachelor of Science in Accounting degree from the University of Phoenix and in 2006 I completed a Master of Accounting and Financial Management degree from Keller Graduate School of Management. In 2007, I obtained a Certified Public Accountant ("CPA") license in Arizona, and I currently hold a CPA license in Virginia.

I joined Washington Gas in April 2012 as Senior Specialist in the Operational Risk Assessment department where I performed Sarbanes-Oxley Act ("SOX") control risk assessments and testing for various areas of the Company. In November 2013, I joined the Regulatory Accounting department as a Senior Accountant. In that role, I assisted with the preparation of cost-of-service analyses such as the jurisdictional allocation study and the class cost of service study, as well as ratemaking and pro forma adjustments and revenue requirement calculations in support of the Company's cost of service witnesses in rate cases and for other required regulatory filings. In March 2020, I was promoted to my current position, Manager of Regulatory Accounting. In this role, I manage the preparation of the jurisdictional and class cost of service studies, ratemaking and pro forma adjustments, and the revenue requirement calculation.

Prior to joining Washington Gas, I worked for several non-utility companies in a variety of accounting and auditing roles. From 2000 to 2008, I worked at America West Airlines (now American Airlines) in various accounting functions, including Fixed Asset, Fuel (Inventory) Accounting, and General Accounting. In 2006, I transitioned to the General Accounting department as Senior Accountant & System Administrator where I performed various month-end close processes and administered the general ledger system.

From March 2008 to April 2012, I worked in internal audit for a pet-specialty retailer and for accounting firm KPMG. In these roles, I planned and performed financial and operational audits of various business processes and information systems, performed SOX control testing, conducted risk control assessments to identify control gaps, and suggested internal controls to mitigate risks.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA ("PSC" OR "COMMISSION") OR ELSEWHERE?

A. Yes, I have. I provided testimony in Formal Case No. 1169, a base rate case, before this Commission. Additionally, I provided testimony in base rate cases PUR-2022-00054 before the Virginia State Corporation Commission and Case No. 9704 before the Maryland Public Service Commission. Prior to sponsoring my own testimony in base rate cases, I worked under the direct supervision of Company Accounting and Cost of Service witnesses in the development and preparation of computations and studies in multiple base rate cases in each of the jurisdictions the Company serves.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to describe and support the Company's labor and labor-related accounting adjustments. I also describe and support the Company's Per Book Jurisdictional Cost of Service Study ("PBCOSA") and the Class Cost of Service Study ("CCOSS").

III. SUMMARY OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I sponsor the following five (5) exhibits:

- Exhibit WG (F)-1 – The Per Book Jurisdictional Cost of Service Study Narrative;
- Exhibit WG (F)-2 – The Per Book Jurisdictional Cost of Service Study;
- Exhibit WG (F)-3 – The Class Cost of Service Study Narrative;
- Exhibit WG (F)-4 – The Class Cost of Service Study;
- Exhibit WG (F)-5 – Class Cost of Service Study Workpapers.

The detailed workpapers associated with the labor and labor-related accounting adjustments that I support are included with all other cost of service adjustments in Exhibits WG (D)-3 and WG (D)-5 attached to Company Witness Tuoriniemi's direct testimony.

Q. HAVE YOU PROVIDED ANY ADDITIONAL INFORMATION THAT WILL ASSIST IN DEVELOPING A CLEARER UNDERSTANDING OF THE UNDERLYING JURISDICTIONAL AND CLASS COST STUDIES' COMPUTATIONS?

A. Yes, I have provided electronic copies of Exhibits WG (F)-2, (F)-4, and (F)-5, which are the supporting computations for each of these studies. Washington Gas agreed to provide this documentation with its next base rate application during the Technical Conference held in November 2019 to discuss class cost of service topics from Formal Case. No. 1137.[1] Furthermore, providing the electronic versions of my exhibits and supporting calculations is consistent with the Settlement in Formal Case No. 1162[2] and with the information provided in Formal Case No. 1169.

IV. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. I support the Company's labor-related accounting adjustments. The adjustments for labor expense as presented below are necessary so that the test year more accurately reflects labor costs that the Company will experience during the rate effective period. All the labor adjustments represent known and measurable adjustments to the test year. The historical test year amounts on

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[1] *In The Matter Of The Application Of Washington Gas Light Company For Authority To Increase Rates And Charges For Gas Service*, Formal Case No. 1137, Report on Technical Conference (February 5, 2020).

[2] *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*, Formal Case No. 1162, Order No. 20705, Attachment A, Page 7. (February 24, 2021).

their own are not representative of the costs the Company will face when rates in this case go into effect. Equally, labor is the most significant operating cost comprising the Company's cost of service. Therefore, for rates to properly reflect the cost of service, the adjustments I have proposed herein should be adopted. If inflation related to labor and benefits is not recognized, the Company will not have an adequate opportunity to earn its authorized return.

I also support the Per Book Jurisdictional Cost of Service Study, which utilizes the same allocation factors and methods approved in prior rate cases[3] to allocate costs among Washington Gas' three jurisdictions except for two allocation factor changes, which I discuss further below. The Commission should adopt the Company's Jurisdictional Cost of Service Study in this proceeding as it was prepared using a methodology previously approved by the Commission except for the two allocation factor changes.

Finally, I present and support the CCOSS that complies with Order No. 21939 in Formal Case No. 1169 by (1) using a 50/50 peak and annual composite factor to allocate mains investment costs for all customer classes, including interruptible and special contract customers,[3] and (2) classifying compressed natural gas ("CNG") customers in a separate category from all other commercial and industrial ("C&I") customers.[4] The peak and annual composite method is supported by both cost causation and utilization of the assets, and it represents a reasonable basis to allocate the cost of distribution mains to the individual customer classes. Therefore, the Commission should adopt the

[3] *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*, Formal Case No. 1169, Order 21939, Page 119 (December 22, 2023).
[4] Ibid.

Company's Class Cost of Service Study, discussed in Section VII, in setting rates in this case.

V. LABOR AND LABOR-RELATED ADJUSTMENTS

Q. DO THE LABOR AND LABOR-RELATED ADJUSTMENTS THAT YOU SUPPORT CONFORM TO PRECEDENT FOR THESE ADJUSTMENTS AS ESTABLISHED IN COMMISSION ORDER NO. 21939 IN FORMAL CASE NO. 1169?

A. Yes, the labor and labor-related adjustments that I discuss in detail below have been prepared using the methodologies approved by the Commission in Formal Case No. 1169, with the exception that, where appropriate, the adjustments have been updated to reflect the impact of the involuntary separation event that occurred in April 2024 reducing the Company's workforce. Additionally, I am proposing a medical plans cost inflation adjustment that was not proposed in the prior case and an adjustment to remove the per book salaries and related expenses for the former employees whose positions were eliminated in April 2024.[5]

Q. PLEASE SUMMARIZE THE TOTAL IMPACT OF THE LABOR AND LABOR-RELATED ADJUSTMENTS TO THE COST OF SERVICE IN THIS CASE.

A. The table below shows the net change in labor and labor-related expense based on the adjustments that I propose in this case.

Wages and Salaries[6]	$	1,001,057
Long-term Incentives[7]	$	(3,390,371)

[5] Refer to the Direct Testimony of Company Witness Steffes.
[6] Exhibit WG (D)-5 Adjustment 5
[7] Exhibit WG (D)-5 Adjustment 6.

OPEB Expense[8]	$	(630,366)
Pension Expense[9]	$	(565,665)
401(k) Expense[10]	$	79,796
Executive Fringe Elimination[11]	$	(39,094)
Medical Plans Inflation[12]	$	195,423
Involuntary Separation[14]	$	(1,978,270)
Total Labor and Labor-related Adjustments	$	(5,327,490)
Payroll Taxes[13]	$	(22,322)

Wages and Salaries (Adjustment 5)

Q. WHAT IS THE TOTAL PRO FORMA LABOR EXPENSE ADJUSTMENT YOU ARE PROPOSING FOR DISTRICT OF COLUMBIA OPERATIONS?

A. The pro forma adjustment to labor expense applicable to the District of Columbia is $1.0 million. Other than the cost for purchased gas, labor costs are the Company's most significant expense item. This proposed adjustment reflects: (1) an annualization of pay increases that occurred in the test year; (2) wage increases for union employees pursuant to current contracts; (3) salary increases for management employees that will occur within 12 months of the end of the test year in this case; and (4) an adjustment to normalize union ratification bonuses. The purpose of including these components is to present known and measurable wages and salaries at levels consistent with what the Company will incur in the rate effective period.

[8] Exhibit WG (D)-5 Adjustment 7.
[9] Exhibit WG (D)-5 Adjustment 8.
[10] Exhibit WG (D)-5 Adjustment 9.
[11] Exhibit WG (D)-5 Adjustment 10.
[12] Exhibit WG (D)-5 Adjustment 11.

Q. IS THE COMPANY'S LABOR ADJUSTMENT FOLLOWING PRECEDENT FROM FORMAL CASE NO. 1169?

A. Yes. The labor adjustment uses the approved methodology and approved update periods that the Commission adopted in Formal Case No. 1169, with one exception. I discontinued the elimination of per book payroll expenses for the three (3) Damage Prevention employees whose payroll costs were funded by AltaGas Ltd. pursuant to Merger Commitment No. 7 in the Company's Merger Case (Formal Case No. 1142).

Q. HOW DID YOU CALCULATE BASIC ANNUALIZED PAYROLL?

A. I started with the Company's total test year payroll, excluding items not related to base pay[13] for the 12 months ended March 31, 2024. From this, I subtracted the payroll amounts for the former employees whose positions were eliminated.[14] This step is necessary to avoid calculating incremental salary expense on payroll costs that will not exist in the rate effective period in this case. Because this revised payroll amount does not include the full annual effect of salary and wage increases that occurred during the test year, such as contractual union increases and management merit and market increases, an annualization adjustment is necessary to reflect the salary and wage expense that the Company will experience in the rate effective period. For management and each union bargaining unit, I segregated the effect of the test year increases on test year payroll; then I annualized the increase amounts. The effect of this part of the adjustment is to annualize the pay increases that occurred in the test year.

[13] The items not related to base pay are primarily reimbursements for mileage, meals, vehicle use, and flexible spending accounts for medical or dependent care.
[14] Refer to Exhibit WG (D)-5 Adjustment 5, pages 14 and 15 for details of this calculation.

Q. HOW WERE UNION WAGE INCREASES THAT WILL OCCUR SUBSEQUENT TO THE TEST YEAR CALCULATED?

A. I increased union wages based on the contractual wage increases that will occur prior to the rate effective period. There are five unions that represent collective bargaining units at the Company. The Company's contracts with each of these unions specify a schedule for wage increases. As each contract presents a legal obligation, these scheduled wage increases are known and measurable. To calculate this part of the adjustment, I multiplied the annualized payroll for the applicable union by the contractual wage increases that occur within 12 months of the end of the test year in this case.[15]

Q. HAVE YOU INCLUDED ANY INCREASES FOR MANAGEMENT EMPLOYEES BEYOND THE TEST YEAR?

A. Yes. regular pay increases will occur in January 2025, which is within 12 months of the end of the test year as approved by the Commission in the prior rate case.[16] Thus, the Company knows that management wages and salaries will be higher than what is represented in the test year. As a result, I increased management wages and salaries by the expected increases that will be granted in January 2025. Like the union increases, this increase is known and measurable. To calculate this part of the adjustment, I multiplied the annualized payroll for management employees by the expected increase percentage. I estimated the increase percentage using an historical three-year average.

Q. WHAT LEVEL OF EMPLOYEES DID YOU USE IN THE ADJUSTMENT?

A. The basic payroll information from the test year assumes an average of the employee count during the test year. I have not adjusted the level of

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[15] Formal Case No. 1169, Order No. 21939, page 62, paragraph 209.
[16] *Id.*

employees in the test year. However, as stated above, I have removed the payroll costs associated with the organizational redesign to avoid including wages and salaries for these former employees. This along with the cost reductions reflected in Adjustment No. 13, which I discuss in detail below, effectively adjusts employee count to reflect the expected level of headcount in the rate effective period. No additional headcount adjustments are warranted.

Q. DOES THE LABOR ADJUSTMENT INCLUDE ANY AMOUNTS FOR SHORT-TERM INCENTIVES?

A. Yes, short-term incentives are a component of total employee compensation and are included in the test year gross payroll used in this adjustment. The Commission, in Order Nos. 17132, 18712, and 21939, approved the inclusion of short-term incentives in the cost of service. Therefore, this adjustment also conforms to precedent.

Q. DOES THE LABOR ADJUSTMENT INCLUDE ANY AMOUNTS FOR LONG-TERM INCENTIVE COMPENSATION?

A. No, there are no amounts for long-term incentives included in this adjustment. I have removed test year long-term incentive compensation expense in Adjustment No. 6.

Q. PLEASE SUMMARIZE ADJUSTMENT 5—WAGES AND SALARIES.

A. I took each of the amounts computed above, which were done on a system basis, and allocated them to the District of Columbia jurisdiction using an apportionment factor of 19.36 percent, which is the District of Columbia direct labor allocation factor. I also computed the amount applicable to operation and maintenance ("O&M") expense by applying the 75.53 percent O&M allocation factor. The net total of all the adjustments for pro forma incremental expense was $1.0 million. I then allocated a portion of the total pro forma adjustment to maintenance expense using a factor of 35.66 percent, which was computed using total per book direct labor charged to maintenance accounts as a percentage of total book direct labor costs.

Long-term Incentive Compensation Elimination (Adjustment 6)

Q. PLEASE DESCRIBE ADJUSTMENT 6—LONG-TERM INCENTIVE ELIMINATION.

A. While the Company maintains that expense for long-term incentives ("LTI") is a component of total, reasonable compensation, competitive with the market, and are necessary to attract and retain talent, the Company will not pursue recovery of these costs in rates at this time. Therefore, in compliance with Commission precedent from Formal Case No. 1169, I have eliminated the per book LTI expense of $3.4 million on a DC jurisdictional basis. Therefore, no cost for LTI related to financial performance measures is included in the Company's DC cost of service.

Q. WHY HAVE YOU NOT EXCLUDED ANY PORTION OF SHORT-TERM INCENTIVE COMPENSATION FROM THE COST OF SERVICE AS THE COMMISSION DECIDED IN FORMAL CASE NO. 1169?

A. In the prior rate case, the Commission eliminated a portion of STI recovery because of issues with the Company's call center performance in 2020 and 2021. The remaining STI costs were determined to be "reasonable, competitive, and beneficial to ratepayers."[17] The 2023 scorecard, attached to Company Witness Steffes's Direct Testimony as Exhibit WG (A)-1, supports inclusion of 100% of

[17] Formal Case No. 1169, Order No. 21939, page 69, paragraph 231.

STI in the cost of service and the Company's call center quality has improved.[18] Therefore, no elimination of STI expense is necessary in this case.

Other Post-Employment Benefits ("OPEB") and Pension Costs (Adjustments 7 and 8)

Q. PLEASE DESCRIBE ADJUSTMENT 7—OPEB COSTS.

A. Adjustment No. 7 adjusts the per book amounts included in the test year related to OPEB expense to amounts expected to be incurred in the rate effective period, which is the methodology prescribed by the Commission.

Q. HOW ARE THE AMOUNTS RECORDED FOR OPEB EXPENSE COMPUTED?

A. Each year, the Company's actuary, Willis Towers Watson, completes an actuarial study to determine the periodic cost of the Company's OPEBs. The actuarial study is prepared in accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 715-60, *Compensation-Retirement Benefits—Defined Benefit Plans-Other Postretirement* ("ASC 715-60"). The Company uses the actuarial study as the basis for recording OPEB expenses.[19]

Q. PLEASE DESCRIBE HOW YOU COMPUTED THE OPEB ADJUSTMENT PROPOSED IN THIS FILING.

A. I used the estimated 2024 expense per Willis Towers Watson as the basis for the total system OPEB costs.[20] After allocating a portion of the total to Hampshire Gas, I arrive at system OPEB expense of *****BEGIN CONFIDENTIAL**

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[18] Refer to Direct Testimony of Company Witness Steffes (Exhibit WG (A)) for call center performance discussion.

[19] The relevant expense page of the study is included in Exhibit WG (D)-5, Adjustment No. 14.

[20] The final Willis Towers Watson actuarial report for 2024 was not available at the time of this filing. I will update this adjustment when the report is made available.

[redacted] **END CONFIDENTIAL***** These calculations result in the District of Columbia's share of OPEB expense on a ratemaking basis totaling ($7.8) million. I subtracted from this amount the per book amount of ($6.6) million. This generates a ratemaking adjustment to **DECREASE** per book expense by $0.6 million.

Q. PLEASE DESCRIBE ADJUSTMENT 8—PENSION EXPENSE.

A. Similar to the OPEB adjustment, Adjustment No. 8 adjusts the per book amount included in the test year related to pension expense to amounts expected to be incurred in the rate effective period. While the Company's compensation philosophy is to provide total compensation that is competitive with the market, which includes retirement benefits and deferred compensation, this adjustment, in accordance with Commission precedent,[23] also removes 100% of the Defined Benefit Supplemental Employee Retirement Plan ("DB SERP"), Defined Benefit Restoration Plan ("Restoration Plan"), and the Defined Contribution SERP ("DC SERP).[24]

Q. HOW ARE THE AMOUNTS RECORDED FOR PENSION COSTS COMPUTED?

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[21] The OPEB plans generate income, which I state in testimony as negative expense, reflecting the way it is shown in the Federal Energy Regulatory Commission ("FERC") statements.

[22] The O&M factor for both pension and OPEB expense is based on how these benefits were allocated during the test year. The amount distributed out of O&M is lower than overall labor expense because of the adoption of Accounting Standards Update 2017-07, which permits capitalization of only the service component of actuarial expense.

[23] Formal Case No. 1169, Order No. 21939, page 34, paragraph 108 (the Company's pension expense was uncontested).

[24] The Company maintains that total compensation is a necessary and reasonable expense, and total pension expense including SERP should be included in the cost of service. However, the Company is not pursuing recovery of SERP at this time.

A. As with OPEBs, an actuarial report is performed each year by the Company's actuary to determine the periodic cost of the Company's pension benefits. The actuarial study is prepared in accordance with FASB ASC 715-30, *Compensation-Retirement Benefits—Defined Benefit Plans-Pension* ("ASC 715-30"). The Company uses the actuarial study as the basis for recording pension expenses.

Q. PLEASE DESCRIBE HOW YOU COMPUTED THE PENSION ADJUSTMENT PROPOSED IN THIS FILING.

A. I used the 2024 expense per Willis Towers Watson as the basis for total system pension costs. After allocating a portion of the total to Hampshire Gas and removing 100% of the DB and DC SERP and Restoration Plans, I arrive at the total system amount of *****BEGIN CONFIDENTIAL***** [redacted] *****END CONFIDENTIAL***** to determine the District of Columbia amount, ($0.608) million. Finally, I subtracted the District of Columbia pension expense per book amount of ($42,494) from the rate year amount, resulting in a ($0.566) million ratemaking adjustment reflecting a pension expense **DECREASE** versus the per book amount.

Q. HAVE YOU ADJUSTED OPEB OR PENSION EXPENSE FOR THE INVOLUNTARY SEPARATION PROGRAM?

A. Not at this time. The Company engaged Willis Towers Watson to analyze the impact of the involuntary separation program. The analysis showed that the organizational redesign did not have a material impact on post-retirement benefits and did not trigger curtailment accounting in accordance with ASC 715 for either the OPEB or pension plans. Any change in future expenses due to the involuntary separation program is not expected to be material and will be captured in the remeasurement of the plan liabilities at year-end.

401(k) Expense (Adjustment 9)

Q. PLEASE DESCRIBE THE 401(K) ADJUSTMENT.

A. As the Company presented in Formal Case No. 1169, I adjusted the Company contributions to the Company's 401(k) plans. Consistent with Commission Order No. 21939, I have applied the growth factor for 12 months post-test year. The Company contributions are affected by total wages and salaries, as well as greater employee participation in the enhanced benefit portion of the plans; therefore, the change in labor costs reflected in Adjustment 5—Wages and Salaries, as well as greater employee participation, must be accounted for here to appropriately adjust known and measurable expenses to the level of costs that will be incurred during the rate effective year.

Q. PLEASE DESCRIBE THE COMPANY'S 401(K) PLANS.

A. The Company maintains two 401(k) plans: one for management employees and one for union employees. As their titles suggest, both plans are 401(k)-type qualified pension, profit-sharing, and stock bonus plans as defined in the Internal Revenue Code ("IRC"). All management employees are eligible to participate in the Washington Gas Savings Plan 401(k) program for management employees; and all union employees are eligible to participate in the Washington Gas Capital Appreciation Plan 401(k) program for union employees. In both plans, the Company matches 100% of the first 4% of the pre-tax contributions of employee salaries.

Beginning on January 1, 2009, the 401(k) plan began to provide a benefit specific to employees who are no longer eligible to participate in the Company's

Defined Benefit Pension Plan or elected to cease accruing benefits under the pension plan. For these eligible management and Teamsters Local 96 employees, the Company makes an automatic contribution between 4% and 6% of the employee's pay, based on years of service. For all other union employees, the automatic contribution is 4% of their compensation. The automatic contribution is in addition to the Company's matching of employee contributions.

Q. HOW DID YOU CALCULATE THE 401(K) ADJUSTMENTS?

A. First, I calculated the average annual growth rate of 401(k) expense for the twelve months ended March 2022, 2023, and 2024. To account for the employees whose positions were eliminated, I reduced the test year 401(k) expense by $0.6 million before calculating the annual growth from March 2023 to March 2024. I applied the average growth rate to the test year per book 401(k) expense, reduced by the $0.6 million related to the employees whose positions were eliminated. The result of these calculations is that the Company will contribute an incremental amount of $0.5 million on a system-wide basis for both 401(k) plans. After applying the O&M factor and District of Columbia labor allocation factor, the incremental 401(k) benefits expense is $80,000.

Q. WHY IS THIS METHOD REASONABLE FOR ESTIMATING FUTURE 401(K) EXPENSE?

A. Given the plan change that occurred in 2009, more employees over time are eligible for the enhanced benefit. The change in the mix of employees eligible for the enhanced benefit versus the pension plan continues to shift as employees eligible for the pension plan retire and as the Company's workforce changes. To appropriately reflect the increase in eligibility for the enhanced benefit, it is necessary to use recent historical growth to estimate future expenses. Eventually, as employees currently eligible for the pension plan leave the

Company or retire, this growth rate will return to aligning with annual growth in payroll.

Employee Fringe Expense Elimination (Adjustment 10)

Q. PLEASE EXPLAIN ADJUSTMENT 10—EMPLOYEE FRINGE BENEFITS ELIMINATION.

A. While the Company maintains that certain executive fringe benefit expenses are a component of total, reasonable compensation, competitive with the market, and necessary to attract and retain talent, the Company will not pursue recovery of these costs in rates at the present time. Therefore, in compliance with Commission precedent from Formal Case No. 1169, I have removed the costs related to executive fringe benefits. After applying the O&M factor and the District of Columbia allocation factor to the system total expense for these items, test year expense is decreased by $39,094.

Medical Plans Inflation (Adjustment 11)

Q. PLEASE DESCRIBE THE MEDICAL PLANS ADJUSTMENT (ADJUSTMENT 11).

A. Adjustment 11—Medical Plans Inflation adjusts the cost of the Company's medical plans to capture accurately the cost of these plans in the rate effective period. The adjustment is based on an analysis of historical medical cost inflation and supported by the Company's Human Resources ("HR") Department annual plan renewals. The estimates provided by our service providers and from independent studies show higher medical inflation rates than used in the adjustment.[25]

[25] Refer to Exhibit WG (D)-5 Adjustment 11 page 4 for additional detail.

To calculate the adjustment, I applied the inflation factor recommended by the HR Department to the test year expense for the medical plans, adjusted to remove the employer portion of medical costs for the employees whose positions were eliminated in April 2024. After applying the O&M factor and District of Columbia allocation factor, this adjustment increases test year medical plans expense by $195,423.

Q. WHY IS IT APPROPRIATE TO REFLECT MEDICAL PLAN INFLATION IN THE DEVELOPMENT OF THE REVENUE REQUIREMENT?

A. The Company maintains self-insured medical plans and has experienced inflation in the cost of providing these benefits to employees. In addition, the Company's HR Department reviews and approves annual benefit plan costs including a review of the expected increase in the cost of the medical plans based on a combination of actual claims experience and studies of medical cost inflation provided by outside experts. Adopting this adjustment will appropriately reflect the cost of these plans expected to be incurred in the rate effective period.

Payroll Taxes Adjustment (Adjustment 12)

Q. PLEASE EXPLAIN ADJUSTMENT 12—PAYROLL TAXES.

A. As a result of adjusting the Company's total labor expense, it is also necessary to adjust the payroll tax expenses that are based on labor expense. As reported by the Social Security Administration, the tax rates for Federal Insurance Contribution Act ("FICA") and Medicare are 6.20% and 1.45%, respectively, and the maximum taxable earnings for social security was $160,200 in 2023. To determine the wage base subject to FICA, I calculated the ratio of calendar year 2023[26] Social Security earnings to total calendar year 2023 payroll.

[26] The latest calendar year for which information was available at the time this testimony was filed.

I then applied this ratio to the incremental labor adjustment to determine the Social Security wage base. Finally, I applied the payroll tax rates to the relevant wage base to determine the level of incremental FICA and Medicare taxes to be adjusted in the rate effective period totaling $22,322.

Involuntary Separation Program Labor Expense Adjustment (Adjustment 13)

Q. PLEASE DESCRIBE THE INVOLUNTARY SEPARATION PROGRAM LABOR O&M EXPENSE ADJUSTMENT.

A. As discussed by Company Witness Steffes, in April 2024 the Company eliminated approximately 70 positions as part of the involuntary separation program. Adjustment 13 removes the test year per book amount of salaries and wages, short-term incentive compensation, and employer portion of benefits O&M[27] costs based on the actual amounts incurred for these costs. This adjustment, for the District of Columbia jurisdiction, is a ($2.0) million **DECREASE** in the cost of service. It is appropriate to make this adjustment because these reduced employee-related costs are known and measurable and will not occur in the rate effective period proposed in this case. The cost of implementing the involuntary separation program is discussed by Company Witness Tuoriniemi.

VI. JURISDICTIONAL ALLOCATION STUDY

Q. WHAT IS THE PER BOOK JURISDICTIONAL COST OF SERVICE STUDY AND WHAT IS ITS PURPOSE?

A. The PBCOSA assigns or allocates the total test year cost of service to each of the three jurisdictions in which the Company operates. The study starts

[27] No adjustment has been made for capital costs or costs charged to capital expenditures or affiliates.

with the amounts recorded on the books of the Company. As the Company uses the Federal Energy Regulatory Commission Uniform System of Accounts ("USOA"), the per book amounts are functionalized. These amounts are either directly attributable to a jurisdiction or common to the entire distribution system. Common costs are allocated based on a relevant cost driver. The result is a per book cost of service by jurisdiction. The ratemaking cost of service is determined by applying adjustments to the District of Columbia test year derived from the PBCOSA.

Q. HAVE YOU PREPARED A JURISDICTIONAL ALLOCATION STUDY IN THIS PROCEEDING USING THE SAME METHODS AS PRIOR DC RATE CASES?

A. Yes, I have, except for two allocation factor changes I discuss below.

The methodology I used to prepare the study was approved in at least the last six rate cases, and most recently in Formal Case No. 1169. The study continues to follow precedent for determining allocations and allocating costs; and therefore, continues to be appropriate in determining the District of Columbia cost of service. The assignment and allocation of all elements of the cost of service are presented in Exhibit WG (F)-2. Exhibit WG (F)-1 includes a detailed narrative describing the allocations.

Q. PLEASE DESCRIBE DIRECTLY ASSIGNED COSTS AND ALLOCATED COSTS.

A. Costs directly assigned to a jurisdiction are those that specifically and solely serve customers in that jurisdiction. Most rate base is directly assigned by jurisdiction. For example, the cost of situs plant, which serves only customers in a particular jurisdiction, is directly assigned in the PBCOSA to the jurisdiction where that plant is located. In contrast, common plant, which serve all customers across the entire distribution system in Maryland, Virginia, and the District of

Columbia, is an allocable cost. Examples of common plant include transmission plant and storage facilities that serve all jurisdictions. These costs are allocated in the jurisdictional study.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE ALLOCATIONS DESCRIBED IN DETAIL IN EXHIBIT WG (F)-1.

A. The allocation factor used for any cost in the study is determined by the underlying driver of that cost. The allocation factors used in the current case are consistent with those used in prior cases, except for two new allocation factors.

In rate base, common plant is allocated by one of three main allocators: a composite of peak and annual usage, total throughput, or based on the distribution of situs plant. As examples, transmission mains are allocated on the composite peak and annual factor; storage is allocated on total throughput; and general plant is allocated based on situs plant.

Most revenues are directly assigned because they are billed jurisdictionally according to the tariffs applicable to each jurisdiction. Miscellaneous allocable revenue[28] amounts are generally allocated on actual firm throughput as they relate to gas costs.

O&M expenses are generally allocated based on the underlying plant or activity to which they relate. For example, administrative and general ("A&G") expenses are typically allocated on either the assignment of direct labor, a composite A&G factor, or a three-part factor known as the Modified Massachusetts Method.

Q. PLEASE DESCRIBE THE CHANGES MADE IN THE JURISDICTIONAL ALLOCATION STUDY SINCE FORMAL CASE NO. 1169.

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[28] Currently, only Rent from Gas Property revenues are being allocated. All other revenues are directly assigned to a jurisdiction.

A. I have made two substantive changes to the PBCOSA related to new allocation methods.

First, I created a new allocation factor base on the average accounts receivable balances for each jurisdiction[29] and applied this factor to the allocable portion of customer collections costs.[30] In the prior rate case (Formal Case No. 1169), total allocable customer collections costs were allocated based on the ratio of meters in each jurisdiction. During calendar year 2021, 97% of the customer credit costs were not booked to a specific jurisdiction and required allocation. A review of the small amount of costs that were directly assigned showed that using the ratio of directly assigned costs by jurisdiction was not a reasonable allocation methodology because the count of meters in each jurisdiction does not represent the cost driver for these expenses. The change I propose here more closely aligns the allocation of customer collection costs to the actual underlying cost driver (*i.e.*, accounts receivable balances).

Second, I have disaggregated the expenses associated with customers paying their bills by credit or debit card from other allocable customer collection expenses.[31] The breakout of credit and debit card transaction fees was based on a review of vendor invoices to determine the total costs incurred for the test year. Then I created a new allocation factor based on the count of card transactions for each jurisdiction[32] and applied this factor to the card transaction costs.[33] In the prior rate case (Formal Case No. 1169), card transaction fees were allocated based on the average number of meters in each jurisdiction. I

[29] Refer to Exhibit WG (F)-2, Schedule AL Page 4 of 5, Line 43 for details of this calculation (AVG_AR).
[30] Refer to Exhibit WG (F)-2, Schedule EX Page 7 of 10, Line 13 for details (EX 7:13).
[31] Refer to Exhibit WG (F)-2, Schedule EX Page 7 of 10, Lines 15 and 16 (EX 7:15 and EX 7:16).
[32] Refer to Exhibit WG (F)-2, Schedule AL Page 5 of 5, Line 32 for details of this calculation (CREDIT_DEBIT_CARD).
[33] Refer to Exhibit WG (F)-2, Schedule EX Page 7 of 10, Line 16 for details (EX 7:16).

have made this change to be consistent with a requirement in Virginia that credit and debit card transaction fees should be allocated to the jurisdictions using the ratio of the count of card transactions rather than meter counts for each jurisdiction.[34]

Q. PLEASE EXPLAIN THE RESULTS OF THE JURISDICTIONAL ALLOCATION STUDY APPLIED IN THIS PROCEEDING.

A. The allocations of rate base, operating revenues, and operating expenses for the test year are presented in Exhibit WG (F)-2. When I apply the allocation study to the test year financial data, the analysis computes the DC jurisdictional test year results. The assignment for situs property and the allocation factors reflect the results of the study.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE JURISDICTIONAL COST OF SERVICE STUDY?

A. I recommend that the Commission adopt this study and the allocations contained therein for the purpose of determining the jurisdictional cost of service in DC. The general methodology used to develop the study has been approved[35] and used in numerous past rate case proceedings and continues to be reasonable and appropriate for use in this proceeding.

VII. CLASS COST OF SERVICE STUDY

Class Study Purpose

Q. WHAT IS THE PURPOSE OF A CLASS COST OF SERVICE STUDY?

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[34] *Application of Washington Gas Light Company, For authority to increase existing rates and charges and to revise the terms and conditions applicable to gas service pursuant to § 56-237 of the Code of Virginia*, Case No. PUR-2018-00080, Report of Michael D. Thomas, Senior Hearing Examiner at 104 (September 16, 2019).

[35] The PBCOSA was last approved in Formal Case No. 1169.

A. A CCOSS further breaks down the ratemaking jurisdictional cost of service by customer class and is instructive in designing rates. The Company does not track costs by customer class. Therefore, a CCOSS is necessary to allocate costs to customer classes and develop the cost to serve individual customer classes. Exhibit WG (F)-3 provides a narrative description of the allocations in the study and explains how to utilize the electronic version of the CCOSS, and Exhibit WG (F)-4 details the results of the CCOSS in this case.

The CCOSS shows the components of rate base, revenues, and operating expenses as they have been assigned or allocated to the various DC customer classes. In addition, the CCOSS presents a rate of return for each class based on these components and shows which classes are over or under earning compared to the total DC jurisdictional earned return percentage.

The CCOSS also functionalizes and classifies costs. The study uses the functionalization from the PBCOSA for per book amounts, and ratemaking and pro forma adjustments are functionalized when added to the CCOSS to calculate the fully embedded cost of service. The classification of each cost as customer, commodity, or demand determines the class allocation factor to be applied. The Cost Categorization pages of the CCOSS summarize the cost of service by cost category and high-level function.

Cost Categories and Allocations

Q. PLEASE BRIEFLY EXPLAIN THE THREE CATEGORIES OF COSTS AND HOW THE CLASSIFICATION IS PRESENTED IN THE COMPANY'S CCOSS.

As described by the National Association of Regulatory Utility Commissioners' ("NARUC") *Gas Distribution Rate Design Manual*, costs can generally be classified into three categories:

- Customer-related costs vary based on the number of customers served rather than the amount of utility service supplied. Customer-driven costs include metering and meter reading expense; customer billing, collecting, and accounting expense; and capital investment related to metering equipment and service connections.[36]
- Commodity/usage costs vary based on the quantity of gas used. Purchased gas cost is an example of an expense that is usage-related.[37]
- Demand/capacity costs vary with the size or quantity of plant or equipment. These costs relate to maximum system design components that are intended to serve for short intervals (such as very cold, high usage days) and do not vary due to the number of customers or therm usage.[38]

The classification of costs is presented on the Cost Categorization schedules of the CCOSS. The classification was determined based on the cost driver associated with each account and is further detailed in Schedule CC of Exhibit WG (F)-4.

Q. HOW ARE COSTS ASSIGNED IN THE CCOSS?

A. To the extent possible, revenues, operating expenses, and rate base are directly assigned by class. Any components that cannot be directly assigned are allocated to the various DC customer classes based on allocation factors that are developed within the study.

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[36] NARUC *Gas Distribution Rate Design Manual* (June 1989), Page 22.
[37] NARUC *Gas Distribution Rate Design Manual* (June 1989), Page 23.
[38] NARUC *Gas Distribution Rate Design Manual* (June 1989), Pages 23-24.

In the CCOSS presented in this case, operating revenues and certain other related components are directly assigned by class, as developed in Adjustment 1–Revenues, supported by Company Witness Banks.[39] In addition to customer sales revenues, forfeited discounts, reconnect revenues, returned check charges, service initiation charges, and field collection charges, the CCOSS directly assigns Right-of-Way ("ROW"), Sustainable Energy Trust Fund ("SETF"), Energy Assistance Trust Fund ("EATF"), and Delivery Tax revenues. Finally, an estimate of the distribution service investment cost applicable to the interruptible, special contract, compressed natural gas ("CNG"), and combined heat and power ("CHP") customers has been used to directly assign those costs. All other components are allocated based on the underlying cost drivers.

Q. WHY IS IT NECESSARY TO ALLOCATE MANY COMPONENTS OF THE CCOSS?

A. Some jurisdictional assignment methodologies cannot be readily extended to a class cost of service allocation. For example, distribution plant is directly assigned to the jurisdiction in which it is physically located. In the Company's records, capital costs are maintained by jurisdiction, but not by individual customer class. Thus, when considering a particular item of distribution plant, such as meters installed on customers' property, it is necessary to depart from the jurisdictional allocation study and find another basis for apportioning the total jurisdictional cost among the various customer classes.

In those instances where it is necessary to depart from the jurisdictional allocation study, I allocated the components using factors that were developed by the Company to conduct its class cost of service study in prior cases, unless

[39] Refer to WG (D)-5 Adjustment No. 1—Revenues for detailed workpapers.

otherwise noted. For example, I assigned meter costs by determining, for each type of meter, the average original cost per meter and cross-referenced the data with customer records that indicate the type of meter installed for each customer.

Q. WHAT ARE THE MAJOR ALLOCATORS USED IN THE CCOSS?

A. The major allocators in the CCOSS are customers and usage (a combination of normal weather throughput and peak usage). Because some costs, such as common plant, cash working capital, and general and administrative costs are not easily assigned to a single cost type, it is necessary to develop composite, or blended, factors to allocate these costs.[40] Consequently, I have also used blended factors to allocate those types of costs that have multiple cost drivers. An example of a blended factor is the total labor factor, a composite factor composed of various other factors that rely on number of customers, usage, and demand drivers. The allocations are also defined and calculated in Exhibit WG (E)-6 on Schedule AL.

Changes to the CCOSS from Formal Case No. 1169

Q. DOES THE CCOSS FILED IN THIS CASE COMPLY WITH THE COMMISSION ORDER IN FORMAL CASE NO. 1169?

A. Yes, it does. The CCOSS filed in this case uses the same methodologies as that presented in the prior rate case, with two exceptions. In Formal Case No. 1169, Order No. 21939, the Commission ordered that distribution mains costs be allocated using an equal weighting of peak day and annual usage for all classes, and include interruptible customers and special contract customers.[41] Further, the Commission ordered that CNG customers be classified in the CCOSS

[40] NARUC *Gas Distribution Rate Design Manual* (June 1989) Page 25.
[41] Formal Case No. 1169, Order No. 21939 at 118-119 (paragraph 406).

separately from other commercial and industrial customers.[42] The version of the CCOSS that I have filed in this case complies with both of these requirements. No other changes were made.

Reconciling Differences Between CCOSS and Other Studies

Q. ARE THERE RECONCILING DIFFERENCES BETWEEN THE CCOSS AND OTHER STUDIES?

A. Yes, there are four differences between the CCOSS and other studies presented in this case.

First, unlike the CCOSS, interruptible customer distribution revenues are not included in Exhibit WG (D)-5, Adjustment No. 1–Revenues. This creates a reconciling difference in net operating income between the income statement summary of Exhibit WG (D)-1 and the CCOSS of $12.1 million. This difference is attributable to including 100% of interruptible customer class distribution revenues in the CCOSS, as required by this Commission in Order No. 18712, in Formal Case No. 1137.[43]

Second, the non-firm peak day therm usage calculated for the interruptible and special contract customer classes in the Normal Weather Study is excluded from the calculation of the peak day usage factor in the CCOSS.[44]

Third, the ARO asset and liability that are removed in the CCOSS are included in the rate base schedule presented by Company Witness Tuoriniemi in Exhibit WG (D)-1, Page 2 of 4. Although net rate base is the same in both schedules, Gas Plant in Service and Reserve for Depreciation are both lower in the CCOSS than in Exhibit WG (D)-1. Workpapers 4 and 5 included in Exhibit

[42] Formal Case No. 1169, Order No. 21939 at 119 (paragraph 408).
[43] Formal Case No. 1137, Order No. 18712 at 120-121.
[44] Refer to Exhibit WG (F)-4, Schedule AL, Page 2, Line 5 for details of this calculation.

WG (F)-5 provide detailed reconciliations between the CCOSS and Normal Weather Study and the CCOSS and Exhibit WG (D)-1, Pages 1 and 2 of 4.

CCOSS Results and Recommendations

Q. PLEASE DESCRIBE EXHIBIT WG (F)-4.

A. This exhibit contains a summary of the class cost of service results for Washington Gas' DC customers, in addition to 30 pages of the study. The first page summarizes the results of the study, including the return earned by each customer class. The other pages detail the allocations of rate base, revenues, expenses, and income taxes in the same format as the PBCOSA. The final four pages summarize costs by category (customer, demand, and commodity). As with the PBCOSA, the allocation pages demonstrate how each allocation factor was developed. The reference column on the study pages refers to the allocation factor used.

Q. WHAT DOES THE CCOSS SHOW AND WHAT IS YOUR RECOMMENDATION?

A. The CCOSS shows that one (1) class is earning close to the system average rate of return, six (6) classes are earning below the system average, and six (6) customer classes are earning above the system average.

I recommend the Commission adopt the Company's CCOSS, Exhibit WG (F)-4, because it provides a reasonable estimate of class rates of return.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

Washington Gas Light Company
District of Columbia
Per Book Jurisdictional Cost of Service Allocation Study ("PBCOSA")

Description of Allocation Procedures

General

This exhibit discusses the allocation to District of Columbia of the rate base, operating revenue and operating expense per book amounts using weather normalized therm sales for the twelve months ended March 31, 2024. This allocation is necessary because some of the Company's property is planned, constructed, and operated on a system basis even though physically located in three separate jurisdictions - the District of Columbia, Maryland, and Virginia.[1] This "common use" property and related expenses pertain to various major facilities, which happen to be located in one or another of the jurisdictions but are used to serve all jurisdictions. Similarly, it is necessary to determine the share of total operating revenues, operating expenses, and other deductions from revenues that properly relate to each jurisdiction.

Schedule SM, consisting of two (2) pages, shows an earnings statement using data from the following schedules discussed below. Schedule ETR, consisting of (1) page, relates to the reconciliation of flow-throughs, permanent, and other tax adjustments, and shows the development of the effective tax rate among the four jurisdictions. Schedule RB, consisting of twelve (12) pages, relates to the allocation of rate base among the jurisdictions. Schedule RV (2 pages) relates to the determination of operating revenues. Schedule EX, consisting of ten (10) pages, relates to the allocation of operating expenses. Schedule AL, consisting of five (5) pages, relates to the development of allocation factors. Schedule FERC Alloc (3 pages) relates to the development of allocation factors for the FERC jurisdiction. Schedule WEX, consisting of (13) pages, relates to workpapers support.

In general, all the schedules are formatted in a similar manner. Column A is a description of the item. Columns D, E, F, G and H show the System (WG), District of Columbia (DC), Maryland (MD), Virginia (VA), and Federal Energy Regulatory Commission (FERC) jurisdictional amounts, respectively. Column B lists one of three sources by schedule, page, and line number. First, if an item is directly assigned, it will be designated as 'Financial Stmt.' in Column C. Second, if the item is developed on another schedule, the reference to that schedule, page and line number will be indicated. Finally, if an item is allocated, the source of the allocation factor will be listed in Column B. An allocated item also has the name of its allocator listed in Column C. For clarity, a naming convention is used that provides a brief description of the allocator. The schedules relating to the development of allocation factors, as shown in Schedule AL, have the same basic format as the other schedules, with two

[1] The Federal Energy Regulatory Commission jurisdiction represents a single customer in West Virginia served through Virginia's situs transmission system

exceptions: 1) column C shows the name of the allocator being developed; and 2) columns H, I, and J show the allocation factors for DC, MD, and VA, respectively.

SCHEDULE SUMMARY (SM)

Earnings Statement

The Summary page (Schedule SM Page 1) is an income statement that consists of all the allocated amounts of rate base, operating revenues, and operating expenses that were carried forward to Schedule SM, to reflect an earnings statement by jurisdiction.

Schedule SM Page 2 determines the effective tax rate calculation of the Company.

SCHEDULE EFFECTIVE TAX RATE RECONCILIATION (ETR)

The Effective Tax Rate reconciliation is a schedule used to verify that jurisdictional income tax is explained by income tax at the statutory rates adjusted by flow- through, permanent items, and prior period adjustments. The tax items are detailed here to confirm tax adjustments are properly allocated to the respective jurisdictions.

Line 1 begins with the taxable income that is derived from Schedule SM, Page 2, Line 8.

Line 5 (AFUDC Equity) is allocated to DC and MD based on the Adjusted CWIP factor developed on Schedule AL, Page 3, Line 14.

Line 6 (Excess Deferred) is assigned to the appropriate jurisdictions based on the Company's tax provision system.

If applicable, Meals and Entertainment (Line 7), Compensation Limitations (Line 10), and Parking (Line 16) are allocated based on the labor factor shown on Schedule AL, Page 4, Line 11.

Capitalized OPEB (Line 12) is directly assigned to District of Columbia and Maryland.

Prior Period Flow-Through Income Tax – Reg. Asset (Line 14), and Charitable Contributions (line 15) are directly assigned to Virginia.

Other Tax Adjustments (Line 17) is allocated based on taxable income, if applicable.

Investment tax credit (Line 19) originates from Schedule SM, Page 2, Line 6.

The total tax and effective tax rate from the reconciliation reconciles to Schedule SM, Page 2, Line 9 by the jurisdiction.

SCHEDULE RATEBASE (RB)

Rate Base

<u>Schedule RB Page 1</u>

Schedule RB, Page 1 summarizes the per book elements of net rate base at March 31, 2024.

Lines 1-6 shows the division among the four jurisdictions based on the rate base descriptions. Column B indicates where the division is developed. As an example, for Line 1 (Gas Plant in Service), the supporting calculations are shown on Schedule RB, Page 3, Line 17.

Lines 7 (FC 1027 Rate Base CWIP Reg Asset) and 8 (Unamortized East Station Cost) are directly assigned to District of Columbia.

Line 10 (Cash Working Capital) is calculated using the lead/lag method detailed on Schedule RB, Pages 7 through 9.

Gross Rate Base is shown on Line 11 of Schedule RB, Page 1.

The balance of lines 13 - 24 items represent deductions made from gross rate base to arrive at net rate base.

Line 13 shows the depreciation reserve balance. As detailed on Schedule RB, Page 10, Line 35, the depreciation reserve is assigned directly by function and jurisdiction. Line 14 shows accumulated deferred income taxes attributable to depreciation. The amount shown is summarized and jurisdictionalized on Schedule RB, Page 11.

Lines 15, 16, and 17 show the accumulated deferred income taxes attributable to the Gain or Loss on Reacquired Debt allocated by the Net Rate Base allocator developed on Schedule AL, Page 3, Line 6.

Lines 18, 19, and 20 show the Net Operating Loss Carryforward for Federal and State and the Net Operating Loss Federal Benefit of State. These lines are allocated on the Net Rate Base allocator developed on Schedule AL, Page 3, Line 6.

Line 21 shows Customer Advances for Construction. This amount consists of refundable advances made by customers to install distribution facilities. These amounts are tracked by jurisdiction and, therefore, are directly assigned.

Customer Deposits (Line 22) and Supplier Refunds (Line 23) are directly assigned to their respective jurisdiction. Line 24, Deferred Tenant Allowance, is allocated on the Non-General Plant allocator (Schedule AL, Page 2, Line 23) and is related to the tenant allowance at the Wharf, Tysons, and Maritime Plaza.

Line 26 shows Net Rate Base balance after deducting Line 25 from Line 11.

Schedule RB Page 2

Schedule RB Page 2, Depreciable Gas Plant in Service, details the development of jurisdictional amounts relating to depreciable property. Note that "common use" property contains capitalized AFUDC for all four jurisdictions.

Line 2 shows the allocation of capitalized software using the Non-General Plant allocator shown on Page 2 of Schedule AL at Line 23.

Line 3 shows the allocation of the plant balance for storage properties. These facilities are required during the winter season to supply customers' requirements. Since the need for these facilities is directly related to the weather-sensitive gas requirements of our customers, the investment is allocated on each jurisdiction's annual weather gas requirements. The development of these factors is shown on Page 1 of Schedule AL at Line 19.

Line 16 shows total Transmission Plant in service for the company. This plant has been segregated into six elements. Line 8 shows the amount for Spur Lines and Related Regulating Equipment and Structures. These facilities serve exclusively the areas where they are located and, therefore, were assigned to the jurisdictions on a situs basis. WSSC (Line 9), Chalk Point Plant (Line 10), and Panda (Line 11), are assigned directly to Maryland. Both Chalk Point and Panda Brandywine are power plants located in Maryland. WSSC is a water and wastewater utility in Maryland that receives gas from Washington Gas and can inject renewable natural gas into the Company's distribution system.

Other transmission properties, shown on Line 12, are facilities used to transport gas into Washington Gas's system from connections with the pipelines of the Company's gas suppliers. These facilities, which are common to the entire system, meet both peak day and annual requirements of our customers. For that reason, the investment is allocated using a composite factor based on equal weighting of design day and annual sales factors for each jurisdiction. The composite factor is shown on Line 28 of Page 1 in Schedule AL. The Maryland Interruptible Customer Plant shown on Line 14 is situs property assigned to Maryland. AFUDC on Line 15 assigned to Virginia to reflect Virginia's ratemaking treatment.

Line 18 of Page 2, Schedule RB, shows an investment in compressor station equipment and related structures. This equipment represents compressor station equipment and related structures and improvements common to the system, such as, telemetric receivers and alarms located at the Springfield Operations Center. The distribution compressor station equipment pumps gas during the winter, and the telemetric receivers and alarms monitor the distribution system. Accordingly, these costs are allocated based on the annual weather gas factor.

Distribution plant facilities, mains, services, meters, house regulators, and gas light services (Lines 19-28), serve the jurisdiction in which they are installed. Therefore, these amounts are assigned on a situs basis. Maryland Interruptible Customer Plant shown on Line 29 is assigned to Maryland. AFUDC on Line 30 is assigned to Virginia to reflect Virginia's ratemaking treatment.

General Plant shown on Lines 33, 34, and 36, is allocated based on the allocation of all other properties. In arriving at the factors used to allocate General Plant, the amounts for storage, transmission, and distribution plant are added to obtain the totals for such properties for the system and for each jurisdiction. From these totals, the allocation factors are developed by dividing the amount for each jurisdiction by the system total. Details of the development of the factors are shown on Schedule AL, Page 2, Line 23. Other–Direct on Line 35 consists of miscellaneous equipment and Enscan equipment.

The system total of Depreciable Gas Plant in Service is shown on Line 42.

<u>Schedule RB Page 3</u>

Schedule RB Page 3 relates to non-depreciable property. Intangible Plant shown on Line 2 consists of organizational expense and has been allocated on the same basis as general plant described above. Other non-depreciable plant shown on Lines 3 through 13, including land and land rights, is detailed by function and allocated on the same basis as the related depreciable plant. Total non-depreciable Gas Plant in Service is shown on line 15.

<u>Schedule RB Page 4</u>

Schedule RB Page 4 relates to Gas Plant Held for Future Use. There are currently no amounts recorded to these accounts.

<u>Schedule RB Page 5</u>

Schedule RB Page 5 relates to Construction Work in Progress. The system total is detailed by function and allocated on the same basis as the related functional gas plant in service items.

<u>Schedule RB Page 6</u>

Schedule RB Page 6 includes materials and supplies. Materials and supplies consists of the average inventory balances of: (1) General Supplies used for construction and operation; (2) oil and propane stock; and (3) storage gas purchased from natural gas suppliers to meet our customers' winter usage requirements.

Column C of Page 6 shows the factor used to allocate the various materials and supplies components among the jurisdictions. First, the general supplies inventory is segregated between construction and operations based on the apportionment shown in Footnote 1. Construction supplies are allocated based on actual stores issued for construction in each jurisdiction during the test period. The allocation factor for construction supplies is shown on Schedule AL, Page 3, Line 2. General supplies for operations are allocated on the basis of annual therm sales, shown on Schedule AL, Page 1, Line 20.

Fuel stock, consisting of propane inventory used for peak shaving operations, is allocated based on firm annual weather gas requirementsfor each jurisdiction. The factors for this allocation are shown on Schedule AL, Page 1, Line 2.

The inventory cost of storage gas purchased on Line 10 relates to the gas purchased from our suppliers for use in serving customers during the winter season. The inventory cost allocation is based on the annual weather gas factor. The fuelstock materials – hexane, on Line 11, is allocated based on annual weather gas factor. The total for materials and supplies, shown on Line 12, is carried forward to Schedule RB, Page 1, Line 5.

<u>Schedule RB Pages 7-9</u>

Schedule RB Pages 7-9 relates to cash working capital in the respective jurisdictions District of Columbia, Maryland, and Virginia. Cash working capital consists of the different lead lag studies that are applied to revenue and expenses.

<u>Schedule RB Page 10</u>

Schedule RB Page 10 relates to the reserves for depreciation. The schedule follows a similar format to Schedule RB Page 2 for depreciable property.

Line 2 shows the allocation of capitalized software using the Non-General Plant allocator shown on Page 2 of Schedule AL at Line 23.

Line 4 reflects an amortization reserve deficiency of capitalized software for Maryland that is based on Commission Order No. 83139, Case No. 9103.

Line 6 includes storage reserves that are directly assigned to the respective jurisdictions.

Line 21 shows the total reserves for transmissions and are assigned directly to the respective jurisdictions, except for reserve for transmission asset retirement obligation ("ARO") which is allocated on the composite peak and annual usage factor shown on Schedule AL, Page 1, Line 28 .

Line 27 shows the total reserves for distribution plants facilities. These amounts are directly assigned based on the assignment of situs property. Interruptible Customer Plant on Line 24 is assigned to Maryland.

Line 33 shows the total reserves for general plant. The allocable portion uses the same allocation factor as the related depreciable property. Amounts reflected on line

32 are the rebalancing of general plant reserves based on Maryland Public Commission Order No. 83139, Case No. 9103.

Schedule RB Page 11

Schedule RB Page 11 shows Accumulated Deferred Income Taxes ("ADIT") related to the Company's gas plant in service. These amounts are categorized in Company's tax provision system and are primarily allocated using the Modified Accelerated Cost Recovery System ("MACRS") method for current federal taxes, based on the Company's tax provision system.

Excess Deferred Gross Up (Line 13), Amortization of Excess Deferred (line 15), and Deferred Income Taxes (Line 19) are directly assigned from the Company's tax provision system.

Schedule RB Page 12

Schedule RB Page 12 shows Accumulated Deferred Income Taxes ("ADIT") related to temporary differences other than depreciation. Each temporary difference uses either a specific allocator or is directly assigned to a jurisdiction.

Line 1 is allocated based on the total normal weather allocation factor that is shown on Schedule AL, Page 1, Line 19.

Lines 2 and 7 are all non-plant items that are directly assigned to their respective jurisdictions based on the Commission's order.

Lines 3, 8, 12, and 15 are allocated based on the total labor allocation factor that is shown on Schedule AL, Page 4, Line 11.

Lines 4, 6, 11, and 16 are allocated based on Net Rate Base allocation factor that is shown on Schedule AL, Page 3, Line 6.

Line 5 is allocated based on the total uncollectible account expense by jurisdiction.

Line 9 is allocated based on the adjusted CWIP allocation factor that is shown on Schedule AL, Page 3, Line 14.

Line 10 is allocated based on the gas cost recovered allocation factor that is shown on Schedule AL, Page 5, Line 31.

Line 14 is allocated based on the total of all non-general plant factor that is shown on Schedule AL, Page 2, Line 23.

Line 17 is allocated using the Modified Accelerated Cost Recovery System ("MACRS") method for current federal taxes, based on the Company's tax provision system.

SCHEDULE REVENUE (RV)

Operating Revenues

Schedule RV Page 1

Schedule RV, Page 1 summarizes the total operation revenues for the system and each jurisdiction. Line 13 of Page 1 shows revenues from gas sales and transportation sales which are directly assigned to each jurisdiction.

Total Other Operating Revenues (Line 34) consists of revenues from forfeited discounts, rent from gas property, miscellaneous service revenues, and other gas revenues relating principally to compressed natural gas ("CNG"), margins from off system sales, and other miscellaneous revenues. These are primarily directly assigned based on billing. Rent from gas properties is allocated on actual firm therm sales, and off-system sales is reclassified from gas purchased, Schedule EX, Page 3. Total operating revenues is shown in Column D, Line 35.

Schedule RV Page 2

Schedule RV, Page 2 shows the transportation revenues by customer class and by jurisdiction. This information is then summarized and reflected on Schedule RV, Page 1, Line 7 plus Line 8.

SCHEDULE EXPENSE (EX)

Operating Expenses

Schedule EX Page 1

Schedule EX, Page 1 details Total Operating Expenses and summarizes these expenses. Schedule EX Pages 2-10 provides the detail of how these amounts are developed.

Total Operating Expenses shown on Line 14 are the sums of the various expenses as allocated.

Schedule EX Page 2

Schedule EX, Page 2 shows the allocation of expenses which are designated as Operation Expenses. Beginning with gas purchased, shown on Line 2 of Page 2 has been analyzed by components of cost and allocated to jurisdictions as shown on

Schedule EX, Page 3.

Line 3 shows Purchased Gas Expenses, consisting of costs principally related to gas odorization, are allocated on annual therm sales, adjusted for propane.

Line 4 reflects Purchased Gas Expenses that are directly assigned.

Line 5 reflects Purchased Gas Expenses - Hexane directly assigned to Virginia.

Line 6 reflects Purchased Gas Expenses – Chalk Point directly assigned to Maryland.

Line 7, propane holding expense, is allocated on the total weather gas requirements of our firm customers. This factor is developed on Schedule AL, Page 1, Line 2.

Lines 8 through 12 show production and storage operations expenses. These costs, incurred to meet weather gas requirements of our customers, are allocated based on the firm weather gas factor. As shown on Line 8, costs related to Watergate is directly assigned to the District of Columbia.

Line 13, Transmission expenses, are allocated to the four jurisdictions based on Transmission Plant in Service. This factor is developed on Schedule AL, Page 2, Line 8.

Transmission expenses related to Chalk Point and PANDA are shown on Lines 14 and 15 and are directly assigned to Maryland.

Lines 17 through 37 relate to distribution expenses. Supervision and engineering applicable to the Distribution Department is allocated on: (1) the operating expense of mains, measuring and regulating station equipment; and (2) the maintenance expense of mains, services, meters and regulator installations, measuring and regulating station equipment and gas light services. On Line 20, the allocable portion of the supervision and engineering of Appliance Service Department operations is allocated based on the cost of related meter servicing and other services on customer premises. This factor is developed on Schedule AL, Page 5, Line 6. For other departments of supervision and engineering expenses (Line 21) are allocated based on Distribution Plant in Service, this factor is developed on Schedule AL, Page 2, Line 22.

Line 22 represents load dispatch expenses. These costs represent checking, maintaining and controlling distribution pressures, are allocated using composite factors for design day and annual volumes. This factor is developed on Schedule AL, Page 1, Line28.

As shown on Line 23, any expenses related to Chalk Point are directly assigned to Maryland.

Expenses related to the operation of compressor station equipment, mains, and measuring and regulating station equipment shown on Lines 24, 25, 29 and 30 are allocated on the same basis as the respective property balances.

Costs related to removing and resetting meters are shown on Line 27 and 28. Line 27 represents the portion of those costs assigned directly to the jurisdiction where the costs were incurred. Any allocable costs shown on line 28 are allocated based on the underlying property.

Costs related to services on customer premises are shown on Line 31. Line 31 represents the portion of those costs assigned directly to the jurisdiction where the costs were incurred. Any allocable amounts shown on line 32 are allocated based on the assignment of direct costs.

Office Expenses applicable to the Transmission and Distribution Department (Line 34) are allocated based on: (1) the operating expense of mains, measuring and regulating station equipment; and (2) the maintenance expense of mains, services, meters and regulator installations, measuring and regulating station equipment and gas light services. For other departments, the office expenses shown on Line 37 are allocated based on Distribution Mains in Service from Schedule AL Page 2, Line 16.

Rents (Line 38) are principally for rights-of-way for gas Lines. These costs are assigned directly to the jurisdictions to which they apply.

Expenses related to customer accounts (Line 39) are detailed on Schedule EX, Page 7.

Customer Service and Information Expense (Line 40) consists principally of costs related to informational bill inserts sent to all Washington Gas customers. As such, this expense is allocated based on average meters. This factor is develop on Schedule AL, Page 4, Line 12.

Sales expenses shown on Line 42 are also allocated based on average meters.

The allocation of administrative and general expenses is detailed on Schedule EX, Page 5.

<u>Schedule EX Page 3</u>

Schedule EX Page 3 details the development of Gas Purchased expenses. Line 5 shows the total purchased gas cost and Propane Gasified on a system basis (Column D) and by jurisdiction (Columns E, F, G and H).

<u>Schedule EX Page 4</u>

Schedule EX Page 4 reflects maintenance expenses of the assets. Line 2 shows storage maintenance expenses. These expenses incurred are to maintain the

Company's storage facilities. These expenses are allocated based on annual weather gas shown on Schedule AL, Page 1 at Line 19.

Line 3, Transmission Maintenance Expenses, are allocated to the four jurisdictions based on Transmission Plant in Service. This factor is shown on Schedule AL, Page 2, Line 8.

Transmission maintenance expenses that consist of structures and improvements and maintaining the measuring and regulating station equipment are related to Chalk Point and PANDA. Lines 4 through 9 are directly assigned to Maryland.

Lines 11 through 25 relate to distribution maintenance expenses. Maintenance of mains, services, meter and house regulating station equipment, measuring and regulating station equipment, general DIMP expenditures and gas light services are shown on Lines 11, 12, 13, 14, 15, and 18 are assigned based on actual charges to those accounts.

Compressor station expenses (Line 16) is allocated using the same factor used to allocate the related plant amounts, annual weather gas. This factor is shown on Schedule AL, Page 1, Line 19.

Measuring and regulating station equipment expense (Line 17) is allocated based on its associated plant balance.

Meter and house regulator expense (Line 19) and supervisor and engineering appliance service expense (Line 21) is allocated based on meter and house regulator expense.

On Line 22, the allocable portion of the supervision and engineering of other department operations is allocated based on the cost of related distribution mains. This factor is developed on Schedule AL, Page 5, Line 25.

Other Equipment – Allocable, line 24, is allocated based on the direct assignments of distribution operating and maintenance expenses. This factor is developed on Schedule AL, Page 5, Line 17.

Line 25, Maintenance of General Plant, is allocated using the same factor that underlying plant was allocated on. This factor is developed on Schedule AL, Page 2, Line 26.

Line 26 showing total maintenance expenses and Line 27 showing total operation expenses of are summarized on EX. Page 2.

<u>Schedule EX Page 5</u>

Schedule EX Page 5 consists of administrative and general expenses.

Lines 8, 9 and 14 include those expenses that are directly related to labor activity and consist of expenses for pension and labor related employee benefits. These expenses are allocated to the jurisdictions based on all other labor allocated to the jurisdictions. This factor is developed on Schedule AL, Page 4, Line 11.

Lines 3, 5, 17, 20, and 30 include Administrative and General Salaries, Office Supplies and Expenses, Rate Case Expenses, General Advertising Expenses and Miscellaneous General Expenses that are allocated based on a composite A&G Factor that is computed on Schedule AL, Page 4, Line 23.

Outside Services (Line 6) are allocated to the individual jurisdictions based on a three-part factor consisting of: 1) Net Rate Base; 2) Annual Therm Sales; and 3) Operation and Maintenance expenses excluding gas purchased, uncollectible accounts, administrative and general expenses (A&G) and Watergate expenses. The development of this factor is shown on Schedule AL, Page 5 at Line 30.

The remaining Administrative and General items listed on Schedule EX, Page 5 are directly assigned.

<u>Schedule EX Page 6</u>

Schedule EX Page 6 reflects the depreciation expenses of storage, transmission spurlines and equipment, distribution equipment that are directly assigned to the jurisdictions.

<u>Schedule EX Page 7</u>

On Schedule EX Page 7, each item consists of a direct assignment and an allocated portion. The direct assigned amounts are shown on Lines 2, 5, 8, 12, 14, 18, and 19. The allocated amounts are explained below.

- General supervision expenses (Line 3) are allocated based on a composite of meter reading, applications and orders, collecting and billing and accounting expenses, after the assignment of direct charges incurred by the jurisdiction. This factor is developed on Schedule AL, Page 4, Line 10.

- Meter read expenses (Line 6), applications and orders (Line 9), other collecting expenses (Line 15) and billing and accounting expenses (Line 20) are allocated on average customer's meters. This factor is developed on Schedule AL, Page 4, Line 12.

- Collection expenses (Line 13), applicable to our Credit and Appliance Service Departments, relate primarily to efforts to collect delinquent gas accounts and are allocated based on the average accounts receivable factor on Schedule AL, Page 4, Line 43.

- Credit and Debit Card Transactions expenses (Line 16) are allocated based on the debit/credit card transaction counts by jurisdiction. This factor is developed on Schedule AL, Page 5, Line 32.

<u>Schedule EX Page 8</u>

Schedule EX Page 8 shows the allocation of General Taxes.

Property taxes shown on Line 2 are assigned by function and jurisdiction. Property taxes attributable to Chalk Point (Line 3) and PANDA Brandywine (Line 5) are assigned directly to Maryland.

Gross receipts taxes (Line 8) and DC Rights-of-Way Fee (Line 9) are assigned directly to each jurisdiction.

FICA taxes (Line 10), Medicare taxes (Line 11) and Unemployment Taxes (Line 12) are allocated based on total labor expenses. This allocation factor is shown on Schedule AL, Page 4, Line 11.

Montgomery County Fuel Energy Tax (Line 13) and St. Mary's County Fuel Energy Tax (Line 14) both apply entirely to Maryland.

Federal Excise Tax shown on Line 17 is allocated based on total labor expense as developed on Schedule AL, Page 4, Line 11. This item relates primarily to public liability insurance which uses the same factor.

DC Sustainable Energy Trust Fund (Line 18), DC Energy Assistance Trust Fund (Line 19), and DC Natural Gas Trust Fund (Line 20) apply to the District of Columbia.

Miscellaneous other taxes on Line 22 include use taxes and other miscellaneous taxes and are directly assigned by jurisdiction; miscellaneous other taxes (Line 23) are allocated on net rate base.

The total for General Taxes by jurisdictions is shown on Line 24 and carried forward to Line 8 of Schedule EX Page 1.

<u>Schedule EX Page 9</u>

Schedule EX Page 9 is an allocation of Interest. Bank interest loans (Lines 2 through 8), amortization of debt discount expenses (Line 9), amortization of gain/loss on reacquired debt (Line 10, and other interest expenses (Line 19) are allocated based on Net Rate Base. This factor is developed on Schedule AL, Page 3, Line 6.

AFUDC is allocated on adjusted construction work in progress. This factor is developed on Schedule AL, Page 3, Line 14.

Interest expenses which consist of AFUDC (Line 22), supplier refund interest (Line

24), interest expenses relating to DC carrying cost (Line 25), and customer deposit interests (Line 27) are removed to reflect an actual interest expense for the cost of service study.

Schedule EX Page 10

Schedule EX Page 10 reflects the Income tax expenses. Current federal income and state current income taxes are reflected on lines 2 and 3, respectively. Current income taxes are allocated to jurisdictions based on the ETR schedule, ETR Page 1. Deferred income taxes related to plant items are shown on lines 6 and 7. Deferred income taxes related to non-plant items are shown on lines 10 and 11. Deferred taxes are assigned directly to their respective jurisdictions based on the Company's tax provision system. Investment tax credit adjustments, shown on line 14, are directly assigned to their appropriate jurisdictions. Total income tax expense is reflected on line 24.

SCHEDULE WORKPAPERS (WEX)

WORKPAPERS

Workpapers are primarily supporting schedules used to develop deferred income tax assignments and develop the labor allocation factor for Schedule AL. Workpapers related to income taxes are presented but are not currently being used to develop factors within the study.

Schedule WEX Page 1 - Schedule WEX Page 9

Collectively, Schedule WEX Page 1 through Schedule WEX Page 9 are workpapers that segregate labor amounts from the total expenses shown in the EX schedules. The workpapers follows the same format and allocation methodology as the related Expense Schedules (Schedule EX). Schedule WEX, Page 3, Lines 28 and 29 differentiates labor expenses based on direct and indirect labor amounts. Direct Labor amounts from Schedule WEX Page 3, Line 28 is used to develop the labor allocation factor in Schedule AL Page 4 Line 11.

Schedule WEX Page 10

Schedule WEX Page 10 is a workpaper used to develop an adjustment to exclude depreciation expenses for transportation and power-operation equipment from the calculation of cash working capital in Schedule RB Pages 7-9.

SCHEDULE ALLOCATION FACTORS (AL)

Factors

Schedule AL Page 1

Schedule AL Page 1 generate factors based on the Normal Weather Study. Allocators generated from the study are related to firm normal weather, annual firm sales, annual firm delivery, all weather gas, firm annual pipeline, peak day based on weather and base gas, and composite annual peak.

Schedule AL Page 2

Schedule AL Page 2 are allocation factors based on Gas Plant in Service. Allocators generated from the study are related to transmissions, meters and house regulators, mains, plant distribution, non-plant excluding Chalk Point and depreciable and non-depreciable Gas Plant in Service.

Schedule AL Page 3

Schedule AL Page 3 is similar to Schedule AL Page 2 where the factors are derived from Gas Plant in Service. The allocators that are generated are related to construction supplies issued from store stocks, net rate base, construction work in progress, Net-Gas Plant in Service and adjusted construction work in progress.

Schedule AL Page 4

Schedule AL Page 4 is developed based on Operation and Maintenances expenses. The allocators that are generated are related to direct collection expenses, customer accounts, direct labor, average meters, and total O&M expenses excluding purchased gas. Composite A&G factor is generated by a combination of other factors that consists of O&M adj, the three-part factor, labor, average meters, distribution field operations, annual normal weather, Net Gas-Plant In Service and expenses that are assigned directly.

Schedule AL Page 5

Schedule AL Page 5 is a continuation from Schedule AL Page 4. Additional factors are generated for meters, appliance services, distribution field operations formains and services, distribution factors for maintenance expenses, gas cost, and credit and debit card fees.

The Three-Part factor is developed based on 1) Net Rate Base, 2) Annual therm sales, and 3) Operation and Maintenance expenses excluding gas purchased, uncollectible accounts, administrative and general expenses (A&G) and Watergate expenses.

SCHEDULE FERC ALLOCATION (FERC AL)

FERC Allocation

The FERC allocation schedule consists of three (3) pages and is a study used to allocate costs to the FERC jurisdiction. This jurisdiction represents the service to a local distribution company, Mountaineer Gas, located in West Virginia. This customer is served at the border of Virginia by situs transmission plant located in Virginia.

Schedule FERC Allocations Page 1

The schedule generates factors bases on rate base and consists of Gas Plant in Service, transmission plant, construction work in progress and customer advances for constructions.

Schedule FERC Allocations Page 2

Schedule FERC Allocations Page 2 are allocated based on 3-day peak and throughput measurements from the Nineveh and Clearbrook Gate Stations. The schedule generates a composite peak factor for the FERC jurisdiction by averaging the 3-day peak and throughput therms sales.

Schedule FERC Allocations Page 3

Schedule FERC Allocations Page 3 are allocated based on operating and maintenance expenses. The direct labor allocator is generated for the FERC jurisdiction.

SCHEDULE MACRS APB 11 ALLOCATION (MARCS AL)

MACRS Allocation

MACRS Allocation

The MARCS allocation schedule consists of one page. This allocation factor is used to allocate certain accumulated deferred income tax items on the rate base schedule. The factor is based on the level of annual amortization of the timing difference associated with the election of accelerated depreciation for tax purposes on eligible plant.

Washington Gas Light Company
Income Statement Summary -- Combined
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operating Revenues**	RV:1:34		$ 1,608,715,831	$ 276,904,880	$ 677,942,095	$ 650,536,019	$ 3,332,837
2	Operating Expenses							
3	Gas Purchased	EX:2:2		$ 454,828,378	$ 64,262,645	$ 200,704,535	$ 189,861,198	$ -
4	Operation - Other than Gas Purchased	EX:2:3>44		322,051,962	61,031,214	137,950,468	122,960,170	110,110
5	Maintenance	EX:4:26		114,413,313	25,568,839	46,799,501	41,961,616	83,356
6	Depreciation	EX:6:22		135,410,640	23,907,431	41,034,291	70,456,187	12,731
7	Amortization of Capitalized Software		Financial Stmt.	21,433,284	3,757,163	8,810,769	8,785,972	79,380
8	Amortization of Chalk Point / MD Post 1989 Inter		Financial Stmt.	94,718	-	94,718	-	-
9	Amortization of General Plant			14,127,280	1,878,281	5,415,781	6,833,217	-
10	Amortization of Unrecovered Plant Loss Chillum		Financial Stmt.	-	-	-	-	-
11	Interest on Customer Deposits	EX:1:6		528,578	41,769	128,646	358,163	-
12	Interest on Supplier Refunds	EX:1:7		73,600	11,533	31,581	30,486	-
13	General Taxes	EX:8:24		171,665,153	58,992,535	88,254,140	24,335,027	83,452
14	Other Income Taxes	EX:10:23	Financial Stmt.	13,182,317	756,509	5,234,557	7,027,005	164,246
15	Expenses Before Federal Income Taxes	=3>14		$ 1,247,809,223	$ 240,207,920	$ 534,458,986	$ 472,609,042	$ 533,275
16	Federal Income Tax Expense	EX:10:22		$ 50,043,363	$ 2,871,897	$ 19,871,685	$ 26,676,264	$ 623,518
17	ITC Adjustment	EX:10:22		(305,994)	(90,913)	(108,018)	(107,064)	-
18	Loss- Disposition of Utility Plant		Financial Stmt.	451,758	100,274	351,484	-	-
19	Total Operating Expenses	=15 > 17		$ 1,297,998,351	$ 243,089,178	$ 554,574,138	$ 499,178,242	$ 1,156,793
20	Net Operating Income	=1-18		$ 310,717,480	$ 33,815,702	$ 123,367,957	$ 151,357,777	$ 2,176,044
21	Net Income Adjustments							
22	AFUDC	AL:3:14	ADJ_CWIP	1,259,101	467,443	791,658	-	-
23	LCP Equity Accrual			-	-	-	-	-
24	Net Operating Income - Adjusted	19+21-22+23		$ 311,976,581	$ 34,283,145	$ 124,159,615	$ 151,357,777	$ 2,176,044
25	Net Rate Base	RB:1:26		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952
26	Return Earned	=24 / 25		7.28%	4.22%	7.83%	8.14%	7.84%

Effective Tax Rate Calculation
Per Book Cosa
Twelve Months Ended March 2024 - AVG

Description	----- Reference ----- Sc-Pg-Ln		WG	DC	MD	VA	FERC
A	B	C	D	E	F	G	H
1 Net Operating Income - Adjusted	SM:1:24		$ 311,976,581	$ 34,283,145	$ 124,159,615	$ 151,357,777	$ 2,176,044
2 Interest expense per Cost of Service			100,062,947	19,142,496	37,235,816	43,684,636	-
3 Income Taxes:							
4 Federal Income Taxes	SM:1:16		$ 50,043,363	$ 2,871,897	$ 19,871,685	$ 26,676,264	$ 623,518
5 Other Income Taxes	SM:1:14		13,182,317	756,509	5,234,557	7,027,005	164,246
6 ITC Adjustment			(305,994)	(90,913)	(108,018)	(107,064)	-
7 Total Income Taxes	= 4>6		$ 62,919,686	$ 3,537,493	$ 24,998,224	$ 33,596,205	$ 787,764
8 Pre-Tax Income	= 1-(2+7)		274,833,320	18,678,142	111,922,024	141,269,347	2,963,808
9 Effective Tax Rate	= 7 / 8		**22.89%**	**18.94%**	**22.34%**	**23.78%**	**26.58%**

Exhibit WG (F)-2
Schedule ETR
Page 1 of 1

Washington Gas Light Company
ETR Calculation by Jurisdiction
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Ln.		System			DC			MD			VA			Ferc		
		Basis	Tax rate	Taxes	Basis	Tax rate	Taxes	Basis	Tax rate	Taxes	Basis	Tax rate	Taxes	Basis	Tax rate	Taxes
		274,833,320			18,678,142	18,678,142		111,922,024	111,922,024		141,269,347	141,269,347		2,963,808	2,963,808	
					-			-			-			-		
1	**Taxable Income Before Permanent Items**	274,833,320	26.58%	73,049,193	18,678,142	26.58%	4,964,548	111,922,024	26.58%	29,748,262	141,269,347	26.58%	37,548,620	2,963,808	26.58%	787,764
2	Flow-Through, Permanent Items, and Other Tax Adjustments															
3	Depreciation	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
4	Cost of Removal	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
5	AFUDC Equity	-	0.02%	50,092	70,134	0.10%	18,608	118,666	0.03%	31,484	-	0.00%	-	-	0.00%	-
6	Excess Deferred	-	-2.73%	(7,509,698)	-	-5.41%	(1,010,925)	-	-3.17%	(3,551,810)	-	-2.09%	(2,946,963)	-	0.00%	-
7	Meals and Entertainment	-	0.09%	253,970	184,959	0.26%	49,073	410,911	0.10%	109,022	361,359	0.07%	95,875	-	0.00%	-
8	Medicare Part D	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
9	FAS 123 R - write off	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
10	Non-deductible executive compensation under 162(m) (Perm item, est.)	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
11	Return to Provision True-Up	-	-0.58%	(1,588,785)	(806,112)	-1.15%	(213,876)	(2,832,214)	-0.67%	(751,437)	(2,349,909)	-0.44%	(623,472)	-	0.00%	-
12	Capitalized OPEB	-	-0.02%	(60,597)	(46,113)	-0.07%	(12,235)	(182,281)	-0.04%	(48,362)	-	0.00%	-	-	0.00%	-
13	Unprotected EDIT Amortization	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
14	Prior Period Flow through Income Tax Reg Asset- VA	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
15	Charitable Contributions	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-	-	0.00%	-
16	Parking	-	0.05%	132,115	96,216	0.14%	25,526	213,756	0.05%	56,713	187,979	0.04%	49,874	-	0.00%	-
16	R&D credits	-	-0.27%	(753,411)	-	-0.78%	(145,577)	-	-0.29%	(323,418)	-	-0.20%	(284,417)	-	0.00%	-
17	Other Tax Adjustments	-	-0.13%	(347,198)	(176,160)	-0.25%	(46,738)	(618,925)	-0.15%	(164,212)	(513,527)	-0.10%	(136,248)	-	0.00%	-
18	Total Flow-through, Permanent Items, and Other Tax Adjustments	-	-3.57%	(9,823,512)	(677,077)	-7.15%	(1,336,142)	(2,890,087)	-4.15%	(4,642,020)	(2,314,097)	-2.72%	(3,845,351)	-	0.00%	-
19	Investment Tax Credit (ITC)	-	-0.11%	(305,994)	-	-0.49%	(90,913)	-	-0.10%	(108,018)	-	-0.08%	(107,064)	-	0.00%	-
20	Total Tax & Effective tax Rate	274,833,320	22.89%	62,919,686	18,001,065	18.94%	3,537,492	109,031,937	22.34%	24,998,224	138,955,249	23.78%	33,596,205	2,963,808	26.58%	787,764

Washington Gas Light Company
Rate Base Summary
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Gas Plant in Service	RB:3:17		$ 7,249,016,177	$1,317,182,832	$ 2,711,617,252	$ 3,190,657,625	$ 29,558,468
2	Gas Plant Held for Future Use	RB:4:13		-	-	-	-	-
3	Unrecovered Plant - Peaking Facility		Total_Weather_All_NW	-	-	-	-	-
4	Construction Work in Progress	RB:5:29		397,111,025	79,322,274	134,339,566	183,449,185	-
5	Materials & Supplies	RB:6:12		123,327,981	19,836,447	52,379,031	51,112,503	-
6	Non Plant - ADIT	RB:12:18	Financial Stmt.	(34,509,521)	(3,062,666)	(21,491,098)	(9,955,757)	0
7	FC 1027 - Rate Base CWIP (Reg Asset)			(0)	(0)			
8	Unamortized East Station Cost (Net of Deferred Taxes)		Financial Stmt.	1,075,846	1,075,846	-	-	-
9	Sub-Total	=1>10		$ 7,736,021,508	$1,414,354,734	$ 2,876,844,750	$ 3,415,263,556	$ 29,558,468
10	Cash Working Capital	RB:7>9:17		$ 121,292,100	$ 39,219,091	$ 67,230,077	$ 14,826,433	$ 16,500
11	Total Rate Base Additions	= 12 + 11		$ 7,857,313,609	$1,453,573,825	$ 2,944,074,827	$ 3,430,089,989	$ 29,574,968
12	LESS:							
13	Reserve for Depreciation	RB:10:35		$ 2,370,279,045	$ 449,057,859	$ 864,931,885	$ 1,054,487,285	$ 1,802,016
14	Accumulated DIT re Depreciation	RB:11:17		1,298,608,831	212,149,665	532,439,389	554,019,777	0
15	Accumulated DIT re Gains/Losses On Reacquired Debt							
16	Federal	RB:11:9	Net_Rate_Base	175,290	29,300	70,009	75,981	-
17	State	RB:11:9	Net_Rate_Base	57,829	10,143	22,631	25,055	-
18	NOL Carryforward Federal		Net_Rate_Base	(78,173,336)	(14,916,809)	(29,119,631)	(34,136,895)	-
19	NOL Carryforward State		Net_Rate_Base	(68,626,785)	(13,095,164)	(25,563,533)	(29,968,088)	-
20	NOL Federal Benefit of State		Net_Rate_Base	14,411,625	2,749,985	5,368,342	6,293,298	-
21	Customer Advances for Construction		Financial Stmt.	2,698,381	305,769	244,862	2,147,750	-
22	Customer Deposits		Financial Stmt.	12,871,928	1,432,785	2,467,234	8,971,908	-
23	Supplier Refunds		Financial Stmt.	4,509,391	626,315	1,675,549	2,207,527	-
24	Deferred Tenant Allowance		Non_Genl_Plnt	16,261,534	3,017,287	6,000,718	7,243,529	-
25	Total Rate Base Deductions	=14>26		$ 3,573,073,733	$ 641,367,135	$ 1,358,537,454	$ 1,571,367,128	$ 1,802,016
26	Net Rate Base	= 13 - 27		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952

Washington Gas Light Company
Depreciable Gas Plant In Service
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Depreciable Gas Plant In Service**							
2	Capitalized Software	AL:2:23	Non_Genl_Plnt	$ 168,881,787	$ 31,956,957	$ 62,038,051	$ 74,886,780	$ -
3	Storage	AL:1:19	Total_Weather_All_NW	76,262,465	$ 12,565,793	$ 32,404,277	$ 31,292,394	$ -
4	Storage - AFUDC		Financial Stmt.	(511,776)	-	-	(511,776)	0
5	Total Storage	=3+4		$ 75,750,689	$ 12,565,793	$ 32,404,277	$ 30,780,618	$ -
6	Transmission							
7	Spurlines and Related Regulating							
8	Equipment and Structures		Financial Stmt.	$ 414,164,974	$ 56,197,740	$ 120,198,620	$ 209,444,575	$ 28,324,039
9	WSSC			5,547	-	5,547	-	-
10	ChalkPoint		Financial Stmt.	13,995,741	-	13,995,741	-	-
11	Panda		Financial Stmt.	2,034,808	-	2,034,808	-	-
12	Other	AL:1:32	Comp_Peak_Ann_NW	696,637,349	108,628,696	304,409,695	283,598,957	-
13	Transmission Mains - ARO			6,956,762	2,515	3,954,742	2,999,506	-
14	Post 1989 MD Interruptible Customers		Financial Stmt.	2,477,416	-	2,477,416	-	-
15	AFUDC		Financial Stmt.	(5,268,645)	-	-	(5,268,645)	0
16	Total Transmission	=8>13		$ 1,131,003,953	$ 164,828,951	$ 447,076,569	$ 490,774,393	$ 28,324,039
17	Distribution							
18	Compressor Station Equipment	AL:1:19	Total_Weather_All_NW	$ 2,735,941	$ 450,802	$ 1,162,514	$ 1,122,625	$ -
19	Mains		Financial Stmt.	2,573,799,925	549,032,913	887,779,494	1,136,987,518	-
20	Distribution Mains - ARO			61,255,520	1,086,978	34,552,539	25,616,002	-
21	Measuring and Regulator Station Equipment		Financial Stmt.	17,875,325	10,637,047	4,323,013	2,915,266	-
22	Services		Financial Stmt.	2,297,650,823	399,729,625	873,174,680	1,024,746,517	-
23	Distribution Services - ARO			61,635,355	967,723	35,467,125	25,200,508	-
24	Meters		Financial Stmt.	138,243,994	26,892,685	53,287,464	58,063,846	-
25	Meter Installations		Financial Stmt.	252,239,013	35,970,717	91,047,414	125,220,882	-
26	House Regulators		Financial Stmt.	43,226,309	4,731,358	15,452,640	23,042,310	-
27	House Regulator Installations		Financial Stmt.	15,195,671	3,744,785	6,522,287	4,928,599	-
28	Gas Light Services		Financial Stmt.	5,022,656	107,137	1,977,956	2,937,563	-
29	Post 1989 MD Interruptible Customers		Financial Stmt.	2,917,888	-	2,917,888	-	-
30	AFUDC		Financial Stmt.	(17,294)	-	-	(17,294)	-
31	Total Distribution	=16>26		$ 5,471,781,126	$ 1,033,351,770	$ 2,007,665,014	$ 2,430,764,342	$ -
32	General							
33	Transportation	AL:2:23	Non_Genl_Plnt	$ 42,991,069	$ 7,947,207	$ 15,805,240	$ 19,078,670	$ 159,953
34	POE	AL:2:23	Non_Genl_Plnt	4,988,314	922,126	1,833,904	2,213,725	18,560
35	Other - Direct		Financial Stmt.	65,528,429	11,564,934	36,619,764	17,343,732	-
36	Other - Allocable	AL:2:23	Non_Genl_Plnt	283,802,687	52,462,958	104,337,239	125,946,573	1,055,916
37	AFUDC		Financial Stmt.	(5,105,363)	-	-	(5,105,363)	-
38	Total General	=29>33		$ 392,205,136	$ 72,897,224	$ 158,596,147	$ 159,477,337	$ 1,234,428
39	CNG Equipment		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
40	CIAC - GPIS		Financial Stmt.	-	-	-	-	
41	CIAC - Liability		Financial Stmt.	-	-	-	-	
42	Total Depreciable Gas Plant in Service	=2+5+14+27+3 4+35+36+37		$ 7,239,622,691	$ 1,315,600,695	$ 2,707,780,058	$ 3,186,683,470	$ 29,558,468

Washington Gas Light Company
Non Depreciable Gas Plant In Service
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Non Depreciable Gas Plant in Service**							
2	Intangible	AL:2:23	**Non_Genl_Plnt**	$ 78,009	$ 14,474	$ 28,786	$ 34,748	$ -
3	Storage	AL:1:19	**Total_Weather_All_NW**	$ 341,480	$ 56,266	$ 145,096	$ 140,118	$ -
4	Transmission							
5	Spurlines and Related Regulating							
6	Equipment and Structures		**Financial Stmt.**	-	-	-	-	-
			and & Land Rights	-	-	-	-	
7	Land and Land rights			-	-	-	-	$ -
8	Other	AL:1:32	**Comp_Peak_ Ann_NW**	5,182,929	808,189	2,264,785	2,109,955	-
9	Total Transmission	=6+7		$ 5,182,929	$ 808,189	$ 2,264,785	$ 2,109,955	$ -
10	Distribution - Other		**Financial Stmt.**	$ 1,159	$ -	$ -	$ 1,159	$ -
11	General							
12	Other - Direct		**Financial Stmt.**	$ -	$ -	$ -	$ -	$ -
13	Other - Allocable	AL:2:23	**Non_Genl_Plnt**	3,789,910	703,208	1,398,526	1,688,176	-
14	Total General	=11+12		$ 3,789,910	$ 703,208	$ 1,398,526	$ 1,688,176	$ -
15	Total Non-Depreciable Gas Plant in Service	=2+3+8+9+13		$ 9,393,486	$ 1,582,138	$ 3,837,194	$ 3,974,155	$ -
16	Total Depreciable Gas Plant in Service	RB:2:42		7,239,622,691	1,315,600,695	2,707,780,058	3,186,683,470	29,558,468
17	Total Gas Plant in Service	=14+15		$ 7,249,016,177	$1,317,182,832	$ 2,711,617,252	$ 3,190,657,625	$ 29,558,468

Washington Gas Light Company
Gas Plant Held For Future Use
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	---Reference--- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Gas Plant Held For Future Use**							
2	Storage	AL:1:19	Total_Weather_All_NW	$ -	$ -	$ -	$ -	$ -
3	Transmission							
4	Spurlines and Related Regulating							
5	Equipment and Structures		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
6	Other	AL:1:32	Comp_Peak_ Ann_NW	-	-	-	-	-
7	Total Transmission	=4+5		$ -	$ -	$ -	$ -	$ -
8	Distribution							
9	Compressor Station Equipment		Total_Weather_All_NW	$ -	$ -	$ -	$ -	$ -
10	Other		Financial Stmt.	-	-	-	-	-
11	Total Distribution	=8+9		$ -	$ -	$ -	$ -	$ -
12	General	AL:2:23	Non_Genl_Plnt	$ -	$ -	$ -	$ -	$ -
13	Total Gas Plant Held for Future Use	=6+10+11		$ -	$ -	$ -	$ -	$ -

Washington Gas Light Company
Construction Work In Progress
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

Description	Reference: Sc-Pg-Ln	Reference: Allocator	WG	DC	MD	VA	FERC
A	B	C	D	E	F	G	H
1 **Construction Work In Progress**							
2 Intangible	AL:2:23	Non_Genl_Plnt	$ 9,544,190	$ 1,770,901	$ 3,521,930	$ 4,251,359	$ -
3 Intangible Situs		Financial Stmt.	259,636	-	259,636	-	$ -
4 Total Intangible	=2+3		$ 9,803,825	$ 1,770,901	$ 3,781,566	$ 4,251,359	$ -
5 Storage	AL:1:19	Total_Weather_All_NW	$2,055,949.78	$ 338,760	$ 873,583	$ 843,608	$ -
6 Storage - Chalk Point	AL:1:19	Financial Stmt.	0	-	0	-	
7 Storage - VA Gas Reserves		Financial Stmt.					
8 Total Storage	=3+4		$ 2,055,950	$ 338,760	$ 873,583	$ 843,608	
9 Transmission							
10 Spurlines and Related Regulating							
11 Equipment and Structures		Financial Stmt.	20,718,087	157,674	2,754,916	17,805,496	
12 WSSC			(1,532)		(1,532)		
13 Panda		Financial Stmt.	-	-	-	-	
14 Other	AL:1:32	Comp_Peak_ Ann_NW	31,910,231	$ 4,975,856	$ 13,943,817	$ 12,990,559	$ -
15 Total Transmission	=9>11		$ 52,626,786	$ 5,133,530	$ 16,697,201	$ 30,796,055	$ -
16 Distribution							
17 Compressor Station Equipment	AL:1:19	Total_Weather_All_NW	-	$ -	$ -	$ -	$ -
18 Other		Financial Stmt.	302,781,574	66,743,485	102,356,539	133,681,550	
19 Mains			-	-	-	-	
20 Services			-	-	-	-	
21 Total Distribution	=13 > 17		$ 302,781,574	$ 66,743,485	$ 102,356,539	$ 133,681,550	$ -
22 General Alloc	AL:2:23	Non_Genl_Plnt	28,662,461	$ 5,318,248	$ 10,576,821	$ 12,767,392	$ -
23 General - Situs	AL:1:19	Financial Stmt.	1,180,429	17,351	53,856	1,109,222	
24 General - Panda	AL:1:19	Financial Stmt.	-	-	-	-	
25 General - Chalk Point	AL:1:19	Financial Stmt.	-	-	-	-	
26 Total General	=19>22		29,842,890	5,335,599	10,630,677	13,876,613	
27 AFUDC		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
28 CNG Equipment		Financial Stmt.	$ -	$ -	$ -	$ -	
29 Total Construction Work in Progress	=2+6+12+18+23+24+25		$ 397,111,025	$ 79,322,274	$ 134,339,566	$ 183,449,185	$ -

Washington Gas Light Company
Materials and Supplies
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
Average Rate Base

	--------Reference------						
Description	Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
A	B	C	D	E	F	G	H
1 **Materials and Supplies**							
2 General Supplies : 1/							
3 Construction	AL:3:2	Stores _Stock	$ 2,091,723	$ 58,422	$ 721,129	$ 1,312,171	$ -
4 Operation	AL:1:20	Annual_Total_NW	5,670,176	956,999	2,492,511	2,220,666	-
5 Total General Supplies	=3+4		$ 7,761,899	$ 1,015,421	$ 3,213,641	$ 3,532,837	$ -
6 Fuel Stock:							
7 Watergate		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
8 Propane Fuel Stock	AL:1:2	Firm_Weather_NW	12,445,064	1,829,740	5,348,787	5,266,536	-
9 Total Fuel Stock	=7+8		$ 12,445,064	$ 1,829,740	$ 5,348,787	$ 5,266,536	$ -
10 Storage Gas Purchased	AL:1:19	Total_Weather_All_NW	$ 102,538,469	$ 16,895,300	$ 43,569,074	$ 42,074,095	$ -
11 Fuel Stock Materials - Hexane	AL:1:19	Total_Weather_All_NW	582,550	$ 95,987	$ 247,528	# $ 239,035	$ -
12 Total Materials and Supplies	=5+9+10+11		$ 123,327,981	$ 19,836,447	# $ 52,379,031	# $ 51,112,503	$ -

1/ Apportionment of supplies balance between
Construction and Operation is based on actual
issues from stores stock during the test period.

Construction	781,698	$ 0
Operation	2,119,003	$ 1
Total	$ 2,900,702	$ 1

Washington Gas Light Company
Cash Working Capital
District of Columbia
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Reference: Sc-Pg-Ln	Reference: Allocator	Expenses	Adjustments	Adjusted Expenses	Lead/Lag Days	Cash Working Capital Requirement
	A	B	C	D	E	F	G	H
1	Composite Revenue Lag						89.00	
2	Gas Purchased	EX:3:5		$ 64,262,645	$ -	$ 64,262,645	38.19	$ 2,454,184,506
3	Payroll	WEX:6:30		25,573,530	-	25,573,530	11.71	299,504,692
4	Other Operations and Maintenance Expenses 1/			61,026,523	128,636 1/	61,155,159	25.47	1,557,527,820
5	Less: Pension Benefit 2/		Total_Labor	42,494	-	42,494	25.47	1,082,247
6	Less: OPEB Benefit 3/		Total_Labor	6,584,462	-	6,584,462	25.47	167,696,128
7	General Taxes							
8	Property Taxes	EX:8:2		2,013,868	-	2,013,868	71.02	143,032,994
9	Delivery Tax	EX:8:8		23,451,041	-	23,451,041	26.13	612,799,160
10	Rights-of-Way Fee	EX:8:9		12,518,268	-	12,518,268	(54.53)	(682,621,127)
11	FICA Taxes	EX:8:10>11		2,103,553	-	2,103,553	9.97	20,970,937
12	Unemployment Tax	EX:8:12		(6,961)	-	(6,961)	9.99	(69,562)
13	Federal Excise Tax	EX:8:17		(21,714)	-	(21,714)	(17.51)	380,156
14	Sustainable Trust Fund	EX:8:18		16,761,017	-	16,761,017	26.13	437,982,135
15	Energy Assistance Fund	EX:8:19		2,156,914	-	2,156,914	26.13	56,362,323
16	Firm Storage Service	EX:8:23		29	-	29	308.86	8,840
17	Other Taxes - Direct Assignment	EX:8:22		16,520	-	16,520	79.00	1,305,080
18	Federal Income Taxes	EX:10:2		(1,201,342)	-	(1,201,342)	-	0
19	Other Income Taxes	EX:10:3		(696,105)	-	(696,105)	-	0
20	Total Net Expenses	=2>9		$ 214,584,743	$ 128,636	$ 214,713,379	23.61	$ 5,070,146,329
21	Subtotal					$ 588,256	65.39	$ 38,466,327
22	**Other Lead-Lag Items:**							
23	Imprest Funds	AL:4:30	O&M _X_ Gas	$ -				$ -
24	Economic Eval. of Facility Ext. (GSP 14)		Accts186200 & 174400	752,764	-	752,764		752,764
25	Interest on Long-Term Debt	EX:9:		0		$ -	91.25	0
26	Preferred Dividends			812,206,690	0.00%	-	0.00	-
27	Total Cash Working Capital	=11+(13>16)						$ 39,219,091

1/ Represents an adjustment to exclude depreciation expense for transportation and POE equipment from the calculation of cash working capital.(WEX13:10)
2/ To exclude Pension Benefit from Working Capital calculations, because it is a noncash item.
3/ To exclude OPEB Benefit from Working Capital calculations, because it is a noncash item.

Washington Gas Light Company
Cash Working Capital
Maryland
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	------ Reference ------ Sc-Pg-Ln	Allocator	Expenses	Adjustments 1/	Adjusted Expenses	Lead/Lag Days	Cash Working Capital Requirement
	A	B	C	D	E	F	G	H
1	Composite Revenue Lag						72.18	
2	Gas Purchased	EX:3:5		$ 200,704,535	$ -	$ 200,704,535	38.19	$ 7,664,887,698
3	Payroll	WEX:6:30		56,810,467	-	56,810,467	11.71	665,336,429
4	Other Operations and Maintenance Expenses			127,939,502	274,429 1/	128,213,931	25.47	3,265,411,587
5	Less: Pension Benefit 2/		Total_Labor	94,398	-	94,398	25.47	2,404,165
6	Less: OPEB Benefit 3/		Total_Labor	14,627,092	-	14,627,092	25.47	372,529,532
7	General Taxes	EX:8:24			-			
8	Property Taxes	EX:8:2		28,069,820	-	28,069,820	(45.72)	(1,283,415,787)
9	Delivery Tax	EX:8:8		12,820,467	-	12,820,467	26.13	335,011,634
10	FICA Taxes	EX:8:10>11		4,672,951	-	4,672,951	9.97	46,586,009
11	Unemployment Tax	EX:8:12		(15,463)	-	(15,463)	9.99	(154,530)
12	Federal Excise Tax	EX:8:17		(48,238)	-	(48,238)	26.13	(1,260,501)
13	Firm Storage Service	EX:8:23		56	-	56	308.86	17,257
14	Other Taxes - Direct Assignment	EX:8:22		25,043	-	25,043	79.00	1,978,388
15	Montgomery County Fuel Energy Tax	EX:8:15		42,701,928	-	42,701,928	-	0
16	St Mary's County Fuel Energy Tax	EX:8:14		27,577	-	27,577	-	0
17	Federal Income Taxes	EX:10:2		(8,312,516)	-	(8,312,516)	-	0
18	Other Income Taxes	EX:10:3		(4,816,599)	-	(4,816,599)	-	0
19	Total Net Expenses	=2>9		$ 475,301,019	$ 274,429	$ 475,575,448	23.28	$11,069,331,881
20	Subtotal					$ 1,302,946	48.91	$ 63,723,028
21	**Other Lead-Lag Items**							
22	Imprest Funds	AL:4:30	O&M _X_ Gas	-				$ -
23	Economic Eval. of Facility Ext. (GSP 14)		Accts186200 & 174400	3,507,048	-	3,507,048		3,507,048
24	Interest on Long-Term Debt	EX:9:		0		$ -	91.25	0
25	Preferred Dividends			1,585,537,373	0.00%	-	0.00	0
26	Total Cash Working Capital	=11+ (13>16)						$ 67,230,077

1/ See Footnote on Schedule RB Page 7
2/ To exclude Pension Benefit from Working Capital calculations, because it is a noncash item.
3/ To exclude OPEB Benefit from Working Capital calculations, because it is a noncash item.

Washington Gas Light Company
Cash Working Capital
Virginia
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Reference: Sc-Pg-Ln	Reference: Allocator	Expenses	Adjustments	Adjusted Expenses	Lead/Lag Days	Cash Working Capital Requirement
	A	B	C	D	E	F	G	H
1	Composite Revenue Lag						50.50	
2	Gas Purchased	EX:3:5		$ 189,861,198	$ -	$ 189,861,198	38.19	$ 7,250,781,677
3	Payroll	WEX:6:30		49,698,205	-	49,698,205	11.71	582,041,088
4	Other Operations and Maintenance Expenses			115,223,582	244,976 1/	115,468,558	25.47	2,940,806,526
5	Less: Pension Benefit 2/		Total_Labor	82,580	-	82,580	25.47	2,103,181
6	Less: OPEB Benefit 3/		Total_Labor	12,795,885	-	12,795,885	25.47	325,891,510
7	General Taxes							
8	Property Taxes	EX:8:2		19,988,883	-	19,988,883	116.95	2,337,655,899
9	Delivery Tax	EX:8:8		-	-	0	26.13	0
10	FICA Taxes	EX:8:10>11		4,087,931	-	4,087,931	9.97	40,753,776
11	Unemployment Tax	EX:8:12		(13,527)	-	(13,527)	9.99	(135,184)
12	Federal Excise Tax	EX:8:17		(42,199)	-	(42,199)	(17.51)	738,774
13	Firm Storage Service	EX:8:23		66	-	66	308.86	20,231
14	Other Taxes - Direct Assignment	EX:8:22		313,873	-	313,873	79.00	24,796,006
15	Federal Income Taxes	EX:10:2		(11,158,937)	-	(11,158,937)	-	-
16	Other Income Taxes	EX:10:3		(6,465,927)	-	(6,465,927)	-	-
17	Total Net Expenses	=2>9		$ 374,371,613	$ 244,976	$ 374,616,589	$ 36	$13,505,453,483
18	Subtotal					$ 1,026,347	14.45	$ 14,826,433
19	**Other Lead-Lag Items**							
20	Imprest Funds	AL:4:30	O&M _X_ Gas	-				$ -
21	Interest on Long-Term Debt	EX:9:		0		$ -	91.25	0
22	Preferred Dividends			1,858,722,862	0.00%	-	0.00	0
23	Total Cash Working Capital	=11+ (13>16)						$ 14,826,433

1/ See Footnote on Schedule RB Page 7
2/ To exclude Pension Benefit from Working Capital calculations, because it is a noncash item.
3/ To exclude OPEB Benefit from Working Capital calculations, because it is a noncash item.

Washington Gas Light Company
Reserve For Depreciation
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	——Reference—— Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Reserve for Depreciation**							
2	Capitalized Software	AL:2:23	Non_Genl_Plnt	$ 93,226,573	$ 17,297,958	$ 34,401,819	$ 41,526,796	$ -
3	Capitalized Software Reserve Deficiency		Financial Stmt.	-	-	-	-	-
4	Capitalized Software Amort Res Def		Financial Stmt.	(632,048)	-	(632,048)	-	-
5	Total Capitalized Software	=2>4		$ 92,594,525	$ 17,297,958	$ 33,769,771	$ 41,526,796	$ -
	Storage							
6	Storage		Financial Stmt.	52,670,681	8,251,328	22,503,733	21,915,620	
7	AFUDC		Financial Stmt.	(120,084)	-	-	(120,084)	
8	Total Storage	=6+7		$ 52,550,597	$ 8,251,328	$ 22,503,733	$ 21,795,536	
	Transmission							
9	Spurlines and Related Regulating Equip		Financial Stmt.	97,106,167	5,147,487	42,913,619	49,045,060	
10	Depreciation Res - Trans - ARO		Comp_Peak_ Ann_NW	6,956,762	2,515	3,954,741	2,999,506	-
11	21.5 Mile Loop RE: Save Amendment		Financial Stmt.	700,103	-	-	379,096	321,006
12	New 21.5 Mile loop		Financial Stmt.	-	-	-	-	-
	17.44 Miles of the 19.44 Serving							
13	Shen/Spurlines & Reg Equip		Financial Stmt.	1,663,719	-	-	1,663,719	
14	2.00 Miles of the 19.44 Serving Mountaineer		Financial Stmt.	32,515	-	-	-	32,515
15	Ninevah/Clearbrook Gate Stations		Financial Stmt.	1,067,637	-	-	578,111	489,525
16	Chalk Point		Financial Stmt.	14,153,002	-	14,153,002	-	
17	Post 1989 MD Interr Customers		Financial Stmt.	2,477,416	-	2,477,416	-	
18	Panda Cogeneration		Financial Stmt.	1,897,999	-	1,897,999	-	
19	AFUDC		Financial Stmt.	(484,314)	-	-	(484,314)	
20	Other - Allocable		Financial Stmt.	106,037,142	16,493,465	46,174,133	43,007,895	361,650
21	Total Transmission	=9>20		$ 231,608,146	$ 21,643,467	$ 111,570,910	$ 97,189,074	$ 1,204,696
	Distribution							
22	Distribution - Situs		Financial Stmt.	$ 1,716,026,917	$ 376,928,298	$ 563,332,270	$ 775,766,349	
23	Depreciation Res - Dist - ARO			122,890,875	2,054,701	70,019,664	50,816,510	-
24	Post 1989 MD Interr Customers		Financial Stmt.	2,865,602	-	2,865,602	-	
25	AFUDC		Financial Stmt.	(9,853)	-	-	(9,853)	
26	Other - Allocable		Financial Stmt.	174,161	27,373	74,145	72,643	
27	Total Distribution	22>26		$ 1,841,947,702	$ 379,010,372	$ 636,291,681	$ 826,645,649	
	General Plant							
28	Direct		Financial Stmt.	$ 38,579,720	$ (115,289)	$ 22,510,263	$ 16,049,785	$ 134,961
29	AFUDC		Financial Stmt.	(3,868,312)	-	-	(3,868,312)	
30	Allocable		Non_Genl_Plnt	124,269,880	22,972,177	45,686,587	55,148,758	462,359
31	General Plant - Reserve Deficiency		Financial Stmt.	-	-	-	-	-
32	General Plant - Amort Res Def		Financial Stmt.	(7,381,009)	-	(7,381,009)	-	-
33	Total General Plant	28>32		$ 151,600,279	$ 22,856,888	$ 60,815,842	$ 67,330,230	$ 597,320
34	CNG Equipment		Financial Stmt.	(22,205)	(2,154)	(20,051)	-	
35	Total Reserve for Depreciation	=5+8+21+27+32+34		$ 2,370,279,045	$ 449,057,859	$ 864,931,885	$ 1,054,487,285	$ 1,802,016

Washington Gas Light Company
Accumulated Deferred Income Taxes
Modified Accelerated Cost Recovery System (MACRS)
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	---Reference--- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Avoided Cost of Interest		Macrs APB 11	$ (17,061,547)	$ (2,886,713)	$ (6,780,216)	$ (7,394,618)	$ -
2	Capitalized OPEB		Macrs APB 11	222,938	37,720	88,595	96,623	-
3	Capitalized Pension		Macrs APB 11	495,257	83,796	196,813	214,649	-
4	CIAC Contribs in Aid of Construct		Macrs APB 11	(7,068,198)	(1,195,915)	(2,808,866)	(3,063,416)	-
5	Cost of Removal - Net of Salvage		Macrs APB 11	30,921,154	5,231,613	12,288,049	13,401,491	-
6	Tax Depreciation - Utility		Macrs APB 11	394,484,673	66,618,859	156,889,706	170,976,108	-
7	Tax Depreciation - UTP		Macrs APB 11	-	-	-	-	-
8	Bk/Tx Unit of Property		Macrs APB 11	579,061,891	97,972,844	230,118,709	250,970,339	-
9	Amortization of Reacquisition Debt		Macrs APB 11	233,118	39,443	92,640	101,035	-
10	Other Tax Credits		Macrs APB 11	26,746,386	4,347,544	10,802,318	11,596,524	-
11	Disposition of Assets		Macrs APB 11	2,338,729	395,702	929,402	1,013,625	-
12	Repairs Deduction		Macrs APB 11	50,617,548	8,564,320	20,115,159	21,938,070	-
13	Excess Deferred Gross Up (Direct)		Financial Statement	324,983,819	44,401,403	153,046,134	127,536,283	-
14	Excess Deferred Gross Up (Allocable)		Macrs APB 11	26,884,429	4,493,784	10,737,343	11,653,302	-
15	Amortization of Excess Deferred (Direct)		Financial Statement	(76,775,043)	(10,462,048)	(36,555,897)	(29,757,097)	-
16	Amortization of Excess Deferred (Allocable)		Macrs APB 11	(8,364,813)	(1,398,195)	(3,340,814)	(3,625,805)	-
17	Amort of Excess Deferred Asset		Macrs APB 11	447,844	75,745	177,999	194,100	-
18	Other Adjustments		Macrs APB 11	(3,352,825)	(567,173)	(1,332,507)	(1,453,145)	-
19	Deferred Income Taxes (Direct)		Financial Statement	(23,908,456)	(3,218,460)	(11,307,818)	(9,382,179)	-
20	Deferred Income Taxes (Allocable)		Macrs APB 11	(2,064,955)	(345,161)	(824,720)	(895,074)	-
21	Total Plant ADIT	Sum of 1 > 17		$ 1,298,841,949	$ 212,189,108	$ 532,532,029	$ 554,120,813	$ -

Washington Gas Light Company
Accumulated Deferred Income Taxes - Non Plant Items
System
Twelve Months Ended March 2024 - AVG
Average Rate Base

	Description	Sc-Pg-Ln (Reference)	Allocator (Reference)	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
	Non Plant Items							
1	Environmental		Total_Weather_All_NW	$ (721,399)	$ (118,865)	$ (306,526)	$ (296,008)	$ -
2	Regulatory Assets & Liabilities - Rate cases		Financial Statement	(7,973,446)	-	(7,973,446)	-	-
3	Employee Benefits		Total_Labor	(51,724,255)	(10,014,762)	(22,247,351)	(19,462,142)	-
4	Amortization Gain on Sale of Property		Net_Rate_Base	42,691	8,146	15,902	18,642	-
5	Uncollectible Accounts		Uncoll. Accounts	5,410,038	2,265,125	1,376,477	1,768,436	-
6	ADIT - Debt / Interest		Net_Rate_Base	(1,277,582)	(243,784)	(475,900)	(557,897)	-
7	General Taxes		Financial Statement	1,401,810	1,401,810	-	-	-
8	Lawsuits		Total_Labor	139,206	26,953	59,874	52,379	-
9	Customer Advances		ADJ_CWIP	162,864	60,464	102,401	-	-
10	Gas Costs		Gas_Cost_Rec	(31,708)	(4,319)	(13,938)	(13,452)	-
11	Misc. Derivative Reserves		Net_Rate_Base	574,090	109,546	213,849	250,695	-
12	Merger Commitment Costs		Total_Labor	963,908	186,630	414,591	362,687	-
13	BPO		Comp_A&G	-	-	-	-	-
14	Deferred Rent		Non_Genl_Plnt	1,698,724	315,194	626,851	756,679	-
15	Misc. Items		Total_Labor	2,418,586	468,283	1,040,269	910,035	-
16	Sec. 174 R&D Expense Amort.		Net_Rate_Base	2,905,701	554,457	1,082,376	1,268,867	
17	Non-Plant ADIT Regulatory Asset		Macrs APB 11	11,501,250	1,922,456	4,593,472	4,985,322	-
18	Total Non-Plant ADIT	Sum of 1 > 14		$ (34,509,521)	$ (3,062,666)	$ (21,491,098)	$ (9,955,757)	$ -

Washington Gas Light Company
Revenues
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Sc-Pg-Ln (Reference)	Allocator (Reference)	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operating Revenues**							
2	Sales of Gas and Transportation to Customers							
3	Residential		Financial Stmt.	$ 917,499,221	$ 114,679,781	$ 387,260,842	$ 415,558,598	$ -
4	Commercial and Industrial other than Group Metered Apts		Financial Stmt.	185,406,991	45,038,920	68,772,040	71,596,030	-
5	Group Metered Apartments		Financial Stmt.	37,945,816	16,671,589	10,825,850	10,448,377	-
6	Commercial and Industrial - Interruptible		Financial Stmt.	2,467,672	1,970,320	414,562	82,789	-
7	Transportation Sales / Mountaineer		Financial Stmt.	313,468,665	78,440,325	136,629,702	95,065,801	3,332,837
8	WSSC Revenues			586,938		586,938		-
9	Total Heating/Cooling and Other Uses	=3>7		$ 1,457,375,303	$ 256,800,936	$ 604,489,935	$ 592,751,595	$ 3,332,837
10	Rate Adjustment due Customers		Financial Stmt.	(1,841,180)	(268,728)	(805,138)	(767,313)	-
11	Unbilled Gas Accrual/Reversal		Financial Stmt.	(6,749,446)	(6,782,977)	446,100	(412,569)	-
12	Provision for Rate Refunds		Financial Stmt.	3,798,715	-	2,211,388	1,587,327	-
13	Total Gas Sales & Transportation Revenues	=8 > 11		$ 1,452,583,392	$ 249,749,231	$ 606,342,285	$ 593,159,040	$ 3,332,837
14	Other Operating Revenues							
15	Forfeited Discounts (Non POR)		Financial Stmt.	11,349,728	3,245,453	4,328,263	3,776,011	-
16	Forfeited Discounts (POR)		Financial Stmt.	582,776	360,143	222,583	50	-
17	Rent from Gas Property		Annual Firm_ ACT	967,406	139,688	416,107.68	411,610.20	-
18	Miscellaneous Service Revenues							
19	Reconnect Revenues		Financial Stmt.	847,711	174,354	568,927	104,430	-
20	Reconnect Revenues - Premium		Financial Stmt.	(234)	-	(234)	-	-
21	Dishonored Check Charge		Financial Stmt.	647,108	44,740	303,282	299,086	-
22	Service Initiation Charge		Financial Stmt.	3,947,838	838,570	1,816,987	1,292,280	-
23	Field Collection Charge		Financial Stmt.	4,951	433	3,528	990	-
24	IRATE Non Compliance MTR. Charge		Financial Stmt.	-	-	-	-	-
25	Other Gas Revenues							
26	Watergate Revenues		Financial Stmt.	-	-	-	-	-
27	Third Party Balancing Charges		Financial Stmt.	50,236,702	6,609,061	25,841,472	17,786,168	-
28	CNG Sales for Natural Gas Vehicles		Financial Stmt.	1,934,788	847,959	606,779	480,050	-
29	Off System Sales Revenue Net of Gas Cost		EX:3:2	86,111,467	14,177,234	38,508,187	33,426,045	-
30	Miscellaneous							
31	Other Allocable Miscellaneous		Financial Stmt.	(2,331,859)	(133,354)	(1,653,845)	(544,660)	-
32	Oth Gas Rev - MD RM-35		Financial Stmt.	1,374,694	736,920	637,773	-	-
33	Third Party Billing		Financial Stmt.	459,364	114,447	-	344,917	-
34	Total Other Operating Revenues	=14>32		$ 156,132,439	$ 27,155,649	$ 71,599,810	$ 57,376,979	$ -
35	Total Operating Revenues	=13+34		$ 1,608,715,831	$ 276,904,880	$ 677,942,095	$ 650,536,019	$ 3,332,837

Washington Gas Light Company
Transportation Revenues
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	f	B	C	D	E	F	G	H
1	**Residential Delivery**			$ 78,345,188	$ 9,308,970	$ 39,428,193	$ 29,608,025	$ -
2	**Commercial Delivery**			$ 109,282,902	$ 29,973,003	$ 51,316,479	$ 27,993,419	$ -
3	**Commercial Delivery - Large Customers**			15,640,355	-	-	15,640,355	-
4	**Commercial Delivery - Special Contract Firm**			3,873,688	(2,038,965)	5,912,653	-	-
5	**Commercial Delivery - Panda, Chalk Point, WSSC**			1,910,816	-	1,910,816	-	-
6	**Total Commercial Delivery**		= 2>5	$ 130,707,760	$ 27,934,038	$ 59,139,948	$ 43,633,774	$ -
7	**Group Metered Apts. Delivery**			$ 40,052,358	$ 13,595,563	$ 15,293,831	$ 11,162,964	$ -
8	**Group Metered Apts. Delivery Large Customers**			2,516,336	-	-	2,516,336	-
9	**Total Group Metered Apts. Delivery**		= 7+8	$ 42,568,694	$ 13,595,563	$ 15,293,831	$ 13,679,300	$ -
10	**Interruptible Delivery**			$ 59,613,360	$ 28,113,990	$ 23,354,668	$ 8,144,702	$ -
11	**Interruptible Delivery - Spec Contract - AOC**			(512,236)	(512,236)	-	-	-
12	**Interruptible Delivery - Mountaineer Gas**			3,332,837	-	-	-	3,332,837
13	**Total Interruptible Delivery**		= 10>12	$ 62,433,961	$ 27,601,754	$ 23,354,668	$ 8,144,702	$ 3,332,837
14	**Total Delivery Transportation Therms (Excl NGV)**		=sum(1+6+9+13)	$ 314,055,603	$ 78,440,325	$ 137,216,640	$ 95,065,801	$ 3,332,837

Washington Gas Light Company
Operating Expense Summary
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	—— Reference —— Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operating Expenses**							
2	Operation	EX:2:46		$ 776,880,340	$ 125,293,859	$ 338,655,003	$ 312,821,368	$ 110,110
3	Maintenance	EX:4:26		114,413,313	25,568,839	46,799,501	41,961,616	83,356
4	Depreciation	EX:6:22		135,410,640	23,907,431	41,034,291	70,456,187	12,731
5	Amortization	SM:1:7>SM:1:10		35,655,282	5,635,445	14,321,268	15,619,189	79,380
6	Interest on Customer Deposits		Financial Stmt.	528,578	41,769	128,646	358,163	-
7	Interest on Supplier Refunds		Financial Stmt.	73,600	11,533	31,581	30,486	-
8	General Taxes	EX:8:24		171,665,153	58,992,535	88,254,140	24,335,027	83,452
9	Other Income Taxes		Financial Stmt.	13,182,317	756,509	5,234,557	7,027,005	164,246
10	Expenses Before Federal Income Taxes	=2>9		$ 1,247,809,223	$ 240,207,920	$ 534,458,986	$ 472,609,042	$ 533,275
11	Federal Income Taxes	EX:10:22		$ 50,043,363	$ 2,871,897	$ 19,871,685	$ 26,676,264	$ 623,518
12	Investment Tax Credit Adjustment	Ln.11 - Ln.9		(305,994)	(90,913)	(108,018)	(107,064)	-
13	Federal taxes - Total	EX:10:22		$ 49,737,369	$ 2,780,984	$ 19,763,667	$ 26,569,200	$ 623,518
14	Total Operating Expenses	=10+11+12+13		$ 1,297,546,592	$ 242,988,904	$ 554,222,653	$ 499,178,242	$ 1,156,793

Washington Gas Light Company
Operations Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operation Expenses**							
2	Gas Purchased	EX:3:5		$ 454,828,378	$ 64,262,645	$ 200,704,535	$ 189,861,198	$ -
3	Purchased Gas Expenses		Financial Stmt.	896,834	151,366	394,233	351,236	-
4	Purchased Gas Expenses		Financial Stmt.	54,868	596	17,799	36,473	-
5	Purchased Gas Expenses - Hexane		Financial Stmt.	3,460,797	-	-	3,460,797	-
6	Purchased Gas Expenses- Chalk Point		Financial Stmt.	32,044	-	32,044	-	-
7	Propane Holding	AL:1:2	Firm_Weather_NW	-	-	-	-	-
8	Watergate		Financial Stmt.	102,248	102,248	-	-	-
9	Hampshire Exchange Service	AL:1:2	Firm_Weather_NW	278,568	40,957	119,726	117,885	-
10	Property Modifications - Chalk Point		Financial Stmt.	-	-	-	-	-
11	Storage - Direct		Financial Stmt.	245	-	105	140	-
12	Storage - Allocable	AL:1:2	Firm_Weather_NW	16,757,838	2,463,828	7,202,383	7,091,628	-
13	Transmission	AL:2:8	Transmission_Plnt	3,214,585	474,160	1,246,238	1,410,951	83,237
14	Transmission - Chalk Point		Financial Stmt.	24,972	-	24,972	-	-
15	Transmission - Panda		Financial Stmt.	8,960	-	8,960	-	-
16	Distribution							
17	Supervision and Engineering -							
18	Distribution	AL:5:17	Dist_X_Admin	955,435	218,452	389,587	347,396	-
19	Appliance Service - Direct		Financial Stmt.	-	-	-	-	-
20	Appliance Service - Allocable	AL:5:6	Appl_Svc_X_Admin	-	-	-	-	-
21	Other	AL:2:22	Tot_Dist_Plnt	5,208,625	1,004,253	1,886,834	2,317,538	-
22	Load Dispatching	AL:1:32	Comp_Peak_Ann_NW	2,154,642	335,980	941,514	877,148	-
23	Load Dispatching - Chalk Point		Financial Stmt.	-	-	-	-	-
24	Compressor Station Equipment	AL:1:32	Comp_Peak_Ann_NW	-	-	-	-	-
25	Mains	AL:2:16	Dist_Mains_Plnt	1,368,210	291,861	471,936	604,413	-
26	Mains - Chalk Point		Financial Stmt.	-	-	-	-	-
27	Removing/Setting Meters - Direct		Financial Stmt.	1,689,348	121,682	1,105,374	462,292	-
28	Removing/Setting Meters - Allocable	AL:5:2	Direct_Meter_Exp	-	-	-	-	-
29	Measuring and Regulating Station Equipment	AL:2:17	Dist_Meas_Reg_Plnt	509,583	303,237	123,239	83,107	-
30	Measuring and Reg Station Equip - Chalk Point		Financial Stmt.	-	-	-	-	-
31	Services On Customer Premises-Direct		Financial Stmt.	44,751	1,533	8,132	35,086	-
32	Services On Customer Premises-Allocable	AL:5:4	Direct_SOCP	0	0	0	0	-
33	Office Expenses -			-				-
34	Distribution	AL:5:17	Dist_X_Admin	12,555,986	2,870,823	5,119,808	4,565,354	-
35	Appliance Service - Direct		Financial Stmt.	-	-	-	-	-
36	Appliance Service - Allocable	AL:5:6	Appl_Svc_X_Admin	-	-	-	-	-
37	Other	AL:2:16	Dist_Mains_Plnt	245,147	52,294	84,559	108,295	-
38	Rents		Financial Stmt.	14,652	-	298	14,355	-
39	Customer Accounts	EX:7:23		52,124,547	12,768,405	19,560,728	19,795,414	-
40	Customer Service and Information Exp - Allocable	AL:4:12	Avg_Meters	3,156,065	437,277	1,246,549	1,472,238	-
41	Information Exp - Direct		Financial Stmt.	240,680	75,837	150,863	13,981	-
42	Sales Expense	AL:4:12	Avg_Meters	602,426	83,467	237,940	281,019	-
43	Advertising Exp - Direct	AL:4:12	Financial Stmt.	1,770	-	1,770	-	-
44	Administrative and General	EX:5:31		215,854,266	39,138,720	97,390,911	79,297,762	26,873
45	Interest on Financing Leases	AL:3:6	Net_Rate_Base	$ 493,872	$ 94,239	$ 183,968	$ 215,665	$ -
46	Total Operation Expenses	=2>44		$ 776,880,340	$ 125,293,859	$ 338,655,003	$ 312,821,368	$ 110,110

Washington Gas Light Company
Development of Gas Purchased Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Gas Purchase Costs		Financial Stmt.	$ 381,002,051	$ 51,891,638	$ 167,476,401	$ 161,634,012	$ -
2	Less: Off System Sales Cost of Gas Recovered			$ (86,111,467)	$ (14,177,234)	$ (38,508,187)	$ (33,426,045)	$ -
3	PGC Recovered - DC/MD/VA	=1-2		$ 467,113,518	$ 66,068,873	$ 205,984,588	$ 195,060,057	$ -
4	Propane Gasified		Financial Stmt.	$ (12,285,140)	$ (1,806,227)	$ (5,280,054)	$ (5,198,859)	$ -
5	Total Gas Purchased & Propane Gasified	=3+4	Financial Stmt.	$ 454,828,378	$ 64,262,645	$ 200,704,535	$ 189,861,198	$ -

Washington Gas Light Company
Operation and Maintenance Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Maintenance Expenses**							
2	Storage	AL:1:19	Total_Weather_All_NW	$ 380,003	$ 62,613	$ 161,465	$ 155,925	-
3	Transmission	AL:2:8	Transmission_Plnt	2,993,733	441,583	1,160,617	1,314,014	77,518
4	Transmission - Chalk Point							
5	Structures & Improvements		Financial Stmt.	43,547	-	43,547	-	-
6	Measuring & Regulating Station Equipment		Financial Stmt.	25,542	-	25,542	-	-
7	Transmission - Panda							
8	Structures & Improvements		Financial Stmt.	-	-	-	-	-
9	Measuring & Regulating Station Equipment		Financial Stmt.	25,208	-	25,208	-	-
10	Distribution							
11	Mains		Financial Stmt.	33,302,827	8,648,128	12,660,520	11,994,178	-
12	Services		Financial Stmt.	35,487,205	9,541,079	15,284,083	10,662,043	-
13	Meter & House Regulator Installations Direct		Financial Stmt.	29,865,372	3,713,786	12,696,300	13,455,285	-
14	Meter & House Regulator Installations Allocable		Financial Stmt.	699,643	87,001	297,431	315,211	-
15	General DIMP Expenditures		Financial Stmt.	2,519	-	-	2,519	-
16	Compressor Station Equipment	AL:1:19	Total_Weather_All_NW	-	-	-	-	-
17	Measuring and Regulating Station Equipment		Dist_Meas_Reg_Plnt	1,532,095	911,702	370,526	249,868	-
18	Gas Light Services		Financial Stmt.	1,894	-	-	1,894	-
19	Meter & House Regulators	AL:2:14	Mtr_Hse_Reg_Plnt	800,351	127,191	296,513	376,647	-
20	Supervision and Engineering -							-
21	Appliance Service	AL:2:14	Mtr_Hse_Reg_Plnt	-	-	-	-	-
22	Other	AL:5:25	Dist_Maint_Exp	7,321,829	1,662,047	2,997,912	2,661,870	-
23	Other Equipment - Direct		Financial Stmt.	4,430	389	270	3,771	-
24	Other Equipment - Allocable	AL:5:17	Dist_X_Admin	358,079	81871.74631	146,010	130,197	-
25	Maintenance of General Plant	AL:2:26	Genl_Plnt	1,569,038	291,448	633,558	638,194	5,838
26	Total Maintenance	=2>25		$ 114,413,313	$ 25,568,839	$ 46,799,501	$ 41,961,616	$ 83,356
27	Total Operation	EX:2:46		776,880,340	125,293,859	338,655,003	312,821,368	110,110
28	Total Operation and Maintenance Expenses	=26+27		$ 891,293,653	$ 150,862,698	$ 385,454,504	$ 354,782,984	$ 193,466

Washington Gas Light Company
Administrative and General Expenses
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Administrative & General Expenses**							
2	Administrative & General Salaries-Direct		Financial Stmt.	$ 4,032,355	$ 930,862	$ 1,648,492	$ 1,449,739	$ 3,262
3	Administrative & General Salaries-Allocable	AL:4:23	Comp_A&G	100,516,479	19,641,740	43,423,120	37,451,620	-
4	Office Supplies & Expenses-Direct		Financial Stmt.	3,942,404	1,103,503	1,731,733	1,104,963	2,204
5	Office Supplies & Expenses-Allocable	AL:4:23	Comp_A&G	33,046,634	6,457,582	14,276,146	12,312,906	-
6	Outside Services	AL:5:30		37,435,574	7,053,669	15,176,292	15,205,613	-
7	Property Insurance	AL:3:13	Net_GPIS	-	-	-	-	-
8	Injuries & Damages	AL:4:11	Total_Labor	18,995,900	3,677,954	8,170,412	7,147,535	-
9	Pension Expense	AL:4:11	Total_Labor	(219,656)	(42,494)	(94,398)	(82,580)	(185)
10	DC Regulatory			-				
11	Pension Expense		Financial Stmt.	-	-	-	-	-
12	Amortization of Rate Case Expenses		Financial Stmt.	475,776	475,776	-	-	-
13	Least Cost Planning Expenses		Financial Stmt.	-	-	-	-	-
14	Employee Health Benefits			24,779,774	4,793,783	10,649,176	9,315,976	20,840
15	OPEB	Labor factor	Financial Stmt.	(34,007,440)	(6,584,462)	(14,627,092)	(12,795,885)	-
16	Rate Case Expenses-Direct		Financial Stmt.	1,526,109	206,553	1,049,073	269,875.64	607
17	Rate Case Expenses-Allocable	AL:4:23	Comp_A&G	9,523	1,861	4,114	3,548	-
18	DC PSC Assessment Expense		Financial Stmt.	-	-	-	-	-
19	General Advertising Expenses - Direct		Financial Stmt.	1,269	-	984	285	-
20	General Advertising Expenses - Allocable	AL:4:23	Comp_A&G	644,209	125,884	278,298	240,027	-
21	Environmental Expense - Regulatory Amortization		Financial Stmt.	686,319	263,068	423,250	-	-
22	Environmental Reserve - Regulatory Adjustment		Financial Stmt.	1,738,655	-	-	1,738,655	-
23	Rents		Financial Stmt.	263,877	-	-	263,877	-
24	MD Demand Side Management Expenses		Comp_A&G	1,041,022	203,424	449,721	387,876	-
25	VA Care Expenses		Financial Stmt.	4,294,347	-	-	4,294,347	-
26	MD EmPOWER MD Expenses		Financial Stmt.	13,710,995	-	13,710,995	-	-
27	Multi-Family Unit Contribution Amortization Expense		Financial Stmt.	199,129	17,451	140,914	40,764	-
28	Multi-Family Unit Contribution Amortization Expense - Allocable			-	-	-	-	-
29	Miscellaneous General Expenses-Direct		Financial Stmt.	367,847	348,831	(45,528)	64,398	145
30	Miscellaneous General Expenses-Allocable	AL:4:23	Comp_A&G	2,373,165	463,736	1,025,207	884,222	-
31	Total Administrative & General Expenses	= 2 >30		$ 215,854,266	$ 39,138,720	$ 97,390,911	$ 79,297,762	$ 26,873

Washington Gas Light Company
Depreciation Expense
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Depreciation Expense**							
2	Storage			$ 2,122,869	$ 332,141	$ 908,114	$ 882,613	$ -
3	AFUDC		Financial Stmt.	(8,124)	-	-	(8,124)	-
4	Total Storage	=2+3	Financial Stmt.	$ 2,114,745	$ 332,141	$ 908,114	$ 874,490	$ -
5	Transmission							
6	Spurlines & Related Regulating							
7	Equipment & Structures		Financial Stmt.	$ 6,709,023	$ 402,270	$ 1,796,786	$ 4,509,967	$ -
8	Other		Financial Stmt.	12,131,831	1,861,656	5,276,819	4,993,357	-
9	AFUDC		Financial Stmt.	(71,443)	-	-	(71,443)	-
10	Total Transmission	=7>9		$ 18,769,411	$ 2,263,926	$ 7,073,604	$ 9,431,881	$ -
11	Distribution							
12	Compressor Station Equipment		Financial Stmt.	$ 86,810	$ 13,595	$ 37,092	$ 36,124	$ -
13	Other		Financial Stmt.	111,224,910	20,661,758	31,501,698	59,061,455	-
14	AFUDC		Financial Stmt.	(268)	-	-	(268)	-
15	Total Distribution	=12>14		$ 111,311,452	$ 20,675,352	$ 31,538,789	$ 59,097,311	$ -
16	General							
17	Other		Financial Stmt.	$ 3,555,562	$ 636,011	$ 1,513,783	$ 1,393,036	$ 12,731
18	AFUDC		Financial Stmt.	(340,530)	-	-	(340,530)	-
19	Total General	=17+18		$ 3,215,032	$ 636,011	$ 1,513,783	$ 1,052,506	$ 12,731
20	CNG Equipment		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
21	Depreciation Exp. - Regulatory Recovery		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
22	Total Depreciation Expense	=4+10+15+19+20+ 21		$ 135,410,640	$ 23,907,431	$ 41,034,291	$ 70,456,187	$ 12,731

Washington Gas Light Company
Customer Accounts
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Customer Accounts**							
2	General Supervision-Direct		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
3	General Supervision-Allocable	AL:4:10	Customer_Accts	-	-	-	-	-
4	Total General Supervision	=2+3		$ -	$ -	$ -	$ -	$ -
5	Meter Reading-Direct		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
6	Meter Reading-Allocable	AL:4:12	Avg_Meters	5,504,551	762,664	2,174,130	2,567,758	-
7	Total Meter Reading	=5+6		$ 5,504,551	$ 762,664	$ 2,174,130	$ 2,567,758	$ -
8	Dispatch Applications and Orders-Direct		Financial Stmt.	$ 2,171,311	$ 296,545	$ 1,132,179	$ 742,587	$ -
9	Dispatch Applications and Orders-Allocable	AL:4:12	Avg_Meters	13,855,708	1,919,729	5,472,583	6,463,397	-
10	Total Dispatch Applications and Orders	=8+9		$ 16,027,019	$ 2,216,274	$ 6,604,762	$ 7,205,984	$ -
11	Customer Collection Expenses							
12	Customer Credit and Appliance Service-Direct		Financial Stmt.	$ 8,268	$ -	$ (46,049)	$ 54,317	$ -
13	Customer Credit and Appliance Service-Allocable	AL:4:5	Avg_AR	8,373,169	2,191,914	3,899,276	2,281,979	-
14	Other-Direct		Financial Stmt.	-	-	-	-	-
15	Other-Allocable	AL:5:32	Avg_Meters	(1,669,693)	(231,338)	(659,478)	(778,877)	-
16	Credit and Debit Card Transactions	AL:5:32	Credit_Debit_Card	3,520,829	478,381	1,594,599	1,447,850	
17	Total Customer Collection Expenses	=12>15		$ 10,232,573	$ 2,438,956	$ 4,788,348	$ 3,005,269	$ -
18	Customer Billing and Accounting-Direct		Financial Stmt.	$ 108,799	$ 108,700	$ -	$ 99	$ -
19	Customer Billing and Acct-POR Collection Exp		Financial Stmt.	621,466	226,115	395,350	-	-
20	Customer Billing and Accounting-Allocable	AL:4:12	Avg_Meters	4,295,147	595,099	1,696,452	2,003,596	-
21	Total Customer Billing and Accounting	=17>19		$ 5,025,412	$ 929,915	$ 2,091,803	$ 2,003,695	$ -
22	Total Uncollectible Accounts			$ 15,334,992	$ 6,420,597	$ 3,901,686	$ 5,012,709	$ -
23	Total Customer Accounts	=4+7+10+16+20+2 1		$ 52,124,547	$ 12,768,405	$ 19,560,728	$ 19,795,414	$ -

Washington Gas Light Company
General Tax Expense
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----- Reference ----- Sc-Pg-Ln		WG	DC	MD	VA	FERC
	A	B		D	E	F	G	H
1	**General Taxes**							
2	Property Taxes		Analysis	$ 50,009,514	$ 2,013,868	$ 27,934,055	$ 19,988,883	$ 72,707
3	Property Taxes - Chalk Point							
4	Maryland State & Prince George's County		Financial Stmt.	135,764	-	135,764	-	-
5	Property Taxes - Panda							
6	Maryland State & Prince George's County		Financial Stmt.	-	-	-	-	-
7	Total Property Taxes	=2>6		$ 50,145,278	$ 2,013,868	$ 28,069,820	$ 19,988,883	$ 72,707
8	Gross Receipts Taxes		Financial Stmt.	$ 36,271,509	$ 23,451,041	$ 12,820,467	$ -	$ -
9	DC Rights-of-Way Fee		Financial Stmt.	12,518,268	12,518,268	-	-	-
10	F.I.C.A. Taxes	AL:4:11	Total_Labor	8,469,616	1638232.747	3,639,262	3,183,652	8,470
11	Medicare Taxes	AL:4:11	Total_Labor	2,405,694	465,321	1033689.079	904,279	2,406
12	Unemployment Taxes	AL:4:11	Total_Labor	(35,988)	(6,961)	(15,463)	(13,527)	(36)
13	Montgomery County Fuel Energy Tax		Financial Stmt.	42,701,928	-	42,701,928	-	-
14	St Mary's County Fuel Energy Tax		Financial Stmt.	27,577	-	27,577	-	-
15	PG County Maintenance Fees		Financial Stmt.	-	-	-	-	-
16	Environmental Tax	AL:1:20	Annual_Total_NW	-	-	-	-	-
17	Federal Excise Tax	AL:4:11	Total_Labor	(112,245)	(21,714)	(48,238)	(42,199)	(94)
18	DC Sustainable Energy Trust Fund		Financial Stmt.	16,761,017	16,761,017	-	-	-
19	DC Energy Assistance Trust Fund		Financial Stmt.	2,156,914	2,156,914	-	-	-
20	DC Natural Gas Trust Fund		Financial Stmt.	-	-	-	-	-
21	Virginia save Program		Financial Stmt.	-	-	-	-	-
22	Miscellaneous Other Taxes - Direct Assignment		Financial Stmt.	355,436	16,520	25,043	313,873	-
23	Miscellaneous Other Taxes - Allocated	AL:3:6	Net_Rate_Base	150	29	56	66	-
24	Total General Taxes	=7+ (8>23)		$ 171,665,153	$ 58,992,535	$ 88,254,140	$ 24,335,027	$ 83,452

Washington Gas Light Company
Interest Expense
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Interest Expense**							
2	Interest on Long Term Debt	AL:3:6	Net_Rate_Base	85,860,916	16,374,320	31,994,268	37,492,328	-
4	Interest on Commercial Paper	AL:3:6	Net_Rate_Base	11,735,620	2,239,357	4,371,528	5,124,735	-
5	Interest on Credit Line Fees	AL:3:6	Net_Rate_Base	48,962	9,343	18,238	21,381	-
6	Interest on Credit Line Fees	AL:3:6	Net_Rate_Base	1,006,084	191,978	374,767	439,339	-
7	Interest On Bank Loans	AL:3:6	Net_Rate_Base	-	-	-	-	-
8	Interest on Financing Leases	AL:3:6	Net_Rate_Base	493,872	94,239	183,968	215,665	-
9	Interest on Short-Term Revolver	AL:3:6	Net_Rate_Base	-	-	-	-	-
9	Amortization of Debt Discount/Expenses	AL:3:6	Net_Rate_Base	753,779	149,466	267,345	336,969	-
10	Amort. Gain/Loss/Premium on Reacquired Debt	AL:3:6	Net_Rate_Base	(365,099)	(64,061)	(149,669)	(151,368)	-
11	AFUDC	AL:3:14	ADJ_CWIP	(1,259,101)	(467,443)	(791,658)	-	-
12	POR CWC Costs		Financial Stmt.	58,019	58,019	0	0	-
13	Interest on Supplier Refunds		Financial Stmt.	73,600	11,533	31,581	30,486	-
14	Interest on Customer Deposits		Financial Stmt.	528,578	41,769	128,646	358,163	-
15	Interest re LCP Expenses		Financial Stmt.	-	-	-	-	-
16	Int Exp re DC Carrying Costs		Financial Stmt.	-	-	-	-	-
17	Oth Int Costs VA Save Carrying Costs		Financial Stmt.	-	-	-	-	-
18	Interest re Maryland Demand Side Management Expenses		Financial Stmt.	-	-	-	-	-
19	Other Interest Expense	AL:3:6	Net_Rate_Base	470,794	89,836	175,371	205,587	-
20	Total Interest	=2>15		$ 99,406,025	$ 18,728,355	$ 36,604,384	$ 44,073,285	$ -
	Adjusted to Remove:							
21	Interest on debt to Associated Company	AL:3:6	Net_Rate_Base	$ -	$ -	$ -	$ -	$ -
22	Non-Utility Interest Charges	AL:3:6	Net_Rate_Base	-	-	-	-	-
23	AFUDC	AL:3:14	ADJ_CWIP	(1,259,101)	(467,443)	(791,658)	-	-
24	Interest on Supplier Refunds		Financial Stmt.	73,600	11,533	31,581	30,486	-
25	Int Exp re DC Carrying Costs		Financial Stmt.	-	-	-	-	-
26	Oth Int Costs VA Save Carrying Costs		Financial Stmt.	-	-	-	-	-
27	Oth Int Exp Customer Deposits		Financial Stmt.	528,578	41,769	128,646	358,163	-
28	Non-Utility Interest on Equity Investment in Comme	AL:3:6	Net_Rate_Base	-	-	-	-	-
29	Non-Utility Interest on Equity Investment in Primary	AL:3:6	Net_Rate_Base	-	-	-	-	-
30	Interest per Cost of Service	=18-(19>28)		$ 100,062,947	$ 19,142,496	$ 37,235,816	$ 43,684,636	$ -

* Based on weighted average of Commercial Paper rates on average investment.

Washington Gas Light Company
Income Tax Expenses

Twelve Months Ended March 2024 - AVG

Ln	Description	Reference: Sc-Pg-Ln	Reference: Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Current Income Tax**							
2	Current Federal Income Tax		ETR Schedule	$ (20,933,618)	$ (1,201,342)	$ (8,312,516)	$ (11,158,937)	$ (260,824)
3	Current State Income Tax		ETR Schedule	(12,129,762)	(696,105)	(4,816,599)	(6,465,927)	(151,131)
4	Current Income Tax - Total	Ln. 2 + Ln.3		**$ (33,063,380)**	**$ (1,897,447)**	**$ (13,129,115)**	**$ (17,624,864)**	**$ (411,955)**
5	**Deferred Income Tax - Plant**							
6	Deferred Income Tax - Plant - Federal		ETR Schedule	$ (11,404,761)	$ (654,498)	$ (4,528,709)	$ (6,079,456)	$ (142,098)
7	Deferred Income Tax - Plant - State		ETR Schedule	-	-	-	-	-
8	Deferred Income Tax - Plant - Total	Ln. 6+ Ln.7		**$ (11,404,761)**	**$ (654,498)**	**$ (4,528,709)**	**$ (6,079,456)**	**$ (142,098)**
9	Deferred Income Tax - Non Plant							
10	Deferred Income Tax - Non Plant - Federal		ETR Schedule	$ 32,644,374	$ 1,873,401	$ 12,962,732	$ 17,401,507	$ 406,734
11	Deferred Income Tax - Non Plant - State		ETR Schedule	12,129,762	696,105	4,816,599	6,465,927	151,131
12	Deferred Income Tax - Non Plant - Total	Ln. 10+ Ln.11		$ 44,774,136	$ 2,569,506	$ 17,779,331	$ 23,867,433	$ 557,866
13	Deferred Income Tax - Total	Ln. 8 + Ln.12	ETR Schedule	**$ 33,369,375**	**$ 1,915,007**	**$ 13,250,622**	**$ 17,787,978**	**$ 415,768**
14	**Investment Tax Credit Adjustments**		ETR Schedule	**$ (305,994)**	**$ (90,913)**	**$ (108,018)**	**$ (107,064)**	**$ -**
15	Tax Adjustment #1	Ln. 16 + Ln.17	Financial Stmt.	62,919,686	3,610,846	24,984,735	33,540,154	783,951
16	Tax Adjustment #1 - Federal			49,737,369	2,854,336	19,750,177	26,513,149	619,706
17	Tax Adjustment #1 - State			13,182,317	756,509	5,234,557	7,027,005	164,246
18	Tax Adjustment #2	Ln. 19 + Ln.20	Financial Stmt.	-	-	-	-	-
19	Tax Adjustment #2 - Federal			-	-	-	-	-
20	Tax Adjustment #2 - State			-	-	-	-	-
21	**Tax Summary - Total**							
22	**Federal Tax Total**	Sum(2+6+10+14)		**49,737,369**	**2,780,984**	**19,763,667**	**26,569,200**	**623,518**
23	**State Tax Total**	Sum(3+7+11)		**13,182,317**	**756,509**	**5,234,557**	**7,027,005**	**164,246**
24	**Tax Summary - Total**	Ln. 22 + Ln. 23		**$ 62,919,686**	**$ 3,537,493**	**$ 24,998,224**	**$ 33,596,205**	**$ 787,764**

Washington Gas Light Company
Allocation Factors Based on Normal Weather Study

Twelve Months Ended March 2024 - AVG

	------ Reference ------								
Description	Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
A	B	C	D	E	F	G	H	I	J
1 **Firm Annual Weather Gas**									
2 TOTAL FIRM WEATHER GAS - NW	NW Study	Firm_Weather_NW	966,262,395	142,065,096	415,291,747	408,905,552	0.147025	0.429792	0.423183
3 TOTAL FIRM THERM SALES - NW	NW Study	Annual_ Firm_NW	1,418,556,506	206,081,756	605,693,246	606,781,504	0.145276	0.426979	0.427746
4 TOTAL FIRM THERM SALES - NW(sales only)		Annual_ Firm_Sales_NW	914,452,500	122,542,753	382,007,337	409,902,410	0.134007	0.417744	0.448249
5 **Non-Firm Annual Weather Gas**									
6 June Sales	Financial Stmt.		19,106,249	4,878,086	10,601,572	3,626,591			
7 July Sales	Financial Stmt.		16,385,284	4,144,577	9,130,761	3,109,946			
8 Aug. Sales	Financial Stmt.		15,994,187	4,074,410	9,020,913	2,898,865			
9 Total Summer Usage	=+6+7+8		51,485,720	13,097,073	28,753,246	9,635,401			
10 Annualization Factor	Constant		4	4	4	4			
11 Annualized Summer Usage	=9*10		205,942,881	52,388,293	115,012,983	38,541,605			
12 Watergate Usage	Financial Stmt.		-	-	-	-			
13 Calculated Base Usage	=11+12		205,942,881	52,388,293	115,012,983	38,541,605			
14 Actual Usage	NW Study		239,874,935	73,882,136	116,925,204	49,067,596			
15 Weather Usage	=14-13		33,932,054	21,493,843	1,912,220	10,525,990			
16 Total Interruptible Therm Sales - NW			263,839,380	77,868,955	133,858,923	52,111,502			
17 Weather Gas Interruptible - NW			57,843,990	26,677,272	19,855,837	11,310,880			
18 TOTAL FIRM THERM SALES - NW(Delivery only)		Annual_ Firm_Delivery_NW	509,207,172	81,663,741	227,864,492	199,678,939	0.160374	0.447489	0.392137
19 TOTAL ALL WEATHER GAS	=2+18	Total_Weather_All_NW	1,024,106,385	168,742,368	435,147,584	420,216,432	0.164770	0.424905	0.410325
20 TOTAL ANNUAL THERM SALES	=4+17	Annual_Total_NW	1,682,395,886	283,950,710.85	739,552,169	658,893,006	0.168778	0.439583	0.391640
21 ANNUAL THERMS ADJUSTED	=20-24	Pipeline_NW	1,682,395,886	283,950,711	739,552,169	658,893,006	0.1688	0.4396	0.3916
22 FIRM ANNUAL PIPELINE	=3-24	Firm_Pipe_ Ann_ Adj	1,418,556,506	206,081,756	605,693,246	606,781,504	0.145276	0.426979	0.427746
23 FIRM ANNUAL PIPELINE(Sales only)	=4-24	Firm_Pipe_ Ann_Sales_ Adj	914,452,500	122,542,753	382,007,337	409,902,410	0.134007	0.417744	0.448249
24 **Peak Day Therm Sales- Normal Weather**									
25 Weather Gas	NW Study	Peak_Day _Weather	15,991,500	2,290,271	6,959,692	6,741,537	0.143218	0.435212	0.421570
26 Base Gas	NW Study	Peak_Day_Base	1,218,969	172,345	515,804	530,820	0.141386	0.423148	0.435466
27 Total Peak Day Therms	=29+30	Peak_Day_Total	17,210,469	2,462,616	7,475,496	7,272,357	0.143088	0.434357	0.422554
28 PEAK DAY AND ANNUAL SALES	=(20+31)/2	Comp_Peak_ Ann_NW					0.155933	0.436970	0.407097
29 TOTAL WINTER THERMS (NOV-APR)	NW Study	Wintr_Pipe_NW	1,277,081,957	214,413,097	552,242,395	510,426,464	0.167893	0.432425	0.399682

Washington Gas Light Company
Allocation Factors Based on Gas Plant in Service

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

	Description	Reference: Sc-Pg-Ln	Reference: Allocator	WG	DC	MD	VA	DC	MD	VA
	A	B	C	D	E	F	G	H	I	J
1	**Gas Plant In Service(GPIS)**									
2	Storage - Depreciable	RB:2:5		$ 75,750,689	$ 12,565,793	$ 32,404,277	$ 30,780,618			
3	- Non Depreciable	RB:3:3		341,480	56,266	145,096	140,118			
4	Total Storage	=2+3		$ 76,092,169	$ 12,622,059	$ 32,549,374	$ 30,920,736			
5	Transmission - Depreciable	RB:2:14		$ 1,102,679,913	$ 164,828,951	$ 447,076,569	$ 490,774,393			
6	- Non - Depreciable	RB:3:8		5,182,929	808,189	2,264,785	2,109,955			
7	Less: Chalk Point			13,995,741	-	13,995,741	-			
8	Total Transmission	=6+7-8	Transmission_Plnt	$ 1,093,867,101	$ 165,637,140	$ 435,345,613	$ 492,884,348	0.151423	0.397988	0.450589
9	Distribution Plant									
10	Meters	RB:2:20		$ 138,243,994	$ 26,892,685	$ 53,287,464	$ 58,063,846			
11	Meter Installations	RB:2:21		252,239,013	35,970,717	91,047,414	125,220,882			
12	House Regulators	RB:2:22		43,226,309	4,731,358	15,452,640	23,042,310			
13	House Regulator Installations	RB:2:23		15,195,671	3,744,785	6,522,287	4,928,599			
14	Total Meters and House Regulators	=10>13	Mtr_Hse_Reg_Plnt	$ 448,904,987	$ 71,339,545	$ 166,309,806	$ 211,255,636	0.158919	0.370479	0.470602
15	Compressor Station Equipment	RB:2:16		$ 2,735,941	$ 450,802	$ 1,162,514	$ 1,122,625			
16	Mains	RB:2:17	Dist_Mains_Plnt	2,573,799,925	549,032,913	887,779,494	1,136,987,518	0.213316	0.344929	0.441754
17	Measuring and Regulator Station Equipment	RB:2:18	Dist_Meas_Reg_Plnt	17,875,325	10,637,047	4,323,013	2,915,266	0.595069	0.241842	0.163089
18	Services	RB:2:19		2,297,650,823	399,729,625	873,174,680	1,024,746,517			
19	Gas Light Services	RB:2:24		5,022,656	107,137	1,977,956	2,937,563			
20	Post 1989 MD Interruptible Distribution Plant	RB:2:25		2,917,888	-	2,917,888	-			
21	AFUDC	RB:2:26		(17,294)	-	-	(17,294)			
22	Total Distribution	=14+ (15>21)	Tot_Dist_Plnt	$ 5,348,890,251	$ 1,031,297,069	$ 1,937,645,351	$ 2,379,947,832	0.192806	0.362252	0.444942
23	Total GPIS Excluding Gen/Intang -Chalk Point	=4+8+22	Non_Genl_Plnt	$ 6,518,849,521	$ 1,209,556,268	$ 2,405,540,337	$ 2,903,752,916	0.185548	0.369013	0.445439
24	General Plant - Depreciable	RB:2:34		$ 390,970,707	$ 72,897,224	$ 158,596,147	$ 159,477,337			
25	General Plant - Non-Depreciable	RB:3:13		3,789,910	703,208	1,398,526	1,688,176			
26	Total General GPIS	=24+25	Genl_Plnt	$ 394,760,617	$ 73,600,432	$ 159,994,673	$ 161,165,512	0.186443	0.405295	0.408261
27	CNG Equipment	RB:2:35		$ -	$ -	$ -	$ -			
28	Total GPIS Excluding Chalk Point & Intang	=23+26+27	Tot_GPIS_X_Chalk Point	$ 6,913,610,138	$ 1,283,156,701	$ 2,565,535,010	$ 3,064,918,428	0.185599	0.371084710	0.443317

Washington Gas Light Company
Allocation Factors Based on Gas Plant in Service

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

	Description	------ Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
	A	B	C	D	E	F	G	H	I	J
1	**Actual Construction Supplies Issued**									
2	**from Stores Stock**	Analysis	Stores _Stock	$ 781,698	$ 21,833	$ 269,494	$ 490,372	0.027930	0.344754	0.627316
3	**Adjusted Net Rate Base**									
4	Net Rate Base	RB:1:26		$ 4,256,466,925	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862			
5	Less: Chalk Point			-	-	-	-			
6	Adjusted Net Rate Base	=4-5	Net_Rate_Base	$ 4,256,466,925	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	0.190817	0.372501	0.436682
7	**Net Gas Plant in Service**									
8	Gas Plant in Service	RB:1:1		$ 7,219,457,709	$ 1,317,182,832	$ 2,711,617,252	$ 3,190,657,625			
9	Gas Plant Held for Future Use	RB:1:2		-	-	-	-			
10	Construction Work In Progress	RB:1:4	CWIP	397,111,025	79,322,274	134,339,566	183,449,185	0.199748	0.338292	0.461959
11	Less: Reserve for Depreciation	RB:1:14		2,368,477,029	449,057,859	864,931,885	1,054,487,285			
12	Less: Accumulated Deferred Income taxes	RB:1:15		1,298,608,831	212,149,665	532,439,389	554,019,777			
13	Net Gas Plant in Service	=(8>10)-11-12	Net_GPIS	$ 3,949,482,875	$ 735,297,583	$ 1,448,585,543	$ 1,765,599,748	0.186176	0.366779	0.447046
14	Adjusted Construction Work In Progress	RB:5:23	ADJ_CWIP	$ 213,661,840	$ 79,322,274	$ 134,339,566	$ -	0.371251	0.628749	0.000000

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

	Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
	A	B	C	D	E	F	G	H	I	J
1	**Customer Accounts**									
2	General Supervision	EX:7:4		$ -	$ -	$ -	$ -			
3	Meter Reading	EX:7:7		5,504,551	762,664	2,174,130	2,567,758			
4	Dispatch Applications and Orders	EX:7:10		16,027,019	2,216,274	6,604,762	7,205,984			
5	Collecting - Direct	EX:7:12	Direct_Collect_Exp	8,268	0	(46,049)	54,317	0.000000	-5.569481	6.569481
6	Collecting - Allocable	EX:7:13		8,373,169	2,191,914	3,899,276	2,281,979			
7	Other	EX:7:15		(1,669,693)	(231,338)	(659,478)	(778,877)			
8	Credit and Debit Card Transactions	EX:7:16		3,520,829	478,381	1,594,599	1,447,850			
9	Billing and Accounting	EX:7:19		5,025,412	929,915	2,091,803	2,003,695			
10	Total Customer Accounts	=2>8	Customer_Accts	$ 36,789,555	$ 6,347,808	$ 15,659,042	$ 14,782,705	0.172544	0.425638	0.401818
11	**Total Direct Labor**	WEX:6:28	Total_Labor	$ 113,349,657	$ 21,946,567	$ 48,753,328	$ 42,649,762	0.193618	0.430114	0.376267
12	**Average Meters**	Financial Stmt.	Avg_Meters	1,183,623	163,993	467,495	552,135	0.138551	0.394970	0.466479
13	**Expenses allocated on**									
14	**Composite A&G Factor**									
15	Expenses allocated on - O&M_Adj	Analysis	O&M_Adj	$ 1,238,545	247328.6975	504205.3234	$ 487,011	0.199693	0.407095	0.393212
16	Expenses allocated on - Three part	Analysis	Three_Part_Factor	37,827,710	7052190.247	15,372,909	15,402,611	0.186429	0.406393	0.407178
17	Expenses allocated on - Labor	Analysis	Labor	13,118,735	2,540,027	5,642,558	4,936,150	0.193618	0.430114	0.376267
18	Expenses allocated on - Average meters	Analysis	Avg_Meters	2,635,016	365,085	1,040,751	1,229,179	0.138551	0.394970	0.466479
19	Expenses allocated on - Distribution field	Analysis	Dist_X_Admin	4,404,548	1,007,064	1,795,991	1,601,493	0.228642	0.407758	0.363600
20	Expenses allocated on - Sales	Analysis	Annual_Total_NW	4,002,263	675,492	1,759,326	1,567,445	0.168778	0.439583	0.391640
21	Expenses Direct Assignment	Analysis	Financial Statement	10,979,150	2,621,484	5,999,311	2,358,354			
22	Expenses allocated on - Net plant	Analysis	Net_GPIS	890,408	165,772	326,582	398,053	0.186176	0.366779	0.447046
23	Composite A&G Factor	=13>20	Comp_A&G	$ 75,096,374	$ 14,674,444	$ 32,441,634	$ 27,980,296	0.1954	0.4320	0.3726
24	**Actual Firm Therm Sales(August)**	Analysis	Annual Firm_ ACT	1,296,577,104	187,218,841	557,693,034	551,665,229	0.144395	0.430127	0.425478
25	**Operations & Maintenance**									
26	**Expenses - Adjusted**									
27	Total Operations Expense	EX:2:46		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
28	Total Maintenance Expense	EX:4:26		114,329,957	25,568,839	46,799,501	41,961,616			
29	Less: Purchased Gas	EX:3:5		454,828,378	64,262,645	200,704,535	189,861,198			
30	Subtotal	=26+27-28	O&M _X_ Gas	436,271,809	86,600,053	184,749,969	164,921,786	0.198500	0.423474	0.378025
31	Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709	0.418689	0.254430	0.326880
32	Less: Watergate Expenses	EX:2:8		102,248	102,248	-	-			
33	Less: Administrative & General Expense	EX:2:44		215,827,393	39,138,720	97,390,911	79,297,762			
34	Operations & Maintenance Expenses -									
25	Adjusted	=29- (30>32)	O& M _Adjusted	$ 205,007,176	$ 40,938,488	$ 83,457,373	$ 80,611,316	0.199693	0.407095	0.393212
36	**Operations Expense Excluding**									
37	**Purchased Gas & Uncollectibles**									
38	Total Operations Expense	EX:2:40		$ 776,770,230	$ 125,293,859	$ 338,655,003	$ 312,821,368			
39	Less: Purchased Gas	EX:2:2		454,828,378	64,262,645	200,704,535	189,861,198			
40	Less: Uncollectible Accounts	EX:7:21		15,334,992	6,420,597	3,901,686	5,012,709			
41	Operations Expense Excluding									
42	Purchased Gas & Uncollectibles	=37- (38>39)	Nongas_Oper_Exp	$ 306,606,860	$ 54,610,617	$ 134,048,782	$ 117,947,461	0.178113	0.437201	0.384686
43	Average Accounts Receivable	Analysis	Avg_AR	178,799,635	46,805,868	83,264,666	48,729,101	0.261778	0.465687	0.272535

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses (Continued)

Twelve Months Ended March 2024 - AVG
Excluding FERC Portion

	Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	DC	MD	VA
	A	B	C	D	E	F	G	H	I	J
1	**Appliance Service - Field**									
2	Removing/resetting Meters - Direct	EX:2:27	Direct_Meter_Exp	$ 1,689,348	$ 121,682	$ 1,105,374	$ 462,292	0.072029	0.654320	0.273651
3	Removing/resetting Meters - Allocable	EX:2:28		-	-	-	-			
4	SOCP - Direct	EX:2:31	Direct _SOCP	44,751	1,533	8,132	35,086	0.034256	0.181725	0.784019
5	SOCP - Allocable	EX:2:32		0	0	0	0			
6	Total Appliance Service - Field	=2>5	Appl_Svc_X_Admin	$ 1,734,099	$ 123,215	$ 1,113,507	$ 497,378	0.071054	0.642124	0.286822
7	**Distribution - Field**									
8	Operations Expense:									
9	Mains	EX:2:25		$ 1,368,210	$ 291,861	$ 471,936	$ 604,413			
10	Measuring/Regulating Station	EX:2:29		509,583	303,237	123,239	83,107			
11	Maintenance Expense:									
12	Mains	EX:4:11		33,302,827	8,648,128	12,660,520	11,994,178			
13	Services	EX:4:12		35,487,205	9,541,079	15,284,083	10,662,043			
14	Meter & House Regulators	EX:4:19		30,565,014	3,800,788	12,993,731	13,770,496			
15	Measuring & Regulating Station Equipt.	EX:4:17		1,532,095	911,702	370,526	249,868			
16	Gas Light Services	EX:4:18		1,894	-	-	1,894			
17	Total Distribution - Field	=9>16	Dist_X_Admin	$ 102,766,828	$ 23,496,794	$ 41,904,035	$ 37,365,999	0.228642	0.407758	0.363600
18	**Distribution Maintenance Expenses**									
19	Mains	EX:4:11		$ 33,302,827	$ 8,648,128	$ 12,660,520	$ 11,994,178			
20	Services	EX:4:12		35,487,205	9,541,079	15,284,083	10,662,043			
21	Meter & House Regulators	EX:4:13		30,565,014	3,800,788	12,993,731	13,770,496			
22	Compressor Station Equipment	EX:4:16		-	-	-	-			
23	Measuring & Regulating Station Equip.	EX:4:17		1,532,095	911,702	370,526	249,868			
24	Gas Light Services	EX:4:18		1,894	-	-	1,894			
25	Total Distribution Maintenance Expenses	=19>24	Dist_Maint_Exp	$ 100,889,035	$ 22,901,696	$ 41,308,860	$ 36,678,479	0.226999	0.409448	0.363553
26	**Three Part Factor**									
27	Net Rate Base	AL:3:6	Net_Rate_Base	$ 4,256,466,925	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	0.190817	0.372501	0.436682
28	O&M Adjusted	AL:4:33	O & M_Adjusted	205,007,176	40,938,488	83,457,373	80,611,316	0.199693	0.407095	0.393212
29	Total Annual Therm Sales	AL:1:20	Annual _Total _NW	1,682,395,886	283,950,711	739,552,169	658,893,006	0.168778	0.439583	0.391640
30	Three Part Factor	Average 27>29	Three _Part _Factor					0.186429	0.406393	0.407178
31	**Gas Costs Recovered**	EX:3:1	Gas_Cost_Rec	$ 381,002,051	$ 51,891,638	$ 167,476,401	$ 161,634,012	0.136198	0.439568	0.424234
32	**Credit and Debit Card Transactions**	Analysis	Credit_Debit_Card	2,450,284	332,924	1,109,744	1,007,616	0.135872	0.452904	0.411224

WASHINGTON GAS LIGHT COMPANY
FERC ALLOCATION FACTORS BASED ON RATE BASE
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	DESCRIPTION	Reference Sc-Pg-Ln	Reference Allocator	PER BOOK AMOUNTS WG SYSTEM	PER BOOK AMOUNTS Jurisdictional	PER BOOK AMOUNTS Virginia Direct	PER BOOK AMOUNTS FERC	ALLOCATIONS JUR	ALLOCATIONS FERC	ALLOCATIONS Virginia Direct	ALLOCATIONS TOTAL
	A	B	C	D	E		F	G	H		I
1	GAS PLANT IN SERVICE										
2	TRANSMISSION - DEPRECIABLE			$ 1,102,679,913	$ 1,074,355,874	$ 490,774,393	$ 28,324,039				
3	Less Chalk Point			13,995,741	13,995,741	-	-				
4	TOTAL TRANSMISSION DEPRECIABLE			1,088,684,172	1,060,360,133	490,774,393	28,324,039				
5	TRANSMISSION - NON DEPRECIABLE			5,182,929	5,182,929	2,109,955	-				
6	DISTRIBUTION PLANT			6,518,849,521	6,518,849,521	2,903,752,916	-				
7	TOTAL GPIS EXCL. GEN PLT. / Chalk Point		**GENERAL PLANT**	7,612,716,622	7,584,392,582	3,396,637,263	28,324,039	0.99628	**0.00372**	**0.00834**	1.0000
8	GENERAL			394,760,617	393,526,189	161,165,512	1,234,428				
9	TOTAL GPIS EXCL Chalk Point	=LN 2 > 6	**GPIS**	8,007,477,239	7,977,918,771	3,557,802,776	29,558,468	0.99631	**0.00369**	**0.00831**	1.0000
10	ALLOCATED TRANSMISSION PLANT										
11	DEPRECIABLE		**ALLOC DEP TRANS PLT**	$ 1,088,684,172	$ 1,060,360,133	$ 490,774,393	$ 28,324,039	0.97398	**0.02602**	**0.05771**	1.0000
12	NON DEPRECIABLE			5,182,929	5,182,929	2,109,955	-				
13	TOTAL	=LN 9 > 10	**ALLOC TRANS PLT**	$ 1,093,867,101	$ 1,065,543,061	$ 492,884,348	$ 28,324,039	0.97411	**0.02589**	**0.05747**	1.0000
14	CONSTRUCTION WORK IN PROGRESS		**CWIP**	$ 397,111,025	$ 397,111,025	$ 183,449,185	$ -	1.0000	0.0000	0.0000	1.0000
15	CUSTOMER ADVANCES FOR CONSTRUCTION			$ 2,698,381	$ 2,698,381	$ 2,698,381	$ -	1.0000	0.0000	0.0000	1.0000

WASHINGTON GAS LIGHT COMPANY
ALLOCATION FACTORS BASED ON THERM SALES
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	---- Reference ----		PER BOOK AMOUNTS			ALLOCATIONS		
DESCRIPTION	Sc-Pg-Ln	Allocator	Total Shenandoah	Shenandoah VA	W. VA. (FERC)	JUR	FERC	TOTAL
A	B	C	D	E	F C/	G	H	I
1 3 - DAY PEAK SENDOUT								
2 ACTUAL	Per Books		-	(15,438)	15,438			
3 EXCLUDE CUSTOMERS NOT USING TRANS. SYSTI	A/		34,248	34,248	-			
4 EXCLUDE GAS USED BY			-	-	-			
5 ADJUSTED 3-DAY PEAK SENDOUT LINE 2+3+4			34,248	18,810	15,438	0.5492	0.45078	1.0000
6 ANNUAL THROUGHPUT								
7 ACTUAL THERMS	Per Books		-	(3,433,867)	3,433,867			
8 ADJUSTMENT	B/		7,364,850	7,364,850	-			
9 ADJUSTED ANNUAL THROUGHPUT LINE 7+8			7,364,850	3,930,983	3,433,867	0.5337	0.46625	1.0000
10 COMPOSITE (PEAK SENDOUT-ANNUAL SENDOUT)	=(LN 5+LN 9)/2	**COMP PEAK SENDOUT**				0.5415	**0.45851**	1.0000

A/ Virginia - Excludes amounts applicable to New Market, Howell Metal, Mt. Jackson, Mt. View and Strasburg, Virginia served from Columbia Gas Transmission Corporation's 24" and 26" Lines. Use gas at general offices in Winchester, Virginia and includes adjustment for customers served in Virginia from Nineveh 12" line.

B/ Virginia - Excludes all sales applicable to New Market, Strasburg, Mt. Jackson, Mt. View and Howell Metal Virginia Areas.

C/ Represents FERC Firm Transportation Service's actual co-incident peak and throughput for the year.

WASHINGTON GAS LIGHT COMPANY
ALLOCATION FACTORS BASED ON OPERATING EXPENSES
Twelve Months Ended March 2024 - AVG
AVG Rate Base

		------ Reference ------		PER BOOK AMOUNTS				ALLOCATIONS			
	DESCRIPTION	Sc-Pg-Ln	Allocator	WG SYSTEM	Jurisdictional	Virginia Direct	FERC	JUR	FERC	Virginia Direct	TOTAL
	A	B	C	D	E		F	G	H		I
1	ALLOCATED OPERATING EXPENSES										
2	(EXCL GAS PURCHASED AND A&G)										
3	OPERATION										
4	TRANSMISSION			3,248,517	3,165,280	1,410,951	83,237				
5	DISTRIBUTION			24,746,378	24,746,378	9,414,983	-				
6	CUSTOMER ACCOUNTS			52,124,547	52,124,547	19,795,414	-				
7	CUSTOMER SERVICE INFORMATION			3,396,745	3,396,745	1,486,218	-				
8	SALES PROMOTIONS			604,195	604,195	281,019	-				
9	TOTAL OPERATION less A&G / GAS PURCHASE	=LN 4 > 9		$ 84,120,382	$ 84,037,145	$ 32,388,585	$ 83,237				
10	MAINTENANCE										
11	TRANSMISSION			3,088,029	3,010,511	1,314,014	77,518				
12	DISTRIBUTION			109,376,242	109,376,242	39,853,483	-				
13	GENERAL			1,569,038	1,563,201	638,194	5,838				
14	TOTAL MAINTENANCE	=LN 12 > 14		$ 114,033,310	$ 113,949,954	$ 41,805,692	$ 83,356				
15	TOTAL OPER EXP & MAINT EXCLUDING										
16	GAS PURCHASED AND A&G EXPENSES	=LN 10 + 15	**OPEX -X-GP AND A&G**	$ 198,153,692	$ 197,987,099	$ 74,194,276	$ 166,593	0.999159000	**0.0008410**	**0.0022**	1.0000
17	DIRECT LABOR CHARGES		**Direct_Labor**	$ 113,457,726	$ 113,349,657	$ 42,649,762	$ 108,069	0.9990	**0.0010**	**0.0025**	1.0000

Income Statement Related Deferred Tax Analysis
Tax Year 2023
Federal Damped for the State Impact and State(s) @ The Statutory Rate

Pulls Only - Do not change   The numbers come from "\\spwsvfil001\finance\Regulatory Accounting\01. COS Production Environment\PBCOSA\2023-12 Dec\support\WGL - 2023 EOY

Federal	PowerTax Federal APB11	Rate True Up	Net
CMWG	92,349,123	668,554	93,017,678
DCWG	154,622,878	609,507	155,232,386
MDWG	375,856,696	1,398,576	377,255,272
VAWG	403,686,917	2,034,430	405,721,347
WG Fed Tot	1,026,515,614	4,711,068	1,031,226,682
WG State Totals			234,807,214
WG Grand T	1,026,515,614	4,711,068	1,266,033,897
HAMP Fed		-	-
HAMP State			
HAMP Total	-	-	-

PowerTax States	
VA	**VA APB11**
CMWG	8,796,211
DCWG	15,246,048
MDWG	32,747,966
VAWG	38,678,944
Virginia To	95,469,170
MD	**MD APB11**
CMWG	7,897,335
DCWG	14,042,376
MDWG	30,730,389
VAWG	34,431,908
Maryland T	87,102,007
DC	**DC APB11**
CMWG	3,470,528
DCWG	6,504,836
MDWG	17,251,616
VAWG	15,361,550
D.C. Total	42,588,531
WV	**WV APB11**
CMWG	871,836
DCWG	1,517,049
MDWG	3,333,744
VAWG	3,660,445
WV Total	9,383,074
PA	**PA APB11**
CMWG	
DCWG	
MDWG	
VAWG	240,622
PA Total	240,622
NY	**NY APB11**
CMWG	
DCWG	
MDWG	
VAWG	23,810
NY Total	23,810
HAMP	-

		PBCOSA Dec-2023 Avg Study#288 Tot_GPIS_X_Chalk Point		Ratebase MACRS Plant Allocation Factor
Fed				
CMWG	93,017,678			
DCWG	155,232,386	0.184257	172,371,533.65	0.1671519
MDWG	377,255,272	0.372029	411,860,505.40	0.3993889
VAWG	405,721,347	0.443715	446,994,643.20	0.4334592
	1,031,226,682		1,031,226,682.25	
State				
CMWG	21,035,910			
DCWG	37,310,308	0.184257	41,186,319.68	0.1754048
MDWG	84,063,716	0.372029	91,889,675.62	0.3913409
VAWG	92,397,280	0.443715	101,731,219.11	0.4332542
	234,807,214		234,807,214.41	

no state apportionment factor

no state apportionment factor

Washington Gas Light Company
Book vs. Tax True-up Adjustments - Non Plant

Twelve Months Ended March 2024 - AVG

	Description	Account	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Least Cost Planning Expenses - federal	410103		$ 1,124,286	$ 222,485	$ 479,522	$ 422,280	$ -
2	Environmental Costs - Federal	410105		106,670	-	-	106,670	-
3	Environmental Costs - state	410106		1	0	1	0	-
4	EICP - Federal	410113		18,503,632	3,661,686	7,892,020	6,949,926	-
5	Loss on Reacquired Debt - Federal	410115		515,578	70,596	283,664	161,318	-
6	SERP - Federal	410119		1,870,037	370,062	797,593	702,382	-
7	EICP - state	410120		4,149,694	821,184	1,769,894	1,558,616	-
8	Loss on Reacquired Debt - state	410125		1	0	1	1	-
9	Unamort Premium-Hedge Gain-Federal	410126		82,328	14,450	32,135	35,744	-
10	Unamort Premium-Hedge Gain-state	410127		26,254	4,608	10,248	11,398	-
11	SERP - state	410129		27,828	5,456	11,964	10,408	-
12	Uncollectible Accounts Expense - state	410132		1	1	0	0	-
13	Uncollectible Accounts Expense - Federal	410133		31,756	11,232	14,163	6,361	-
14	Accenture Transition Costs - Federal	410134		1,153,745	228,315	492,086	433,344	-
15	Accenture Transition Costs - State	410135		392,027	85,120	216,110	90,798	-
16	DC RC989 - Carry Cst Reg Exp-Federal	410141		268,782	268,782	-	-	-
17	DC RC989 - Carry Cst Reg Exp-state	410143		0	0	-	-	-
18	Purchased Gas Costs - Federal	410144		1,922,307	280,354	769,796	872,157	-
19	Purchased Gas Costs - state	410145		613,002	89,402	245,479	278,121	-
20	Capitalization of Inventory - state	410146		472,251	72,629	184,993	214,629	-
21	Capitalization of Inventory - Federal	410147		1,480,927	257,911	618,094	604,922	-
22	DC RC989 - Carry Cst Pension-Federal	410148		3,192,764	680,870	1,335,668	1,176,225	-
23	DC RC989 - Carry Cst Pension-state	410149		19,502	19,502	-	-	-
24	DC RC989 - Carry Cst DC OPEB-Federal	410150		130,642	25,853	55,720	49,069	-
25	DC RC989 - Carry Cst DC OPEB-state	410151		3,550	703	1,514	1,333	-
26	Maryland Gross Receipts Tax - Federal	410155		458,661	-	458,661	-	-
27	Maryland Gross Receipts Tax - state	410156		130,449	-	130,449	-	-
28	Contingency Reserve - Federal	410165		4,921	974	2,099	1,848	-
29	Contingency Reserve -state	410166		3	0	1	1	-
30	Environmental Costs - Federal	410196		796,192	297,241	498,951	-	-
31	Environmental Costs - state	410197		125,934	32,222	59,468	34,243	-
32	Deferred Pension Costs - Federal	410303		4,749,163	939,812	2,025,575	1,783,776	-
33	Derivatives - Federal	410306		2	0	1	1	-
34	Derivatives - state	410307		72,023	10,504	28,842	32,677	-
35	Pension Expense - Federal	410312		314,721	62,280	134,232	118,209	-
36	Pension Expense - state	410313		147,525	29,194	62,921	55,410	-
37	Maryland Demand Side Management Expenses	410322		18,552	-	18,552	-	-
38	Accrued Vacation - Federal	410324		6,552	1,285	2,817	2,451	-
39	Accrued Vacation - State	410325		(13,056)	(2,674)	(5,640)	(4,742)	-
40	Employee Health Insurance - Federal	410326		691,163	135,503	297,148	258,512	-
41	Employee Health Insurance - state	410327		220,405	34,110	86,460	99,835	-
42	Misc Utility Reserve - Federal	410328		748,086	146,940	321,106	280,040	-
43	Misc Utility Reserve - state	410329		210,731	9,095	93,574	108,061	-
44	OPEB Expenses - Federal	410330		10,064,517	1,991,669	4,292,637	3,780,212	-
45	OPEB Expenses - state	410331		651,995	103,889	258,008	290,098	-
46	Purchased Gas Costs - Federal	410332		66,844	9,749	26,768	30,327	-
47	Purchased Gas Costs - state	410333		12,011	3,251	8,333	427	-
48	Deferred OPEB Expenses - Federal	410334		693	137	295	260	-
49	1994 DC Rate Case Expenses - Federal	410336		1,773,371	1,773,371	-	-	-
50	1994 DC Rate Case Expenses - state	410337		36,002	36,002	-	-	-
51	PDIT 2002 DC Rate Case - Federal	410338		827,639	827,639	-	-	-

Washington Gas Light Company
Book vs. Tax True-up Adjustments - Non Plant

Twelve Months Ended March 2024 - AVG

	Description	Account	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
52	PDIT 2002 DC Rate Case - state	410339		0	0	-	-	-
53	PDIT 2003 DC Rate Case - Federal	410350		12,394	12,394	-	-	-
54	Worker's Compensation - Federal	410352		63,945	12,538	27,488	23,919	-
55	Worker's Compensation - State	410353		20,166	3,112	7,902	9,152	-
56	DC Rights of Way	410361		878,947	878,947	-	-	-
57	DC Rights of Way state	410362		1	1	-	-	-
58	Employees Compensation Expense -Federal	410363		8,560,340	1,689,611	3,659,245	3,211,484	-
59	Employees Compensation Expense -state	410364		650,884	95,928	251,516	303,440	-
60	PDIT Utility - state	410366		1,558	308	665	585	-
61	DIT LCP Federal	411103		(1,124,286)	(222,485)	(479,522)	(422,280)	-
62	Least Cost Planning Expenses - state	411104		(73,129)	(73,129)	-	-	-
63	Environmental Costs - Federal	411105		(187,014)	(66,617)	(120,396)	-	-
64	Environmental Costs - state	411106		(25,620)	(4,054)	(10,384)	(11,182)	-
65	EICP - Federal	411113		(9,094,412)	(1,792,973)	(3,891,349)	(3,410,091)	-
66	Loss on Reacquired Debt - Federal	411115		(515,578)	(98,292)	(192,680)	(224,605)	-
67	SERP - Federal	411119		(2,223,401)	(439,474)	(949,263)	(834,664)	-
68	EICP - state	411120		(1,149,130)	(177,133)	(450,218)	(521,779)	-
69	Loss on Reacquired Debt - state	411125		(1)	(0)	(0)	(1)	-
70	Unamort Premium-Hedge Gain-Federal	411126		(82,328)	(15,695)	(30,767)	(35,865)	-
71	Unamort Premium-Hedge Gain-state	411127		(26,254)	(5,005)	(9,812)	(11,437)	-
72	SERP - state	411129		(113,629)	(17,626)	(44,606)	(51,397)	-
73	Uncollectible Accounts Expense - state	411132		(0)	(0)	(0)	0	-
74	Uncollectible Accounts Expense - Federal	411133		(31,756)	(11,232)	(14,163)	(6,361)	-
75	Accenture Transition Costs - Federal	411134		(795,641)	(157,246)	(339,727)	(298,667)	-
76	Accenture Transition Costs - State	411135		(339,886)	(68,160)	(167,741)	(103,985)	-
77	DC RC989 - Carry Cst Reg Exp-Federal	411141		(381,618)	(381,618)	-	-	-
78	DC RC989 - Carry Cst Reg Exp-state	411143		(35,981)	(35,981)	-	-	-
79	Purchased Gas Costs - Federal	411144		(3,787,545)	(552,386)	(1,516,739)	(1,718,421)	-
80	Purchased Gas Costs - state	411145		(1,207,704)	(184,228)	(472,183)	(551,293)	-
81	Purchased Gas Costs - state	411146		(330,871)	(50,472)	(129,364)	(151,036)	-
82	Purchased Gas Costs - state	411147		(1,037,579)	(151,323)	(415,503)	(470,753)	-
83	DC RC989 - Carry Cst Pension-Federal	411148		(3,344,347)	(661,813)	(1,426,404)	(1,256,130)	-
84	DC RC989 - Carry Cst Pension-state	411149		(67,845)	(10,506)	(26,604)	(30,736)	-
85	DC RC989 - Carry Cst DC OPEB-Federal	411150		(125,053)	(125,053)	-	-	-
86	DC RC989 - Carry Cst DC OPEB-state	411151		(1,768)	(1,768)	-	-	-
87	Maryland Gross Receipts Tax - Federal	411155		(66,832)	-	(66,832)	-	-
88	Maryland Gross Receipts Tax - state	411156		(5,499)	-	(5,499)	-	-
89	Contingency Reserve - Federal	411165		(4,920)	(974)	(2,098)	(1,848)	-
90	Contingency Reserve -state	411166		(1)	(0)	(0)	(0)	-
91	Environmental Costs - Federal	411196		(401,274)	(167,404)	(233,871)	-	-
92	Deferred Pension Costs - Federal	411303		(5,036,385)	(1,045,704)	(2,121,995)	(1,868,686)	-
93	Deferred Pension Costs - state	411304		(91,597)	(14,182)	(35,921)	(41,494)	-
94	Derivatives - state	411307		(71,806)	(10,472)	(28,755)	(32,579)	-
95	Pension Expense - Federal	411312		(1,338,386)	(264,278)	(571,906)	(502,202)	-
96	Pension Expense - state	411313		(418,148)	(51,531)	(134,000)	(232,616)	-
97	Amort of MD Shared Gain/sale 11th street - FED	411318		(17,059)	-	(17,059)	-	-
98	Amort of MD Shared Gain/sale 11th street - FED	411319		(5,440)	-	(5,440)	-	-
99	Maryland Demand Side Management Expenses	411322		(18,552)	-	(18,552)	-	-
100	Accrued Vacation - Federal	411324		(325,084)	(64,331)	(138,652)	(122,101)	-
101	Accrued Vacation - State	411325		(88,520)	(906)	(40,651)	(46,964)	-
102	Employee Health Insurance - Federal	411326		(916)	(181)	(391)	(344)	-

Washington Gas Light Company
Book vs. Tax True-up Adjustments - Non Plant

Twelve Months Ended March 2024 - AVG

	Description	Account	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
103	Employee Health Insurance - state	411327		(293)	(46)	(115)	(132)	-
104	OPEB Expenses - Federal	411330		(8,878,969)	(2,061,109)	(3,668,323)	(3,149,537)	-
105	OPEB Expenses - state	411331		(273,918)	(45,330)	(109,784)	(118,805)	-
106	Purchased Gas Costs - Federal	411332		(31,949)	(4,659)	(12,794)	(14,495)	-
107	Purchased Gas Costs - state	411333		(884)	(1,554)	(3,983)	4,653	-
108	Deferred OPEB Expenses - Federal	411334		(693)	(137)	(295)	(260)	-
109	1994 DC Rate Case Expenses - Federal	411336		(1,832,971)	(1,832,971)	-	-	-
110	1994 DC Rate Case Expenses -state	411337		19,868	19,868	-	-	-
111	PDIT 2002 DC Rate Case - Federal	411338		(853,531)	(853,531)	-	-	-
112	PDIT 2002 DC Rate Case - state	411339		(8,259)	(8,259)	-	-	-
113	PDIT 2003 DC Rate Case - Federal	411350		(12,394)	(12,394)	-	-	-
114	Worker's Compensation - State	411353		(429)	(85)	(183)	(161)	-
115	DC Rights of Way	411361		(878,947)	(878,947)	-	-	-
116	DC Rights of Way state	411362		(2)	(2)	-	-	-
117	Employees Compensation Expense -Federal	411363		(10,334,912)	(2,043,766)	(4,410,582)	(3,880,564)	-
118	Employees Compensation Expense -state	411364		(1,216,778)	(94,265)	(520,840)	(601,672)	-
119	PDIT Utility - Federal	411365		(0)	(0)	(0)	(0)	-
120	PDIT Utility - state	411366		(1,560)	(297)	(583)	(679)	-
121	Total Non Plant ADIT			$ 10,091,480	$ 1,584,516	$ 5,122,207	$ 3,384,758	$ -

Washington Gas Light Company
Operation and Maintenace Expenses - Labor
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operation Expenses**							
2	Gas Purchased		Annual_ Firm_NW	$ 33,113	$ 4,811	$ 14,139	$ 14,164	
3	Purchased Gas Expenses - Allocable	AL:1:25	Pipeline_NW	482,342	81,409	212,029	188,904	-
4	Purchased Gas Expenses - Direct	AL:1:25	Financial Stmt.	41,593	431	11,432	29,730	-
5	Purchased Gas Expenses - Hexane	AL:1:25	Financial Stmt.	-	-	-	-	-
6	Purchased Gas Expense - Chalk Point		Financial Stmt.	15,480	-	15,480	-	-
7	Propane Holding			-	-	-	-	-
8	Watergate		Financial Stmt.	79,209	79,209	-	-	-
9	Hampshire Exchange Service	AL:1:19	Total_Weather_All_NW	-	-	-	-	-
10	Property Modifications - Chalk Point		Financial Stmt.	-	-	-	-	-
11	Storage - Direct			-	-	-	-	-
12	Storage - Allocable	AL:1:19	Total_Weather_All_NW	2,074,729	341,854	881,562	851,313	-
13	Transmission	AL:2:8	Transmission_Plnt	1,114,120	164,336	431,925	489,011	28,848
14	Transmission - Chalk Point		Financial Stmt.	14,453	-	14,453	-	-
15	Transmission - Panda		Financial Stmt.	5,813	-	5,813	-	-
16	Distribution							-
17	Supervision and Engineering -							-
18	Distribution	AL:5:17	Dist_X_Admin	56,707	12,966	23,123	20,619	-
19	Appliance Service - Direct	AL:5:6	Financial Stmt.	-	-	-	-	-
20	Appliance Service - Allocable	AL:5:6	Appl_Svc_X_Admin	-	-	-	-	-
21	Other	AL:2:22	Tot_Dist_Plnt	1,704,899	270,941	631,629	802,329	-
22	Load Dispatching	AL:1:32	Comp_Peak_ Ann_NW	1,540,673	240,242	673,228	627,203	-
23	Load Dispatching - Chalk Point		Financial Stmt.	-	-	-	-	-
24	Compressor Station Equipment	AL:1:32	Comp_Peak_ Ann_NW	-	-	-	-	-
25	Mains	AL:2:16	Dist_Mains_Plnt	423,170	90,269	145,964	186,937	-
26	Mains - Chalk Point	AL:2:16	Financial Stmt.	-	-	-	-	-
27	Removing/Setting Meters - Direct		Financial Stmt.	353,781	-	353,645	136	-
28	Removing/Setting Meters - Allocable	AL:5:2	Direct_Meter_Exp	-	-	-	-	-
29	Meas and Reg Station Equip	AL:2:17	Dist_Meas_Reg_Plnt	312,688	186,071	75,621	50,996	-
30	Meas and Reg Station Equip-Chalk Point		Financial Stmt.	-	-	-	-	-
31	Services On Customer Premises-Direct		Financial Stmt.	29,851	1,037	4,878	23,936	-
32	Services On Customer Premises-Allocable	AL:5:4	Direct _SOCP	-	-	-	-	-
33	Office Expenses -							-
34	Distribution	AL:5:17	Dist_X_Admin	6,522,726	1,491,368	2,659,696	2,371,662	-
35	Appliance Service - Direct	AL:5:6	Financial Stmt.	-	-	-	-	-
36	Appliance Service - Alloc.	AL:5:6	Appl_Svc_X_Admin	-	-	-	-	-
37	Other	AL:2:16	Dist_Mains_Plnt	-	-	-	-	-
38	Rents	AL:4:12	Avg_Meters	-	-	-	-	-
39	Customer Accounts	WEX:9:22		5,976,662	817,956	2,660,756	2,497,949	-
40	Customer Service And Information Expense	AL:4:12	Avg_Meters	675,013	93,524	266,609	314,879	-
41	Informational expense - Direct		Financial Stmt.	-	-	-	-	-
42	Sales Expense	AL:4:12	Avg_Meters	263,889	36,562	104,228	123,099	-
43	Advertising Exp - Direct		Financial Stmt.	-	-	-	-	-
44	Administrative and General	WEX:11:31		51,363,558	10,207,551	22,066,378	19,047,810	41,819
45								
46	Total Operation Expenses	=2>36		$ 73,084,468	$ 14,120,535	$ 31,252,588	$ 27,640,678	$ 70,667

Washington Gas Light Company
Operation and Maintenance Expenses - Labor
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	Sc-Pg-Ln (Reference)	Allocator (Reference)	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Maintenance Expenses**							
2	Storage	AL:1:19	Total_Weather_All_NW	$ 182,296	$ 30,037	$ 77,458	$ 74,801	$ -
								0
3	Transmission	AL:2:8	Transmission_Plnt	1,413,305	208,466	547,913	620,330	36,595
4	Transmission - Chalk Point							
5	Structures & Improvements		Financial Stmt.	27,724	-	27,724	-	-
6	Measuring & Regulating Station Equipment		Financial Stmt.	16,430		16,430	-	-
7	Transmission - Panda							
8	Structures & Improvements							
9	Measuring & Regulating Station Equipment			-	-	-	-	-
10	Distribution							0
11	Mains		Financial Stmt.	6,090,916	996,933	2,807,037	2,286,945	-
12	Services		Financial Stmt.	12,162,250	3,357,534	5,600,047	3,204,669	-
13	Meter & House Regulator Installations Direct		Financial Stmt.	13,823,239	1,879,116	5,470,734	6,473,388	-
14	Meter & House Regulator Installations Allocable		Financial Stmt.	427,767	58,150	169,295	200,322	-
15	General DIMP Expenditures		Financial Stmt.					
16	Compressor Station Equipment	AL:4:12	Avg_Meters	-	-	-	-	-
17	Measuring and Regulating Station Equipment	AL:1:19	Total_Weather_All_NW	589,570	45,835	488,989	54,746	-
18	Gas Light Services		Financial Stmt.	1,115	-	-	1,115	-
19	Meter & House Regulators		Financial Stmt.	313,328	49,794	116,081	147,453	-
20	Supervision and Engineering -							0
21	Appliance Service	AL:2:14	Mtr_Hse_Reg_Plnt	-	-	-	-	-
22	Other	AL:5:25	Dist_Maint_Exp	5,053,459	1,147,129	2,069,131	1,837,199	-
23	Other Equipment - Direct		Financial Stmt.	228	228	-	-	-
24	Other Equipment - Allocable	AL:5:17	Dist_X_Admin	54,879	12,548	22,377	19,954	-
25	Maintenance of General Plant	AL:2:26	Genl_Plnt	216,752	40,262	87,522	88,162	806
26	Total Maintenance - Labor	=2>20		$ 40,373,257	$ 7,826,032	$ 17,500,740	$ 15,009,083	$ 37,402
27	Total Operation - Labor	WEX:5:46		73,084,468	14,120,535	31,252,588	27,640,678	70,667
28	Total Ops and Maintenance Exp.-Direct Labor	=21+22		$ 113,457,726	$ 21,946,567	$ 48,753,328	$ 42,649,762	$ 108,069
29	Total Ops and Maintenance Exp.-Indirect Labor	AL:4:11	Total_Labor	18,750,406	3,626,964	8,057,139	7,048,443	17,860
30	Total Ops and Maintenance Expense - Labor	=23+24		132,208,131	25,573,530	56,810,467	49,698,205	125,929

Washington Gas Light Company
Operation and Maintenance Expenses - Other
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operation Expenses**							
2	Gas Purchased	EX:3:8	Annual_ Firm_NW	$ 454,795,265	$ 64,257,835	$ 200,690,396	$ 189,847,034	$ -
3	Purchased Gas Expenses - Allocable	AL:1:25	Pipeline_NW	414,492	69,957	182,204	162,332	-
4	Purchased Gas Expenses - Direct	AL:1:25	Pipeline_NW	13,275	165	6,367	6,743	-
5	Purchased Gas Expenses - Hexane	AL:1:25	Pipeline_NW	3,460,797	-	-	3,460,797	-
6	Purchased Gas Expense - Chalk Point		Financial Stmt.	16,564	-	16,564	-	-
7	Propane Holding			-	-	-	-	-
8	Watergate		Financial Stmt.	23,039	23,039	-	-	-
9	Hampshire Exchange Service	AL:1:19	Total_Weather_All_NW	278,568	40,957	119,726	117,885	-
10	Property Modifications - Chalk Point		Financial Stmt.	-	-	-	-	-
11	Storage - Direct			245	-	105	140	-
12	Storage - Allocable	AL:1:19	Total_Weather_All_NW	14,683,109	2,121,974	6,320,821	6,240,314	-
13	Transmission	AL:2:8	Transmission_Plnt	2,100,465	309,824	814,313	921,939	54,388
14	Transmission - Chalk Point		Financial Stmt.	10,519	-	10,519	-	-
15	Transmission - Panda		Financial Stmt.	3,147	-	3,147	-	-
16	Distribution							
17	Supervision and Engineering -							
18	Distribution	AL:5:17	Dist_X_Admin	898,728	205,487	366,464	326,777	-
19	Appliance Service - Direct			-	-	-	-	-
20	Appliance Service - Allocable	AL:5:6	Financial Stmt.	-	-	-	-	-
21	Other	AL:2:22	Tot_Dist_Plnt	*3,503,726*	*733,312*	*1,255,205*	*1,515,209*	-
22	Load Dispatching	AL:1:32	Comp_Peak_ Ann_NW	613,969	95,738	268,286	249,945	-
23	Load Dispatching - Chalk Point		Financial Stmt.	-	-	-	-	-
24	Compressor Station Equipment	AL:1:32	Comp_Peak_ Ann_NW	-	-	-	-	-
25	Mains	AL:2:16	Dist_Mains_Plnt	945,040	201,592	325,972	417,475	-
26	Mains - Chalk Point		Financial Stmt.	-	-	-	-	-
27	Removing/Setting Meters - Direct		Financial Stmt.	1,335,567	121,682	751,730	462,156	-
28	Removing/Setting Meters - Allocable	AL:5:2	Direct_Meter_Exp	-	-	-	-	-
29	Meas and Reg Station Equip	AL:2:17	Dist_Meas_Reg_Plnt	196,894	117,166	47,617	32,111	-
30	Meas and Reg Station Equip-Chalk Point		Financial Stmt.	-	-	-	-	-
31	Services On Customer Premises-Direct		Financial Stmt.	14,900	496	3,255	11,150	-
32	Services On Customer Premises-Allocable	AL:5:4	Direct _SOCP	0	0	0	0	-
33	Office Expenses -							
34	Distribution	AL:5:17	Dist_X_Admin	6,033,259	1,379,455	2,460,112	2,193,692	-
35	Appliance Service - Direct			-	-	-	-	-
36	Appliance Service - Allocable	AL:5:6	Appl_Svc_X_Admin	-	-	-	-	-
37	Other	AL:2:16	Dist_Mains_Plnt	245,147	52,294	84,559	108,295	-
38	Rents		Avg_Meters	14,652	-	298	14,355	-
39	Customer Accounts	WEX:10:19		46,147,885	11,950,449	16,899,972	17,297,464	-
40	Customer Service and Inform. Exp - Allocable	AL:4:12	Avg_Meters	2,481,052	343,753	979,940	1,157,359	-
41	Information Exp - Direct			240,680	75,837	150,863	13,981	-
42	Sales Expense	AL:4:12	Avg_Meters	338,537	46,905	133,712	157,920	-
43	Advertising Exp. - Direct	AL:4:12		1,770	-	1,770	-	-
44	Administrative and General			164,490,708	28,931,170	75,324,532	60,249,951	(14,946)
45								
46	Total Operation Expenses	=1>46		$ 703,301,999	$ 111,079,085	$ 307,218,447	$ 284,965,025	$ 39,442

Washington Gas Light Company
Operation and Maintenance Expenses - Other
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Maintenance Expenses**							
2	Storage	AL:1:19	Total_Weather_All_NW	$ 197,707	$ 32,576	$ 84,007	$ 81,124	$ -
3	Transmission	AL:2:8	Transmission_Plnt	1,580,428	233,117	612,704	693,684	40,923
4	Transmission - Chalk Point							
5	Structures & Improvements		Financial Stmt.	15,823	-	15,823	-	-
6	Measuring & Regulating Station Equipment		Financial Stmt.	9,112	-	9,112	-	-
7	Transmission - Panda							
8	Structures & Improvements		Financial Stmt.	-	-	-	-	-
9	Measuring & Regulating Station Equipment		Financial Stmt.	25,208	-	25,208	-	-
10	Distribution							
11	Mains		Financial Stmt.	27,211,911	7,651,194	9,853,483	9,707,233	-
12	Services		Financial Stmt.	23,324,955	6,183,545	9,684,036	7,457,374	-
13	Meter & House Regulator Installations Direct		Financial Stmt.	16,042,133	1,834,670	7,225,566	6,981,897	-
14	Meter & House Regulator Installations Alloc.	AL:4:12	Avg_Meters	271,876	28,851	128,136	114,889	-
15	General DIMP Expenditures		Financial Stmt.	2,519	-	-	2,519	-
16	Compressor Station Equipment	AL:1:19	Total_Weather_All_NW	-	-	-	-	-
17	Measuring and Regulating Station Equipment		Financial Stmt.	942,525	865,867	(118,464)	195,122	-
18	Gas Light Services		Financial Stmt.	779	-	-	779	-
19	Meter & House Regulators	AL:2:14	Mtr_Hse_Reg_Plnt	487,023	77,397	180,432	229,194	-
20	Supervision and Engineering -							
21	Appliance Service	AL:2:14	Mtr_Hse_Reg_Plnt	-	-	-	-	-
22	Other	AL:5:25	Dist_Maint_Exp	2,268,370	514,917	928,780	824,672	-
23	Other Equipment - Direct		Financial Stmt.	4,202	161	270	3,771	-
24	Other Equipment - Allocable	AL:5:17	Dist_X_Admin	303,200	69,324	123,632	110,243	-
25	Maintenance of General Plant	AL:2:26	Genl_Plnt	1,352,286	251,187	546,036	550,032	5,031
26	Total Maintenance	=2>20		$ 74,040,055	$ 17,742,807	$ 29,298,761	$ 26,952,533	$ 45,954
27	Total Operation	WEX:7:46		703,301,999	111,079,085	307,218,447	284,965,025	39,442
28	Total Operation and Maintenance Expenses	=26+27		$ 777,342,055	$ 128,821,892	$ 336,517,208	$ 311,917,558	$ 85,397

Washington Gas Light Company
Customer Accounts - Labor
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----- Reference ----- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Customer Accounts**							
2	General Supervision-Direct		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
3	General Supervision-Allocable	AL:4:10	Customer_Accts	-	-	-	-	-
4	Total General Supervision	2+3		$ -	$ -	$ -	$ -	$ -
5	Meter Reading-Direct		Financial Stmt.	3,019,382	458,724	1,468,714	1,091,943	-
6	Meter Reading-Allocable	AL:4:12	Avg_Meters	477,816	66,202	188,723	222,891	-
7	Total Meter Reading	=3+4		$ 3,497,198	$ 524,926	$ 1,657,437	$ 1,314,834	$ -
8	Dispatch Applications and Orders-Direct		Financial Stmt.	329,671	361	162,614	166,695	-
9	Dispatch Applications and Orders-Allocable	AL:4:12	Avg_Meters	1,299,013	179,980	513,071	605,962	-
10	Total Dispatch Applications and Orders	=6+7		$ 1,628,684	$ 180,341	$ 675,685	$ 772,657	$ -
11	Customer Collection Expenses							
12	Customer Credit and Appliance Service-Direct		Financial Stmt.	37,447	-	6,392	31,055	-
13	Customer Credit and Appliance Service-Allocal	AL:4:5	Avg_Meters	239,416	33,171	94,562	111,683	-
14	Other-Direct			-	-	-	-	-
15	Other-Allocable	AL:4:12	Avg_Meters	1,670	231	660	779	-
16	Total Customer Collection Expenses	=10>13		$ 278,533	$ 33,403	$ 101,614	$ 143,517	$ -
17	Billing and Accounting-Direct		Financial Stmt.	-	-	-	-	-
18	Customer Billing and Acct-POR Collection Exp		No Labor	-	-	-	-	-
19	Billing and Accounting-Allocable	AL:4:12	Avg_Meters	572,247	79,286	226,020	266,941	-
20	Total Billing and Accounting	=15+16		$ 572,247	$ 79,286	$ 226,020	$ 266,941	$ -
21	Uncollectible Accounts		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
22	Total Customer Accounts	=4+7+10+16+20+21		$ 5,976,662	$ 817,956	$ 2,660,756	$ 2,497,949	$ -

Washington Gas Light Company
Customer Accounts - Other
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	---- Reference ---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Customer Accounts**							
2	General Supervision-Direct			$ -	$ -	$ -	$ -	$ -
3	General Supervision-Allocable	AL:4:10	Customer_Accts	-	-	-	-	-
4	Total general Supervision			$ -	$ -	$ -	$ -	$ -
5	Meter Reading-Direct		Financial Stmt.	$ (3,019,382)	$ (458,724)	$ (1,468,714)	$ (1,091,943)	$ -
6	Meter Reading-Allocable	AL:4:12	Avg_Meters	5,026,735	696,461	1,985,407	2,344,866	0
7	Total Meter Reading	=3+4		$ 2,007,353	$ 237,737	$ 516,693	$ 1,252,923	$ -
8	Dispatch Applications and Orders-Direct		Financial Stmt.	$ 1,841,641	$ 296,184	$ 969,565	$ 575,892	$ -
9	Dispatch Applications and Orders-Allocable	AL:4:12	Avg_Meters	12,556,695	1,739,748	4,959,512	5,857,434	0
10	Total Dispatch Applications and Orders	=6+7		$ 14,398,335	$ 2,035,932	$ 5,929,077	$ 6,433,326	$ -
11	Customer Collection Expenses							
12	Customer Credit and Appliance Service-Direct		Financial Stmt.	$ (29,179)	$ -	$ (52,441)	$ 23,262	$ -
13	Customer Credit and Appliance Service-Allocal	AL:4:5	Avg_Meters	8,133,753	2,158,743	3,804,714	2,170,296	0
14	Other-Direct			0	0	0	0	0
15	Other-Allocable	AL:5:32	Avg_Meters	(1,671,363)	(231,570)	(660,138)	(779,656)	0
16	Credit and Debit Card Transactions	AL:5:32	Credit_Debit_Card	3,520,829	478,381	1,594,599	1,447,850	0
17	Total Customer Collection Expenses	=10>13		$ 9,954,040	$ 2,405,553	$ 4,686,734	$ 2,861,752	$ -
18	Billing and Accounting-Direct		Financial Stmt.	$ 108,799	$ 108,700	$ -	$ 99	$ -
19	Customer Billing and Acct-POR Collection Exp		Financial Stmt.	621,466	226,115	395,350	-	-
20	Billing and Accounting-Allocable	AL:4:12	Avg_Meters	3,722,900	515,813	1,470,432	1,736,655	0
21	Total Billing and Accounting	=15+16		$ 4,453,165	$ 850,629	$ 1,865,783	$ 1,736,754	$ -
22	Uncollectible Accounts		Financial Stmt.	$ 15,334,992	$ 6,420,597	$ 3,901,686	$ 5,012,709	$ -
23	Total Customer Accounts	4+7+10+16+20+21		$ 46,147,885	$ 11,950,449	$ 16,899,972	$ 17,297,464	$ -

Washington Gas Light Company
Administrative and General Expenses - Labor
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Administrative & General Expenses**							
2	Administrative & General Salaries-Direct		Financial Stmt.	$ 3,425,493	$ 748,454	$ 1,425,727	$ 1,209,494	$ 41,819
3	Administrative & General Salaries-Allocable	AL:4:23	Comp_A&G	46,299,820	9,047,362	20,001,522	17,250,935	-
4	Office Supplies & Expenses-Direct		Financial Stmt.	25,166	12,056	1,462	11,648	
5	Office Supplies & Expenses-Allocable	AL:4:23	Comp_A&G	166,863	32,606	72,085	62,172	-
6	Outside Services	AL:5:30	Three _Part _Factor	100,287	18,696	40,756	40,835	
7	Property Insurance	AL:3:13	Net_GPIS	-	-	-	-	-
8	Injuries & Damages	AL:4:11	Total_Labor	30,858	5,975	13,273	11,611	-
9	Pension Expense	AL:4:11	Total_Labor	-	-	-	-	-
10	DC Regulatory							
11	Pension Expense		No Labor	-	-	-	-	-
12	Amortization of Rate Case Expenses		No Labor	-	-	-	-	-
13	Least Cost Planning Expenses		No Labor	-	-	-	-	-
14	Employee Health Benefits			496	96	213	187	-
15	OPEB		Financial Stmt.	-	-	-	-	-
16	Rate Case Expenses-Direct		Financial Stmt.	863,636	306,930	433,319	123,386	-
17	Rate Case Expenses-Allocable	AL:4:23	Comp_A&G	6,871	1,343	2,968	2,560	-
18	DC PSC Assessment Expense		Financial Stmt.	-	-	-	-	-
19	General Advertising Expenses - Direct	AL:4:23	Comp_A&G	-	-	-	-	-
20	General Advertising Expenses - Allocable	AL:4:23	Comp_A&G					
21	Environmental Expense		No Labor	-	-	-	-	-
22	Environmental Reserve Adjustment		No Labor	-	-	-	-	-
23	Rents		No Labor	-	-	-	-	-
24	MD Demand Side Management Expenses		No Labor	-	-	-	-	-
25	VA Care Expenses		Financial Stmt.	270,395	-	-	270,395	-
26	MD EmPOWER MD Expenses		No Labor	-	-	-	-	-
27	Multi-Family Unit Contribution Amortization Expense		No Labor	-	-	-	-	-
28	Multi-Family Unit Contribution Amortization Expense - Allocable		No Labor	-	-	-	-	-
29	Miscellaneous General Expenses-Direct		Financial Stmt.	893	269	411	212	-
30	Miscellaneous General Expenses-Allocable	AL:4:23	Comp_A&G	172,782	33,763	74,642	64,377	-
31	Total Administrative & General Expenses	= 2>27		$ 51,363,558	$ 10,207,551	$ 22,066,378	$ 19,047,810	$ 41,819

Washington Gas Light Company
Administrative and General Expenses - Other
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	----Reference---- Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Administrative & General Expenses**							
2	Administrative & General Salaries-Direct		Financial Stmt.	$ 606,862	$ 182,409	$ 222,765	$ 240,246	$ (38,557)
3	Administrative & General Salaries-Allocable	AL:4:23	Comp_A&G	54,216,660	10,594,378	23,421,597	20,200,685	
4	Office Supplies & Expenses-Direct		Financial Stmt.	3,917,238	1,091,447	1,730,271	1,093,315	2,204
5	Office Supplies & Expenses-Allocable	AL:4:23	Comp_A&G	32,879,771	6,424,975	14,204,061	12,250,734	
6	Outside Services	AL:5:30	Three _Part _Factor	37,335,287	7,034,972	15,135,536	15,164,779	
7	Property Insurance	AL:3:13	Net_GPIS	-	-	-	-	
8	Injuries & Damages	AL:4:11	Total_Labor	18,965,042	3,671,979	8,157,139	7,135,924	
9	Pension Expense	AL:4:11	Total_Labor	(219,656)	(42,494)	(94,398)	(82,580)	(185)
10	DC Regulatory							
11	Pension Expense		Financial Stmt.	-	-	-	-	
12	Amortization of Rate Case Expenses		Financial Stmt.	475,776	475,776	-	-	
13	Least Cost Planning Expenses		Financial Stmt.	-	-	-	-	
14	Employee Health Benefits	AL:4:11	Total_Labor	24,779,279	4,793,687	10,648,963	9,315,789	20,840
15	OPEB		Financial Stmt.	(34,007,440)	(6,584,462)	(14,627,092)	(12,795,885)	-
16	Rate Case Expenses-Direct		Financial Stmt.	662,473	(100,377)	615,754	146,489	607
17	Rate Case Expenses-Allocable	AL:4:23	Comp_A&G	2,652	518	1,146	988	
18	DC PSC Assessment Expense		Financial Stmt.	-	-	-	-	-
19	General Advertising Expenses - Direct	AL:4:23	Comp_A&G	1,269	-	984	285	-
20	General Advertising Expenses - Allocable	AL:4:23	Comp_A&G	644,209	125,884	278,298	240,027	-
21	Environmental Expense		Financial Stmt.	686,319	263,068	423,250	-	-
22	Environmental Reserve - Regulatory Adjustment		Financial Stmt.	1,738,655	-	-	1,738,655	-
23	Rents		Financial Stmt.	263,877	-	-	263,877	
24	MD Demand Side Management Expenses		Financial Stmt.	1,041,022	203,424	449,721	387,876	
25	VA Care Expenses		Financial Stmt.	4,023,952	-	-	4,023,952	
26	MD EmPOWER MD Expenses		Financial Stmt.	13,710,995	-	13,710,995	-	
27	Multi-Family Unit Contribution Amortization Expense		Financial Stmt.	199,129	17,451	140,914	40,764	
28	Multi-Family Unit Contribution Amortization Expense - Allocable			-	-	-	-	
29	Miscellaneous General Expenses-Direct		Financial Stmt.	366,954	348,562	(45,939)	64,186	145
30	Miscellaneous General Expenses-Allocable	AL:4:23	Comp_A&G	2,372,272	463,467	1,024,796	884,010	-
31	Total Administrative & General Expenses	= 2>27		$ 164,662,596	$ 28,964,663	$ 75,398,763	$ 60,314,116	$ (14,946)

Washington Gas Light Company
Development of CWC Elimination of Depreciation Expense
RE: Transportation and POE
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

Line No.	Description	Calculation			Transportation	Power-Operated	Total To Be Allocated
1	Total charges to clearing accounts		Transportation Pool	POE Pool	**17,172,978**	**278,422**	
2	Total Charged to O&M Expense						
3	through expense apportionment		Transportation O&M	POE O&M	15,424,153	221,545	
4	% Applicable to Operations & Maintenance	=4/2			0.898164	0.795718	
5	Total Depreciation Accrual						
6	(A/C 108.235/335)		X_108235	X_108335	**(1,066,152)**	**389,005**	
7	Amount to be Eliminated From						
8	Cash Working Capital - Other O&M	=5*7			(957,579)	309,538	(648,041)
		Allocator	**System**		DC	MD	VA
9	Allocation by Jurisdiction	O&M _X_ Gas	$ (648,041)		$ (128,636)	(274,429)	(244,976)

Washington Gas Light Company
<u>District of Columbia Jurisdiction</u>
<u>Class Cost of Service Narrative</u>

Description of Allocation Procedures

General

This exhibit discusses the allocation of total District of Columbia ratemaking rate base, expenses, and revenues to the various District of Columbia customer classes. The methodology is like the jurisdictional allocation study (Exhibit WG (F)-2) used to allocate revenues, expenses, and rate base between the District of Columbia, Maryland, Virginia, and the Federal Energy Regulatory Commission.

The instances in which the allocation methodology in this study differs from that employed in the jurisdictional allocation study occur only when costs are directly assigned in the jurisdictional study and no equivalent direct assignment is possible in the class cost study. The most significant example of such an instance is the direct assignment of "Other" distribution plant which was made on a "situs" basis. No similar means is available for assignment to customer classes within the jurisdiction; that is, although the Company maintains plant investment at original cost by jurisdiction, it does not maintain plant investment cost by individual customer or class of customer except for specific special contracts that require it. The class cost of service study allocation methods employed in this instance and other similar instances are discussed further below.

The class cost study consists of seven main schedules.

- **Schedule SM** (1 page) – summarizes revenues, expenses, and rate base as well at the return earned by customer class.
- **Schedule RV** (1 page) – relates to the allocation of operating revenues to the various customer classes.
- **Schedule EX** (9 pages) – relates to the allocation of operating expenses to the various customer classes. The first page is a summary of expenses and the following pages show the allocation of expenses by function.
- **Schedule RB** (9 pages) – relates to the allocation of rate base among the various customer classes. The first page is summary of the rate base and the following pages show the allocation of rate base by function.
- **Schedule AL** (6 pages) – relates to the development of the allocation factors.
- **Schedule ETR** (1 page) – details the allocation of income taxes.
- **Schedule CC** (4 pages) – summarizes expenses and rate base by cost type (customer, demand, and commodity) and by high-level function.

In general, all the schedules are formatted in a similar manner.

- Column A is a description of the item.
- Column B lists the source of the data on that line. If an item is developed on another schedule, the reference to that schedule, page, and line number will be indicated.
- Column C shows the name of the allocator for that line. For clarity, a naming convention is used to provide a brief description of the allocator.

- Column D shows the cost type for each line. The cost type is generally determined by the class allocation factor.
- Column E shows the per book amounts carried forward from the Per Book Jurisdictional Cost of Service Allocation Study ("PBCOSA").
- Column F contains adjustments made to arrive at the ratemaking total in Column G.
- Columns H-S contain the amounts assigned to each customer class.
- Column T and U are provided for users to add class breakdowns. Refer to the accompanying user guide for more details.

SCHEDULE SUMMARY (SM)

The Summary Page (Schedule SM Page 1) is an income statement that consists of all the allocated amounts of operating revenues, operating expenses, and rate base that were carried forward to Schedule SM from Schedules RV, EX, and RB, and reflects the earned return by customer class.

Revenues

Operating Revenue, shown on Summary Page 1, Line 1, is developed on Schedule Revenue (RV), Page 1, Line 32. Operating Revenue consists of revenues from the sales of gas, distribution service, and other operating revenues. Sales of gas and distribution revenues by class are also explained in detail in Adjustment No. 1 (normal weather therm sales at current base rates) and Adjustment No. 6 (forecasted revenues).

Forfeited Discounts (Non-POR), Forfeited Discounts (POR), Reconnect Revenues, Dishonored Check Charges, Services Initiation Charges, and Field Collection Charges (Schedule RV, Page 1, Lines 11, 12, and 16-19) were directly assigned by class based on an analysis of billing system data. All other operating revenues were allocated among the customer classes in proportion to the revenues from sales of gas and distribution service to each class, or proportion of total customer count.

Expenses

Summary Page 1, Lines 2 through 14 detail operating expenses as they relate to each of the customer classes. The customer class allocation factors for operating expenses are developed from different schedules of the study.

Purchased Gas

Line 3 consists of Cost of Gas Purchased that originated from Schedule EX, Page 2, Line 2. This expense is fully excluded from the cost of service.

Other Operation Expenses

Line 4 consists of all operation expenses other than Cost of Gas Purchased included on

Line 3. Schedule EX, Page 2 summarizes Operating Expenses. Operation expenses other than gas purchased were functionalized and allocated to the classes based on their proportionate responsibility for each component of other operation expense.

<u>Maintenance</u>

This expense, Line 5, relates to the various plant functions and was allocated based on the related allocated plant. The detailed class allocation occurs in Schedule EX, Page 4.

<u>Depreciation</u>

This expense, Line 6, was allocated based on allocated plant by function. The class allocation of depreciation expenses is developed on Schedule EX, Page 6.

<u>Amortization</u>

Amortization of General Plant, Computer Software, and Unrecovered Plant (Lines 7, 8, and 10), was allocated on the same basis as the underlying plant.

<u>Interest on Customer Deposits</u>

Interest on Customer Deposits, Line 10, was allocated to the various classes based on firm gas sales to customers shown on Schedule RV, Page 1, Line 5.

<u>Taxes</u>

General Taxes, Line 13, includes property taxes, gross receipts taxes, payroll taxes (FICA and Medicare), unemployment taxes, and other miscellaneous taxes. The general taxes expenses are developed on Schedule EX, Page 8. Each of these items was allocated to the various classes using a factor representing the underlying activity driver.

State and Federal Income Taxes applicable to District of Columbia operations, Line 15, are developed on Schedule EX, Page 1. Income taxes are allocated based on each class's effective tax rate shown on Schedule ETR, Page 1, Line 27.

<u>Other</u>

Line 19 reflects the Allowance for Funds Used During Construction ("AFUDC").

The data on Lines 20, 21, and 22 reflect the Net Utility Operating Income (Loss), Net Rate Base, and the Return Earned by class of service, respectively.

SCHEDULE RATE BASE (RB)

Rate Base

SCHEDULE RB, Page 1

Page 1 of Schedule RB is a summarization of the allocation of the various elements of net rate base to each customer class. Lines 1 through 12 detail the gross rate base items as they relate to each of the customer classes. Lines 13 through 25 detail the rate base deductions as they relate to each of the customer classes. Line 26, Page 1 of Schedule RB reflects the total net rate base as allocated among the various customer classes.

Gas Plant in Service

Gas Plant in Service, shown on Schedule RB Page 1, Line 1 is developed on Schedule RB, Page 3, Line 15, and includes the following:

Storage Plant — From Schedule RB, Page 2, Line 5 and allocated based on each class's annual weather gas requirements. The annual weather gas allocator is shown on Schedule AL, Page 1, Line 6.

Transmission Plant — Schedule RB Page 2, Line 14 is allocated on a composite factor based on equal weighting of the design day and annual sales factors for each customer class. The allocation factor is shown on Schedule AL, Page 2, Line 7.

Distribution Plant

(a) Compressor Station Equipment and Related Structures and Improvements — Represents District of Columbia's allocated portion of the facilities that are used to inject gas into the system during the winter and generally to monitor the distribution system. Thus, they have been allocated by each class's respective contribution to the District of Columbia jurisdictional annual weather gas sales shown on Schedule AL, Page 1, Line 6.

(b) House Regulators and House Regulator Installations — Allocated based on each class's average number of customer bills reduced to reflect meters at common addresses. The allocation factor is shown on Schedule AL, Page 3, Line 4.

(c) Meter Installations and ENSCAN (electronic meter reading devices) — Allocated based on the meter investment as it relates to each of the classes of service shown on Schedule AL, Page 5, Line 10.

(d) Measuring and Regulating Station Equipment — Consists of those facilities located in the District of Columbia which are used in connection with distribution system operations other than the measurement of gas deliveries to District of Columbia jurisdictional customers. These costs have been allocated based on each class's "composite factor" which reflects an equal weighing of their respective contributions to the total District of Columbia jurisdictional design day and annual requirements. The composite factor is shown on Schedule AL, Page 2, Line 7.

(e) Mains on Line 17 — Mains are allocated among the customer classes using a composite factor based the respective class design day requirements for each class as well as the annual usage for each class, shown on Schedule AL, Page 2, Line 7.

(f) Services on Lines 18 through 24 — On Line 19, Combined Heat and Power ("CHP"), natural gas vehicle ("NGV"), interruptible, and special contract services investment costs are directly assigned to those classes using an estimate of their services costs based on the footage and pipe size per the Company's mapping system and the average cost per foot of pipe from the Company's property accounting system.

The remaining services investments costs are allocated to the firm customer classes on two factors (customer and capacity) to reflect that differing pipe sizes have different costs.

- The customer component of services was determined by multiplying total District of Columbia customers by the average cost per customer. The average cost per customer is determined by dividing the total cost to install the minimum size service line for the residential customers (1 ¼ inch or less) by the number of services. This cost represents the minimum cost required to service all customers. The difference between total service investment and the customer component is the capacity component.
- On Line 22, the capacity component of the service investment is allocated among the firm, non-residential customer classes based the respective class design day requirements for each class in excess of the residential class design day requirements, shown on Schedule AL, Page 2, Line 31.
- On Line 24, the customer component of the services investment is allocated among the firm customer classes using the average number of firm customer bills reduced to reflect customers at common addresses (to represent a single service to customers who have more than one meter installed), shown on Schedule AL, Page 3, Line 11.

(g) Gas Light Services — Allocated based on an analysis of WG's records of the number of gas light services by customer class. The class allocation factor is shown on Schedule AL, Page 5, Line 4.

(h) Meter Investment – Directly assigned to each class of service based on an analysis of customer records of the types of meters in each class and the average cost of each type of meter.

(i) General and Intangible Plant on RB Page 3 — These are allocated based on the allocation of all other property.

Construction Work in Progress

CWIP on Schedule RB, Page 1, Line 3 is developed on Schedule RB, Page 5. As with GPIS discussed above, CWIP is functionalized and allocated to the customer classes based on the underlying cost drivers for each function. In difference to the jurisdictional cost of service study ("PBCOSA"), in the CCOSS, the per book total "Distribution Other" amount has been divided between mains (Schedule RB, Page 5, Line 13) and services (Schedule RB, Page 5, Lines 14 to 18) based on property accounting records.

Material and Supplies

On Schedule RB Page 1, Line 4 includes the average inventory balances of: (1) general supplies used for operation and construction, and (2) oil and propane stock. Material and supplies originated from Schedule RB, Page 6, Line 12.

General Supplies

Supplies used for construction, from Schedule RB, Page 6, Line 3, were allocated to the customer classes based on the total of storage, transmission, and distribution plant as distributed to the customer classes. The allocator used to develop the cost is shown on Schedule AL, Page 4, Line 30. General supplies for operations, Schedule RB, Page 6, Line 4, was allocated on the ratio of each class's therm sales to total jurisdictional therm sales. The annual therm sales allocator is shown on Schedule AL, Page 1, Line 8.

Cash Working Capital

Cash Working Capital, Schedule RB Page 1, Line 10, was allocated among the classes based on Operation and Maintenance expenses less Gas Purchased, Administrative and General and Uncollectible expenses. The allocation factor is developed on Schedule AL, Page 6, Line 37. Cash Working Capital related to multi-family unit payments pursuant to General Services Provision No. 14 on Schedule RB, Page 1, Line 11 are related to residential heating customers and are assigned directly to that class.

Deductions

Reserve for Depreciation

This item was allocated to the customer classes using the same allocation methodology as was employed with the respective plant balances. Schedule RB, Page 7, Line 33 develops the Reserve for Depreciation and is then carried forward to Schedule RB, Page 1, Line 14.

Customer Deposits

Customer Deposits, Line 22, were allocated based on each class's sales of gas revenues to total sales of gas revenues, excluding the interruptible class. The class allocation factor for customer deposits is shown on Schedule RV, Page 1, Line 5.

Deferred Income Taxes

Lines 15 relates to accumulated deferred income taxes related to depreciation. This item was allocated to the various customer classes using net rate base factor, which is shown on Schedule AL, Page 5, Line 2. Other accumulated deferred income taxes on the Lines 5 and 16 to 19 were allocated based on the cost drivers for the underlying activity.

Customer Advances for Construction

This item, Line 21, was allocated based on Distribution Mains Plant Investment shown on Schedule AL, Page 4, Line 20.

Deferred Tenant Allowance

This item, Line 23, was allocated based on how all other rate base was allocated. The development of the factor is shown on Schedule AL, Page 5, Line 2.

SCHEDULE COST CATEGORIZATION (CC)

Cost Categorization

Schedule CC shows the distribution of expenses and rate base by cost category. There are three cost categories: customers, demand, and commodity. The cost category for each component of operating expense and rate base was determined by assigning a cost type to each class allocation factor developed on Schedule AL. Whenever appropriate, class allocation factors were assigned to a single cost category. For example, the peak usage-related factors on Schedule AL, Page 2 are all categorized as demand costs. Similarly, the class allocation factors on Schedule AL, Page 3 are based on the number of customers and are categorized as customer costs.

Certain class allocation factors were developed using multiple individual components from the Schedules RB, EX, and SM whose underlying cost activity drivers are not the same. For these factors, the study calculated the proportion related to customers, demand, and commodity using the underlying amounts that build the allocation factor. For example, the Dist_X_Admin class allocation factor developed on Schedule AL, Page 6, Line 18 is based on operating and maintenance expenses for mains and services as well as meter and house regulators expense, measuring and regulatory station equipment expense, and gas light expense. These expenses were allocated by varying class allocation factors, some of which are categorized at customer costs and others that are categorized as demand costs. The study then uses those underlying amounts to determine the assignment between customer, demand, and commodity for that composite factor.

Washington Gas Light Company
District of Columbia Jurisdiction
Class Cost of Service Allocation Study Model

User Guide

Purpose

This exhibit discusses how to use the class cost of service study ("CCOSS") Excel file. Refer to the allocations narrative for a discussion of the allocation factors.

The CCOSS presents ratemaking revenues, expenses, and rate base by customer class as well as the rate of return for each class. Whenever possible, costs are allocated directly to each customer class. Allocation factors are developed within this file to allocate any cost that cannot be directly assigned by class. Outside of revenues and related-revenue taxes, it is not practical to track costs by customer class. Thus, most costs are allocated to classes in this study.

Preliminary Studies

Various other studies and adjustment calculations must first be completed prior to preparing the CCOSS.

- Normal weather study ("NWS")[1] – Normal Weather therm usage, peak day therms, and number of customers from this study are used on the Factors worksheet.

- Jurisdictional cost allocation study ("PBCOSA" or "COSA")[2] – Per book revenues, expenses, and rate base prior to the application of distribution, ratemaking, and pro forma adjustments. Per book information is presented on the ***Summary***, ***Ratebase***, ***Revenue***, ***Expenses***, and ***Workpapers*** worksheets in CCOSS schedule Column E (Excel column K).

- Revenue Study / Revenue Adjustment[3] – Determines the normal weather revenue amount (and the adjustment to per book revenues) including the allocation of Sales of Gas to Customers used on the ***Revenue*** worksheet. Related revenue taxes are also calculated in the revenue study and used on the ***Expenses*** worksheet of the CCOSS file.

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[1] Refer to the Normal Weather Study ("NWS") filed as Exhibit WG (N)-5.
[2] Refer to PBCOSA filed as Exhibit WG (F)-2.
[3] Refer to electronic Revenue Study file provided with Adjustment 1 – Revenue in Exhibit WG (D)-5, as well as CCOSS workpaper 7.

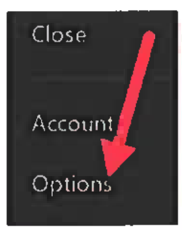
- Ratemaking Pro Forma ("RMPF")[4] – Summary of ratemaking revenues, expenses, rate base, and all adjustments to per book amounts. Income tax and interest expense are also adjusted to the ratemaking amount in this file. The adjustments that flow from the RMPF to the CCOSS are reflected in schedule column F (Excel column M) on the ***Summary***, ***Ratebase***, ***Revenue***, and ***Expenses*** worksheets. Additionally, the ratemaking total in the RMPF reconciles to the rate making total for the District of Columbia presented in schedule column G (Excel column O) of those same worksheets.

- Other data (such as meter counts and average meter costs) are obtained from customer records and the property accounting system or developed and support in CCOSS workpapers.[5]

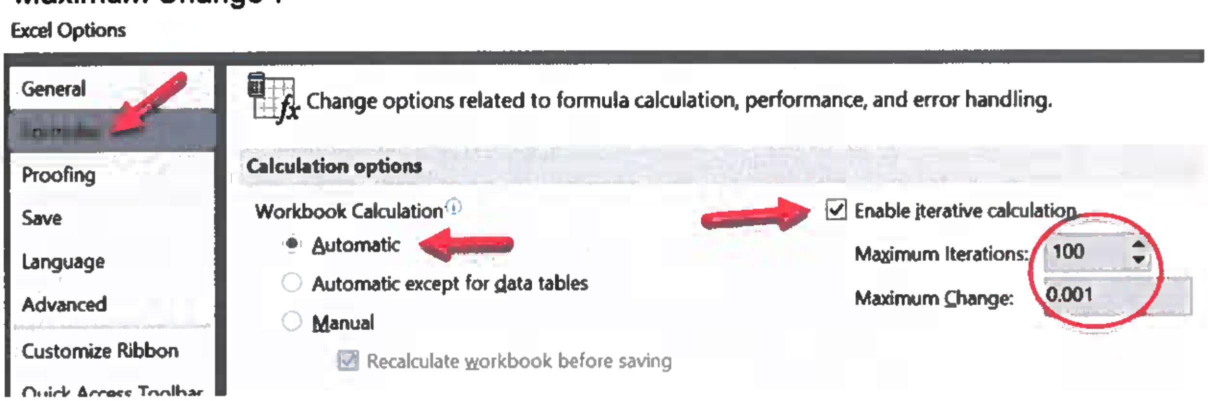
Excel Tip

For this file to operate correctly, it is best to set the Excel formula option to "Automatic" and allow iterative calculations (Maximum Iterations = 100 and Maximum Change = .001). Below are the steps for doing this in Excel 2016.

1. Click on the "File" menu option and select "Options" to access Excel options.



2. Click on "Formulas" and in the "Calculation Options" section, click the radio button for "Automatic" under "Workbook Calculation". Then click the check box for "Enable iterative calculation" and enter 100 for "Maximum Iterations" and .001 for "Maximum Change".



[4] Refer to electronic version of Exhibit WG (D)-1 and Exhibit WG (F)-5 Workpaper 8.
[5] Refer to Exhibit WG (F)-5 for detailed CCOSS workpapers.

3. Click "OK" to save these selections.

About Making Changes in this File

When making changes, keep the following points in mind:

- Impact of Rate Base Allocations: How rate base is allocated (particularly distribution mains and distribution services) has a significant impact on how costs are allocated to the classes throughout the study. This is because some rate base factors, such as the composite factor *Net_Rate_Base*, are used to allocate many expense items on the ***Expense*** worksheet and/or are used to calculate other composite allocation factors that are used to allocate expenses.

- Distribution Mains Allocation – This is one of the factors that users of the study are most likely to want to change. This can be done two ways.
    - The allocation of mains can be changed by selecting a different factor from the drop-down menu in Excel cell G75 of the ***Ratebase*** worksheet.
    - The composite peak and annual factor itself can also be modified for various splits between annual usage and peak usage by updating the values in Excel cells D25-D28 on the ***Control & Manual Input*** worksheet.

- Distribution Services Allocation – This is one of the factors that users of the study are most likely to want to change. This can be done two ways.
    - Option #1 – The percentage split of distribution services between the customer and capacity components can be changed in Excel cells O78 and O80, respectively, of the ***Ratebase*** worksheet. The total of these two cells should add up to 100%.
    - Option #2 – Both components can be allocated using the same class allocation factor. This can be done by selecting the desired allocation factor from the drop-down menus in Excel cells G80 and G82 of the ***Ratebase*** worksheet.

- Cost Functionalization and Classification: When making changes to the allocation factors, it is best to apply a consistent approach regarding functionalization, classification, and cost drivers. The function and classification of the cost is instructive in determining the appropriate allocation factor to allocate costs to the customer classes.
    - Cost Functionalization – Elements of the cost of service are functionalized according to FERC Uniform System of Accounts ("USOA"). For example,

Depreciable Gas Plant in Service includes software, transmission plant, distribution plant, and general plant (refer to the ***Ratebase*** worksheet, Excel rows 53-109).

- Cost Classification – Within the CCOSS, each allocation factor is classified as relating to one of three cost types.
  - Customer-related costs vary based on the number of customers served. Customer-driven costs include metering and meter-reading expense; customer billing, collecting, and accounting expense; and capital investment related to metering equipment and service connections.[6]
  - Commodity/usage costs vary based on the amount of gas used. Purchased gas cost is an example of an expense that is usage-related.[7]
  - Demand/capacity costs vary with the size or quantity of plant or equipment. These costs relate to maximum system design components that are designed to serve for short intervals (such as very cold, high usage days) and do not vary due to the number of customers or therm usage.[8]
- An illustrative example:
  - Transmission plant on the ***Ratebase*** worksheet Excel rows 61-69 and the related depreciation expense on the ***Expenses*** worksheet Excel rows 203-207 are allocated using a demand-related composite factor related to annual therm usage and peak day usage.
  - This allocation factor was selected for these costs because it best reflects cost drivers related to this plant and expense. When selecting the allocation factor for these cost elements, it would be inappropriate to select a customer-related allocation factor. Transmission plant and its related depreciation expense cost vary with the aggregate peak requirements of customers rather than the number of customers in a particular class.
  - If the class allocation factor for one of these cost elements is changed, then the allocation factor for the other cost element should also be changed so that similar and related cost elements are consistently assigned among the customer classes.

- Allocation Factor Switches: The lines on which amounts are allocated on any of the worksheets are highlighted in yellow. For the main schedule worksheets (***Summary***, ***Revenue***, ***Expenses***, and ***Ratebase***,), the name of the allocator is in schedule column C (Excel column G). The location of the allocation factor

[6] NARUC *Gas Distribution Rate Design Manual* (June 1989), Page 22.
[7] NARUC *Gas Distribution Rate Design Manual* (June 1989), Page 23.
[8] NARUC *Gas Distribution Rate Design Manual* (June 1989), Page 23-24.

details is indicated in schedule column B (Excel column E). In order to change the allocation factor, select the desired factor from the drop-down list. When the file recalculates, the allocator reference in schedule column B (Excel column E) and amounts allocated to each class in schedule columns H – S (Excel columns Q – AM) will update.

- Check Figures: There are check figures on most of the schedule worksheets to verify that each line crossfoots (i.e., the sum of the individual class amounts is equal to the DC rate making total for that line) to the right of the class columns (as an example, see Excel columns AR-AS on the ***Summary*** worksheet). If there are significant variances in these check columns, it will be necessary to correct them to ensure the mathematical integrity of the study.

- Directly Assigned Amounts: Amounts that are directly assigned by class are indicated by "Financial Statement" or "Billing System" as the source. Sales of Gas to Customer (***Revenue*** worksheet, Excel row 13) is the primary example of a directly assigned amount.[9] Ratemaking revenues in the CCOSS are sourced from the Revenue study, which calculates normal weather revenues by class. Changing these directly assigned amounts would change the total ratemaking revenues, which would cause mismatching in the study. For example, if normal weather/ratemaking revenues increased or decreased, there would be a corresponding increase or decrease to the related revenue taxes and revenue tax expense[10] that the CCOSS model is not set up to calculate and is not intended to calculate.

- Extra Columns: Two additional columns are included at the far right of all schedules. These columns are provided to allow users to model different class breakouts and are fully integrated into the CCOSS model. However, users should exercise caution when adding a new class or breaking out existing customer classes.
    - At a minimum, each additional customer class should be assigned some amount of revenues, expenses, rate base, therm usage, and customer count.
    - The cells where it is safe for users to make changes are highlighted in green. Other cells that are not highlighted are formula-based and will update when the file is recalculated.

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[9] Forfeited discounts (***Revenue*** worksheet, Excel rows 25 and 26) and miscellaneous service revenues (***Revenue*** worksheet, Excel rows 30 to 34) are also directly assigned. Refer to CCOSS Workpaper 3 for details of this analysis.
[10] Revenue tax expense is on the ***Expenses*** worksheet on Excel rows 284, 285, 294, and 295.

- Any change/additions to the study may change the total revenues, expenses, and rate base in the study and consequently may change the jurisdictional ratemaking rate of return and class rates of return.

WORKSHEET: VALIDATIONS

This worksheet summarizes various validations that exist throughout the file. Whenever changes are made and the file is recalculated, this worksheet will identify certain types of errors on the schedules such as cross-footing errors that indicate that the schedule is mathematically incorrect.

When using the two user-defined classes (discussed below), if users add incremental additional revenues, expenses, or rate base to the file that do not tie to the Company's total cost of service as filed, some of the validation calculation may no longer be valid.

WORKSHEET: CONTROL & MANUAL INPUT

This worksheet is used for the following purposes:

- Data entry for headers and titles used throughout the file (Excel rows 4-7).
- Dates and study numbers used on the ***DATABASE - TM1*** worksheet to pull data from the TM1 database when the file is linked to the database (Excel rows 9-20). These are not relevant to external users of the electronic copy of the study and should not be changed.
- Number of days in peak month (Excel row 21) and number of months in study period (Excel row 22) are used on the ***Factors*** worksheet.
- Composite peak and annual split information (Excel rows 24-28) are used on the ***Factors*** worksheet.
- Data that is needed for calculations that is not included in the TM1 database on Excel rows 30-94.
  - Services allocation components from CCOSS Workpapers 1 and 2 used on the ***Ratebase*** worksheet.
  - Therms and customer count for CNG from CCOSS Workpaper 4 used on the ***Factors*** worksheet.
  - Per book cash working capital components from the PBCOSA that are used in the development of the composite cost categorization factor calculations on the ***Factors (CC)*** worksheet.
  - Directly assigned revenues from CCOSS Workpaper 3 that are used on the ***Revenue*** worksheet.

WORKSHEET: DATABASE – TM1

This worksheet contains data from an internal database tool called TM1. The links to the database are broken to make the CCOSS file fully functional for external users. The data in this database comes from the studies discussed above that calculate per book revenues, expenses, and rate base as well as ratemaking and pro-forma adjustments.

Data flows from this worksheet to all the other worksheets in the file. No changes should be made to this worksheet.

Worksheet Layout:

- Rows can be expanded and collapsed using the "plus" symbols.
- Excel rows 1-14 are an index of what's included on this worksheet. Double-clicking the name will take the user to that section.
- Most of the sections are set up with a description of the data in Excel column A and the amount in Excel column B.
    - The "Meter Counts and Cost" section has some information in columns A-C and additional data in columns G-U.
    - The "Normal Weather Therms and Customers Counts" section has data in column G-Q.
- Schedule Excel column C shows the source of the data, including a reference to the exhibit or workpaper where additional details can be found, if applicable.
- Schedule Excel column D shows a reference to the CCOSS schedule, page, and line where the amount is used.

<u>**WORKSHEET: MANUAL INPUT – PLANT ADJS.**</u>

This worksheet provides a breakdown by function of the various rate base adjustments and includes a reference to where each line is used in the CCOSS. Changes should only be made to this tab if the adjustment amounts are to be updated.

<u>**WORKSHEET: SUMMARY**</u>

This worksheet presents a summarization of revenues, expenses, and rate base amounts by class and allocates certain lines that are not allocated on other schedules in the file.

Each line in this summary indicates either the ***Ratebase***, ***Revenue***, or ***Expenses*** schedule where the class allocations are calculated or the factor used to allocate that line. The source of the information is shown in schedule column B (Excel column E).

The starting point for each line is the unadjusted per book amount from the jurisdictional allocation study in schedule column E (Excel column K). Adjustments, in schedule column F (Excel column M), are added to the per book amount to determine the allocable ratemaking jurisdictional total in schedule column G (Excel column O). The ratemaking total reconciles to the total cost of service in the RMPF.

Data on this worksheet that does not come from one of the other main schedules (***Ratebase***, ***Revenue***, or ***Expenses*** worksheet) comes from the ***DATABASE-TM1*** worksheet. The per book amounts on this worksheet come from the "Per Book Summary" section. The adjustment amounts come from the ***Ratebase***, ***Revenue***, and ***Expenses*** worksheets as applicable. The allocation factors come from the ***Factors*** worksheet.

<u>WORKSHEET: REVENUE</u>

This worksheet presents revenues by class.

Sales of Gas to Customers revenues on schedule line 2 (Excel row 13) are directly assigned by class from the revenue study. The *Gas_Sales_Revenue* factor is calculated on schedule line 3 (Excel row 14) and the *Gas_Sales_Ex_Non_Firm* factor is calculated on schedule line 5 (Excel row 17). These factors are used to allocate other elements of revenues on this worksheet. Forfeited discounts (Excel rows 25-26) and miscellaneous service revenues (Excel rows 30-34) are also directly assigned by class.[11]

The starting point for each line is the unadjusted per book revenues from the jurisdictional allocation study in schedule column E (Excel column K). Adjustments, in schedule column F (Excel column M), are added to the per book amount to determine the allocable ratemaking jurisdictional total in schedule column G (Excel column O). The ratemaking total reconciles to the total cost of service in the RMPF.

Data on this worksheet comes from the ***DATABASE-TM1*** worksheet. The per book amounts on this worksheet come from the "Per Book Revenues" section and the adjustment amounts come from the "Revenue Adjustments" section. The allocation factors other than *Gas_Sales_Revenue* and *Gas_Sales_Ex_Non_Firm* (which are derived on this worksheet) come from the ***Factors*** worksheet.

<u>WORKSHEET: EXPENSES</u>

This worksheet presents the functionalization of operating expenses and allocates all elements of expense to the customer classes.

The first page of the expense schedule (Excel rows 1-22) is the expense summary. Each line in this summary indicates either the sub-schedule where the class allocations are calculated or the factor used to allocate that line. Following this section, there are sub-sections where the components of expense such as operation expense, maintenance expense, deprecation, and taxes are allocated to the customer classes.

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[11] Refer to CCOSS Workpaper 3 included in Exhibit WG (F)-5 for further details.

The starting point for each line is the unadjusted per book functionalization of expenses from the jurisdictional allocation study in schedule column E (Excel column K). Adjustments, in schedule column F (Excel column M), are added to the per book amount to determine the allocable ratemaking jurisdictional total in schedule column G (Excel column O).

Data on this worksheet comes from the ***DATABASE-TM1*** worksheet. The per book amounts on this worksheet come from the "Per Book Expenses" section and the adjustment amounts come from the "Expense Adjustments" section. The allocation factors come primarily from the ***Factors*** worksheet. Additional factors come from the ***Revenue*** worksheet and the ***Effective Tax Rate*** worksheet.

WORKSHEET: RATEBASE

This worksheet presents the functionalization of rate base and allocates all elements of rate base to the customer classes.

The first page of the rate base schedule (Excel rows 1-40) is the rate base summary. Each line in this summary indicates either the sub-schedule where the class allocations are calculated or the factor used to allocate that line. Following this section, there are sub-sections where the functionalized components of rate base such as plant in service, materials & supplies, and depreciation reserve are allocated to the customer classes.

The starting point for each line is the unadjusted per book functionalization of rate base from the jurisdictional allocation study in schedule column E (Excel column K). Adjustments, in schedule column F (Excel column M), are added to the per book amount to determine the allocable ratemaking jurisdictional total in schedule column G (Excel column O). The ratemaking total reconciles to the total cost of service in the RMPF.

Data on this worksheet comes from the ***DATABASE-TM1*** worksheet. The per book amounts on this worksheet come from the "Per Book Ratebase" section and the adjustment amounts come from the "Ratebase Adjustments" section. The allocation factors come from the ***Factors*** worksheet.

WORKSHEET: FACTORS

This worksheet presents the calculation of the allocation factors that are used throughout the CCOSS.

- Factors related to therm usage or throughput are calculated on ***Factors*** Page 1 (Excel rows 1-31).
- Peak day factors are calculated on ***Factors*** Page 2 (Excel rows 34-83).

- Customer-related factors are calculated on ***Factors*** Page 3 (Excel rows 85-111).

- The remaining allocation factors on ***Factors*** Page 4-6 (Excel rows 114-276) are composite allocation factors based on various components of the cost of service and factors developed on other worksheets in the file.

- User defined factors can be input on the ***Factors*** worksheet in Excel rows 277-281. User can add allocation factors for any or all classes here.[12] If the name of the user defined factor is changed on these lines, the name will also be changed on the ***Factors List*** worksheet and in the drop-down menu for selecting class allocation factors.

Data on this worksheet comes from the ***DATABASE-TM1***, ***Ratebase***, and ***Expenses*** worksheets. The source of the information is shown in schedule column B (Excel column E).

WORKSHEET: FACTORS LIST

This worksheet is the list of the allocation factors (developed on the ***Factors*** worksheet) that can be selected in the drop-down menus on the ***Summary***, ***Ratebase***, ***Revenue***, ***Expense***, ***Workpapers***, and ***Effective Tax Rate*** worksheets.

This worksheet should not be altered.

WORKSHEET: WP – FEE FREE

This worksheet is a workpaper to the ***Factors*** worksheet.

The count of transactions by tariff class from the customer billing system is used to calculate each tariff class's ratio of the total number of transactions. These ratios are carried forward to the ***Factors*** worksheet Excel row 109 and are used along with the adjusted customer count by class in Excel row 103 on the same worksheet to calculate the *Fee_Free_Credit* allocation factor on Excel row 111. This factor is used to allocate the fee-free credit card expense on ***Expenses*** worksheet Excel row 259.

Fee-free credit expense is calculated on this worksheet based on the actual total expense paid during the test year, allocated to the District of Columbia jurisdiction based on the per book average meter count from the PBCOSA.

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[12] For each allocation factor, the total of the individual class allocation factors must equal 1. Otherwise, the factor will not allocate the full cost among the customer classes and the study will be out of balance and mathematically incorrect.

WORKSHEET: WP – METER COSTS

This worksheet is a workpaper to the ***Factors*** worksheet. It shows the calculation of meter costs by class based on the type and number of meters for each class per the customer billing system and the average meter cost from the property accounting records. The totals on Excel row 37 of this worksheet are used on the Excel row 196 of the ***Factors*** worksheet to calculate the *Meter_Cost* allocation factor.

Data on this worksheet comes from Meter Data section of the ***DATABASE-TM1*** worksheet.

WORKSHEET: WORKPAPERS

This worksheet is a workpaper to the ***Factors*** worksheet. It is used to calculate labor expense by class in order to calculate the *Total_Labor* factor on Excel row 193 of the ***Factors*** worksheet.

Data on this worksheet comes from the Workpapers section of the ***DATABASE-TM1*** worksheet and the allocation factors come from the ***Factors*** worksheet.

WORKSHEET: EFFECTIVE TAX RATE

This worksheet has a dual purpose.

- First, it presents the reconciliation of income tax within the CCOSS and demonstrates that any difference between the effective tax rate and the statutory tax rate is explained by permanent tax differences and tax amortizations.
- Second, it shows the calculation of the *Tax_Factor* used to allocate income taxes on Excel row 21 of the ***Expenses*** worksheet.

Data on this worksheet comes from the ***DATABASE-TM1*** and ***Summary*** worksheets. The allocation factors come from the ***Factors*** worksheet. The source of the information can be found in schedule column B (Excel column D).

WORKSHEET: COST CATEGORIZATION

This worksheet shows the breakout of the cost of service by cost type (customer, demand, and commodity) by function in a format similar to the main Summary, Revenue, Expenses, and Rate Base schedules.

The cost category type or composite type allocator is shown in schedule column D (Excel column I) of the main schedules. Using allocators developed on worksheet ***Factors (CC)***, costs are assigned to the appropriate category in this worksheet.

The information on this worksheet will change when changes are made to other schedules. Otherwise, this worksheet should not be altered.

WORKSHEET: FACTORS (CC)

This worksheet calculates the cost categorization factors used on the ***Cost Categorization*** worksheet. The source of data for calculating each factor is indicated at the top of the block of cells where the factor is being calculated.

Generally, this worksheet should not be altered. Changes to this worksheet will not impact the overall cost of service or class rates of return on the Summary worksheet.

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Income Statement Summary

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Reference: So-Pg-Ln	Reference: Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH
	A	B	C	D	G	H	I	J
1	Operating Revenues	RV 1:32			223,783,787	94,381,333	2,221,121	2,088,124
2	Operating Expenses							
3	Gas Purchased	EX 2:2			-	-	-	-
4	Operation - Other than Gas Purchased				67,130,032	29,606,687	1,080,820	760,976
5	Maintenance	EX 4:25			28,826,812	12,840,825	272,434	347,252
6	Depreciation	EX 6:20			31,830,384	14,795,151	214,108	360,073
7	Amortization of General Plant	AL 4:30	Tot_Plnt_Ex_Genl	Comp TPE	1,870,281	867,415	12,401	22,163
8	Amortization of Capitalized Software	AL 4:30	Tot_Plnt_Ex_Genl	Comp TPE	3,888,183	1,888,888	24,150	43,176
9	Amortization of Unrecovered Plant Loss	AL 1:6	Total_Weather_All_NW	Demand	160,274	41,876	184	764
10	Interest on Customer Deposits	RV 1:5	Gas_Sales_Ex_Non_Firm	Comp TCS	77,884	37,511	868	823
11	Interest on Supplier Refunds	AL 1:4	Annual_Firm_NW	Demand	-	-	-	-
12	General Taxes	EX 8:21			63,436,336	19,309,800	184,456	400,830
13	Expenses Before Income Taxes	Ln. 2 > Ln. 12			184,946,261	79,196,834	1,769,461	1,958,860
14	Income Taxes	EX 1:10			3,067,380	907,660	73,887	(32,003)
15	Total Operating Expenses	Ln. 13 + Ln. 14			187,903,644	80,104,584	1,843,348	1,903,857
16	Net Operating Income	Ln. 1 - Ln. 15			35,880,143	14,276,739	377,773	182,267
17	Net Income Adjustments							
18	AFUDC	AL 5:2	Net_Rate_Base	Comp NRB	467,443	214,915	3,240	5,488
19	LCP Equity Accrual	AL 4:26	Tot_Dist_Plnt	Comp TDP	-	-	-	-
20	Net Operating Income - Adjusted				36,317,586	14,491,654	381,021	187,736
21	Net Rate Base	RB 1:26			761,830,866	350,094,405	5,230,745	9,870,952
22	Return Earned	Ln. 20 / Ln. 21			4.77%	4.14%	7.28%	1.89%
23	Uniform Rate of Return				1.00	0.87	1.53	0.40

	Description	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	K	L	M	N	N	O	P	Q	R	S
1	Operating Revenues	6,074,484	52,282,709	852,299	6,422,731	661,251	929,572	22,838,887	3,135,614	16,182,807	15,294,344
2	Operating Expenses										
3	Gas Purchased	-	-	-	-	-	-	-	-	-	-
4	Operation - Other than Gas Purchased	1,787,327	10,236,000	482,583	1,321,177	191,015	346,660	4,813,756	675,348	3,213,709	2,770,733
5	Maintenance	878,084	5,266,850	83,473	679,512	66,746	133,138	2,531,505	365,265	1,225,375	1,134,831
6	Depreciation	814,781	6,846,846	140,085	746,148	114,176	122,763	3,258,886	368,522	1,986,405	1,913,425
7	Amortization of General Plant	53,803	405,386	8,417	44,057	6,844	7,227	182,795	22,967	119,886	114,887
8	Amortization of Capitalized Software	104,427	780,169	16,307	85,830	13,333	14,080	375,984	44,783	233,887	223,818
9	Amortization of Unrecovered Plant Loss	2,408	23,282	889	1,829	63	336	12,182	921	9,443	8,456
10	Interest on Customer Deposits	2,484	21,400	386	2,626	-	378	9,315	1,272	-	-
11	Interest on Supplier Refunds	-	-	-	-	-	-	-	-	-	-
12	General Taxes	1,272,988	15,490,085	508,442	1,184,016	621,473	222,720	6,443,819	863,983	8,853,311	8,321,944
13	Expenses Before Income Taxes	5,116,082	39,040,284	1,250,464	4,074,985	875,862	749,544	17,636,303	2,344,061	15,451,884	14,465,865
14	Income Taxes	61,943	2,100,982	(108,329)	471,536	(56,180)	22,123	732,265	129,513	(236,066)	(169,731)
15	Total Operating Expenses	5,178,025	41,140,857	1,142,135	4,546,533	819,483	771,667	18,367,568	2,473,594	15,215,819	14,296,164
16	Net Operating Income	888,460	11,141,851	(189,836)	1,876,198	(58,213)	157,905	4,572,009	662,020	976,788	998,180
17	Net Income Adjustments										
18	AFUDC	13,265	100,336	2,112	10,946	1,611	1,800	47,633	5,703	31,290	28,916
19	LCP Equity Accrual	-	-	-	-	-	-	-	-	-	-
20	Net Operating Income - Adjusted	908,724	11,242,187	(187,724)	1,887,143	(56,402)	159,706	4,619,642	667,723	1,008,078	1,027,096
21	Net Rate Base	21,500,941	163,735,888	3,230,088	17,812,622	2,942,134	2,919,658	77,703,888	9,279,720	51,180,621	47,331,405
22	Return Earned	4.23%	6.87%	-5.80%	10.59%	-1.92%	5.47%	5.95%	7.20%	1.97%	2.17%
23	Uniform Rate of Return	0.89	1.44	(1.22)	2.22	(0.40)	1.15	1.25	1.51	0.41	0.46

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Revenues

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	----- Reference ----- So-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-BMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	M	N	O	P	Q	R	S
1	Operating Revenues																	
2	Sales of Gas to Customers _1/	Financial Stmt.	Revenue Study	Comp TCS	$ 217,949,912	$ 90,772,884	$ 2,149,044	$ 1,990,531	$ 6,011,582	$ 51,786,411	$ 937,789	$ 6,353,599		$ 915,815	$ 22,542,271	$ 3,077,593	$ 16,025,194	$ 15,287,409
3	Line 2 - Percentage of Total		Gas_Sales_Revenue		1.0000	0.4167	0.0099	0.0091	0.0276	0.2377	0.0043	0.0292	-	0.0042	0.1034	0.0141	0.0735	0.0701
4	Total Gas Sales Revenue excluding Non Firm	Ln. 3 - Ln. 3 Col. N.			$ 186,637,309	90,772,884	2,149,044	1,990,531	6,011,582	51,786,411	937,789	6,353,599	-	915,815	22,542,271	3,077,593	-	-
5	Line 4 - Percentage of Total		Gas_Sales_Ex_Non_Firm		1.0000	0.4864	0.0115	0.0107	0.0322	0.2775	0.0050	0.0341	-	0.0049	0.1208	0.0165	-	-
6	Rate Adjustment Due Customers	RV 1.3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Unbilled Gas Accrual/Reversal	RV 1.3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Provision for Rate Refunds	RV 1.3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total Gas Sales	Lns. 6 > 8			$ 217,949,912	$ 90,772,884	$ 2,149,044	$ 1,990,531	$ 6,011,582	$ 51,786,411	$ 937,789	$ 6,353,599	$ -	$ 915,815	$ 22,542,271	$ 3,077,593	$ 16,025,194	$ 15,287,409
10	Other Operating Revenues																	
11	Forfeited Discounts (Non POR)	Billing System	Direct	Comp TCS	3,784,772	2,513,080	48,403	51,873	52,841	437,119	8,148	90,138	13,292	12,488	377,815	54,015	158,780	-
12	Forfeited Discounts (POR)	Billing System	Direct	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rent from Gas Property	RV 1.3	Gas_Sales_Revenue	Comp TCS	98,473	41,084	973	801	2,721	23,430	424	2,876	-	415	10,203	1,383	7,253	6,910
14	Rental Income from WGCC/Maritime/ACI	AL 1.4	Annual_Firm_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Miscellaneous Service Revenues																	
16	Reconnect Revenues	Billing System	Direct	Customer	174,364	162,876	3,137	3,349	441	3,647	51	493		(1)	(38)	(9)	405	-
17	Dishonored Check Charge	Billing System	Direct	Customer	44,740	36,750	747	797	330	2,605	30	370		23	686	100	54	-
18	Service Initiation Charge	Billing System	Direct	Customer	836,870	775,705	14,841	15,950	2,601	21,518	303	2,911		121	3,858	523	338	-
19	Field Collection Charge	Billing System	Direct	Customer	433	139	3	3	27	227	3	31		-	-	-	-	-
20	IRATE Non Compliance MTR Charge	Billing System	Direct	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Other Gas Revenues																	
22	Watergate Revenues	Financial Stmt.	Direct	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Third Party Balancing Charges	RV 1.3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	CNG Sales for Natural Gas Vehicles	AL 6.48	C&I Other	Customer	847,959	-	-	-	-	-	-	-	847,959	-	-	-	-	-
25	Off System Sales Revenue Net of Gas Cost	RV 1.5	Gas_Sales_Ex_Non_Firm	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Miscellaneous Revenues																	
27	Other Allocable Miscellaneous	RV 1.3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Oth Gas Rev - MD RM-35	RV 1.3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Third Party Billing	AL 2.29	Delv_Cust	Customer	114,447	77,016.60	3,874	2,820	3,852	7,541	7,541	3,303	-	703	4,981	1,886	993	16
30	Firm Margin Sharing Adjustment	RV 1.3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total Other Operating Revenues	Ln. 22 > Ln. 30			5,843,875	$ 3,608,449	$ 72,077	$ 75,593	$ 62,822	$ 496,297	$ 14,510	$ 69,132	$ 861,251	$ 13,757	$ 397,326	$ 58,021	$ 167,413	$ 6,935
32	Total Operating Revenues	Ln. 9 + Ln. 31			$ 223,793,787	$ 94,381,333	$ 2,221,121	$ 2,066,124	$ 6,074,404	$ 52,282,708	$ 952,298	$ 6,422,731	$ 861,251	$ 929,572	$ 22,939,597	$ 3,135,614	$ 16,192,607	$ 15,294,344
33	Line 32 Percentage of Total Revenues		Total_Revenues		1.0000	0.4218	0.0099	0.0092	0.0271	0.2337	0.0043	0.0287	0.0038	0.0042	0.1026	0.0140	0.0724	0.0684

_1/ Transportation Sales, which are reported separately in the PSCOSA, are included in the "Sales of Gas to Customers" line in the class cost study for purposes of determining allocation factor "Gas_Sales_Revenue".

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Operating Expense Summary

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	—— Reference —— Sc-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	M	N	O	P	Q	R	S
1	**Operating Expenses**																	
2	Operation	EX 2 48			$ 67,130,832	$ 29,806,697	$ 1,080,828	$ 780,878	$ 1,787,327	$ 10,238,000	$ 482,583	$ 1,321,177	$ 151,015	$ 248,880	$ 4,613,756	$ 675,348	$ 3,213,708	$ 2,770,733
3	Maintenance	EX 4 25			38,828,912	12,840,525	272,434	347,252	970,084	5,288,850	83,473	679,512	88,748	133,159	2,531,808	355,385	1,223,375	1,134,031
4	Depreciation	EX 6 20			31,830,254	14,788,191	214,109	380,073	914,781	6,848,940	140,086	748,149	114,179	122,763	3,256,658	389,522	1,988,405	1,913,425
5	Amortization	SM 1.8+SM 1.9			8,837,730	2,889,250	36,744	88,105	180,437	1,219,030	25,484	131,516	20,240	21,844	580,851	68,681	382,888	345,161
6	Interest on Customer Deposits	RV 1 5	Gas_Sales_Ex_Non_Firm	Comp TCS	77,894	37,511	888	823	2,484	21,400	388	2,828	-	378	9,315	1,272	-	-
7	Interest on Supplier Refunds	EX 9 25			-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	General Taxes	EX 8 21			63,436,330	18,328,850	184,458	400,830	1,272,988	15,450,085	508,442	1,184,018	621,473	222,730	6,443,519	853,883	8,653,311	8,321,844
9	Expenses Before Income Taxes	Ln. 2 > Ln. 8			$ 184,846,281	78,184,833	1,768,461	1,855,880	5,116,082	39,040,254	1,250,464	4,074,995	975,852	749,544	17,635,303	2,344,081	15,451,684	14,485,885
10	Income Taxes	ETR 1 26	Tax_Factor	Comp TAX	3,087,380	907,880	73,887	(52,003)	61,943	2,100,562	(108,329)	471,538	(56,189)	22,123	732,285	129,513	(235,888)	(189,731)
11	Total Operating Expenses	Ln. 9 + Ln. 10			$ 187,933,644	$ 80,104,384	$ 1,843,348	$ 1,803,857	$ 5,178,025	$ 41,140,856	$ 1,142,135	$ 4,546,533	$ 919,463	$ 771,667	$ 18,367,588	$ 2,473,594	$ 15,219,819	$ 14,296,164

Schedule EX Page 1

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Operation and Maintenance Expenses

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	---- Reference ---- So-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NOV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	M	N	O	P	Q	R	S
1	Operation Expenses																	
2	Gas Purchased	EX 3 5			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Purchased Gas Expenses - Allocable	AL 1 14	Pipeline_NW	Commodity	73,198	21,615	173	434	1,380	17,562	536	2,043	611	255	7,564	1,002	10,107	8,743
4	Purchased Gas Expenses - Direct	AL 1 14	Pipeline_NW	Commodity	898	178	1	4	11	143	4	17	7	2	62	8	82	79
5	Purchased Gas Expenses - Hexane				-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Purchased Gas Expense - Chalk Point				-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Propane Holding				-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Watergate		Watergate	Demand	102,346	-	-	-	-	-	-	-	-	-	-	-	102,346.00	-
9	Hampshire Exchange Service	AL 1 2	Firm_Weather_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Property Modifications - Chalk Point				-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Storage - Allocable	AL 1 6	Total_Weather_All_NW	Demand	698,887	282,428	1,279	5,321	16,773	162,057	4,883	11,380	439	2,343	84,729	8,415	65,783	44,978
12	Transmission	AL 2 7	Comp_Peak_ Ann_NW	Demand	474,199	188,425	1,087	3,212	10,073	118,824	3,483	11,858	2,888	1,882	53,938	5,936	49,108	47,888
13	Transmission - Chalk Point				-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission - Ponds				-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution																	
16	Supervision and Engineering -																	
17	Distribution	AL 4 28	Tot_Dist_Plnt	Comp TDP	218,482	104,795	1,804	2,761	6,486	48,086	875	5,104	722	852	21,883	2,672	12,502	11,889
18	Appliance Service Direct	AL 6	Appl_Scv_X_Admin	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Appliance Service Allocable	AL 6	Appl_Scv_X_Admin	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Other	AL 4 28	Tot_Dist_Plnt	Comp TDP	1,094,383	491,754	7,373	12,682	29,883	211,872	4,023	23,484	3,317	3,918	101,107	12,282	57,475	95,113
21	Load Dispatching	AL 2 7	Comp_Peak_ Ann_NW	Demand	336,988	117,925	756	2,276	7,137	82,779	2,488	8,261	2,031	1,192	38,219	4,208	34,795	33,933
22	Load Dispatching - Chalk Point	AL 2 7	Comp_Peak_ Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Compressor Station Equipment	AL 2 7	Comp_Peak_ Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Mains	AL 4 23	Mains_Services	Comp M&S	291,961	140,694.74	1,602	3,713	7,173	62,164	1,226	6,140	1,018	674	29,838	3,229	17,408	16,874
25	Removing/Setting Meters - Direct	AL 3 4	Ave_Customer _Bill	Customer	121,682	101,158	8,148	2,680	3,358	2,529	1	1,376	2	446	1,273	648	82	2
26	Removing/Setting Meters - Allocable	AL 3 4	Ave_Customer _Bill	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Measuring and Regulating Station Equipment	AL 4 18	Dist_Meas_Reg_Plnt	Customer	393,237	108,433	663	2,084	6,442	74,712	2,228	7,456	1,833	1,075	34,485	3,798	31,404	30,626
28	Measuring and Regulating Station Equipment-Chalk Po	AL 4 18	Dist_Meas_Reg_Plnt	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Service On Customer Premises-Direct	AL 3 4	Ave_Customer _Bill	Customer	1,833	1,274	103	34	42	32	0	17	0	8	18	6	1	0
30	Service On Customer Premises-Allocable	AL 3 4	Ave_Customer _Bill	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Office Expenses -																	
32	Distribution	AL 4 28	Tot_Dist_Plnt	Comp TDP	2,870,823	1,377,175	21,077	38,282	85,389	803,670	11,489	67,076	9,483	11,189	388,030	35,111	164,302	157,950
33	Appliance Service Direct	AL 6	Appl_Scv_X_Admin	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Appliance Service Allocable	AL 6	Appl_Scv_X_Admin	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Other	AL 4 28	Tot_Dist_Plnt	Comp TDP	82,294	25,086	384	881	1,555	11,033	209	1,222	173	204	5,265	840	2,893	2,870
36	Rents	AL 4 28	Tot_Dist_Plnt	Comp TDP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Customer Accounts	EX 7 22			11,654,925	7,223,977	441,000	179,145	321,511	1,531,883	25,827	237,861	84	45,926	674,920	114,409	441,191	417,282
38	Customer Service And Information Expense - Allocable	AL 3 4	Ave_Customer _Bill	Customer	437,277	383,523	29,381	9,988	12,058	8,087	3	4,945	7	1,603	4,576	2,230	298	8
39	Information Exp - Direct	AL 3 4	Ave_Customer _Bill	Customer	76,837	63,048	5,078	1,658	2,081	1,576	0	898	1	278	794	404	51	1
40	Sales Expense	AL 3 4	Ave_Customer _Bill	Customer	83,467	68,388	5,589	1,625	2,302	1,734	1	944	1	308	873	445	57	2
41	Advertising Exp - Direct																	
42	Administrative and General	EX 9 29			37,200,773	18,340,785	915,117	480,597	1,236,327	7,086,175	432,212	904,876	125,379	171,508	3,387,795	488,142	2,169,618	1,884,184
43	Interest on Financing Leases	AL 5 2	Net_Rate_Base	Comp NRB	94,239	43,328	655	1,102	2,674	20,228	426	2,207	385	383	9,803	1,150	8,308	9,830
44	Rate-Making Adjustments																	
45	Non-Labor Inflation Adjustment	AL 6 37	O&M Adjusted	Comp OMA	1,843,843	985,711	19,898	14,989	35,714	182,883	3,082	24,113	2,489	4,851	87,805	12,510	47,800	41,873
46	Total Operation Expense	Ln. 2 > Ln. 45			$ 67,139,932	$ 29,808,897	$ 1,080,826	$ 760,978	$ 1,787,327	$ 10,238,000	$ 482,583	$ 1,321,177	$ 151,015	$ 248,880	$ 4,813,798	$ 675,348	$ 3,213,708	$ 2,770,733

Washington Gas Light Company

Development of Gas Purchased Expenses

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	—— Reference —— Sc-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NOV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	M	N	O	P	Q	R	S
1	Gas Purchase Costs		Revenue Study	Eliminated	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Less: Off System Sales Cost of Gas Recovered		Revenue Study	Eliminated	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	PGC Recovered - DC/MD/VA		Revenue Study	Eliminated	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Propane Gasified		Revenue Study	Eliminated	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total Gas Purchased Expense	Ln. 3 - Ln. 4			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Operation and Maintenance Expenses

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	---- Reference ---- Sch-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH	CAI H/C < 3075	CAI H/C > 3075	CAI CHP	CAI NON H/C	CAI NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	M	N	O	P	Q	R	S
1	Maintenance Expenses																	
2	Storage	AL:1 6	Total_Weather_All_NW	Demand	$ 62,013	$ 26,211	$ 115	$ 477	$ 1,903	$ 14,525	$ 418	$ 1,017	$ 39	$ 210	$ 7,994	$ 575	$ 5,998	$ 4,031
3	Transmission	AL:2 7	Comp_Peak_Ann_NW	Demand	441,893	154,891	894	2,891	9,391	108,798	3,244	10,857	2,680	1,986	50,232	5,530	45,732	44,988
4	Transmission - Chalk Point																	
5	Structures & Improvements	AL:2 7	Comp_Peak_Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Measuring & Regulating Station Equipment	AL:2 7	Comp_Peak_Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Transmission - PANDA																	
8	Structures & Improvements	AL:2 7	Comp_Peak_Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Measuring & Regulating Station Equipment	AL:2 7	Comp_Peak_Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Distribution																	
11	Mains	AL:4 20	Dist_Mains_Plnt	Demand	8,840,129	3,035,400	19,489	58,582	183,714	2,130,733	63,332	212,631	52,287	30,672	983,767	108,310	895,620	873,424
12	Services	AL:4 22	Dist_Services_Plnt	Customer	8,641,078	6,297,198	94,314	189,426	277,068	1,589,676	-	154,755	166	21,407	610,821	68,652	-	-
13	Meter & House Regulator Installations	AL:4 15	Mtr_Hse_Reg_Plnt	Customer	3,898,788	1,773,427	127,031	47,113	385,726	677,802	1,628	209,057	1,525	62,087	329,974	108,882	65,986	12,519
14	Compressor Station Equipment	AL:1 6	Total_Weather_All_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Measuring and Regulating Station Equipment	AL:2 7	Comp_Peak_Ann_NW	Demand	911,762	319,988	2,052	6,176	19,367	224,626	6,088	22,416	5,510	3,234	103,711	11,418	84,419	92,078
16	Gas Light Services	AL:5 4	Gas_Lights	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Meter & House Regulators	AL:4 15	Mtr_Hse_Reg_Plnt	Customer	127,191	59,347	4,251	1,577	12,808	22,882	54	6,988	51	2,078	11,042	3,577	2,208	419
18	Supervision and Engineering -																	
19	Appliance Service	AL:6	Appl_Scv_X_Admin	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Other	AL:6 27	Dist_Maint_Exp	Comp DME	1,682,847	829,222	17,826	22,519	82,883	336,219	5,215	43,461	4,316	8,521	161,713	22,736	76,840	70,978
21	Other Equipment - Direct	AL:6 27	Dist_Maint_Exp	Comp DME	388	194	4	5	15	78	1	10	1	2	39	5	18	17
22	Other Equipment - Allocable	AL:6 27	Dist_Maint_Exp	Comp DME	81,872	40,847	888	1,108	3,088	16,562	257	2,141	213	420	7,886	1,120	3,775	3,486
23	Maintenance of General Plant	AL:4 34	Genl_Plnt	Comp TPE	291,448	134,385	1,824	3,438	8,317	62,938	1,308	6,838	1,082	1,121	29,915	3,967	18,802	17,627
24	Pro Forma Labor Adjustment - Maintenance	AL:6 27	Dist_Maint_Exp	Comp DME	368,872	178,089	2,786	4,837	13,806	72,213	1,120	9,334	827	1,830	34,732	4,883	18,461	15,245
25	Total Maintenance Expenses	Ln. 2 > Ln. 23			28,826,812	12,848,525	272,434	347,252	978,084	5,266,850	83,473	678,512	68,748	133,158	2,531,505	355,265	1,225,375	1,134,631
26	Total Operation Expenses	EX 2 48			67,138,032	29,606,697	1,080,828	760,978	1,787,327	10,236,000	492,583	1,321,177	151,015	248,880	4,813,756	675,346	3,213,708	2,770,733
27	Total Operation and Maintenance Expense	Ln. 25 > Ln. 26			$ 95,964,844	42,455,222	1,353,262	1,108,230	2,765,412	15,502,851	576,056	2,000,689	219,761	382,038	7,345,262	1,030,813	4,438,083	3,905,365

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Administrative and General Expenses

Twelve Months Ended March 31, 2024 - Average Rate Base

Line	Description A	---- Reference ---- Sc-Pg-Ln B	Class Allocator C	Cost Category D	District of Columbia Rate Making Total G	RES-HTG/CLG H	RES-NON H/C-BMA I	RES-NON H/C-OTH J	C&I H/C < 3075 K	C&I H/C > 3075 L
1	**Administrative & General Expenses**									
2	Administrative & General Salaries-Direct	AL:5:8	Total_Labor	Comp TLA	$ 930,862	$ 479,337	$ 14,803	$ 12,086	$ 35,971	$ 167,273
3	Administrative & General Salaries-Allocable	AL:5:8	Total_Labor	Comp TLA	15,180,194	7,804,671	238,271	212,048	586,916	2,729,289
4	Office Supplies & Expenses-Direct	AL:6:37	O&M Adjusted	Comp OMA	1,163,883	588,159	20,985	15,848	37,782	193,351
5	Office Supplies & Expenses-Allocable	AL:6:37	O&M Adjusted	Comp OMA	6,486,279	3,472,004	121,886	91,882	219,169	1,122,305
6	Outside Services	AL:6:42	Three_Part_Factor	Comp 3PF	7,887,467	3,284,976	71,754	81,023	205,885	1,384,823
7	Property Insurance	AL:5:2	Net_Rate_Base	Comp NRB	-	-	-	-	-	-
8	Injuries & Damages	AL:5:2	Net_Rate_Base	Comp NRB	4,025,733	1,880,889	27,989	47,085	114,345	864,120
9	Pension Expense	AL:5:8	Total_Labor	Comp TLA	(888,180)	(312,511)	(9,541)	(8,401)	(23,501)	(108,384)
10	DC Regulatory									
11	DC Pension Expense	AL:5:8	Total_Labor	Comp TLA	-	-	-	-	-	-
12	Amortization of DC Rate Case Expenses	AL:5:2	Net_Rate_Base	Comp NRB	478,776	218,748	3,305	5,586	13,902	102,125
13	DC Least Cost Planning Expense	AL:5:2	Net_Rate_Base	Comp NRB	-	-	-	-	-	-
14	Employee Health Benefits	AL:5:8	Total_Labor	Comp TLA	5,828,980	2,584,880	78,909	70,224	194,370	933,888
15	OPEB	AL:5:8	Total_Labor	Comp TLA	(7,214,830)	(3,707,443)	(113,186)	(100,729)	(278,802)	(1,288,461)
16	Rate Case Expenses-Direct	AL:6:37	O&M Adjusted	Comp OMA	2,814,984	1,525,874	53,958	40,438	98,339	483,230
17	Rate Case Expenses-Allocable	AL:6:37	O&M Adjusted	Comp OMA	1,881	1,008	35	27	64	326
18	DC PSC Assessment Expense	AL:1:8	Annual_Total_NW	Demand	-	-	-	-	-	-
19	General Advertising Expenses - Direct	AL:1:8	Annual_Total_NW	Demand	-	-	-	-	-	-
20	General Advertising Expenses - Allocable	AL:1:8	Annual_Total_NW	Demand	-	-	-	-	-	-
21	Environmental Expense - Regulatory Amortization	AL:1:8	Annual_Total_NW	Demand	841,833	198,921	1,278	3,213	10,084	129,861
22	Environmental Reserve - Regulatory Adjustment	AL:1:8	Annual_Total_NW	Demand	-	-	-	-	-	-
23	Rents	AL:4:28	Tot_Dist_Plnt	Comp TDP	-	-	-	-	-	-
24	MD Demand Side Management Expenses	AL:1:8	Annual_Total_NW	Demand	283,434	60,074	480	1,207	3,781	48,781
25	VA CARE Expenses	AL:1:8	Annual_Total_NW	Demand	-	-	-	-	-	-
26	MD EmPOWER MD Expenses	AL:1:8	Annual_Total_NW	Demand	-	-	-	-	-	-
27	Multi-Family Unit Contribution Amortization Expense	AL:1:8	Annual_Total_NW	Demand	17,481	5,153	41	104	334	4,185
28	Miscellaneous General Expenses	AL:5:2	Net_Rate_Base	Comp NRB	887,793	318,225	4,776	8,046	19,519	147,834
29	Total Administrative & General Expense	Ln. 1 > Ln. 28			$ 37,290,775	$ 18,342,785	$ 515,117	$ 480,587	$ 1,238,327	$ 7,086,175

Line	C&I CHP M	C&I NON H/C M	C&I NON H/C - NGV N	GMA H/C < 3075 O	GMA H/C >3075 P	GMA NON H/C Q	NON FIRM R	Special Contract S
1								
2	$ 23,410	$ 23,410	$ 1,986	$ 4,827	$ 80,845	$ 12,204	$ 42,444	$ 32,448
3	381,881	381,881	32,986	80,381	1,319,083	189,122	882,534	529,401
4	3,289	25,488	2,608	5,129	82,847	13,227	50,847	44,064
5	18,974	147,883	15,144	29,771	538,508	78,776	280,879	286,787
6	37,474	189,486	43,846	30,338	733,088	95,016	635,449	584,889
7	-	-	-	-	-	-	-	-
8	18,186	84,287	15,388	15,808	410,228	48,119	288,474	248,030
9	(15,294)	(15,294)	(1,304)	(3,219)	(52,818)	(7,873)	(27,730)	(21,189)
10								
11	-	-	-	-	-	-	-	-
12	2,148	11,141	1,843	1,833	48,482	5,805	31,847	29,431
13	-	-	-	-	-	-	-	-
14	126,485	126,485	10,785	26,823	438,844	65,944	229,348	178,323
15	(181,443)	(181,443)	(15,470)	(38,186)	(828,602)	(94,588)	(328,973)	(251,481)
16	8,339	65,040	6,856	13,064	237,103	33,741	129,188	112,404
17	6	43	4	9	157	22	85	74
18	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-
20	-	-	-	-	-	-	-	-
21	3,983	15,112	5,887	1,884	55,986	7,412	74,777	72,085
22	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-
24	1,489	5,077	2,253	708	21,023	2,784	28,080	27,078
25	-	-	-	-	-	-	-	-
26	-	-	-	-	-	-	-	-
27	139	487	193	61	1,804	238	2,410	2,323
28	3,107	18,105	2,885	2,849	70,087	8,302	48,039	42,547
29	$ 432,212	$ 854,976	$ 125,376	$ 171,506	$ 3,387,795	$ 448,142	$ 2,188,818	$ 1,884,184

Schedule EX Page 5

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Depreciation Expense

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Reference — Sc-Pg-Ln	Reference — Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	M	N	O	P	Q	R	S
1	**Depreciation Expense**																	
2	Storage	AL 1 6	Total_Weather_All_NW	Demand	$ 230,888	$ 100,043	$ 436	$ 1,821	$ 5,736	$ 55,442	$ 1,595	$ 3,883	$ 150	$ 602	$ 28,987	$ 2,195	$ 22,505	$ 15,388
3	AFUDC	AL 1 6	Total_Weather_All_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Total Storage	Ln. 2 + Ln. 3			$ 230,888	100,043	436	1,821	5,736	55,442	1,595	3,883	150	602	28,987	2,195	22,505	15,388
5	Transmission																	
6	Spurlines & Related Regulating Equip & Structures	AL 2 7	Comp_Peak_Ann_NW	Demand	(991,868)	(242,730)	(1,357)	(4,880)	(14,681)	(170,387)	(6,080)	(17,003)	(4,180)	(2,453)	(78,888)	(8,661)	(71,620)	(69,844)
7	Other	AL 2 7	Comp_Peak_Ann_NW	Demand	4,880,871	1,435,781	9,209	27,710	86,889	1,007,863	30,051	100,577	24,723	14,509	465,334	51,232	423,643	413,140
8	AFUDC	AL 2 7	Comp_Peak_Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total Transmission	Ln. 6 > Ln. 8			$ 3,899,112	1,193,052	7,852	23,026	72,208	837,476	24,971	83,574	20,543	12,056	386,446	42,571	352,023	343,296
10	Distribution																	
11	Compressor Station Equipment	AL 1 6	Total_Weather_All_NW	Demand	18,746	7,010	31	126	402	3,885	112	272	11	56	2,031	154	1,577	1,078
12	Other	AL 4 28	Tot_Dist_Plnt	Comp TDP	26,996,791	12,850,739	198,207	341,191	602,798	5,685,631	108,136	630,774	88,179	105,315	2,717,990	330,178	1,545,071	1,481,572
13	AFUDC	AL 4 28	Tot_Dist_Plnt	Comp TDP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total Distribution	Ln. 11 > Ln. 13			$ 27,013,536	12,857,749	198,238	341,319	603,196	5,689,516	108,247	631,046	88,189	105,371	2,720,024	330,332	1,546,648	1,482,650
15	General																	
16	Other	AL 4 34	Genl_Plnt	Comp TPE	1,179,836	544,307	7,781.88	13,909	33,636	254,515	5,262	27,846	4,295	4,536	120,980	14,425	75,229	72,082
17	AFUDC	AL 4 34	Genl_Plnt	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Total General	Ln. 16 + Ln. 17			1,179,836	544,307	7,782	13,909	33,636	254,515	5,262	27,846	4,295	4,536	120,980	14,425	75,229	72,082
19	CNG Equipment	AL 5 14	Meter_Count_C&I_Only	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Total Depreciation Expense	Lns. 4+9+14+(18+19)			$ 31,838,264	$ 14,795,151	$ 214,109	$ 380,073	$ 914,781	$ 6,848,949	$ 140,095	$ 748,149	$ 114,176	$ 122,765	$ 3,254,858	$ 389,522	$ 1,996,405	$ 1,913,425

Schedule EX Page 6

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Customer Accounts

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Reference: Sc-Pg-Ln	Reference: Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	M	N	O	P	Q	R	S
	Customer Accounts																	
1	General Supervision-Direct	AL:3 4	Ave_Customer _Bill	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	General Supervision-Allocable	AL:3 4	Ave_Customer _Bill	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total General Supervision	Ln. 1 + Ln. 2			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Meter Reading-Direct	AL:3 4	Ave_Customer _Bill	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Meter Reading-Allocable	AL:3 4	Ave_Customer _Bill	Customer	763,684	634,029	51,070	16,673	21,031	15,849	5	8,624	13	2,796	7,991	4,064	517	14
6	Total Meter Reading	Ln. + Ln. 4			$ 763,684	$ 634,029	$ 51,070	$ 16,673	$ 21,031	$ 15,849	$ 5	$ 8,624	$ 13	$ 2,796	$ 7,991	$ 4,064	$ 517	$ 14
7	Dispatch Applications and Orders-Direct	AL:3 4	Ave_Customer _Bill	Customer	290,545	246,526	19,858	6,463	8,178	6,162	2	3,353	5	1,087	3,103	1,580	201	5
8	Dispatch Applications and Orders-Allocable	AL:3 4	Ave_Customer _Bill	Customer	1,919,729	1,595,936	128,551	41,987	52,938	39,893	12	21,707	32	7,039	20,089	10,226	1,301	35
9	Total Dispatch Applications and Orders	Ln. 7 + Ln. 8			$ 2,210,274	$ 1,842,463	$ 148,409	$ 48,450	$ 61,117	$ 46,055	$ 14	$ 25,060	$ 38	$ 8,126	$ 23,192	$ 11,806	$ 1,502	$ 41
10	Customer Collection Expenses																	
11	Customer Credit and Appliance Service - Direct	AL:3 4	Ave_Customer _Bill	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Customer Credit and Appliance Service - Allocable	AL:3 4	Ave_Customer _Bill	Customer	2,258,480	1,877,986	151,236	49,373	62,281	46,933	14	25,538	37	8,280	23,634	12,033	1,531	42
13	Other-Direct	AL:3 4	Ave_Customer _Bill	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Other-Allocable	AL:3 4	Ave_Customer _Bill	Customer	(231,330)	(192,319)	(15,491)	(5,057)	(6,379)	(4,807)	(1)	(2,616)	(4)	(848)	(2,421)	(1,233)	(157)	(4)
15	Credit and Debit Card Transactions	AL:3 14	Fee_Free_Credit	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Total Customer Collection Expenses	Ln. 11 > Ln. 14			$ 2,027,151	$ 1,685,667	$ 135,745	$ 44,316	$ 55,902	$ 42,126	$ 13	$ 22,922	$ 33	$ 7,432	$ 21,213	$ 10,801	$ 1,374	$ 37
17	Customer Billing and Accounting-Direct	AL:3 4	Ave_Customer _Bill	Customer	100,769	90,366	7,279	2,376	2,998	2,259	1	1,229	2	398	1,138	579	74	2
18	Customer Billing and Accounting-POR Collection Exp	AL:3 4	Ave_Customer _Bill	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Customer Billing and Accounting-Allocable	AL:3 4	Ave_Customer _Bill	Customer	665,000	484,726	39,850	13,009	16,411	12,366	4	6,729	10	2,182	6,227	3,171	403	11
20	Total Customer Billing and Accounting	Ln. 17 > Ln. 19			$ 765,769	$ 575,092	$ 47,129	$ 15,385	$ 19,409	$ 14,625	$ 4	$ 7,958	$ 12	$ 2,580	$ 7,365	$ 3,750	$ 477	$ 13
21	Uncollectible Accounts	RV 1 3	Gas_Sales_Revenue	Comp TCS	$ 5,846,027	2,477,146	56,846	94,321	164,053	1,413,226	25,892	173,387	-	24,862	615,169	83,886	437,320	417,187
22	Total Customer Accounts	Lns. 3+6+9+16+20+21			$ 11,664,926	7,223,977	441,000	179,145	321,511	1,531,883	25,927	237,951	84	45,826	674,920	114,409	441,191	417,292

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
General Tax Expense

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	---- Reference ---- Sch-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NOV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	M	N	O	P	Q	R	S
1	**General Taxes**																	
2	Property Taxes	AL 4 37	Tot_Plnt_Ex_Pepco	Comp TPE	$ 2,813,888	$ 930,031	$ 13,298	$ 23,763	$ 57,472	$ 434,877	$ 9,024	$ 47,237	$ 7,336	$ 7,749	$ 308,712	$ 24,847	$ 128,940	$ 123,180
3	Property Taxes - Chalk Point	AL 4 37	Tot_Plnt_Ex_Pepco	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Property Taxes - Panda	AL 4 37	Tot_Plnt_Ex_Pepco	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Total Property Taxes	Ln. 3 + Ln. 4			$ 2,813,888	930,031	13,298	23,763	57,472	434,877	9,024	47,237	7,336	7,749	308,712	24,847	128,940	123,180
6	Gross Receipts Taxes		Rev Study	Comp TCS	36,882,983	7,257,891	58,001	145,815	802,422	6,482,970	197,822	507,132	247,308	85,525	2,539,982	336,376	3,733,088	3,588,885
7	DC Rights-of-Way Fee		Rev Study	Comp TCS	9,980,079	2,959,281	23,649	59,463	188,231	2,403,019	73,326	129,127	150,517	34,871	1,035,626	137,152	1,383,723	1,333,804
8	F.I.C.A. Taxes	AL 5 8	Total_Labor	Comp TLA	1,888,986	883,300	28,051	23,184	64,169	298,398	41,761	41,761	3,561	8,789	144,218	21,770	75,716	57,880
9	Medicare Taxes	AL 5 8	Total_Labor	Comp TLA	486,321	239,112	7,300	6,497	17,981	83,817	11,702	11,702	988	2,483	40,413	6,101	21,217	16,219
10	Unemployment Taxes	AL 5 8	Total_Labor	Comp TLA	(6,961)	(3,577)	(108)	(97)	(288)	(1,251)	(175)	(175)	(19)	(37)	(605)	(91)	(317)	(243)
11	Montgomery County Fuel Energy Tax	AL 5 2	Net_Rate_Base	Comp NRB	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	St Mary's County Fuel Energy Tax	AL 5 2	Net_Rate_Base	Comp NRB	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	PG County Maintenance Fees	AL 5 2	Net_Rate_Base	Comp NRB	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Environmental Tax	AL 5 2	Net_Rate_Base	Comp NRB	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Federal Excise Tax	AL 5 8	Total_Labor	Comp TLA	(21,714)	(11,158)	(341)	(303)	(839)	(3,902)	(548)	(548)	(47)	(115)	(1,889)	(285)	(980)	(757)
16	DC Sustainable Energy Trust Fund		Rev Study	Comp TCS	21,338,996	6,372,208	50,823	128,021	401,011	5,174,408	157,883	417,031	185,128	75,088	2,230,009	285,326	2,979,984	2,872,288
17	DC Energy Assistance Trust Fund		Rev Study	Comp TCS	2,366,884	708,827	5,649	14,200	44,482	573,983	17,514	40,265	38,508	8,329	247,380	32,759	330,904	318,604
18	Virginia SAVE Program	AL 5 2	Net_Rate_Base	Comp NRB	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Miscellaneous Other Taxes - Direct	AL 1 8	Annual_Total_NW	Demand	16,839	4,879	39	96	307	3,982	121	461	183	57	1,707	226	2,281	2,198
20	Miscellaneous Other Taxes - Allocated	AL 1 8	Annual_Total_NW	Demand	29	9	0	0	1	7	0	1	0	0	3	0	4	4
21	Total General Taxes	Ln. 5 > Ln. 20			$ 83,436,336	19,308,800	164,458	400,630	1,272,988	15,480,086	508,442	1,184,016	621,473	222,720	6,443,819	853,883	8,853,311	8,321,844

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Interest Expense

Twelve Months Ended March 31, 2024 - Average Rate Base

Ln	Description	Reference Sc-Pg-Ln	Reference Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MA	RES-NON H/C-OTH
	A	B	C	D	G	H	I	J
1	**Interest Expense**							
2	Interest on Long Term Debt	AL S 2	Net_Rate_Base	Comp NRB	$ 18,232,082	$ 7,003,213	$ 105,824	$ 176,192
3	Interest on Commercial Paper	AL S 2	Net_Rate_Base	Comp NRB	2,230,367	1,029,382	15,556	26,197
4	Interest on Credit Line Fees	AL S 2	Net_Rate_Base	Comp NRB	9,343	4,296	65	109
5	Interest on Credit Line Fees	AL S 2	Net_Rate_Base	Comp NRB	191,070	88,285	1,334	2,248
6	Interest on Bank Loans	AL S 2	Net_Rate_Base	Comp NRB	-	-	-	-
7	Interest on Financing Leases	AL S 2	Net_Rate_Base	Comp NRB	94,220	43,328	655	1,102
8	Interest on Short-Term Revolver	AL S 2	Net_Rate_Base	Comp NRB	-	-	-	-
9	Amortization of Debt Discount/Expenses	AL S 2	Net_Rate_Base	Comp NRB	148,488	68,720	1,036	1,748
10	Amortization of Gain/Loss on Reacquired Debt	AL S 2	Net_Rate_Base	Comp NRB	(64,001)	(29,453)	(445)	(748)
11	AFUDC	AL S 2	Net_Rate_Base	Comp NRB	(467,443)	(214,919)	(3,248)	(5,488)
12	PCR CWC Costs	AL 1 4	Annual_Firm_NW	Demand	60,019	23,509	180	472
13	Interest on Supplier Refunds	RV 1 5	Gas_Sales_Ex_Non_Firm	Comp TCS	-	-	-	-
14	Interest on Customer Deposits	AL 1 4	Annual_Firm_NW	Demand	41,700	16,825	135	340
15	Interest re LCP Expenses	AL S 2	Net_Rate_Base	Comp NRB	-	-	-	-
16	Int Exp re DC Carrying Costs	AL 1 4	Annual_Firm_NW	Demand	-	-	-	-
17	Oth Int Costs VA Save Carrying Costs	AL S 2	Net_Rate_Base	Comp NRB	-	-	-	-
18	Interest re Maryland Demand Side Management Expense	AL S 2	Net_Rate_Base	Comp NRB	-	-	-	-
19	Interest re District of Columbia Demand Side Managemer	AL S 2	Net_Rate_Base	Comp NRB	88,836	41,304	624	1,051
20	Total Interest	Ln. 2 > Ln. 19			$ 17,874,586	8,074,774	121,728	205,240
21	Adjusted to Remove:							
22	Interest on debt to Associated Company	AL S 2	Net_Rate_Base	Comp NRB	-	-	-	-
23	Non-Utility Interest Charges	AL S 2	Net_Rate_Base	Comp NRB	-	-	-	-
24	AFUDC	AL S 2	Net_Rate_Base	Comp NRB	(467,443)	(214,919)	(3,248)	(5,488)
25	Interest on Supplier Refunds	RV 1 5	Gas_Sales_Ex_Non_Firm	Comp TCS	-	-	-	-
26	Int Exp re DC Carrying Costs	AL 1 4	Annual_Firm_NW	Demand	-	-	-	-
27	Oth Int Costs VA SAVE Carrying Costs	AL S 2	Net_Rate_Base	Comp NRB	-	-	-	-
28	Oth Int Exp Customer Deposits	AL 1 4	Annual_Firm_NW	Demand	41,700	16,825	135	340
29	Non-Utility Interest on Equity Investment in Commercial	AL S 2	Net_Rate_Base	Comp NRB	-	-	-	-
30	Non-Utility Interest on Equity Investment in Primary *	AL S 2	Net_Rate_Base	Comp NRB	-	-	-	-
31	Interest per Cost of Service	Ln. 20 - (Ln. 22 > 30)			$ 18,000,288	8,272,784	124,841	210,380

Ln	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	K	L	M	M	N	O	P	Q	R	S
1										
2	$ 432,288	$ 3,268,983	$ 68,812	$ 358,675	$ 59,010	$ 58,570	$ 1,552,171	$ 185,852	$ 1,019,604	$ 942,250
3	63,500	480,676	10,116	52,437	8,675	8,625	228,194	27,323	148,888	138,520
4	285	2,005	42	219	36	36	882	114	625	578
5	5,448	41,208	887	4,485	744	739	19,383	2,342	12,851	11,876
6	-	-	-	-	-	-	-	-	-	-
7	2,674	20,228	426	2,207	385	383	9,803	1,150	6,308	5,830
8	-	-	-	-	-	-	-	-	-	-
9	4,242	32,083	675	3,500	579	576	15,231	1,824	10,005	9,248
10	(1,818)	(13,751)	(288)	(1,500)	(248)	(247)	(6,528)	(782)	(4,288)	(3,963)
11	(13,288)	(100,338)	(2,112)	(10,948)	(1,811)	(1,800)	(47,833)	(5,703)	(31,280)	(28,918)
12	1,479	19,080	583	2,222	882	277	8,227	1,080	-	-
13	-	-	-	-	-	-	-	-	-	-
14	1,085	13,743	419	1,580	635	189	5,823	784	-	-
15	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-
19	2,540	19,283	408	2,104	340	348	9,154	1,086	6,013	5,557
20	488,456	3,783,784	79,845	413,011	69,214	67,784	1,794,858	215,080	1,168,727	1,080,884
21										
22	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-
24	(13,288)	(100,338)	(2,112)	(10,948)	(1,811)	(1,800)	(47,833)	(5,703)	(31,280)	(28,918)
25	-	-	-	-	-	-	-	-	-	-
26	-	-	-	-	-	-	-	-	-	-
27	-	-	-	-	-	-	-	-	-	-
28	1,085	13,743	419	1,580	635	189	5,823	784	-	-
29	-	-	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-	-	-
31	510,658	3,870,376	81,838	422,358	70,380	69,285	1,838,588	220,009	1,201,016	1,109,889

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Washington Gas Light Company
District of Columbia Jurisdiction Preferred Class Cost of Service Study
Rate Base Summary

Twelve Months Ended March 31, 2024 - Average Rate Base
Average Rate Base

Ln	Description A	Reference Sc-Pg-Ln B	Reference Class Allocator C	Cost Category D	District of Columbia Rate Making Total G	RES-HTG/CLG H	RES-NON H/C-IMA I	RES-NON H/C-OTH J
1	Gas Plant in Service	RB 3 15			$ 1,341,482,836	$ 618,344,240	$ 8,840,139	$ 15,789,389
2	Gas Plant Held for Future Use	RB 4 12			-	-	-	-
3	Construction Work in Progress	RB 5 27			6,884,877	3,643,988	45,814	102,323
4	Materials & Supplies	RB 6 12			2,841,148	985,803	6,979	19,412
5	Non Plant ADIT	RB 9 10			(3,388,922)	(2,051,237)	(71,143)	(65,030)
6	Unamortized East Station Cost (Net of Deferred Taxes)	AL 1 6	Total_Weather_All_NW	Demand	1,768,327	738,411	3,234	13,458
7	FC 1027 - Rate Base CWIP (Reg Asset)	AL 4 20	Dist_Mains_Plnt	Demand	0	0	0	0
8	Cloud Computing - Prepaid	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	-	-	-
9	Sub-Total	Ln. 1 > Ln. 7			$ 1,348,888,758	$ 621,681,465	$ 8,825,022	$ 15,888,550
10	Cash Working Capital	AL 6 37	O&M Adjusted	Comp OMA	48,829,287	22,181,003	778,547	987,682
11	Cash Working Capital - Multi-Family Unit Contributions	AL 6 48	Residential Heating	Customer	752,784	752,784	-	-
12	Total Rate Base Additions	Ln. 9 + Ln. 10			$ 1,391,371,776	$ 644,585,252	$ 9,603,569	$ 16,457,242
13	LESS							
14	Reserve for Depreciation	RB 7 33			$ 464,149,147	$ 212,868,184	$ 3,149,182	$ 5,537,864
15	Accumulated DIT re Depreciation	AL 5 2	Net_Rate_Base	Comp NRB	216,836,792	99,321,945	1,500,834	2,527,176
16	ADIT re Gains/Losses On Reacquired Debt (Federal)	AL 5 2	Net_Rate_Base	Comp NRB	28,386	13,471	204	343
17	ADIT re Gains/Losses On Reacquired Debt (State)	AL 5 2	Net_Rate_Base	Comp NRB	10,143	4,884	70	119
18	NOL Carryforward Federal	AL 5 2	Net_Rate_Base	Comp NRB	(36,762,077)	(16,442,222)	(248,495)	(418,381)
19	NOL Carryforward State	AL 5 2	Net_Rate_Base	Comp NRB	(12,237,969)	(5,628,592)	(85,022)	(143,164)
20	NOL Federal Benefit of State	AL 5 2	Net_Rate_Base	Comp NRB	2,888,968	1,181,582	17,855	30,085
21	Customer Advances for Construction	AL 4 20	Dist_Mains_Plnt	Demand	386,789	107,322	688	2,071
22	Customer Deposits	RV 1 5	Gas_Sales_Ex_Non_Firm	Comp TCS	1,432,786	687,221	10,807	15,268
23	Supplier Refunds	AL 1 4	Annual_Firm_NW	Demand	-	-	-	-
24	Deferred Taxes Allowance	AL 5 2	Net_Rate_Base	Comp NRB	3,817,287	1,387,249	20,882	35,298
25	Total Rate Base Deductions	Ln. 14 > Ln. 24			$ 839,532,116	$ 294,500,843	$ 4,372,824	$ 7,588,689
26	Net Rate Base	Ln. 12 - Ln. 25			$ 761,839,660	$ 350,084,408	$ 5,230,745	$ 8,870,852

Ln	C&I H/C < 3075 K	C&I H/C > 3075 L	C&I CHP M	C&I NON H/C N	C&I NON H/C - NGV O
1	$ 38,211,282	$ 289,134,304	$ 6,007,651	$ 31,408,404	$ 5,043,291
2	-	-	-	-	-
3	177,459	1,383,625	21,403	138,044	17,677
4	60,281	718,988	21,412	78,424	22,480
5	(188,208)	(381,848)	(219,122)	(74,828)	(13,804)
6	47,412	408,789	11,780	28,889	1,109
7	0	0	0	0	0
8	-	-	-	-	-
9	$ 38,308,317	$ 291,262,615	$ 5,843,133	$ 31,571,843	$ 5,070,934
10	1,400,293	7,169,870	121,218	945,489	86,748
11	-	-	-	-	-
12	$ 39,708,610	$ 298,432,481	$ 5,964,352	$ 32,517,102	$ 5,187,673
13					
14	$ 13,224,849	$ 88,948,888	$ 1,832,316	$ 10,881,889	$ 1,580,864
15	6,130,548	46,389,917	875,912	5,088,489	636,893
16	831	6,289	132	888	114
17	288	2,177	48	238	39
18	(1,014,883)	(7,676,294)	(161,557)	(837,408)	(138,543)
19	(347,295)	(2,626,853)	(55,285)	(288,983)	(47,410)
20	72,832	581,839	11,610	80,178	9,898
21	6,486	75,336	2,346	7,518	1,848
22	48,175	387,789	7,203	48,802	-
23	-	-	-	-	-
24	65,827	847,658	13,631	70,853	11,888
25	$ 18,205,870	$ 134,688,622	$ 2,726,254	$ 14,704,480	$ 2,225,540
26	$ 21,500,941	$ 163,736,868	$ 3,238,098	$ 17,812,622	$ 2,942,134

Ln	GMA H/C < 3075 P	GMA H/C >3075 Q	GMA NON H/C R	NON FIRM S	Special Contract T
1	$ 5,152,087	$ 137,435,384	$ 16,388,780	$ 87,783,759	$ 81,947,929
2	-	-	-	-	-
3	10,243	888,884	72,564	301,726	294,348
4	10,388	323,881	37,831	338,310	325,462
5	(23,877)	(228,383)	(43,154)	(37,469)	38,853
6	5,834	214,241	16,220	168,334	113,729
7	0	0	0	0	0
8	-	-	-	-	-
9	$ 5,163,782	$ 138,414,108	$ 16,470,331	$ 88,519,859	$ 82,720,228
10	190,185	3,448,670	480,486	1,878,088	1,633,974
11	-	-	-	-	-
12	$ 5,353,957	$ 141,860,776	$ 16,960,817	$ 90,397,758	$ 84,354,181
13					
14	$ 1,757,316	$ 46,253,635	$ 5,536,636	$ 27,881,274	$ 38,249,773
15	832,073	22,013,422	2,835,809	14,480,372	13,383,314
16	113	2,886	357	1,881	1,812
17	38	1,034	124	678	627
18	(137,745)	(3,844,208)	(436,344)	(2,383,838)	(2,212,228)
19	(47,137)	(1,247,088)	(149,318)	(819,179)	(757,031)
20	9,889	281,882	31,357	172,028	158,077
21	1,084	34,783	3,829	31,888	30,881
22	7,034	173,146	23,839	-	-
23	-	-	-	-	-
24	11,822	307,486	38,815	201,871	188,846
25	$ 2,434,298	$ 64,157,088	$ 7,682,098	$ 39,214,934	$ 37,022,777
26	$ 2,919,659	$ 77,703,688	$ 9,278,720	$ 51,180,821	$ 47,331,405

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Depreciable Gas Plant in Service

Twelve Months Ended March 31, 2024 - Average Rate Base
Average Rate Base

Ln	Description (A)	----- Reference ----- Sc-Pg-Ln (B)	Class Allocator (C)	Cost Category (D)	District of Columbia Rate Making Total (G)	RES-HTG/CLG (H)	RES-NON H/C-MMA (I)	RES-NON H/C-OTH (J)	C&I H/C < 3075 (K)	C&I H/C > 3075 (L)	C&I CHP (M)	C&I NON H/C (N)	C&I NON H/C - NGV (O)	GMA H/C < 3075 (P)	GMA H/C >3075 (Q)	GMA NON H/C (R)	NON FIRM (S)	Special Contract (T)
1	**Depreciable Gas Plant in Service**																	
2	Capitalized Software	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	$ 31,194,036	$ 14,405,817	$ 205,852	$ 388,085	$ 880,234	$ 6,736,079	$ 130,765	$ 731,886	$ 113,863	$ 120,030	$ 3,201,867	$ 391,769	$ 1,891,040	$ 1,808,016
3	Storage	AL 1 6	Total_Weather_All_NW	Demand	12,886,793	5,380,227	23,007	95,723	301,724	2,915,120	83,875	304,166	7,888	42,146	1,524,130	115,383	1,163,316	809,077
4	Storage - AFUDC	AL 1 6	Total_Weather_All_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Total Storage	Ln. 3 + Ln. 4	Total_Weather_All_NW		$ 12,886,793	$ 5,380,227	$ 23,007	$ 95,723	$ 301,724	$ 2,915,120	$ 83,875	$ 304,166	$ 7,888	$ 42,146	$ 1,524,130	$ 115,383	$ 1,163,316	$ 809,077
6	**Transmission**																	
7	Spurlines & Related Equipment and Structures	AL 2 7	Comp_Peak_ Ann_NW	Demand	$ 56,197,740	$ 19,724,802	$ 126,515	$ 380,693	$ 1,193,821	$ 13,846,043	$ 412,847	$ 1,381,728	$ 339,648	$ 199,316	$ 6,382,767	$ 703,825	$ 5,830,017	$ 5,675,730
8	Chalkpoint	AL 2 7	Comp_Peak_ Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Ponds	AL 2 7	Comp_Peak_ Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Other	AL 2 7	Comp_Peak_ Ann_NW	Demand	108,628,696	38,127,503	244,580	735,850	2,307,623	26,764,023	798,022	2,670,843	656,527	385,272	12,367,044	1,380,475	11,249,934	10,971,031
11	Mains - ARO	AL 2 7	Comp_Peak_ Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Post 1989 MD Interruptible Customers	AL 2 7	Comp_Peak_ Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	AFUDC	AL 2 7	Comp_Peak_ Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total Transmission	Ln. 7 > Ln. 13	Comp_Peak_ Ann_NW		$ 164,826,436	$ 57,852,304	$ 371,095	$ 1,116,533	$ 3,501,444	$ 40,610,066	$ 1,210,869	$ 4,052,571	$ 996,174	$ 584,587	$ 18,749,811	$ 2,084,300	$ 17,080,950	$ 16,646,761
	Distribution																	
15	Compressor Station Equipment	AL 1 6	Total_Weather_All_NW	Demand	469,802	186,712	425	3,434	10,824	104,501	3,009	7,325	283	1,512	54,679	4,140	42,452	29,026
16	Measuring and Regulator Station Equipment	AL 2 7	Comp_Peak_ Ann_NW	Demand	10,637,047	3,733,480	23,947	72,085	225,985	2,620,764	78,143	261,532	64,268	37,726	1,210,016	133,219	1,101,808	1,074,288
17	**Mains**	AL 2.7	Comp_Peak_ Ann_NW	Demand	$ 699,804,349	198,730,906	1,281,832	3,796,853	11,808,814	136,097,475	4,117,849	13,781,081	3,387,581	1,987,832	63,780,084	7,019,800	58,047,804	56,608,517
18	**Services** _1/				$ 415,368,463													
19	Services - Interruptible and Special Contracts	CCOSS WP 2	Direct	Customer	2,813,794	-	-	-	-	-	7,605	-	164,486	-	-	-	2,291,879	49,723
20	Services - Firm Customers	Ln. 18 - Ln. 19			412,551,749													
21	Services - Capacity Component Factor	CCOSS WP1			24.936%													
22	Services - Capacity Component	AL 2 26	Peak Day Adjusted	Customer	102,846,369	-	-	-	2,987,019	62,400,880	-	3,915,106	-	480,881	30,985,921	2,207,383	-	-
23	Services - Customer Component Factor	CCOSS WP 1			75.064%													
24	Services - Customer Component	AL 3 11	Firm_Cust_Bill_Adj	Customer	309,904,880	272,485,789	4,081,073	8,586,075	9,047,880	6,818,842	-	2,781,273	7,165	435,439	4,119,082	1,542,223	-	-
25	**Meters**																	
26	Meters	AL 5 10	Meter_Cost	Customer	$ 20,076,762	9494016	$ 657,319	$ 252,910	$ 1,073,816	$ 4,083,985	$ 10,752	$ 1,123,674	$ 9,880	$ 310,298	$ 1,970,285	$ 565,706	$ 430,477	$ 84,677
27	Encoder Units	AL 5 10	Meter_Cost	Customer	682,888	387,910	26,857	10,333	76,581	168,040	439	45,911	404	13,045	80,503	23,831	17,589	3,460
28	Index Correctors & Demand Recs	AL 5 12	Meter_Count_Ex_Res	Customer	6,162,832	-	-	-	1,627,248	1,313,701	785	722,418	1,178	252,081	658,208	342,383	43,188	785
29	Meter Installations	AL 5 10	Meter_Cost	Customer	$ 38,976,717	$ 16,358,215	$ 1,132,542	$ 436,764	$ 3,228,591	$ 7,002,256	$ 18,525	$ 1,938,083	$ 17,024	$ 550,097	$ 3,394,806	$ 1,008,173	$ 741,713	$ 145,889
30	House Regulators	AL 3 4	Avg_Customer_Bill	Customer	4,731,388	3,933,337	316,827	103,432	130,473	96,320	29	53,500	78	17,347	40,512	25,209	3,207	87
31	House Regulator Installations	AL 3 4	Avg_Customer_Bill	Customer	3,744,785	3,113,168	250,763	81,865	103,267	77,819	23	42,344	62	13,730	30,166	19,953	2,530	69
32	Gas Light Services	AL 5 4	Gas_Lights	Customer	107,137	100,091	207	1,865	207	1,451	-	414	-	-	2,072	829	-	-
33	Post 1989 MD Interruptible Customers				-													
34	AFUDC				-													
35	Total Distribution	Lns. (15+17)+18+(25+34)			$ 1,080,404,333	$ 508,525,660	$ 7,752,212	$ 13,344,586	$ 31,380,744	$ 222,765,651	$ 4,238,861	$ 24,670,690	$ 3,652,436	$ 4,119,038	$ 108,308,373	$ 12,813,829	$ 62,722,254	$ 57,998,539
36	**General**																	
37	Transportation	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	$ 7,847,267	$ 3,670,125	$ 52,470	$ 93,776	$ 226,800	$ 1,716,130	$ 35,613	$ 168,410	$ 28,966	$ 30,580	$ 615,735	$ 87,282	$ 507,251	$ 468,080
38	PDE	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	822,136	425,680	6,088	10,681	38,316	189,125	4,132	21,629	3,360	3,548	94,651	11,286	98,867	58,403
39	Other - Direct	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	11,857,700	5,337,486	76,307	138,379	328,837	2,486,784	51,782	271,086	42,113	44,472	1,186,331	141,449	737,700	708,939
40	Other - Allocable	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	62,462,980	24,226,095	346,376	619,095	1,487,202	11,338,917	235,095	1,230,572	191,162	201,870	5,385,019	642,070	3,348,564	3,208,951
41	AFUDC				-													
42	Total General	Ln. 37 > Ln. 41	Tot_Plnt_Ex_Genl		$ 72,886,960	$ 33,661,557	$ 481,241	$ 880,091	$ 2,080,155	$ 15,730,956	$ 326,632	$ 1,708,709	$ 265,593	$ 280,470	$ 7,481,736	$ 892,087	$ 4,692,382	$ 4,456,382
43	CNG Equipment	AL 5 14	Meter_Count_C&I_Only	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	CIAC - OPIS				-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	CIAC - Liability				-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Total Depreciable Gas Plant in Service	Lns. 2+5+14+35+42+(43+45)			$ 1,339,869,489	$ 617,705,565	$ 8,633,477	$ 15,765,017	$ 38,172,291	$ 288,767,151	$ 5,986,122	$ 31,368,766	$ 5,035,794	$ 5,148,270	$ 137,282,936	$ 16,367,366	$ 87,616,952	$ 81,816,784

_1/ Firm services investment is split between capacity (allocated on peak day factor) and customer component (allocated on average firm customer factor). Services investment for interruptible and special contracts are directly assigned. Refer to CCOSS Workpaper 1 for capacity/customer split and CCOSS Workpaper 2 for calculation of services investment directly assigned.

Schedule RB Page 2

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Non Depreciable Gas Plant In Service

Twelve Months Ended March 31, 2024 - Average Rate Base
Average Rate Base

	Description	— Reference — Sc-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	**Non Depreciable Gas Plant in Service**																	
2	Intangible	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	$ 14,474	$ 6,884	$ 98	$ 171	$ 413	$ 3,126	$ 165	$ 340	$ 53	$ 58	$ 1,486	$ 177	$ 924	$ 885
3	Storage	AL 1 6	Total_Weather_All_NW	Demand	$ 86,289	$ 23,954	$ 103	$ 429	$ 1,351	$ 13,053	$ 376	$ 914	$ 35	$ 165	$ 6,825	$ 517	$ 5,299	$ 3,623
4	Transmission																	
5	Spurlines and Related Regulating Equip & Struct	AL 2 7	Comp_Peak_ Ann_NW	Demand	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Other	AL 2 7	Comp_Peak_ Ann_NW	Demand	808,189	283,268	1,819	5,475	17,189	199,122	5,837	19,871	4,885	2,886	91,935	10,122	83,889	81,624
7	Total Transmission	Ln. 5 + Ln. 6	Comp_Peak_ Ann_NW		$ 808,189	$ 283,268	$ 1,819	$ 5,475	$ 17,189	$ 199,122	$ 5,837	$ 19,871	$ 4,885	$ 2,886	$ 91,935	$ 10,122	$ 83,889	$ 81,624
8	Distribution Other	AL 1 6	Total_Weather_All_NW	Demand	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	General																	
10	Other - Direct	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Other - Allocable	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	703,269	324,751	4,643	8,298	20,088	151,852	3,151	16,494	2,562	2,708	72,180	8,608	44,864	43,012
12	Total General	Ln. 10 + Ln. 11	Tot_Plnt_Ex_Genl		$ 703,269	$ 324,751	$ 4,643	$ 8,298	$ 20,088	$ 151,852	$ 3,151	$ 16,494	$ 2,562	$ 2,708	$ 72,180	$ 8,608	$ 44,864	$ 43,012
13	Total Non-Depreciable Gas Plant in Service	Lns. 2+3+7+12			$ 1,612,138	$ 638,856	$ 6,661	$ 14,372	$ 39,001	$ 367,153	$ 9,529	$ 37,619	$ 7,535	$ 5,817	$ 172,426	$ 19,422	$ 134,805	$ 129,144
14	Total Depreciable Gas Plant in Service	RB 2 48			$ 1,339,850,488	$ 617,705,585	$ 8,833,477	$ 15,785,017	$ 38,172,291	$ 288,767,151	$ 5,998,122	$ 31,368,785	$ 5,035,756	$ 5,146,270	$ 137,262,938	$ 16,367,358	$ 87,618,952	$ 81,818,784
15	Total Gas Plant in Service	Ln. 13 + Ln. 14			$ 1,341,462,626	$ 618,344,240	$ 8,840,138	$ 15,799,389	$ 38,211,292	$ 289,134,304	$ 6,007,651	$ 31,406,404	$ 5,043,291	$ 5,152,087	$ 137,435,364	$ 16,386,780	$ 87,753,758	$ 81,947,928

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Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Gas Plant Held For Future Use

Twelve Months Ended March 31, 2024 - Average Rate Base
Average Rate Base

	Description	---- Reference ---- Sc-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-GMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NOV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Gas Plant Held For Future Use																	
2	Storage	AL 1 6	Total_Weather_All_NW	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Transmission																	
4	Spurlines and Related Regulating Equip & Struct	AL 2 7	Comp_Peak_ Ann_NW	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Other	AL 2 7	Comp_Peak_ Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Transmission	Ln. 4 + Ln. 5			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Distribution																	
8	Compressor Station Equipment	AL 1 6	Total_Weather_All_NW	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Other	AL 1 6	Total_Weather_All_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Distribution	Ln. 8 + Ln. 9			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	General	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Total Gas Plant Held for Future Use	Lns. 2+6+10+11			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Construction Work In Progress

Twelve Months Ended March 31, 2024 - Average Rate Base
Average Rate Base

	Description	Reference — Sc-Pg-Ln	Reference — Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Construction Work In Progress																	
2	Intangible	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Storage	AL 1 6	Total_Weather_All_MW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Storage - Chalk Point				-													
5	Total Storage	Ln. 3 + Ln. 4			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Transmission																	
7	Spurlines & Related Equipment and Structures	AL 2 7	Comp_Peak_ Ann_MW	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Ponds	AL 2 7	Comp_Peak_ Ann_MW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Other	AL 2 7	Comp_Peak_ Ann_MW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Transmission	Ln. 7 > Ln. 9			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Distribution																	
12	Compressor Station Equipment	AL 1 6	Total_Weather_All_MW	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Mains	AL 2 7	Comp_Peak_ Ann_MW	Demand	2,813,447	1,022,988	6,989	19,736	81,881	717,817	21,403	71,833	17,808	10,333	331,419	36,489	301,728	294,246
14	Services				3,871,129													
15	Services - Capacity Component Factor	CCOSS WP1			24.930%													
16	Services - Capacity Component	AL 2 26	Peak Day Adjusted	Customer	988,223	-	-	-	28,539	600,218	-	37,698	-	4,722	287,864	21,231	-	-
17	Services - Customer Component Factor	CCOSS WP 1			76.664%													
18	Services - Customer Component	AL 3 11	Firm_Cust_Bill_Adj	Customer	2,888,906	2,620,980	38,225	82,588	87,029	65,588	-	26,752	69	4,186	38,621	14,834	-	-
19	Other	AL 4 28	Tot_Dist_Plnt	Comp TDP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Total Distribution	Ln. 12 + Ln. 19			$ 6,684,877	$ 3,643,568	$ 45,814	$ 102,323	$ 177,459	$ 1,383,625	$ 21,403	$ 136,044	$ 17,877	$ 19,243	$ 888,884	$ 72,554	$ 301,728	$ 294,246
21	General Alloc	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	General - Sites	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	General - Ponds	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	General - Chalk Point	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total General	Ln. 21 > Ln. 24			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	AFUDC				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	CNG Equipment	AL 5 14	Meter_Count_C&I_Only	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Total Construction Work in Progress	Lns. 2+5+10+20+25+26+27			$ 6,684,877	$ 3,643,568	$ 45,814	$ 102,323	$ 177,459	$ 1,383,625	$ 21,403	$ 136,044	$ 17,877	$ 19,243	$ 888,884	$ 72,554	$ 301,728	$ 294,246

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Materials and Supplies

Twelve Months Ended March 31, 2024 - Average Rate Base
Average Rate Base

	Description	Reference: Sc-Pg-Ln	Reference: Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH
	A	B	C	D	G	H	I	J
1	**Materials and Supplies**							
2	General Supplies :							
3	Construction	AL 4 30	Tot_Plnt_Ex_Gen!	Comp TPE	$ 89,432	$ 26,980	$ 386	$ 689
4	Operation	AL 1 8	Annual_Total_NW	Demand	926,989	282,613	2,258	5,678
5	Total General Supplies	Ln. 2 + Ln. 3			$ 1,016,421	$ 309,593	$ 2,644	$ 6,367
6	Fuel Stock							
7	Watergate				$ -			
8	Propane Fuel Stock	AL 2 7	Comp_Peak_Ann_NW	Demand	1,828,740	642,219	4,119	12,395
9	Total Fuel Stock	Ln. 6 + Ln. 7			$ 1,828,740	$ 642,219	$ 4,119	$ 12,395
10	Storage Gas Purchased	AL 2 7	Comp_Peak_Ann_NW	Demand	$ -	$ -	$ -	$ -
11	Fuel Stock Materials - Hexane	AL 2 7	Comp_Peak_Ann_NW	Demand	96,987	33,080	216	650
12	Total Materials and Supplies	Lns. 5+8+10+11			$ 2,941,148	$ 985,303	$ 6,979	$ 19,412

	Description	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	K	L	M	N	O	P	Q	R	S	T
1	**Materials and Supplies**										
2	General Supplies :										
3	Construction	$ 1,667	$ 12,616	$ 282	$ 1,370	$ 213	$ 225	$ 5,997	$ 715	$ 3,729	$ 3,573
4	Operation	17,785	229,490	7,003	26,708	10,599	3,330	98,903	13,098	132,146	127,389
5	Total General Supplies	$ 19,452	$ 242,106	$ 7,284	$ 28,077	$ 10,812	$ 3,556	$ 104,900	$ 13,813	$ 135,875	$ 130,962
6	Fuel Stock										
7	Watergate									$ -	$ -
8	Propane Fuel Stock	38,870	450,613	13,442	44,966	11,058	6,489	208,142	22,916	189,494	184,796
9	Total Fuel Stock	$ 38,870	$ 450,613	$ 13,442	$ 44,966	$ 11,058	$ 6,489	$ 208,142	$ 22,916	$ 189,494	$ 184,796
10	Storage Gas Purchased	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Fuel Stock Materials - Hexane	2,039	23,849	705	2,380	590	340	10,819	1,202	9,941	9,694
12	Total Materials and Supplies	$ 60,361	$ 716,568	$ 21,412	$ 75,424	$ 22,460	$ 10,385	$ 323,861	$ 37,931	$ 335,310	$ 325,452

Washington Gas Light Company
District of Columbia Jurisdiction Preferred Class Cost of Service Study
Reserve For Depreciation

Twelve Months Ended March 31, 2024 - Average Rate Base
Average Rate Base

	Description	— Reference — So-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	**Reserve for Depreciation**																	
2	Capitalized Software	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	$ 18,941,829	$ 7,823,867	$ 111,854	$ 198,809	$ 483,485	$ 3,859,386	$ 75,916	$ 397,383	$ 61,731	$ 65,189	$ 1,738,880	$ 207,341	$ 1,081,343	$ 1,036,252
3	Capitalized Software Reserve Deficiency	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Capitalized Software Amort Res Def	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Total Capitalized Software	Ln. 2 > Ln. 4			$ 18,941,829	$ 7,823,867	$ 111,854	$ 198,809	$ 483,485	$ 3,859,386	$ 75,916	$ 397,383	$ 61,731	$ 65,189	$ 1,738,880	$ 207,341	$ 1,081,343	$ 1,036,252
6	Storage	AL 1 6	Total_Weather_All_NW	Demand	$ 8,261,328	$ 3,454,128	$ 15,107	$ 62,856	$ 198,127	$ 1,914,213	$ 55,076	$ 134,087	$ 5,180	$ 27,075	$ 1,000,820	$ 75,773	$ 777,024	$ 531,280
7	AFUDC	AL 1 6	Total_Weather_All_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Total Storage	Ln. 6 + Ln. 7			$ 8,261,328	$ 3,454,128	$ 15,107	$ 62,856	$ 198,127	$ 1,914,213	$ 55,076	$ 134,087	$ 5,180	$ 27,075	$ 1,000,820	$ 75,773	$ 777,024	$ 531,280
9	**Transmission**																	
10	Spurlines and Related Regulating Equip	AL 2 7	Comp_Peak_Ann_NW	Demand	$ 5,147,487	$ 1,808,713	$ 11,588	$ 34,880	$ 108,349	$ 1,268,242	$ 37,815	$ 126,981	$ 31,110	$ 18,257	$ 585,552	$ 64,488	$ 533,080	$ 519,874
11	Depreciation Res - Trans - ARO	AL 2 7	Comp_Peak_Ann_NW	Demand	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Chalk Point	AL 2 7	Comp_Peak_Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Post 1989 MD Interruptible Customers	AL 2 7	Comp_Peak_Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Panda Cogeneration	AL 2 7	Comp_Peak_Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	AFUDC	AL 2 7	Comp_Peak_Ann_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Other - Allocable	AL 2 7	Comp_Peak_Ann_NW	Demand	16,493,495	5,789,028	37,131	111,727	350,374	4,063,673	121,168	405,523	99,683	58,497	1,876,212	206,565	1,708,118	1,665,769
17	Total Transmission	Ln. 10 > Ln. 16			$ 21,640,982	$ 7,595,741	$ 48,719	$ 146,586	$ 458,723	$ 5,331,915	$ 158,982	$ 532,084	$ 130,793	$ 76,754	$ 2,461,764	$ 271,033	$ 2,241,206	$ 2,185,643
18	**Distribution**																	
19	Distribution - Mass	AL 4 28	Tot_Dist_Plnt	Comp TDP	$ 384,434,131	$ 184,413,715	$ 2,822,382	$ 4,858,440	$ 11,431,521	$ 81,103,672	$ 1,539,806	$ 6,861,985	$ 1,268,875	$ 1,488,641	$ 38,703,206	$ 4,701,612	$ 22,001,234	$ 21,097,030
20	Depreciation Res - Dist - ARO	AL 4 28	Tot_Dist_Plnt	Comp TDP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Post 1989 MD Interruptible Customers	AL 4 28	Tot_Dist_Plnt	Comp TDP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	AFUDC	AL 4 28	Tot_Dist_Plnt	Comp TDP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other - Allocable	AL 4 28	Tot_Dist_Plnt	Comp TDP	27,373	13,131	201	346	814	5,775	110	640	90	107	2,736	335	1,567	1,502
24	Total Distribution	Ln. 19 > Ln. 23			$ 384,461,504	$ 184,426,846	$ 2,822,583	$ 4,858,786	$ 11,432,335	$ 81,109,447	$ 1,539,915	$ 6,862,625	$ 1,268,965	$ 1,488,748	$ 38,705,964	$ 4,701,947	$ 22,002,800	$ 21,098,532
25	**General**																	
26	Direct	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	$ (118,389)	$ (53,242)	$ (761)	$ (1,380)	$ (3,290)	$ (24,898)	$ (517)	$ (2,704)	$ (420)	$ (444)	$ (11,834)	$ (1,411)	$ (7,358)	$ (7,052)
27	AFUDC	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Allocable	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	22,972,177	10,608,854	151,668	271,088	655,586	4,960,641	102,942	538,836	83,705	88,394	2,357,961	281,146	1,466,258	1,405,117
29	General Plant - Reserve Deficiency	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	General Plant - Amort Res Def	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total General	Ln. 26 > Ln. 30			$ 22,854,388	$ 10,555,612	$ 150,908	$ 269,708	$ 652,296	$ 4,935,745	$ 102,425	$ 536,131	$ 83,285	$ 87,950	$ 2,346,127	$ 279,735	$ 1,458,900	$ 1,398,065
32	CNG Equipment	AL 5 14	Meter_Count_C&I_Only	Customer	(2,184)	-	-	-	(1,018)	(732)	(0)	(403)	(1)	-	-	-	-	-
33	Total Reserve for Depreciation	Lns. 5+8+17+24+31+32			$ 464,140,147	$ 213,858,184	$ 3,149,182	$ 5,537,854	$ 13,224,949	$ 96,948,985	$ 1,932,316	$ 10,561,686	$ 1,550,654	$ 1,757,316	$ 48,253,635	$ 5,535,829	$ 27,561,274	$ 26,249,773

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Line	Description (A)	Reference: Sc-Pg-Ln (B)	Reference: Class Allocator (C)	Cost Category (D)	District of Columbia Rate Making Total (G)	RES-HTG/CLG (H)	RES-NON H/C-MA (I)
1	Plant ADIT						
2	Avoided Cost of Interest	AL 5.2	Net_Rate_Base	Comp NRB	$ (2,888,713)	$ (1,327,219)	$ (20,088)
3	Capitalized OPEB	AL 5.2	Net_Rate_Base	Comp NRB	37,720	17,343	282
4	Capitalized Pension	AL 5.2	Net_Rate_Base	Comp NRB	83,796	36,527	582
5	CIAC Contribs in Aid of Construct	AL 5.2	Net_Rate_Base	Comp NRB	(280,988)	(82,411)	(1,388)
6	Cost of Removal - Net of Salvage	AL 5.2	Net_Rate_Base	Comp NRB	6,231,813	2,405,323	36,346
7	Tax Depreciation - Utility	AL 5.2	Net_Rate_Base	Comp NRB	66,618,088	30,820,152	482,831
8	Tax Depreciation - UTP	AL 5.2	Net_Rate_Base	Comp NRB	-	-	-
9	Bk/Tx Unit of Property	AL 5.2	Net_Rate_Base	Comp NRB	166,888,064	48,738,008	738,465
10	Amortization of Reacquisition Debt	AL 5.2	Net_Rate_Base	Comp NRB	38,443	18,135	274
11	Other Tax Credits	AL 5.2	Net_Rate_Base	Comp NRB	(1,865,842)	(852,887)	(12,888)
12	Disposition of Assets	AL 5.2	Net_Rate_Base	Comp NRB	388,782	181,931	2,740
13	Capitalized Interest in CWIP	AL 5.2	Net_Rate_Base	Comp NRB	8,884,320	3,837,382	58,900
14	Excess Deferred Gross Up (Direct)	AL 5.2	Net_Rate_Base	Comp NRB	44,481,465	20,414,298	308,476
15	Excess Deferred Gross Up (Allocable)	AL 5.2	Net_Rate_Base	Comp NRB	4,483,794	2,088,094	31,230
16	Amortization of Excess Deferred (Direct)	AL 5.2	Net_Rate_Base	Comp NRB	(10,482,048)	(4,810,104)	(72,885)
17	Amortization of Excess Deferred (Allocable)	AL 5.2	Net_Rate_Base	Comp NRB	(1,288,198)	(842,844)	(9,714)
18	Amort of Excess Deferred Asset	AL 5.2	Net_Rate_Base	Comp NRB	78,746	34,825	526
19	Other Adjustments	AL 5.2	Net_Rate_Base	Comp NRB	(887,173)	(280,787)	(3,940)
20	Deferred Income Taxes (Direct)	AL 5.2	Net_Rate_Base	Comp NRB	(3,218,480)	(1,479,741)	(22,382)
21	Deferred Income Taxes (Allocable)	AL 5.2	Net_Rate_Base	Comp NRB	(348,161)	(158,884)	(2,388)
18	Total Plant ADIT				$ 215,018,883	$ 98,857,983	$ 1,483,817

Line	Description (A)	RES-NON H/C-OTH (J)	C&I H/C < 3075 (K)	C&I H/C > 3075 (L)	C&I CHP (M)	C&I NON H/C (N)
2	Avoided Cost of Interest	$ (33,770)	$ (81,921)	$ (819,630)	$ (13,041)	$ (87,588)
3	Capitalized OPEB	441	1,070	8,087	170	883
4	Capitalized Pension	980	2,378	17,887	379	1,982
5	CIAC Contribs in Aid of Construct	(2,381)	(5,704)	(43,143)	(908)	(4,707)
6	Cost of Removal - Net of Salvage	61,202	148,488	1,122,981	23,634	122,904
7	Tax Depreciation - Utility	778,337	1,880,554	14,298,672	300,954	1,588,948
8	Tax Depreciation - UTP	-	-	-	-	-
9	Bk/Tx Unit of Property	1,240,129	3,008,367	22,754,528	478,887	2,462,287
10	Amortization of Reacquisition Debt	461	1,119	8,488	170	824
11	Other Tax Credits	(21,701)	(52,644)	(388,163)	(8,382)	(43,438)
12	Disposition of Assets	4,620	11,229	84,897	1,788	9,288
13	Capitalized Interest in CWIP	100,180	243,044	1,839,323	38,680	200,542
14	Excess Deferred Gross Up (Direct)	519,427	1,280,052	9,530,717	200,988	1,039,704
15	Excess Deferred Gross Up (Allocable)	52,570	127,528	964,388	20,301	105,227
16	Amortization of Excess Deferred (Direct)	(122,380)	(288,088)	(2,245,888)	(47,283)	(244,980)
17	Amortization of Excess Deferred (Allocable)	(16,357)	(38,678)	(300,121)	(6,318)	(32,740)
18	Amort of Excess Deferred Asset	886	2,190	16,259	342	1,774
19	Other Adjustments	(6,635)	(16,088)	(121,743)	(2,982)	(13,281)
20	Deferred Income Taxes (Direct)	(37,851)	(91,338)	(880,838)	(14,542)	(75,384)
21	Deferred Income Taxes (Allocable)	(4,038)	(9,785)	(74,088)	(1,558)	(8,082)
18	Total Plant ADIT	$ 2,515,380	$ 6,101,888	$ 48,153,113	$ 871,349	$ 5,034,835

Line	Description (A)	C&I NON H/C - NGV (O)	GMA H/C < 3075 (P)	GMA H/C >3075 (Q)	GMA NON H/C (R)	NON FIRM (S)	Special Contract (T)
2	Avoided Cost of Interest	$ (11,183)	$ (11,118)	$ (284,180)	$ (36,222)	$ (193,230)	$ (176,571)
3	Capitalized OPEB	148	145	3,844	480	2,525	2,333
4	Capitalized Pension	325	323	8,538	1,022	5,609	5,184
5	CIAC Contribs in Aid of Construct	(778)	(774)	(20,482)	(2,482)	(13,454)	(12,433)
6	Cost of Removal - Net of Salvage	20,287	20,151	533,109	63,833	380,183	323,625
7	Tax Depreciation - Utility	258,083	256,597	6,788,305	812,836	4,458,326	4,121,013
8	Tax Depreciation - UTP	-	-	-	-	-	-
9	Bk/Tx Unit of Property	410,676	408,313	10,802,370	1,283,438	7,086,996	6,567,611
10	Amortization of Reacquisition Debt	153	152	4,019	481	2,640	2,440
11	Other Tax Credits	(7,188)	(7,148)	(189,031)	(22,634)	(124,173)	(114,752)
12	Disposition of Assets	1,533	1,524	40,323	4,828	26,487	24,479
13	Capitalized Interest in CWIP	33,170	32,887	872,716	104,488	573,278	528,765
14	Excess Deferred Gross Up (Direct)	172,012	171,021	4,524,365	541,795	2,872,138	2,748,651
15	Excess Deferred Gross Up (Allocable)	17,409	17,308	457,823	54,830	300,804	277,983
16	Amortization of Excess Deferred (Direct)	(40,530)	(40,297)	(1,088,097)	(127,651)	(700,307)	(647,178)
17	Amortization of Excess Deferred (Allocable)	(5,417)	(5,385)	(142,478)	(17,080)	(93,582)	(86,482)
18	Amort of Excess Deferred Asset	293	292	7,718	924	5,070	4,688
19	Other Adjustments	(2,197)	(2,185)	(57,798)	(6,830)	(37,888)	(35,088)
20	Deferred Income Taxes (Direct)	(12,488)	(12,387)	(327,888)	(39,288)	(215,437)	(198,082)
21	Deferred Income Taxes (Allocable)	(1,337)	(1,329)	(35,172)	(4,211)	(23,104)	(21,352)
18	Total Plant ADIT	$ 832,980	$ 828,163	$ 21,810,486	$ 2,823,486	$ 14,382,782	$ 13,300,834

	Description	—— Reference —— Sc-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075
	A	B	C	D	G	H	I	J	K
1	Non-Plant ADIT								
2	Environmental	AL 1:6	Total_Weather_All_NW	Demand	$ -	$ -	$ -	$ -	$ -
3	Regulatory Assets & Liabilities - Rate cases	AL 6:37	O&M Adjusted	Comp OMA	(226,461)	(122,229)	(4,286)	(3,238)	(7,716)
4	Employee Benefits	AL 5:8	Total_Labor	Comp TLA	(16,014,762)	(5,148,229)	(157,111)	(139,830)	(388,988)
5	Amortization Gain on Sale of Property	AL 5:8	Total_Labor	Comp TLA	6,148	4,166	128	114	315
6	Uncollectible Accounts	AL 5:16	Uncollectibles	Customer	2,266,126	943,822	22,345	20,887	82,508
7	ADIT - Debt / Interest	AL 5:2	Net_Rate_Base	Comp NRB	(243,784)	(112,084)	(1,694)	(2,882)	(8,918)
8	General Taxes	RV 1:3	Gas_Sales_Revenue	Comp TCS	1,481,816	584,100	13,828	12,809	38,883
9	Lawsuits	AL 6:37	O&M Adjusted	Comp OMA	26,983	14,610	513	387	822
10	Customer Advances	AL 4:20	Dist_Mains_Plnt	Demand	86,464	21,222	136	410	1,284
11	Gas Costs	RV 1:3	Gas_Sales_Revenue	Comp TCS	(4,316)	(1,786)	(43)	(38)	(118)
12	Misc. Derivative Reserves	AL 5:2	Net_Rate_Base	Comp NRB	166,846	90,288	761	1,282	3,109
13	Merger Commitment Costs	AL 5:8	Total_Labor	Comp TLA	0	0	0	0	0
14	BPO	AL 5:8	Total_Labor	Comp TLA	-	-	-	-	-
15	Deferred Rent	AL 5:8	Total_Labor	Comp TLA	318,184	161,987	4,845	4,401	12,180
16	Misc. Items	AL 6:37	O&M Adjusted	Comp OMA	466,383	253,835	8,910	6,725	16,025
17	Sec. 174 R&D Expense Amort.	AL 5:2	Net_Rate_Base	Comp NRB	864,467	254,921	3,852	6,488	15,735
18	Non-Plant ADIT Regulatory Asset	AL 6:37	O&M Adjusted	Comp OMA	1,922,465	1,042,076	38,577	27,610	65,787
19	Total Non-Plant ADIT				$ (3,364,922)	$ (2,051,237)	$ (71,143)	$ (85,032)	$ (185,208)

	Description	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	L	M	N	O	P	Q	R	S	T
1	Non-Plant ADIT									
2	Environmental	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Regulatory Assets & Liabilities - Rate cases	(38,510)	(888)	(5,210)	(833)	(1,048)	(18,883)	(2,703)	(10,348)	(9,004)
4	Employee Benefits	(1,789,620)	(251,857)	(251,857)	(21,474)	(53,008)	(888,774)	(131,297)	(456,842)	(349,076)
5	Amortization Gain on Sale of Property	1,484	205	205	17	43	707	107	371	284
6	Uncollectible Accounts	536,457	9,751	86,082	-	9,522	234,386	32,000	166,834	139,853
7	ADIT - Debt / Interest	(52,338)	(1,101)	(5,708)	(944)	(838)	(24,842)	(2,974)	(16,318)	(15,080)
8	General Taxes	333,233	8,034	40,884	-	5,683	145,854	19,804	103,118	98,371
9	Lawsuits	4,723	80	623	64	125	2,270	323	1,237	1,076
10	Customer Advances	14,897	444	1,487	385	214	6,076	757	6,262	6,107
11	Gas Costs	(1,027)	(19)	(128)	-	(16)	(447)	(61)	(318)	(303)
12	Misc. Derivative Reserves	23,814	486	2,565	434	422	11,163	1,337	7,330	6,776
13	Merger Commitment Costs	0	0	0	0	0	0	0	0	0
14	BPO	-	-	-	-	-	-	-	-	-
15	Deferred Rent	56,639	7,827	7,827	876	1,888	27,374	4,132	14,372	10,988
16	Misc. Items	82,051	1,387	10,830	1,107	2,177	39,443	6,613	21,483	18,689
17	Sec. 174 R&D Expense Amort.	119,014	2,505	12,883	2,148	2,138	56,500	6,765	37,114	34,286
18	Non-Plant ADIT Regulatory Asset	338,845	5,085	44,416	4,545	8,835	161,826	23,043	88,234	78,785
19	Total Non-Plant ADIT	$ (381,649)	$ (219,122)	$ (74,926)	$ (13,804)	$ (23,877)	$ (228,353)	$ (43,154)	$ (37,466)	$ 38,853

Washington Gas Light Company
Normal Weather Therm Sales Analysis

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Sc-Pg-Ln	— Reference — Class Allocator	Cost Category	District of Columbia Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	E	F	G	H	I	J	K	K	L	M	N	O	P	Q
1	TOTAL FIRM WEATHER GAS - NW	NW Study + SAP			142,171,186	70,729,815	309,352	1,287,100	4,057,018	39,197,035	1,127,791	2,745,282	108,070	586,702	20,483,631	1,551,580	-	-
2			Firm_Weather_NW	Demand	1.0000	0.4975	0.0022	0.0091	0.0285	0.2757	0.0079	0.0193	0.0007	0.0040	0.1441	0.0109	-	-
3	TOTAL FIRM THERM SALES - NW	NW Study + SAP			209,261,703	84,793,186	677,620	1,703,534	5,336,136	68,854,404	2,101,032	8,012,732	3,179,946	998,179	29,674,103	3,929,846	-	-
4			Annual_ Firm_ NW	Demand	1.0000	0.4052	0.0032	0.0081	0.0255	0.3290	0.0100	0.0383	0.0152	0.0048	0.1418	0.0188	-	-
5	TOTAL ALL WEATHER GAS	NW Study + SAP			168,961,110	70,729,815	309,352	1,287,100	4,057,018	39,197,035	1,127,791	2,745,282	108,070	586,702	20,483,631	1,551,580	15,911,005	10,878,930
6			Total_Weather_All_NW	Demand	1.0000	0.4186	0.0018	0.0076	0.0240	0.2320	0.0067	0.0162	0.0006	0.0034	0.1213	0.0092	0.0942	0.0644
7	TOTAL ANNUAL THERM SALES	Revenue Study + SAP			287,130,656	84,793,186	677,620	1,703,534	5,336,136	68,854,404	2,101,032	8,012,732	3,179,946	998,179	29,674,103	3,929,846	39,649,220	38,220,735
8	Factor for Total Annual Therms		Annual_Total_NW	Demand	1.0000	0.2953	0.0024	0.0059	0.0186	0.2398	0.0073	0.0279	0.0111	0.0035	0.1033	0.0137	0.1381	0.1331
9	Deductions for Pipeline																	
10	Propane Holding	AL 1 2	Firm_Weather_NW		-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Propane Cooled	AL 1 2	Firm_Weather_NW		-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Total Pipeline Deductions	Ln. 10 + Ln. 11			-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	ANNUAL THERMS ADJUSTED	Ln. 7 - Ln. 12			287,130,656	84,793,186	677,620	1,703,534	5,336,136	68,854,404	2,101,032	8,012,732	3,179,946	998,179	29,674,103	3,929,846	39,649,220	38,220,735
14	Factor for Annual Therms Adj.		Pipeline_NW	Demand	1.0000	0.2953	0.0024	0.0059	0.0186	0.2398	0.0073	0.0279	0.0111	0.0035	0.1033	0.0137	0.1381	0.1331
15	FIRM ANNUAL PIPELINE	Ln. 3 - Ln. 12			209,261,703	84,793,186	677,620	1,703,534	5,336,136	68,854,404	2,101,032	8,012,732	3,179,946	998,179	29,674,103	3,929,846	-	-
16	Factor for Firm Annual Pipeline		Firm_Pipe_ Ann_ Adj	Demand	1.0000	0.40520	0.00324	0.00814	0.02550	0.32903	0.01004	0.03829	0.01520	0.00477	0.14180	0.01878	-	-

Washington Gas Light Company
Normal Weather Therm Sales Analysis

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	So-Pg-Ln	— Reference — Class Allocator	Cost Category	District of Columbia Total	RES-HTG/CLG	RES-NON H/C-SMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	E	F	G	H	I	J	K	K	L	M	N	O	P	Q
1	Peak Day Therm Sales- Normal Weather																	
2	Weather Gas	NW Study			2,290,271	1,136,887	4,978	20,770	65,270	633,771	18,146	44,047		9,042	330,407	24,853	-	-
3	Base Gas	NW Study			183,837	38,521	987	1,126	3,466	81,489	2,616	13,896		1,160	24,735	6,347	-	11,492
4	Total Peak Day Therms	Ln. 2 + Ln. 3			2,474,108	1,175,408	5,965	21,896	68,736	715,260	20,762	57,943	-	10,202	355,142	31,300	-	11,492
5			Peak_Day_Total	Demand	1.0000	0.4751	0.0024	0.0089	0.0278	0.2891	0.0084	0.0234	-	0.0041	0.1436	0.0127	-	0.0046
6	PEAK DAY AND ANNUAL SALES																	
7	Factor for Peak Day & Annual Sales (Firm)	1/	Comp_Peak_ Ann_NW	Demand	1.0000	0.3519	0.0023	0.0060	0.0213	0.2464	0.0073	0.0246	0.0000	0.0036	0.1130	0.0128	0.1636	0.1010
8	Development of Non-Firm Peak Day Usage:																	
9	Therm Sales in the Peak Month				6,677,977												4,517,811	2,160,167
10	Number of Customers in Peak Month				109												105	3
11	Average Therm Sales in Peak Month	Ln. 9 / Ln. 10			61,633												43,027	720,056
12	Number of Days in Peak Month				31												31	31
13	Average therms per Day	Ln. 11 / Ln. 12			1,988												1,388	23,228
14	Average Number of Customers				114												111	3
15	Total Non-Firm Peak Day Usage	Ln. 13 * Ln. 14			226,553												153,485	69,683
16	Residential - Peak Day Therms				1,203,269	1,175,408	27,861											
17	Residential Customers in Peak Month				150,277	135,801	14,476											
18	Peak Usage Per Customer Per Day	Ln. 16 / Ln. 17			8	9	2											
19	Peak Day Therms Firm Non-Residential	NW Study			1,269,347				68,736	715,260	20,762	57,943	-	10,202	355,142	31,300		
20	Peak Day Therms - Non-Firm	NW Study			223,168												153,485	69,683
21	Total Peak Day Therms Firm N/R & Non-Firm	Ln. 19 + Ln. 20			1,492,515				68,736	715,260	20,762	57,943	-	10,202	355,142	31,300	153,485	69,683
22	Average Customer Bills Non Res. or Non-Firm				13,025				4,480	3,390	1	1,845	3	588	1,707	889	111	3
23	Peak Usage Per Customer Per Day	Ln. 18			8				8	8	8	8	8	8	8	8	8	8
24	Peak Day Adjustment	Ln. 22 * Ln. 23			104,289			-	36,020	27,143	8	14,770	21	4,706	13,669	6,959	885	24
25	Peak Day Adjustec	Ln. 21 - Ln. 24			1,135,236			-	32,718	688,117	-	43,173	-	5,413	341,473	24,341	-	-
26	Peak Day Adjusted		Peak Day Adjusted	Demand	1.0000			-	0.0290	0.6061	-	0.0380	-	0.0048	0.3008	0.0214	-	-
27	Delivery Customers (12 Month Total)	NWB			255,936	172,231	8,664	6,531	8,837	16,864	16,864	7,398		1,571	11,162	4,463	1,327	36
28	Delivery Customers (12 Month Average)	Ln. 27 / 12			21,328	14,353	722	544	736	1,405	1,405	616	-	131	930	372	111	3
29	Delivery Customers Only Factor		Delv_Cust	Customer	1.0000	0.6729	0.0338	0.0255	0.0345	0.0659	0.0659	0.0289	-	0.0061	0.0436	0.0174	0.0052	0.0001

1/ For interruptible and special contract classes, the split is 25% peak usage and 75% annual usage. For all firm classes, the composite peak & annual factor is a 50/50 split between peak and annual after considering the amounts allocated to interruptible and special contract classes.
Interruptible & Special Contract Factors = [75% * annual usage peak usage by class] + [25% peak usage by class]
Firm Factors = [1 - Interruptible Factor - Special Contract Factor] * [(Class Annual Therms /(Total Annual Therms - Interruptible Annual Therms - Special Contract Annual Therms)*.5) + (Class Peak Therms /(Total Peak Therms - Interruptible Peak Therms - Special Contract Peak Therms)*.5)]

Washington Gas Light Company
Allocation Factors Based on Other Elements

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Sc-Pg-Ln	---- Reference ---- Class Allocator	Cost Category	District of Columbia Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	E	F	G	H	I	J	K	K	L	M	N	O	P	Q
1	**Annual Customer Bills**	NW Study			1,957,552	1,627,379	131,084	42,794	53,982	40,679	12	22,136	32	7,177	20,486	10,430	1,327	36
2	Months				12	12	12	12	12	12	12	12	12	12	12	12	12	12
3	Annual Average Customers Bills	Ln. 1 / Ln. 2			163,129	135,615	10,924	3,566	4,499	3,390	1	1,845	3	598	1,707	869	111	3
4	Annual Average Customers Bill Allocators		Ave_Customer _Bill	Customer	1.0000	0.8313	0.0670	0.0218	0.0276	0.0208	0.0000	0.0113	0.0000	0.0037	0.0105	0.0053	0.0007	0.0000
5	Multiple Customers at Common Address				58,775	42,392	10,444	482	1,672	1,260	-	1,116	-	509	379	436	85	-
6	Services Applicable to Common Address Customers				11,326	8,434	1,043	119	549	414	-	309	-	73	209	142	34	0
7	Net Customers at Common Addresses	Ln. 5 - Ln. 6			47,449	33,958	9,401	363	1,123	846	-	807	-	436	170	294	51	-
8	Aver. No. of Customers adjusted for multiple bills (All)	Ln. 3 - Ln. 7			115,681	101,657	1,523	3,203	3,376	2,544	1	1,038	3	162	1,537	575	60	3
9	Allocators for Aver # of Customers after Adj'mt (All)		Ave_Customer _Bill_Adj	Customer	1.0000	0.8788	0.0132	0.0277	0.0292	0.0220	0.0000	0.0090	0.0000	0.0014	0.0133	0.0050	0.0005	0.0000
10	Aver. No. of Customers adjusted for multiple bills (Firm)	Ln. 8 Excl Col. O & P			115,617	101,657	1,523	3,203	3,376	2,544	-	1,038	3	162	1,537	575	-	-
11	Allocators for Aver # of Customers after Adj'mt (Firm)		Firm_Cust_Bill_Adj	Customer	1.0000	0.8793	0.0132	0.0277	0.0292	0.0220	-	0.0090	0.0000	0.0014	0.0133	0.0050	-	-
12	Fee Free Credit By Tariff Class Allocator	Analysis				0.9850	0.9850	0.9850	0.0256	0.0256	0.0256	0.0256	0.0256	0.0083	0.0083	0.0083	0.0002	-
13	Fee Free Credit By Rate Class	Ln. 12 * Ratio Ln. 9				0.8656	0.0143	0.0301	0.4848	0.3855	0.0001	0.1481	0.0004	0.0714	0.5756	0.2530	1.0000	-
14	Fee Free Credit Allocator	Ln. 12 * Ln. 13	Fee_Free_Credit	Customer	1.0000	0.8230	0.0130	0.0281	0.0124	0.0094	0.0000	0.0038	0.0000	0.0006	0.0048	0.0021	0.0002	-

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Washington Gas Light Company
Allocation Factors Based on Gas Plant in Service

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Sc-Pg-Ln	Reference — Class Allocator	Cost Category	District of Columbia Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	E	F	G	H	I	J	K	K	L	M	N	O	P	Q
1	Gas Plant In Service(GPIS)																	
2	Storage - Depreciable	RB:2.5	Total_Weather_All_MW	Demand	$ 12,586,783	$ 5,260,227	$ 23,007	$ 85,723	$ 301,724	$ 2,915,120	$ 83,875	$ 204,168	$ 7,889	$ 42,146	$ 1,524,130	$ 115,393	$ 1,183,316	$ 809,077
3	Storage - Non Depreciable	RB:3.3	Total_Weather_All_MW	Demand	36,266	23,954	103	429	1,351	13,053	376	914	35	189	6,825	517	5,299	3,623
4	Total Storage	Ln. 2 + Ln. 3			$ 12,622,050	$ 5,283,780	$ 23,110	$ 86,151	$ 303,075	$ 2,928,173	$ 84,250	$ 205,082	$ 7,924	$ 42,335	$ 1,530,955	$ 115,910	$ 1,188,615	$ 812,699
5	Transmission - Depreciable	RB:2.14	Comp_Peak_Ann_MW	Demand	$ 164,826,436	$ 57,852,304	$ 371,066	$ 1,116,533	$ 3,501,444	$ 40,610,066	$ 1,210,869	$ 4,052,571	$ 996,174	$ 564,567	$ 18,749,811	$ 2,064,300	$ 17,069,950	$ 16,640,761
6	Transmission - Non Depreciable	RB:3.7	Comp_Peak_Ann_MW	Demand	808,189	283,666	1,819	5,475	17,169	199,122	5,937	19,871	4,885	2,886	91,935	10,122	83,690	81,624
7	Less: Pepco	RB:2.8	Comp_Peak_Ann_MW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Total Transmission	Ln. 5 to Ln. 7			$ 165,634,625	$ 58,135,970	$ 372,884	$ 1,122,008	$ 3,518,613	$ 40,809,188	$ 1,216,807	$ 4,072,442	$ 1,001,058	$ 567,454	$ 18,841,747	$ 2,074,421	$ 17,153,640	$ 16,722,384
			Transmission_Plnt	Demand	1.0000	0.3510	0.0023	0.0068	0.0212	0.2464	0.0073	0.0246	0.0060	0.0034	0.1138	0.0125	0.1036	0.1010
9	Distribution Plant																	
10	Meters	RB:2.28-30	Meter_Cost	Customer	$ 26,882,065	$ 9,801,926	$ 684,178	$ 263,243	$ 3,777,823	$ 5,543,734	$ 11,970	$ 1,882,003	$ 11,462	$ 584,372	$ 2,708,984	$ 952,000	$ 481,253	$ 66,922
11	Meter Installations	RB:2.29	Meter_Cost	Customer	35,970,717	16,356,215	1,132,562	435,764	3,228,501	7,002,258	18,525	1,936,083	17,024	550,087	3,384,608	1,009,173	741,713	145,880
12	House Regulators	RB:2.30	Ave_Customer_Bill	Customer	4,731,359	3,033,337	316,827	103,432	130,473	99,320	29	63,900	78	17,347	40,512	25,209	3,207	87
13	House Regulator Installations	RB:2.31	Ave_Customer_Bill	Customer	3,744,765	3,113,166	250,763	81,865	103,267	77,819	23	42,344	62	13,730	30,186	19,953	2,538	69
14	Total Meters and House Regulators	Ln. 11 > Ln. 13			$ 71,330,545	$ 33,206,844	$ 2,384,329	$ 884,304	$ 7,239,955	$ 12,722,129	$ 30,594	$ 3,923,840	$ 28,625	$ 1,165,545	$ 6,163,488	$ 2,006,335	$ 1,228,712	$ 234,977
15			Mtr_Hse_Reg_Plnt	Customer	1.0000	0.4444	0.0334	0.0124	0.1016	0.1783	0.0004	0.0550	0.0004	0.0163	0.0866	0.0281	0.0174	0.0033
16	Compressor Station Equipment	RB:2.15	Total_Weather_All_MW	Demand	$ 490,892	$ 188,712	$ 825	$ 3,434	$ 10,824	$ 104,581	$ 3,009	$ 7,325	$ 283	$ 1,512	$ 54,679	$ 4,140	$ 42,452	$ 29,026
17	Measuring and Regulator Station Equipment	RB:2.16	Comp_Peak_Ann_MW	Demand	10,637,047	3,733,469	23,947	72,056	225,985	2,620,764	78,143	261,532	64,288	37,726	1,210,016	133,219	1,101,606	1,074,296
18			Dist_Meas_Reg_Plnt	Customer	1.0000	0.3510	0.0023	0.0068	0.0212	0.2464	0.0073	0.0246	0.0060	0.0035	0.1138	0.0125	0.1036	0.1010
19	Mains	RB:2.17	Comp_Peak_Ann_MW	Demand	$ 540,504,248	$ 189,730,856	$ 1,261,832	$ 3,790,653	$ 11,908,914	$ 138,097,475	$ 4,117,640	$ 13,781,081	$ 3,387,961	$ 1,887,932	$ 63,760,084	$ 7,019,800	$ 56,047,804	$ 56,609,517
20			Dist_Mains_Plnt	Demand	1.0000	0.3510	0.0023	0.0068	0.0212	0.2464	0.0073	0.0246	0.0060	0.0035	0.1138	0.0125	0.1036	0.1010
21	Services	RB:2.18	Peak Day Adjusted	Customer	412,851,740	272,465,786	4,081,073	8,506,075	12,014,678	69,219,532	-	6,696,379	7,165	926,321	35,095,013	3,749,906	-	-
22			Dist_Services_Plnt	Customer	1.0000	0.6600	0.0099	0.0206	0.0291	0.1677	-	0.0162	0.0000	0.0022	0.0850	0.0091	-	-
23	Mains & Services Composite		Mains_Services	Comp M&S	1.0000	0.4821	0.0055	0.0127	0.0248	0.2130	0.0043	0.0210	0.0036	0.0030	0.1016	0.0111	0.0604	0.0602
24	Gas Light Services	RB:2.32	Gas_Lights	Customer	107,137	100,091	207	1,885	207	1,451	-	414	-	-	2,072	829	-	-
25	Post 1998 MD Interruptible Distribution Plant	RB:2.33	n/a	n/a	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	AFUDC	RB:2.34	na	na	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Total Distribution Plant	Ln. 24 > Ln. 26			$ 1,055,880,329	$ 508,525,880	$ 7,752,212	$ 13,344,586	$ 31,388,744	$ 222,765,831	$ 4,229,355	$ 24,670,650	$ 3,487,942	$ 4,110,036	$ 106,308,373	$ 12,913,829	$ 60,430,374	$ 57,948,816
28			Tot_Dist_Plnt	Comp TDP	1.0000	0.4797	0.0073	0.0126	0.0297	0.2110	0.0040	0.0234	0.0033	0.0039	0.1007	0.0122	0.0573	0.0548
29	Total GPIS Excluding General/Intangible/Pepco	Ln. 4 + Ln. 8 + Ln. 27			$ 1,234,147,213	$ 569,945,431	$ 8,148,206	$ 14,552,745	$ 35,220,432	$ 266,503,292	$ 5,530,412	$ 28,948,174	$ 4,498,924	$ 4,749,825	$ 126,679,074	$ 15,104,160	$ 78,772,630	$ 75,487,800
30			Tot_Plnt_Ex_Genl	Comp TPE	1.0000	0.4618	0.0066	0.0118	0.0285	0.2159	0.0045	0.0235	0.0036	0.0038	0.1026	0.0122	0.0638	0.0612
31	General Plant - Depreciable	RB:2.42	Tot_Plnt_Ex_Genl	Comp TPE	$ 72,889,880	$ 33,661,557	$ 481,241	$ 860,091	$ 2,080,155	$ 15,739,850	$ 326,632	$ 1,709,709	$ 265,593	$ 280,470	$ 7,481,736	$ 892,067	$ 4,652,382	$ 4,458,392
32	General Plant - Non-Depreciable	RB:3.12	Tot_Plnt_Ex_Genl	Comp TPE	703,208	324,751	4,643	8,298	20,068	151,852	3,151	16,494	2,562	2,706	72,180	8,606	44,884	43,012
33	Total General GPIS	Ln. 31 + Ln. 32			73,593,188	33,986,308	485,884	868,389	2,100,223	15,891,607	329,783	1,726,203	268,155	283,176	7,553,916	900,673	4,697,276	4,501,405
34			Genl_Plnt	Comp TPE	1.0000	0.4618	0.0066	0.0118	0.0285	0.2159	0.0045	0.0235	0.0036	0.0038	0.1026	0.0122	0.0638	0.0612
35	CNG Equipment	RB:2.43			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Total GPIS Excluding Pepco & Intangible	Ln. 29 + Ln. 33 + Ln. 35			$ 1,307,740,411	$ 603,931,739	$ 8,634,090	$ 15,431,134	$ 37,320,655	$ 282,395,099	$ 5,860,195	$ 30,674,377	$ 4,765,080	$ 5,032,001	$ 134,231,990	$ 16,004,833	$ 83,469,914	$ 79,989,205
37			Tot_Plnt_Ex_Pepco	Comp TPE	1.0000	0.4618	0.0066	0.0118	0.0285	0.2159	0.0045	0.0235	0.0036	0.0038	0.1026	0.0122	0.0638	0.0612

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Washington Gas Light Company
Allocation Factors Based on Miscellaneous Items

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Sc-Pg-Ln	—— Reference —— Class Allocator	Cost Category	District of Columbia Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	E	F	G	H	I	J	K	K	L	M	N	O	P	Q
1	Net Rate Base _1/	RB 1:26			$ 720,303,204	$ 331,171,632	$ 5,004,208	$ 8,426,425	$ 20,441,230	$ 154,612,308	$ 3,254,006	$ 16,888,837	$ 2,780,473	$ 2,774,402	$ 73,308,901	$ 8,780,645	$ 46,215,577	$ 44,957,831
2			Net_Rate_Base	Comp NRB	1.0000	0.4598	0.0069	0.0117	0.0284	0.2146	0.0045	0.0234	0.0039	0.0039	0.1018	0.0122	0.0642	0.0624
3	Gas Light Services by Class	Analysis			517	483	1	9	1	7	0	2	0	0	10	4		
4			Gas_Lights	Customer	1.0000	0.9342	0.0019	0.0174	0.0019	0.0135	0.0000	0.0039	0.0000	0.0000	0.0193	0.0077	0.0000	0.0000
5	Total Depreciation Expense	EX 6:20			$ 31,830,254	$ 14,798,151	$ 214,108	$ 380,073	$ 914,781	$ 6,846,846	$ 140,085	$ 746,149	$ 114,179	$ 122,783	$ 3,256,656	$ 389,522	$ 1,986,405	$ 1,913,425
6			Depreciation_Expense	Comp DEX	1.0000	0.4649	0.0067	0.0119	0.0287	0.2151	0.0044	0.0234	0.0036	0.0039	0.1023	0.0122	0.0624	0.0601
7	Total Labor _2/	WEX 2:27			$ 13,386,051	$ 6,883,753	$ 210,159	$ 187,027	$ 517,082	$ 2,407,220	$ 338,891	$ 336,891	$ 28,724	$ 70,805	$ 1,163,437	$ 175,827	$ 610,818	$ 466,934
8			Total_Labor	Comp TLA	1.0000	0.5139	0.0157	0.0140	0.0386	0.1797	0.0251	0.0251	0.0021	0.0053	0.0869	0.0131	0.0456	0.0349
9	Meter Cost by Class				$ 19,410,206	$ 8,827,076	$ 611,144	$ 235,143	$ 1,742,184	$ 3,778,497	$ 9,898	$ 1,044,738	$ 9,186	$ 296,030	$ 1,831,876	$ 544,581	$ 400,237	$ 79,720
10			Meter_Cost	Customer	1.0000	0.4548	0.0315	0.0121	0.0898	0.1947	0.0005	0.0538	0.0005	0.0153	0.0944	0.0281	0.0206	0.0041
11	Meter Count Excluding Residential				13,150				4,654	3,346	2	1,640	3	642	1,679	672	110	2
12			Meter_Count_Ex_Res	Customer	1.000				0.3539	0.2544	0.0002	0.1247	0.0002	0.0488	0.1277	0.0511	0.0084	0.0002
13	Meter Count C&I Only				9,845				4,654	3,346	2	1,640	3					
14			Meter_Count_C&I_Only	Customer	1.000				0.4727	0.3399	0.0002	0.1666	0.0003					
15	Uncollectibles				5,945,027	2,477,148	56,646	54,321	164,053	1,413,226	25,502	173,387	-	24,982	615,189	83,986	437,320	417,187
16			Uncollectibles	Customer	1.000	0.4167	0.0095	0.0091	0.0276	0.2377	0.0043	0.0292	-	0.0042	0.1035	0.0141	0.0736	0.0702

_1/ For purposes of determining the net ratebase factor, net ratebase total excludes certain miscellaneous amounts that are included in ratebase in the PSCOSA and are allocated on net ratebase in the Class Cost Study. Refer to Schedule Ratebase Page 1 for more information.
_2/ If adding amounts for either of the user defined classes in columns Q and R, equivalent amounts must be removed from another class.

Washington Gas Light Company
Allocation Factors Based on Operations & Maintenance Expenses (Continued)

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Sc-Pg-Ln	----- Reference ----- Class Allocator	Cost Category	District of Columbia Total	RES-HTG/CLG	RES-NON H/C-MA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	E	F	G	H	I	J	K	K	L	M	N	O	P	Q
1	**Appliance Service - Field**																	
2	Removing/resetting Meters - Direct	EX 2 25	Ave_Customer_Bill.	Customer	$ 121,882	$ 101,156	$ 6,146	$ 2,880	$ 3,356	$ 2,529	$ 1	$ 1,376	$ 2	$ 446	$ 1,273	$ 646	$ 82	$ 2
3	Removing/resetting Meters - Allocable	EX 2 26	Ave_Customer_Bill.	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	SOCP - Direct	EX 2 29	Ave_Customer_Bill.	Customer	1,533	1,274	103	34	42	32	0	17	0	6	16	8	1	0
5	SOCP - Allocable	EX 2 30	Ave_Customer_Bill.	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Appliance Service - Field	Ln. 2 > Ln. 5			$ 123,215	$ 102,433	$ 6,251	$ 2,884	$ 3,398	$ 2,560	$ 1	$ 1,393	$ 2	$ 452	$ 1,289	$ 654	$ 84	$ 2
			Appl_Serv_X_Admin	Customer	1.0000	0.8313	0.0507	0.0234	0.0276	0.0208	0.0000	0.0113	0.0000	0.0037	0.0105	0.0053	0.0007	0.0000
7	**Distribution - Field**																	
8	Operations Expense																	
9	Mains	EX 2 24	Mains_Services_	Comp M&S	$ 291,861	$ 140,886	$ 1,602	$ 3,713	$ 7,173	$ 62,164	$ 1,235	$ 6,140	$ 1,018	$ 974	$ 29,639	$ 3,229	$ 17,406	$ 16,974
10	Measuring/Regulating Station	EX 2 27	Dist_Meas_Reg_Plnt.	Customer	303,237	168,433	663	2,054	6,442	74,712	2,226	7,456	1,833	1,075	34,465	3,796	31,404	30,626
11	Maintenance Expense																	
12	Mains	EX 4 11	Dist_Mains_Plnt.	Demand	8,648,126	3,035,400	19,460	58,582	183,714	2,130,733	63,532	212,831	52,287	30,672	983,767	108,310	886,628	873,424
13	Services	EX 4 12	Dist_Services_Plnt.	Customer	9,541,079	6,297,196	94,314	196,426	277,886	1,586,676	-	154,756	166	21,407	810,821	86,852	-	-
14	Meter & House Regulators	EX 4 13	Mtr_Hse_Reg_Plnt.	Customer	3,800,786	1,773,427	127,031	47,113	385,726	677,802	1,626	209,057	1,525	62,087	329,974	106,882	65,995	12,519
15	Measuring & Regulating Station Equip.	EX 4 15	Comp_Peak_ Ann_NW.	Demand	911,702	319,986	2,052	6,176	19,367	224,626	6,686	22,416	5,510	3,234	103,711	11,418	94,419	92,076
16	Gas Light Services	EX 4 16	Gas_Lights.	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Distribution - Field	Ln. 9 > Ln. 16			$ 23,466,785	$ 11,673,146	$ 245,151	$ 316,085	$ 880,086	$ 4,760,713	$ 75,330	$ 612,454	$ 63,318	$ 119,380	$ 2,292,485	$ 320,299	$ 1,104,853	$ 1,025,620
18			Dist_X_Admin	Comp DXA	1.0000	0.4966	0.0104	0.0136	0.0375	0.2030	0.0032	0.0261	0.0027	0.0051	0.0978	0.0136	0.0470	0.0436
19	**Distribution Maintenance Expenses**																	
20	Mains	EX 4 11	Dist_Mains_Plnt.	Demand	$ 8,648,126	$ 3,035,400	$ 19,460	$ 58,582	$ 183,714	$ 2,130,733	$ 63,532	$ 212,831	$ 52,287	$ 30,672	$ 983,767	$ 108,310	$ 886,628	$ 873,424
21	Services	EX 4 12	Dist_Services_Plnt.	Customer	9,541,079	6,297,196	94,314	196,426	277,886	1,586,676	-	154,756	166	21,407	810,821	86,852	-	-
22	Meter & House Regulators	EX 4 13	Mtr_Hse_Reg_Plnt.	Customer	3,800,786	1,773,427	127,031	47,113	385,726	677,802	1,626	209,057	1,525	62,087	329,974	106,882	65,995	12,519
23	Measuring & Regulating Station Equipt.	EX 4 15	Comp_Peak_ Ann_NW.	Demand	911,702	319,986	2,052	6,176	19,367	224,626	6,686	22,416	5,510	3,234	103,711	11,418	94,419	92,076
24	Compressor Station Equipment	EX 4 14	Total_Weather_All_NW.	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Gas Light Services	EX 4 16	Gas_Lights.	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Distribution Maintenance Expenses	Ln. 20 > Ln. 25			$ 22,901,687	$ 11,426,021	$ 242,867	$ 310,287	$ 866,474	$ 4,632,837	$ 71,857	$ 598,650	$ 59,480	$ 117,410	$ 2,228,272	$ 313,272	$ 1,056,042	$ 978,021
27			Dist_Maint_Exp	Comp DME	1.0000	0.4989	0.0106	0.0136	0.0378	0.2023	0.0031	0.0261	0.0026	0.0051	0.0973	0.0137	0.0461	0.0427
28	**Calculation of Three Part Factor**																	
29	Net Rate Base	RB 1 26			$ 720,303,204	$ 331,171,632	$ 5,004,266	$ 8,426,425	$ 20,441,230	$ 154,812,388	$ 3,254,008	$ 18,866,837	$ 2,790,473	$ 2,774,402	$ 73,308,901	$ 8,788,845	$ 46,215,577	$ 44,957,631
30	Total Maintenance Expenses	EX 4 25			25,825,612	12,849,525	272,434	347,252	879,884	5,268,850	83,473	879,512	66,746	133,198	2,531,505	355,265	1,225,375	1,134,631
31	Total Operation Expenses	EX 2 46			57,139,032	29,606,887	1,060,826	760,978	1,787,327	10,236,000	402,563	1,321,177	151,015	246,880	4,813,796	675,346	3,213,708	2,770,733
32	LESS:																	
33	Uncollectible Accounts	EX 7 21			5,845,027	2,477,146	58,846	54,321	164,883	1,413,226	25,982	173,387	-	24,882	615,186	63,986	437,320	417,187
34	Purchased Gas Cost	EX 3 1			-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Administrative & General Expenses	EX 5 29			37,200,773	18,340,785	515,117	480,907	1,236,327	7,086,175	432,212	904,976	125,379	171,908	3,387,756	486,142	2,169,610	1,864,184
36	O&M Adjusted	Lns. (30+31-33-34-35)			$ 39,919,044	$ 21,638,291	$ 759,466	$ 573,312	$ 1,366,032	$ 6,984,446	$ 118,252	$ 922,326	$ 94,382	$ 185,541	$ 3,392,330	$ 478,485	$ 1,832,144	$ 1,583,994
37			O&M Adjusted	Comp OMA	1.0000	0.5421	0.0190	0.0144	0.0342	0.1752	0.0030	0.0231	0.0024	0.0046	0.0842	0.0120	0.0459	0.0396
38	Total Annual Therm Sales				287,130,858	84,793,186	677,620	1,703,534	5,336,138	68,654,404	2,101,032	8,012,732	3,179,946	986,179	29,674,103	3,929,846	38,648,220	38,220,735
39	Net Rate Base	AL 5 2	Net_Rate_Base.	Comp NRB	1.0000	0.4598	0.0069	0.0117	0.0284	0.2149	0.0045	0.0234	0.0039	0.0039	0.1018	0.0122	0.0642	0.0624
40	O&M Adjusted	AL 6 37	O&M Adjusted.	Comp OMA	1.0000	0.5421	0.0190	0.0144	0.0342	0.1752	0.0030	0.0231	0.0024	0.0046	0.0842	0.0120	0.0459	0.0396
41	Total Annual Therm Sales	AL 1 6	Annual_Total_NW.	Demand	1.0000	0.2953	0.0024	0.0059	0.0186	0.2390	0.0073	0.0279	0.0111	0.0035	0.1033	0.0137	0.1361	0.1331
42			Three_Part_Factor	Comp 3PF	1.0000	0.4324	0.0094	0.0107	0.0271	0.2096	0.0049	0.0248	0.0058	0.0040	0.0964	0.0126	0.0834	0.0783
43	**Factors Not Developed on Schedule AL**																	
44			Gas_Sales_Revenue	Comp TCS	1.0000	0.4167	0.0088	0.0091	0.0276	0.2377	0.0043	0.0282	0.0000	0.0042	0.1035	0.0141	0.0736	0.0702
45			Gas_Sales_Ex_Non_Firm	Comp TCS	1.0000	0.4866	0.0115	0.0107	0.0322	0.2776	0.0050	0.0341	0.0000	0.0048	0.1208	0.0165	0.0000	0.0000
46	to allocate CNG sales for NGV (RV 1)		C&I Other	Customer									1.0000					
47			Total_Revenues	Comp TCS	1.0000	0.4218	0.0090	0.0092	0.0271	0.2337	0.0043	0.0287	0.0036	0.0042	0.1025	0.0140	0.0724	0.0684
48	If needed used to allocate multi-family unit contributions (EX.5)		Residential Heating	Customer	1.0000	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
49			Tax_Factor	Comp TAX	1.0000	0.2353	0.0182	-0.0135	0.0161	0.5446	-0.0261	0.1222	-0.0146	0.0057	0.1868	0.0336	-0.0811	-0.0482
50			Watergate	WTG	1.0000													1.0000
51			User Defined Factor 1		0.0000													
52			User Defined Factor 2		0.0000													
53			User Defined Factor 3		0.0000													
54			User Defined Factor 4		0.0000													
55			User Defined Factor 5		0.0000													

Washington Gas Light Company
District of Columbia Effective Tax Rate Test
March 2024 Quarterly Review
After Correction of Jurisdictional Allocation of Deferred Taxes

Line	Description A	Sc-Pg-Ln. B	Class Allocator C	Cost Ctgry D	Ratemaking G	RES-HTG/CLG H	RES-NON H/C-GMA I	RES-NON H/C-OTH J
1	Operating Revenues	SM 1:1			223,753,787	94,381,333	2,221,121	2,086,124
2	Less: Operating Expenses	SM 1:13			184,046,251	79,166,934	1,769,461	1,965,860
3	Plus: AFUDC	SM 1:16			467,443	214,916	3,248	5,469
4	Income Before Taxes & Interest	Ln. 1 - 2 + 3			40,174,979	15,389,314	454,908	116,733
5	Interest Expense	EX 9:31			18,000,268	8,272,764	124,841	210,269
6	Taxable Income	Ln. 5 - Ln. 4			22,174,711	7,136,551	330,067	(94,536)
7	Flow Throughs & Permanent Differences							
8	AFUDC Equity	AL 4:37	Tot_Plnt_Ex_Pepco	Comp TPE	18,897	8,588	123	219
9	Meals and Entertainment	AL 5:8	Total_Labor	Comp TLA	184,869	88,044	2,902	2,582
10	Compensation Limitation	AL 5:8	Total_Labor	Comp TLA	-	-	-	-
11	Parking	AL 5:8	Total_Labor	Comp TLA	96,216	48,442	1,509	1,343
12	Other Tax Adjustments	AL 4:37	Tot_Plnt_Ex_Pepco	Comp TPE	-	-	-	-
13	Total Flow Throughs & Permanent Differences	Ln. 8 > Ln. 12			299,771	143,074	4,534	4,144
14	Taxable Income - Adjusted	Ln. 6 + Ln. 13			22,474,483	7,279,626	334,601	(90,491)
15	Statutory Tax Rate (Federal)	Statutory			21.000%	21.000%	21.000%	21.000%
16	Statutory Tax Rate (State)	Statutory			8.250%	8.250%	8.250%	8.250%
17	Statutory Tax Rate (State) (net of federal tax benefit)	Ln. 16 * (1 - Ln. 15)			6.518%	6.518%	6.518%	6.518%
18	Composite Tax Rate	Ln. 15 + Ln. 17			27.518%	27.518%	27.518%	27.518%
19	Income Taxes	Ln. 14 * Ln. 18			6,184,410	2,003,171	92,074	(24,901)
20	Tax - Amortization of Prior Flow-Through Balance	AL 5:2	Net_Rate_Base	Comp NRB	71,421	32,837	466	539
21	Excess Deferred (Protected)	AL 4:28	Tot_Dist_Plnt	Comp TDP	5,257,284	2,521,884	30,888	66,443
22	Excess Deferred (Unprotected)	AL 4:28	Tot_Dist_Plnt	Comp TDP	(7,888,370)	(3,793,788)	(60,082)	(99,948)
23	Excess Deferred - FC 1027 Write Off	AL 4:28	Tot_Dist_Plnt	Comp TDP	343,888	164,888	2,522	4,342
24	Investment Tax Credit (ITC)	ETR 1:26	Tax_Factor	Comp TAX	(90,913)	(21,282)	(1,741)	1,226
25	Total Taxes	Ln. 24 > Ln. 19			3,857,392	907,880	73,867	(52,003)
26	Tax_Factor				100.00%	23.53%	1.92%	-1.36%
27	Income Taxes (per RMPP)	SM 1:14			3,857,393	907,880	73,867	(52,003)
28	Effective Tax Rate	Ln. 27 / Ln. 6			17.40%	12.74%	22.38%	54.98%
29	Difference - Calculated v. Allocated	Ln. 26 - Ln. 27			(1)	-	-	-
30	Break Down of Taxes by Components							
31	Taxes (excl flow throughs/perm diff & ITC	Ln. 6 * Ln. 18			6,101,926	1,961,849	90,826	(26,041)
32	Taxes related to Flow Throughs & Perm Dif	Ln. 13 * Ln. 18			82,490	42,122	1,248	1,141
33	Taxes related to Tax Amortization	Ln. 20 > Ln. 22			(2,238,110)	(1,074,118)	(16,446)	(26,338)
34	Taxes related to Investment Tax Credit	Ln. 24			(90,913)	(21,282)	(1,741)	1,226
35	Total Taxes	Ln. 31 > Ln. 34			3,857,392	907,880	73,867	(52,003)
36	Federal Taxes (excl flow throughs/perm diff & ITC	Ln. 31 / Ln. 6			27.52%	27.52%	27.52%	27.52%
37	Taxes related to Flow Throughs & Perm Dif	Ln. 32 / Ln. 6			0.37%	0.59%	0.38%	-1.21%
38	Taxes related to Tax Amortization	Ln. 33 / Ln.			-10.08%	-15.07%	-4.98%	29.83%
39	Taxes related to Investment Tax Credit	Ln. 34 / Ln. 6			-0.41%	-0.30%	-0.53%	-1.30%
40	Effective Tax Rate	Ln. 36 > Ln. 39			17.40%	12.74%	22.38%	54.98%

Line	C&I H/C < 3075 K	C&I H/C > 3075 L	C&I CHP M	C&I NON H/C N	C&I NON H/C - NGV O	GMA H/C < 3075 P
1	6,074,484	52,282,708	862,290	6,422,731	861,251	929,572
2	5,116,062	39,040,294	1,250,464	4,074,986	975,062	749,544
3	13,265	100,336	2,112	10,846	1,611	1,800
4	971,688	13,342,750	(386,064)	2,358,611	(112,201)	181,829
5	510,686	3,870,375	91,636	422,250	70,300	69,386
6	461,011	9,472,375	(377,691)	1,936,332	(182,501)	112,443
7						
8	531	4,016	63	436	69	72
9	7,147	33,237	4,661	4,661	397	879
10	-	-	-	-	-	-
11	3,718	17,290	2,430	2,430	205	508
12	-	-	-	-	-	-
13	11,396	54,543	7,164	7,567	671	1,560
14	472,407	9,526,916	(370,537)	1,943,931	(182,311)	114,003
15	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%
16	8.250%	8.250%	8.250%	8.250%	8.250%	8.250%
17	6.518%	6.518%	6.518%	6.518%	6.518%	6.518%
18	27.518%	27.518%	27.518%	27.518%	27.518%	27.518%
19	129,995	2,621,569	(101,982)	534,994	(50,167)	31,371
20	2,027	15,331	323	1,672	277	275
21	166,334	1,169,153	21,066	122,636	17,366	20,969
22	(236,169)	(1,668,464)	(31,677)	(184,777)	(26,124)	(30,861)
23	10,216	72,461	1,376	8,027	1,136	1,340
24	(1,489)	(49,907)	2,953	(11,113)	1,324	(821)
25	61,943	2,100,542	(108,328)	471,539	(56,188)	22,123
26	1.61%	54.49%	-2.81%	12.22%	-1.46%	0.57%
27	61,943	2,100,542	(108,328)	471,538	(56,188)	22,123
28	13.44%	22.18%	28.68%	24.35%	30.71%	19.67%
29	-	-	-	-	-	-
30						
31	126,869	2,606,560	(103,931)	532,826	(50,352)	20,942
32	3,136	15,009	1,960	2,086	185	429
33	(66,562)	(471,900)	(9,020)	(52,243)	(7,346)	(8,727)
34	(1,489)	(49,907)	2,953	(11,113)	1,324	(821)
35	61,943	2,100,542	(108,328)	471,539	(56,188)	22,123
36	27.52%	27.52%	27.52%	27.52%	27.52%	27.52%
37	0.68%	0.16%	-0.52%	0.11%	-0.10%	0.38%
38	-14.44%	-4.98%	2.38%	-2.70%	4.01%	-7.76%
39	-0.32%	-0.53%	-0.08%	-0.57%	-0.72%	-0.48%
40	13.44%	22.18%	28.68%	24.35%	30.71%	19.67%

Line	GMA H/C >3075 Q	GMA NON H/C R	NON FIRM S	Special Contract T
1	22,939,897	3,136,614	16,182,807	15,294,344
2	17,636,303	2,344,081	15,451,884	14,485,886
3	47,833	5,703	31,290	28,916
4	5,351,927	797,236	772,213	837,368
5	1,636,568	220,009	1,201,016	1,109,889
6	3,616,359	577,227	(428,804)	(272,521)
7				
8	1,909	226	1,187	1,137
9	16,064	2,426	6,434	6,447
10	-	-	-	-
11	8,356	1,261	4,387	3,264
12	-	-	-	-
13	26,329	3,914	14,008	10,839
14	3,641,688	581,141	(414,796)	(261,687)
15	21.000%	21.000%	21.000%	21.000%
16	8.250%	8.250%	8.250%	8.250%
17	6.518%	6.518%	6.518%	6.518%
18	27.518%	27.518%	27.518%	27.518%
19	974,564	159,916	(114,142)	(71,868)
20	7,276	671	4,781	4,416
21	529,296	84,299	300,963	288,517
22	(796,202)	(96,722)	(462,609)	(434,088)
23	34,980	4,202	19,062	16,684
24	(17,259)	(3,052)	9,959	4,472
25	732,384	129,513	(236,886)	(188,731)
26	18.98%	3.36%	-6.11%	-4.88%
27	732,385	129,513	(236,886)	(188,731)
28	20.33%	22.44%	55.01%	69.62%
29	-	-	-	-
30				
31	967,339	158,839	(117,998)	(74,886)
32	7,246	1,077	3,866	3,910
33	(225,041)	(27,350)	(127,263)	(122,218)
34	(17,259)	(3,052)	9,959	4,472
35	732,384	129,513	(236,886)	(188,731)
36	27.52%	27.52%	27.52%	27.52%
37	0.21%	0.19%	-0.90%	-1.10%
38	-6.40%	-4.74%	29.68%	44.88%
39	-0.49%	-0.53%	-1.30%	-1.64%
40	20.33%	22.44%	55.01%	69.62%

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study Cost Categorizatn

Customer Costs

Twelve Months Ended March 31, 2024 - Average Rate Bas

Line No.	Description A	Reference B		District of Columbia Customer C=Sum (D > P)	Residential Heating/Cooling D	Residential Non Heating/Cooling W/ E	Residential Non Heating/Cooling F	C&I Heating/Cooling <3075 G	C&I Heating/Cooling >3075 H	C&I CHP I	C&I Non Heating/Cooling J	C&I Non Heating/Cooling - NGV K	GMA Heating/Cooling <3075 L	GMA Heating/Cooling >3075 M	GMA Non Heating/Cooling N	Non Firm O	Special Contract P
1	**EXPENSES**																
2	Gas Purchased	EX 2.2		$ -													
3	Operation - Other than Gas Purchases	EX 2.46		31,346,686	17,643,924	774,474	460,387	1,008,586	4,986,380	283,877	688,812	64,984	136,837	2,346,556	351,328	1,386,483	1,219,984
3.01	Customer		Customer	6,732,931	5,451,654	431,236	142,614	183,749	208,324	2,267	80,156	1,938	24,649	101,779	38,056	35,783	30,744
3.02	Comp DemCom		Comp 3PF	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.03	Comp M&S		Comp CDX	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.04	Comp TDP		Comp CWC	1,901,837	912,194	13,961	24,032	56,546	401,176	7,617	44,429	6,201	7,418	191,444	23,256	108,826	104,356
3.05	Comp TPE		Comp DEX	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.06	Comp NRB		Comp DME	2,044,676	940,074	14,205	23,920	58,025	438,686	9,237	47,876	7,921	7,076	208,355	24,946	136,866	126,483
3.07	Comp TLA		Comp DXA	8,780,687	4,516,141	137,875	122,701	339,616	1,579,280	221,020	221,020	18,844	46,519	783,282	115,221	400,732	308,336
3.08	Comp DXA		Comp GTX	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.09	Comp DME		Comp M&S	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.10	Comp OMA		Comp NRB	6,664,196	3,612,356	126,793	95,710	228,049	1,167,672	19,741	153,976	15,756	30,975	561,316	79,880	305,863	266,106
3.11	Comp 3PF		Comp OMA	2,464,480	1,065,590	23,276	26,262	66,692	517,268	12,156	61,142	14,223	9,841	237,805	31,114	206,129	192,972
3.12	Comp TAX		Comp TAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	Comp TCS		Comp TCS	2,750,136	1,145,914	27,130	25,128	75,880	653,751	11,838	80,208	-	11,561	284,574	38,852	202,302	192,988
3.14	Comp GTX		Comp TDP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.15	Comp CWC		Comp TLA	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	Comp CDX		Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.17			Demand / Capacity (Rev Study)														
4	Maintenance	EX 4.25		14,887,672	8,793,532	239,333	285,051	725,879	2,572,493	6,036	405,501	5,338	92,298	1,282,882	215,286	131,951	72,211
5	Depreciation	EX 6.20		12,844,960	6,153,826	93,964	161,950	361,413	2,712,254	51,670	300,162	42,589	50,084	1,294,118	157,101	738,188	707,833
6	Amortization of Capitalized Software	SM 1.8		1,436,920	663,127	9,480	16,944	40,979	310,074	6,435	33,881	5,232	5,525	147,388	17,574	91,651	87,830
7	Amortization of Unrecovered Plant Loss	SM 1.9		-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Amortization of General Plant	SM 1.7		737,867	340,387	4,866	8,687	21,035	158,163	3,303	17,288	2,686	2,836	75,656	9,021	47,045	45,083
9	Interest on Customer Deposits	SM 1.10		36,880	17,352	411	381	1,149	9,800	179	1,215	-	175	4,309	588	-	-
10	Interest on Supplier Refunds	SM 1.11		-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	General Taxes	EX 8.21		29,899,272	9,076,823	90,857	189,382	600,650	7,188,968	244,888	559,202	287,776	104,644	3,001,304	399,628	4,011,725	3,654,416
12	Expenses Before Income Taxes	Ln. 10 + Ln. 11		$ 89,816,990	$ 42,688,770	$ 1,213,388	$ 1,102,791	$ 2,779,671	$ 17,919,211	$ 596,398	$ 2,005,861	$ 408,584	$ 394,400	$ 8,154,014	$ 1,149,503	$ 6,417,045	$ 5,987,356
13	Income Taxes _1			(1,406,827)	(659,773)	(10,610)	(16,260)	(40,659)	(316,924)	(2,755)	(38,388)	(3,656)	(5,524)	(147,223)	(18,368)	(73,826)	(71,863)
14	Total Operating Expenses	Ln. 12 + Ln. 13		$ 88,411,163	$ 42,028,997	$ 1,202,778	$ 1,086,530	$ 2,739,012	$ 17,602,287	$ 593,643	$ 1,967,472	$ 404,928	$ 388,877	$ 8,006,791	$ 1,131,135	$ 6,343,219	$ 5,915,493
15	**Net Income Adjustments:**																
16	AFUDC	SM 1.18		$ (188,898)	$ (83,170)	$ (1,257)	$ (2,116)	$ (5,134)	$ (38,829)	$ (817)	$ (4,236)	$ (701)	$ (697)	$ (18,434)	$ (2,207)	$ (12,109)	$ (11,190)
17	Uncollectible Expense _2			466,530	170,224	4,030	3,733	11,273	97,114	1,758	11,915	-	1,717	42,273	5,771	30,052	28,668
18																	
19	Total Operating Expenses (Adjusted	Ln. 14 > Ln. 18		$ 88,638,797	$ 42,116,052	$ 1,205,549	$ 1,088,147	$ 2,745,152	$ 17,660,573	$ 594,585	$ 1,975,151	$ 404,227	$ 389,897	$ 8,030,631	$ 1,134,699	$ 6,361,162	$ 5,932,971
20	**RATE BASE**																
21	**Rate Base Additions**																
22	Gas Plant in Service	RB 2.46		$ 627,837,944	$ 324,864,963	$ 6,737,133	$ 9,957,522	$ 20,428,700	$ 90,823,670	$ 222,450	$ 11,585,381	$ 350,158	$ 2,250,112	$ 45,501,911	$ 6,239,988	$ 6,155,552	$ 2,800,202
23	Gas Plant Held for Future Use & Deferred Loss	RB 4.12															
24	Construction Work in Progress	RB 5.28		3,971,129	2,620,980	38,255	82,588	115,568	865,807	-	64,411	88	8,910	337,475	36,088	-	-
25	Materials & Supplies	RB 8.12		22,936	10,567	151	271	654	4,951	103	536	84	88	2,353	281	1,463	1,402
26	Non Plant ADIT	RB 9.19		(2,032,373)	(1,289,913)	(45,970)	(42,274)	(118,056)	(198,356)	(143,664)	(42,325)	(10,037)	(14,992)	(129,018)	(25,277)	(7,365)	42,803
27	Cash Working Capital and Other Additions	RB 1.7, 8, 10		24,738,642	13,754,358	456,352	344,481	820,795	4,202,688	71,053	554,189	56,710	111,484	2,020,297	287,503	1,100,853	957,769
28	Total Rate Base Additions	Ln. 22 > Ln. 27		$ 654,538,168	$ 339,850,977	$ 7,186,921	$ 10,342,587	$ 21,247,661	$ 95,500,660	$ 149,942	$ 12,162,194	$ 396,995	$ 2,355,603	$ 47,733,017	$ 6,558,562	$ 7,250,484	$ 3,802,276
29	**Rate Base Deductions**																
30	Reserve for Depreciation	RB 7.33		$ 191,949,268	$ 91,802,252	$ 1,387,732	$ 2,412,832	$ 5,686,275	$ 40,573,684	$ 776,287	$ 4,465,925	$ 638,393	$ 747,974	$ 19,358,064	$ 2,347,747	$ 11,098,712	$ 10,632,390
31	Accumulated Deferred Income Tax	RB 1.15-17		83,815,384	38,443,579	590,913	978,169	2,372,882	17,947,953	377,737	1,957,938	323,928	322,082	8,520,521	1,020,217	5,597,035	5,172,408
32	Other Deductions	RB 1.18-21		(15,750,469)	(7,223,756)	(106,395)	(184,937)	(444,427)	(3,339,090)	(70,816)	(361,758)	(63,565)	(59,985)	(1,592,440)	(188,326)	(1,098,671)	(1,015,318)
33	Total Rate Base Deductions	Ln. 30 > Ln. 32		$ 260,014,133	$ 123,022,074	$ 1,872,251	$ 3,206,065	$ 7,614,730	$ 55,182,547	$ 1,083,208	$ 6,062,104	$ 898,755	$ 1,010,071	$ 26,284,145	$ 3,179,638	$ 15,597,076	$ 14,789,480
34	**Net Rate Base**	Ln. 28 - Ln. 33		394,524,036	216,928,903	5,314,670	7,136,522	13,630,922	40,318,413	(933,266)	6,080,088	(502,751)	1,345,532	21,448,873	3,379,926	(8,336,592)	(10,987,204)
35	Pre Tax Rate of Return			9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%
36	Required Return on Rate Base	Ln. 34 * Ln. 35		29,381,869	21,618,919	529,655	711,219	1,358,444	4,018,093	(93,008)	605,936	(50,104)	134,094	2,137,573	336,840	(830,818)	(1,094,974)
37	**TOTAL COST OF SERVICE**	Ln. 19 + Ln. 36		$ 118,020,666	$ 63,734,970	$ 1,735,204	$ 1,799,366	$ 4,103,596	$ 21,678,665	$ 501,576	$ 2,581,087	$ 354,124	$ 523,992	$ 10,168,204	$ 1,471,539	$ 5,530,346	$ 4,837,997
38	Average Number of Customers	AL 3.3		163,129	135,615	10,924	3,566	4,499	3,390	1	1,845	3	598	1,707	899	111	3
39	Calculated Annual Cost Per Customer	Ln. 37 / Ln. 38		$ 730	$ 470	$ 159	$ 505	$ 912	$ 6,395	$ 501,576	$ 1,399	$ 132,107	$ 876	$ 5,956	$ 1,693	$ 50,011	$ 1,612,666

_1/ Income tax includes only permanent and flow-through items
_2/ Uncollectible expense on revenue deficiency

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study Cost Categorizatio

Demand Costs

Twelve Months Ended March 31, 2024 - Average Rate Base

Line No.	Description	Reference		District of Columbia Demand	Residential Heating/Cooling	Residential Non Heating/Cooling	Residential Non Heating/Cooling	C&I Heating/Cooling <3075	C&I Heating/Cooling >3075	C&I CHP	C&I Non Heating/Cooling	C&I Non Heating/Cooling - NGV	GMA Heating/Cooling <3075	GMA Heating/Cooling >3075	GMA Non Heating/Cooling	Non Firm	Special Contract
	A	B		C=Sum (D > P)	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**EXPENSES**																
2	Gas Purchased	EX 2 2		$ -													
3	Operation - Other than Gas Purchased	EX 2 46		28,648,818	11,856,158	284,705	287,933	772,751	5,216,052	207,465	628,468	84,675	109,193	2,440,543	321,023	1,798,830	1,531,187
3.01	*Demand*		*Demand*	2,373,363	801,925	4,902	15,333	48,152	544,487	16,183	52,545	13,776	7,809	255,679	26,996	357,206	228,285
3.02	*Comp DemCom*		*Comp 3PF*	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.03	*Comp M&S*		*Comp CDX*	188,667	81,019	923	2,138	4,131	35,787	711	3,536	586	503	17,067	1,860	10,023	9,774
3.04	*Comp TDP*		*Comp CWC*	2,344,386	1,078,615	16,477	28,364	86,736	473,487	8,989	52,437	7,414	8,756	225,951	27,448	128,444	123,165
3.05	*Comp TPE*		*Comp DEX*	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.06	*Comp NRB*		*Comp DME*	3,230,158	1,488,795	22,497	37,881	91,894	695,066	14,629	75,825	12,545	12,472	329,972	39,510	216,755	200,311
3.07	*Comp TLA*		*Comp DXA*	4,637,228	2,331,515	71,180	63,346	175,331	815,323	114,105	114,105	9,729	24,015	394,054	59,494	208,883	158,150
3.08	*Comp DXA*		*Comp GTX*	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.09	*Comp DME*		*Comp M&S*	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.10	*Comp OMA*		*Comp NRB*	4,671,633	2,532,279	88,982	67,093	159,864	918,544	13,839	107,938	11,045	21,713	383,487	55,996	214,412	188,541
3.11	*Comp 3PF*		*Comp OMA*	5,126,188	2,216,016	48,405	54,657	136,693	1,075,720	25,279	127,151	29,578	20,466	494,542	64,704	428,668	401,307
3.12	*Comp TAX*		*Comp TAX*	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	*Comp TCS*		*Comp TCS*	3,187,114	1,327,992	31,440	28,121	87,948	757,629	13,720	92,852	-	13,396	329,790	45,025	234,446	223,653
3.14	*Comp GTX*		*Comp TDP*	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.15	*Comp CWC*		*Comp TLA*	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	*Comp CDX*		*Comp TPE*	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.17			*Demand / Capacity (Rev Study)*														
4	Maintenance	EX 4 25		11,118,246	4,085,983	33,101	82,200	252,205	2,684,358	77,437	274,011	63,408	40,880	1,248,623	139,888	1,093,423	1,082,421
5	Depreciation	EX 6 20		18,988,384	8,641,525	120,145	218,123	533,368	4,134,686	88,425	445,987	71,589	72,679	1,982,538	232,421	1,258,216	1,205,592
6	Amortization of Capitalized Software	SM 1 8		2,223,263	1,026,732	14,679	26,234	63,448	480,084	9,963	52,149	8,101	8,555	228,205	27,208	141,906	135,988
7	Amortization of Unrecovered Plant Loss	SM 1 9		188,274	41,976	184	784	2,408	23,262	688	1,629	63	336	12,162	921	9,443	6,456
8	Amortization of General Plant	SM 1 7		1,141,216	527,038	7,535	13,466	32,568	246,435	5,114	26,788	4,158	4,381	117,139	13,987	72,841	89,804
9	Interest on Customer Deposits	SM 1 10		41,325	20,109	478	441	1,332	11,473	208	1,408	-	203	4,884	682	-	-
10	Interest on Supplier Refunds	SM 1 11		-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	General Taxes	EX 8 21		33,740,447	10,209,337	83,420	210,793	670,833	8,241,949	262,958	633,383	332,900	117,609	3,434,295	454,307	4,630,561	4,456,901
12	Expenses Before Income Taxes	Ln. 10 + Ln. 11		$ 92,904,078	$ 36,378,858	$ 554,245	$ 849,955	$ 2,326,913	$ 21,048,318	$ 652,239	$ 2,061,823	$ 564,895	$ 354,026	$ 9,448,699	$ 1,190,528	$ 9,003,229	$ 8,468,349
13	Income Taxes _1			(1,690,848)	(793,535)	(12,761)	(19,557)	(46,902)	(381,177)	(3,313)	(46,171)	(4,397)	(6,643)	(177,071)	(22,092)	(88,793)	(86,433)
14	Total Operating Expenses	Ln. 12 + Ln. 13		$ 91,213,333	$ 35,585,324	$ 541,484	$ 830,398	$ 2,280,011	$ 20,667,141	$ 648,926	$ 2,015,652	$ 560,498	$ 347,383	$ 9,271,628	$ 1,168,437	$ 8,914,436	$ 8,381,916
15	**Net Income Adjustments**																
16	AFUDC	SM 1:18		$ (288,484)	$ (131,716)	$ (1,990)	$ (3,351)	$ (8,130)	$ (61,494)	$ (1,294)	$ (6,708)	$ (1,110)	$ (1,103)	$ (29,193)	$ (3,495)	$ (19,177)	$ (17,722)
17	Uncollectible Expense _2			473,443	197,272	4,670	4,326	13,065	112,545	2,038	13,808	-	1,990	48,980	6,686	34,827	33,223
18																	
19	Total Operating Expenses (Adjusted)	Ln. 14 > Ln. 18		$ 91,400,192	$ 35,650,880	$ 544,164	$ 831,373	$ 2,284,946	$ 20,718,192	$ 649,669	$ 2,022,751	$ 559,388	$ 348,270	$ 9,291,425	$ 1,171,630	$ 8,930,086	$ 8,397,417
20	**RATE BASE**																
21	**Rate Base Additions**																
22	Gas Plant in Service	RB 2 46		$ 813,634,581	$ 293,479,277	$ 2,103,005	$ 5,841,867	$ 17,782,592	$ 198,310,434	$ 5,786,201	$ 19,821,023	$ 4,693,133	$ 2,901,975	$ 91,933,453	$ 10,126,791	$ 81,599,205	$ 79,147,726
23	Gas Plant Held for Future Use & Deferred Loss	RB 4 12															
24	Construction Work in Progress	RB 5 28		2,913,447	1,022,589	6,559	19,736	61,891	717,817	21,403	71,633	17,609	10,333	331,419	35,489	301,726	294,246
25	Materials & Supplies	RB 6 12		2,918,222	974,915	6,828	19,142	59,707	711,617	21,309	74,886	22,387	10,297	321,607	37,650	333,847	324,050
26	Non Plant ADIT	RB 9 19		(1,331,758)	(755,542)	(25,312)	(22,864)	(67,419)	(186,847)	(75,482)	(32,804)	(3,592)	(8,923)	(100,082)	(17,980)	(30,503)	(4,435)
27	Cash Working Capital and Other Additions	RB 1 7, 8, 10		16,880,474	9,853,592	323,138	254,938	617,793	3,355,872	61,599	417,188	40,853	84,075	1,630,479	217,761	938,045	785,129
28	Total Rate Base Additions	Ln. 22 > Ln. 27		$ [illegible]	$ 304,574,830	$ 2,414,220	$ 6,112,819	$ 18,454,564	$ 202,908,893	$ 5,814,029	$ 20,351,927	$ 4,770,390	$ 2,997,757	$ 94,116,886	$ 10,400,711	$ 83,141,320	$ 80,546,716
29	**Rate Base Deductions**																
30	Reserve for Depreciation	RB 7 33		$ [illegible]	$ 122,053,942	$ 1,751,446	$ 3,125,022	$ 7,536,674	$ 56,375,301	$ 1,156,029	$ 6,095,982	$ 911,561	$ 1,009,342	$ 26,897,571	$ 3,188,081	$ 16,472,582	$ 15,617,383
31	Accumulated Deferred Income Tax	RB 1:15-17		132,421,536	60,883,050	919,982	1,549,128	3,757,946	28,424,151	598,221	3,100,786	513,004	510,050	13,493,939	1,615,717	8,864,016	8,191,536
32	Other Deductions	RB 1:18-21		(24,919,820)	(11,489,946)	(171,052)	(293,818)	(706,417)	(5,290,943)	(111,320)	(574,989)	(98,852)	(95,265)	(2,521,188)	(300,655)	(1,708,297)	(1,577,077)
33	Total Rate Base Deductions	Ln. 30 > Ln. 32		$ 369,652,597	$ 171,467,047	$ 2,500,389	$ 4,380,330	$ 10,588,203	$ 79,508,508	$ 1,642,930	$ 8,621,780	$ 1,325,713	$ 1,424,127	$ 37,870,322	$ 4,503,143	$ 23,628,293	$ 22,231,842
34	**Net Rate Base**	Ln. 28 - Ln. 33		466,912,472	133,107,784	(86,169)	1,732,489	7,866,361	123,400,385	4,171,099	11,730,168	3,444,676	1,573,630	56,246,574	5,897,568	59,513,036	58,314,873
35	Pre Tax Rate of Return			9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%
36	Required Return on Rate Base	Ln. 34 * Ln. 35		46,532,630	13,285,380	(8,589)	172,658	783,954	12,297,950	415,699	1,169,017	343,293	156,826	5,605,477	587,746	5,931,010	5,811,802
37	**TOTAL COST OF SERVICE**	Ln. 19 + Ln. 36		$ 137,932,222	$ 48,916,264	$ 535,577	$ 1,004,031	$ 3,068,899	$ 33,016,151	$ 1,065,357	$ 3,191,768	$ 902,681	$ 505,096	$ 14,896,903	$ 1,759,375	$ 14,861,098	$ 14,209,019
38	Average Number of Customers	AL 3 3		163,129	135,615	10,924	3,566	4,499	3,390	1	1,845	3	598	1,707	869	111	3
39	Calculated Annual Cost Per Customer	Ln. 37 / Ln. 38		$ 846	$ 361	$ 49	$ 282	$ 682	$ 9,740	$ 1,065,357	$ 1,730	$ [illegible]	$ 845	$ 8,727	$ 2,024	$ [illegible]	$ 4,736,340

_1/ Income tax includes only permanent and flow-through items
_2/ Uncollectible expense on revenue deficiency

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study Cost Categorizatio

Commodity Costs

Twelve Months Ended March 31, 2024 - Average Rate Bas

Line No.	Description A	Reference B		District of Columbia Commodity C=Sum (D > P)	Residentia Heating/Cooling D	Residentia Non Heating/Cooling (< E	Residentia Non Heating/Cooling F	C&I Heating/Cooling <307 G	C&I Heating/Cooling >307 H	C&I CHP I	C&I Non Heating/Cooling J	C&I Non Heating/Cooling - NGV K	GMA Heating/Cooling <307 L	GMA Heating/Cooling >307 M	GMA Non Heating/Cooling N	Non Firm O	Special Contract P
1	**EXPENSES**																
2	Gas Purchased	EX 2 2		$ -													
3	Operation - Other than Gas Purchases	EX 2 46		347,472	106,616	1,646	2,658	6,010	53,588	1,242	5,877	1,376	850	24,658	3,000	20,386	19,563
3.01	Commodity		Commodity	73,791	21,791	174	438	1,371	17,605	540	2,058	817	257	7,626	1,010	10,189	9,823
3.02	Comp DemCom		Comp 3PF	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.03	Comp M&S		Comp CDX	123,794	58,676	680	1,575	3,042	26,367	524	2,604	432	371	12,571	1,370	7,383	7,200
3.04	Comp TDP		Comp CWC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.05	Comp TPE		Comp DEX	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.06	Comp NRB		Comp DME	716	329	5	8	20	154	3	17	3	3	73	9	48	44
3.07	Comp TLA		Comp DXA	172	88	3	2	7	31	4	4	0	1	15	2	8	6
3.08	Comp DXA		Comp GTX	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.09	Comp DME		Comp M&S	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.10	Comp OMA		Comp NRB	33,433	18,122	638	480	1,144	5,858	99	772	79	155	2,816	401	1,534	1,335
3.11	Comp 3PF		Comp OMA	7,790	3,368	74	83	211	1,635	38	193	45	31	752	94	652	610
3.12	Comp TAX		Comp TAX	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	Comp TCS		Comp TCS	7,777	3,240	77	71	215	1,849	33	227	-	33	805	110	572	546
3.14	Comp GTX		Comp TDP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.15	Comp CWC		Comp TLA	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	Comp CDX		Comp TPE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.17			Demand / Capacity (Rev Study)														
4	Maintenance	EX 4 25		-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Depreciation	EX 6 20		-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Amortization of Capitalized Software	SM 1 8		-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Amortization of Unrecovered Plant Los	SM 1 9		-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Amortization of General Plan	SM 1 7		-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Interest on Customer Deposits	SM 1:10		181	49	1	1	3	28	1	3	-	0	12	2	-	-
10	Interest on Supplier Refunds	SM 1:11		-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	General Taxes	EX 8 21		77,811	22,640	181	455	1,485	19,149	585	1,431	797	267	7,920	1,048	11,025	10,626
12	Expenses Before Income Taxes	Ln. 10 + Ln. 11		$ 328,184	$ 129,305	$ 1,630	$ 3,114	$ 7,498	$ 72,765	$ 1,827	$ 7,312	$ 2,173	$ 1,118	$ 32,590	$ 4,050	$ 31,411	$ 30,191
13	Income Taxes _1			15	7	0	0	0	3	0	0	0	0	2	0	1	1
14	Total Operating Expenses	Ln. 12 + Ln. 13		$ 328,199	$ 129,312	$ 1,630	$ 3,114	$ 7,498	$ 72,768	$ 1,828	$ 7,312	$ 2,173	$ 1,118	$ 32,592	$ 4,050	$ 31,411	$ 30,191
15	**Net Income Adjustments**																
16	AFUDC	SM 1 18		$ (63)	$ (29)	$ (0)	$ (1)	$ (2)	$ (14)	$ (0)	$ (1)	$ (0)	$ (0)	$ (6)	$ (1)	$ (4)	$ (4)
17	Uncollectible Expense _2			1,156	481	11	11	32	275	5	34	-	5	120	16	85	81
18																	
19	Total Operating Expenses (Adjusted	Ln. 14 > Ln. 18		$ 329,291	$ 129,764	$ 1,641	$ 3,124	$ 7,529	$ 73,030	$ 1,832	$ 7,345	$ 2,173	$ 1,122	$ 32,705	$ 4,066	$ 31,492	$ 30,268
20	**RATE BASE**																
21	**Rate Base Additions**																
22	Gas Plant in Service	RB 2 46		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Gas Plant Held for Future Use & Deferred Los	RB 4 12															
24	Construction Work in Progress	RB 5 28		-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Materials & Supplies	RB 6 12		-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Non Plant ADIT	RB 9 19		9,207	4,216	139	108	268	1,554	24	200	15	37	727	102	428	385
27	Cash Working Capital and Other Additions	RB 1 7, 8, 10		120,331	65,226	2,289	1,728	4,118	21,084	356	2,780	285	558	10,135	1,442	5,523	4,805
28	Total Rate Base Additions	Ln. 22 > Ln. 27		$ 129,538	$ 69,444	$ 2,429	$ 1,836	$ 4,386	$ 22,638	$ 381	$ 2,981	$ 300	$ 596	$ 10,862	$ 1,544	$ 5,951	$ 5,190
29	**Rate Base Deductions**																
30	Reserve for Depreciation	RB 7 33		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	Accumulated Deferred Income Tax	RB 1 15-17		29,256	13,450	203	342	830	6,280	132	685	113	113	2,981	357	1,958	1,810
32	Other Deductions	RB 1 18-21		(3,868)	(1,728)	(18)	(47)	(103)	(712)	(17)	(71)	(22)	(13)	(359)	(39)	(384)	(355)
33	Total Rate Base Deductions	Ln. 30 > Ln. 32		$ 25,387	$ 11,722	$ 185	$ 295	$ 728	$ 5,567	$ 116	$ 614	$ 91	$ 100	$ 2,622	$ 318	$ 1,574	$ 1,454
34	**Net Rate Base**	Ln. 28 - Ln. 33		103,151	57,722	2,244	1,541	3,658	17,071	265	2,366	209	497	8,240	1,227	4,377	3,736
35	Pre Tax Rate of Return			9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%	9.97%
36	Required Return on Rate Base	Ln. 34 * Ln. 35		10,280	5,753	224	154	365	1,701	26	236	21	50	821	122	436	372
37	**TOTAL COST OF SERVICE**	Ln. 19 + Ln. 36		$ 339,571	$ 135,517	$ 2,065	$ 3,277	$ 7,893	$ 74,731	$ 1,858	$ 7,580	$ 2,194	$ 1,172	$ 33,526	$ 4,188	$ 31,928	$ 30,641
38	Average Number of Customers	AL 3 3		163,129	135,615	10,924	3,586	4,499	3,390	1	1,845	3	598	1,707	860	111	3
39	Calculated Annual Cost Per Customer	Ln. 37 / Ln. 38		$ 2	$ 1	$ 0	$ 1	$ 2	$ 22	$ 1,858	$ 4	$ 818	$ 2	$ 20	$ 5	$ 288	$ 10,214

_1/ Income tax includes only permanent and flow-through item
_2/ Uncollectible expense on revenue deficienc

Schedule CC Page 3

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study Cost Categorizatio

Cost Type Factors

Twelve Months Ended March 31, 2024 - Average Rate Bas

Line No.	Factor Category	Reference	Key	Cost Type Ratios: Customer	Cost Type Ratios: Demand	Cost Type Ratios: Commodity	Total
	A	B	C	D	E	F	E=Sum (D > F)
1	**Multiple Cost Types**						
2	Purchased Gas Demand / Comm Split (Rev Study		Comp DemCom	-	0.44028	0.55972	1.00000
3	Materials and Supplies		Comp M&S	-	0.57585	0.42415	1.00000
4	Total Distribution Plan		Comp TDP	0.45866	0.54134	-	1.00000
	Total Plant excl. General Plant						
	General Plant		Comp TPE	0.39242	0.60758	-	1.00000
5	Total Plant excluding Pepco						
6	Net Rate Base		Comp NRB	0.38699	0.61287	0.00014	1.00000
7	Total Labor		Comp TLA	0.65951	0.34048	0.00001	1.00000
8	Distribution excl Admin Costs		Comp DXA	0.58072	0.41401	0.00527	1.00000
9	Distribution Maintenance Expense		Comp DME	0.58257	0.41743	-	1.00000
10	Operations & Maintenance Adjuste		Comp OMA	0.58616	0.41090	0.00294	1.00000
11	Three-Part Factor		Comp 3PF	0.32438	0.67459	0.00103	1.00000
12	Income Tax Facto		Comp TAX	0.45398	0.54602	(0.00000)	1.00000
13	Total Cost of Service		Comp TCS	0.46259	0.53610	0.00131	1.00000
14	General Taxes		Comp GTX	0.46676	0.53202	0.00122	1.00000
15	Cash Working Capital _4		Comp CWC	0.44583	0.41759	0.13658	1.00000
16	Total Cost of Service excl. Commodity _5		Comp CDX	0.46320	0.53680	-	1.00000
17							
18	**Single Cost Type - Customer**						
19	Dely_Cust	AL 2 29					
20	Ave_Customer _Bil	AL 3 4					
21	Ave_Customer _Bill_Ad	AL 3 9					
22	Firm_Cust_Bill_Ad	AL 3 11					
23	Fee_Free_Credi	AL 3 14					
24	Mtr_Hse_Reg_Plnt	AL 4 15					
25	Dist_Meas_Reg_Pln	AL 4 18					
26	Dist_Services_Plnt	AL 4 22					
27	Gas_Lights	AL 5 4					
28	Meter_Cost	AL 5 10					
29	Meter_Count_Ex_Res	AL 5 12					
30	Meter_Count_C&I_Only	AL 5 14					
31	Uncollectibles	AL 5 18					
32	Residential Heating	na					
33	C&I <3000	n/a					
34							
35	**Single Cost Type - Demand**						
36	Firm_Weather_NW	AL 1 2					
37	Annual_ Firm_ NW	AL 1 4					
38	Total_Weather_All_NA	AL 1 6					
39	Annual_Total_NW _6	AL 1 8					
40	Pipeline_NW _3	AL 1 14					
41	Firm_Pipe_ Ann_ Ad	AL 1 16					
42	Peak_Day_Tota	AL 2 5					
43	Comp_Peak_ Ann_NA	AL 2 7					
44	Peak Day Adjusted _2	AL 2 28					
45	Transmission_Plnt	AL 4					
46	Dist_Services_Plnt	AL 4 22					
47	Depreciation_Expense	AL 5 6					

_1/ "Comp TPE" is also used to categorize costs for the general plant (Genl_Plnt) and total plant excluding Pepco (Tot_Plnt_Ex_Pepco) class allocat
_2/ Services Investment (RB 2 20) was allocated to the classes using the Peak Day Adjusted factor. However, in total services investment is categorized as a customer c
_3/ Purchase gas costs on lines EX 23 through EX 2 6 are allocated to the classes using either the Pipeline NW or Firm Weather NW class allocation factors. However, these expenses in total are categorized as commodity c
_4/ Cash working capital (RB 1 10) is allocated to the classes using the O&M Adjusted factor and allocated to the cost categories using the Comp CWC fact
_5/ Uncollectible expense (EX 7 21) is allocated to the classes based on the Gas Sales Revenue and allocated to the cost categories using the Comp CDX fa
_6/ Operations materials (RB 6 4) is allocated to the classes based using the Annual Total NW therms factors and allocated to the cost categories using the Comp DXA fac

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpapers
Table of Contents

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper 1 - Firm Distribution Services Customer/Capacity Component Calculation

As of March 31, 2024

Line No.	Class Description	No. of Bills a/	Multiple Customers b/	Bills Adjusted	Average Cost c/	Customer Component	Total Cost d/	Capacity Component
		A	B	C = A - B	D	E = C * D	F	G = F - E
1	**RESIDENTIAL HEATING**							
2	Heating and/or Cooling	2/135,420	8/33,958	101,462	$ 9/2,750	$ 279,048,571		
3	Non-heating and Non-cooling	14,406	9,764	4,642	$ 2,750	$ 12,766,589		
4	**COMMERICAL AND INDUSTRIAL**							
5	Heating and/or Cooling < 3000	4,584	1,128	3,456	$ 2,750	$ 9,504,981		
6	Heating and/or Cooling > 3000	3,419	841	2,578	$ 2,750	$ 7,089,339		
7	Non-heating and Non-cooling	1,838	807	1,031	$ 2,750	$ 2,835,626		
8	**GROUP METER APARTMENTS**							
9	Heating and/or Cooling	2,314	606	1,708	$ 2,750	$ 4,698,410		
10	Non-heating and Non-cooling	871	294	577	$ 2,750	$ 1,587,443		
11	Total	162,852	47,398	115,454		$ 317,530,959	$ 423,554,686 A	$ 106,023,727
12	Customer / Capacity Ratios					0.74968		0.25032

a/ Monthly 'Months billed' per Normal Weather Study (NWS) Schedule 2B as of March 31, 2024.
b/ Net Customers at Common Addressess as of March 31, 2024.
c/ Customer component average cost calculated on page 2.
d/ Distribution Services (EOP Jurisdictional Cost of Service Study#291 Mar-2024 RB Page 2, Line 21) less directly assigned services 1.25 inches or less (CCOSS Workpaper 2.3).

Distribution Services	$	13/423,566,018	*(EOP Study #291)*
Services 1.25 inches or Smaller ($$)		14/(11,332)	*(CCOSS WP #2.3)*
	$	423,554,686A	

Washington Gas Light Company
District of Columbia Jurisdiction

Months Billed (Normal)

As of March 31, 2024

Class	Reference	Mar-2024		
NW DC Res Htg / HC	Exhbit WG (N)-4 Sch 2B	3/ 135,420 1		
NW DC Res Non Htg - IMA	Exhbit WG (N)-4 Sch 2B	10,820	14,406 1	
NW DC Res Non Htg - OTH	Exhbit WG (N)-4 Sch 2B	4/ 3,586		
NW DC C&I Htg / HC < 3075	Exhbit WG (N)-4 Sch 2B	4,584 1 A		A/(A+B) = 57.28% C
NW DC C&I Htg / HC > 3075	Exhbit WG (N)-4 Sch 2B	5/ 3,419 B		B/(A+B) = 42.72% D
NW DC C&I Non Htg	Exhbit WG (N)-4 Sch 2B	1,838		
NW DC GMA Htg / HC < 3075	Exhbit WG (N)-4 Sch 2B	6/ 605	2,314 1	
NW DC GMA Htg / HC > 3075	Exhbit WG (N)-4 Sch 2B	7/ 1,709		
NW DC GMA Non Htg	Exhbit WG (N)-4 Sch 2B	871 1		
		162,852		

C&I Split	Small	57.28% C 8
	Large	42.72% D

Note: The Normal Weather Study (NWS) is Exhibit WG (N)-4

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Therm Sales: Weather Gas: Normal Weather	Therm Sales: Weather Adjustment	Therm Sales: Base Gas b/	Therm Sales: Total	Peak Day: Weather Gas	Peak Day: Base Gas	Peak Day: Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*DC Res Htg / HC*												
2	Mar-2024	135,420 2	516	634	0.1397740	9,766,949	12,000,476	2,233,527	1,105,356	13,105,832			
3	Feb-2024	135,697	699	811	0.1397740	13,257,872	15,382,166	2,124,294	1,119,452	16,501,618			
4	Jan-2024	135,801	655	763	0.1397740	12,432,849	14,482,846	2,049,997	1,132,153	15,614,999	1,138,887	36,521	1,175,408
5	Dec-2023	135,978	536	552	0.1397740	10,187,317	10,491,416	304,099	1,145,488	11,636,904			
6	Nov-2023	135,976	223	288	0.1397740	4,238,318	5,473,702	1,235,384	1,157,330	6,631,032			
7	Oct-2023	135,752	39	47	0.1397740	740,009	891,806	151,797	1,167,262	2,059,068			
8	Sep-2023	135,676	1	-	0.1397740	18,964	-	(18,964)	1,178,441	1,178,441			
9	Aug-2023	135,514	-	-	0.1397740	-	-	-	1,188,853	1,188,853			
10	Jul-2023	135,303	-	-	0.1397740	-	-	-	1,198,802	1,198,802			
11	Jun-2023	135,332	21	35	0.1397740	397,234	662,056	264,822	1,210,861	1,872,917			
12	May-2023	135,360	130	184	0.1397740	2,459,575	3,481,245	1,021,670	1,222,917	4,704,162			
13	Apr-2023	135,570	367	415	0.1397740	6,954,342	7,863,902	909,560	1,236,637	9,100,539			
14	Total	1,627,379	3,187	3,729		60,453,429	70,729,615	10,276,186	14,063,551	84,793,166	1,138,887	36,521	1,175,408
15													
16	*DC Res Non Htg - IMA*												
17	Mar-2024	10,820 2	516	634	0.0076190	42,538	52,265	9,727	30,398	82,663			
18	Feb-2024	10,857	699	811	0.0076190	57,821	67,086	9,265	30,502	97,588			
19	Jan-2024	10,890	655	763	0.0076190	54,346	63,307	8,961	30,594	93,901	4,978	987	5,965
20	Dec-2023	10,910	536	552	0.0076190	44,554	45,884	1,330	30,651	76,535			
21	Nov-2023	10,962	223	288	0.0076190	18,625	24,054	5,429	30,797	54,851			
22	Oct-2023	10,959	39	47	0.0076190	3,256	3,924	668	30,788	34,712			
23	Sep-2023	10,964	1	-	0.0076190	84	-	(84)	30,802	30,802			
24	Aug-2023	10,957	-	-	0.0076190	-	-	-	30,783	30,783			
25	Jul-2023	10,965	-	-	0.0076190	-	-	-	30,805	30,805			
26	Jun-2023	10,935	21	35	0.0076190	1,750	2,916	1,166	30,721	33,637			
27	May-2023	10,920	130	184	0.0076190	10,816	15,309	4,493	30,679	45,988			
28	Apr-2023	10,945	367	415	0.0076190	30,604	34,607	4,003	30,749	65,356			
29	Total	131,084	3,187	3,729		264,394	309,352	44,958	368,268	677,620	4,978	987	5,965

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Therm Sales: Weather Gas: Normal Weather	Therm Sales: Weather Adjustment	Therm Sales: Base Gas b/	Therm Sales: Total	Peak Day: Weather Gas	Peak Day: Base Gas	Peak Day: Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*DC Res Non Htg - OTH*												
2	Mar-2024	3,586 2	516	634	0.0965330	178,622	219,470	40,848	34,896	254,366			
3	Feb-2024	3,581	699	811	0.0965330	241,634	280,350	38,716	34,847	315,197			
4	Jan-2024	3,586	655	763	0.0965330	226,740	264,126	37,386	34,896	299,022	20,770	1,126	21,896
5	Dec-2023	3,589	536	552	0.0965330	185,701	191,244	5,543	34,925	226,169			
6	Nov-2023	3,589	223	288	0.0965330	77,260	99,780	22,520	34,925	134,705			
7	Oct-2023	3,591	39	47	0.0965330	13,519	16,293	2,774	34,945	51,238			
8	Sep-2023	3,570	1	-	0.0965330	345	-	(345)	34,740	34,740			
9	Aug-2023	3,548	-	-	0.0965330	-	-	-	34,526	34,526			
10	Jul-2023	3,547	-	-	0.0965330	-	-	-	34,516	34,516			
11	Jun-2023	3,542	21	35	0.0965330	7,180	11,967	4,787	34,468	46,435			
12	May-2023	3,550	130	184	0.0965330	44,550	63,055	18,505	34,546	97,601			
13	Apr-2023	3,515	367	415	0.0965330	124,528	140,815	16,287	34,205	175,020			
14	Total	42,794	3,187	3,729		1,100,079	1,287,100	187,021	416,434	1,703,534	20,770	1,126	21,896
15													
16	*DC C&I Htg / HC < 3075*												
17	Mar-2024	4,584 2	516	634	0.2397700	567,139	696,833	129,694	108,619	805,452			
18	Feb-2024	4,589	699	811	0.2397700	769,113	892,347	123,234	108,738	1,001,085			
19	Jan-2024	4,537	655	763	0.2397700	712,533	830,019	117,486	107,506	937,525	65,270	3,468	68,738
20	Dec-2023	4,528	536	552	0.2397700	581,924	599,295	17,371	107,292	706,587			
21	Nov-2023	4,509	223	288	0.2397700	241,090	311,363	70,273	106,842	418,205			
22	Oct-2023	4,480	39	47	0.2397700	41,893	50,486	8,593	106,155	156,641			
23	Sep-2023	4,447	1	-	0.2397700	1,066	-	(1,066)	105,373	105,373			
24	Aug-2023	4,471	-	-	0.2397700	-	-	-	105,942	105,942			
25	Jul-2023	4,467	-	-	0.2397700	-	-	-	105,847	105,847			
26	Jun-2023	4,461	21	35	0.2397700	22,462	37,436	14,974	105,705	143,141			
27	May-2023	4,464	130	184	0.2397700	139,143	196,941	57,798	105,776	302,717			
28	Apr-2023	4,445	367	415	0.2397700	391,140	442,298	51,158	105,326	547,624			
29	Total	53,982	3,187	3,729		3,467,503	4,057,018	589,515	1,279,120	5,336,138	65,270	3,468	68,738

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Normal Weather	Weather Adjustment	Base Gas b/	Total	Peak Day: Weather Gas	Base Gas	Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*DC C&I Htg / HC > 3075*												
2	Mar-2024	3,419 (2)	516	634	3.0813470	5,436,125	6,679,269	1,243,144	2,534,980	9,214,249			
3	Feb-2024	3,417	699	811	3.0813470	7,359,745	8,538,989	1,179,244	2,525,778	11,064,767			
4	Jan-2024	3,428	655	763	3.0813470	6,918,672	8,059,460	1,140,788	2,526,164	10,585,624	633,771	81,489	715,260
5	Dec-2023	3,424	536	552	3.0813470	5,655,085	5,823,894	168,809	2,515,482	8,339,376			
6	Nov-2023	3,387	223	288	3.0813470	2,327,344	3,005,718	678,374	2,480,647	5,486,365			
7	Oct-2023	3,373	39	47	3.0813470	405,342	488,489	83,147	2,462,774	2,951,263			
8	Sep-2023	3,384	1	-	3.0813470	10,427	-	(10,427)	2,463,161	2,463,161			
9	Aug-2023	3,363	-	-	3.0813470	-	-	-	2,440,278	2,440,278			
10	Jul-2023	3,363	-	-	3.0813470	-	-	-	2,432,680	2,432,680			
11	Jun-2023	3,373	21	35	3.0813470	218,261	363,768	145,507	2,432,294	2,796,062			
12	May-2023	3,360	130	184	3.0813470	1,345,932	1,905,012	559,080	2,415,329	4,320,341			
13	Apr-2023	3,388	367	415	3.0813470	3,831,335	4,332,436	501,101	2,427,803	6,760,239			
14	Total	40,679	3,187	3,729		33,508,268	39,197,035	5,688,767	29,657,369	68,854,404	633,771	81,489	715,260
15													
16	*DC C&I Non Htg*												
17	Mar-2024	1,838 (2)	516	634	0.3998460	379,217	465,937	86,720	427,724	893,661			
18	Feb-2024	1,837	699	811	0.3998460	513,427	595,693	82,266	429,244	1,024,937			
19	Jan-2024	1,836	655	763	0.3998460	480,847	560,131	79,284	430,762	990,893	44,047	13,896	57,943
20	Dec-2023	1,839	536	552	0.3998460	394,130	405,895	11,765	433,221	839,116			
21	Nov-2023	1,844	223	288	0.3998460	164,421	212,347	47,926	436,158	648,505			
22	Oct-2023	1,846	39	47	0.3998460	28,787	34,691	5,904	438,393	473,084			
23	Sep-2023	1,845	1	-	0.3998460	738	-	(738)	439,916	439,916			
24	Aug-2023	1,844	-	-	0.3998460	-	-	-	441,437	441,437			
25	Jul-2023	1,844	-	-	0.3998460	-	-	-	443,196	443,196			
26	Jun-2023	1,849	21	35	0.3998460	15,526	25,876	10,350	446,162	472,038			
27	May-2023	1,856	130	184	0.3998460	96,475	136,549	40,074	449,622	586,171			
28	Apr-2023	1,857	367	415	0.3998460	272,503	308,143	35,640	451,637	759,780			
29	Total	22,135	3,187	3,729		2,346,071	2,745,262	399,191	5,267,470	8,012,732	44,047	13,896	57,943

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	<---Therm Sales---> <---Weather Gas---> Actual	Normal Weather	Weather Adjustment	Base Gas b/	Total	<---Peak Day---> Weather Gas	Base Gas	Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*CI - Delivery CHP*												
2	Mar-2024	1	516	634	302.4376000	156,058	191,745	35,687	81,103	272,848			
3	Feb-2024	1	699	811	302.4376000	211,404	245,277	33,873	81,103	326,380			
4	Jan-2024	1	655	763	302.4376000	198,097	230,760	32,663	81,103	311,863	18,146	2,616	20,762
5	Dec-2023	1	536	552	302.4376000	162,107	166,946	4,839	81,103	248,049			
6	Nov-2023	1	223	288	302.4376000	67,444	87,102	19,658	81,103	168,205			
7	Oct-2023	1	39	47	302.4376000	11,795	14,215	2,420	81,103	95,318			
8	Sep-2023	1	1	-	302.4376000	302	-	(302)	81,103	81,103			
9	Aug-2023	1	-	-	302.4376000	-	-	-	81,103	81,103			
10	Jul-2023	1	-	-	302.4376000	-	-	-	81,103	81,103			
11	Jun-2023	1	21	35	302.4376000	6,351	10,585	4,234	81,103	91,688			
12	May-2023	1	130	184	302.4376000	39,317	55,649	16,332	81,103	136,752			
13	Apr-2023	1	367	415	302.4376000	110,995	125,512	14,517	81,103	206,615			
14	Total	12	3,187	3,729		963,870	1,127,791	163,921	973,241	2,101,032	18,146	2,616	20,762
15													
16	*DC GMA Htg / HC < 3075*												
17	Mar-2024	605 2	516	634	0.2524320	78,804	96,825	18,021	36,457	133,282			
18	Feb-2024	612	699	811	0.2524320	107,987	125,290	17,303	36,878	162,168			
19	Jan-2024	597	655	763	0.2524320	98,710	114,986	16,276	35,974	150,960	9,042	1,160	10,202
20	Dec-2023	595	536	552	0.2524320	80,506	82,909	2,403	35,854	118,763			
21	Nov-2023	602	223	288	0.2524320	33,888	43,766	9,878	36,276	80,042			
22	Oct-2023	596	39	47	0.2524320	5,868	7,071	1,203	35,914	42,985			
23	Sep-2023	583	1	-	0.2524320	147	-	(147)	35,131	35,131			
24	Aug-2023	590	-	-	0.2524320	-	-	-	35,553	35,553			
25	Jul-2023	596	-	-	0.2524320	-	-	-	35,914	35,914			
26	Jun-2023	598	21	35	0.2524320	3,170	5,283	2,113	36,035	41,318			
27	May-2023	608	130	184	0.2524320	19,952	28,240	8,288	36,637	64,877			
28	Apr-2023	595	367	415	0.2524320	55,122	62,332	7,210	35,854	98,186			
29	Total	7,177	3,187	3,729		484,154	566,702	82,548	432,477	999,179	9,042	1,160	10,202

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Therm Sales: Weather Gas: Normal Weather	Therm Sales: Weather Adjustment	Therm Sales: Base Gas b/	Therm Sales: Total	Peak Day: Weather Gas	Peak Day: Base Gas	Peak Day: Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*DC GMA Htg / HC > 3075*												
2	Mar-2024	1,709 (1)	516	634	3.2184570	2,838,177	3,487,217	649,040	765,898	4,253,115			
3	Feb-2024	1,703	699	811	3.2184570	3,831,242	4,445,117	613,875	763,209	5,208,326			
4	Jan-2024	1,711	655	763	3.2184570	3,606,941	4,201,673	594,732	766,795	4,968,468	330,407	24,735	355,142
5	Dec-2023	1,713	536	552	3.2184570	2,955,084	3,043,296	88,212	767,691	3,810,987			
6	Nov-2023	1,699	223	288	3.2184570	1,219,399	1,574,830	355,431	761,417	2,336,247			
7	Oct-2023	1,701	39	47	3.2184570	213,509	257,306	43,797	762,313	1,019,619			
8	Sep-2023	1,714	1	-	3.2184570	5,516	-	(5,516)	768,139	768,139			
9	Aug-2023	1,709	-	-	3.2184570	-	-	-	765,898	765,898			
10	Jul-2023	1,705	-	-	3.2184570	-	-	-	764,106	764,106			
11	Jun-2023	1,711	21	35	3.2184570	115,642	192,737	77,095	766,795	959,532			
12	May-2023	1,699	130	184	3.2184570	710,861	1,006,141	295,280	761,417	1,767,558			
13	Apr-2023	1,711	367	415	3.2184570	2,020,988	2,285,314	264,326	766,795	3,052,109			
14	Total	20,485	3,187	3,729		17,517,359	20,493,631	2,976,272	9,180,472	29,674,103	330,407	24,735	355,142
15													
16	*DC GMA Non Htg*												
17	Mar-2024	871 (1)	516	634	0.4780260	214,842	263,973	49,131	196,062	460,035			
18	Feb-2024	875	699	811	0.4780260	292,373	339,219	46,846	197,428	536,647			
19	Jan-2024	870	655	763	0.4780260	272,403	317,318	44,915	196,762	514,080	24,953	6,347	31,300
20	Dec-2023	869	536	552	0.4780260	222,657	229,303	6,646	196,998	426,301			
21	Nov-2023	868	223	288	0.4780260	92,529	119,499	26,970	197,233	316,732			
22	Oct-2023	869	39	47	0.4780260	16,201	19,524	3,323	197,922	217,446			
23	Sep-2023	868	1	-	0.4780260	415	-	(415)	198,156	198,156			
24	Aug-2023	869	-	-	0.4780260	-	-	-	198,846	198,846			
25	Jul-2023	868	-	-	0.4780260	-	-	-	199,079	199,079			
26	Jun-2023	868	21	35	0.4780260	8,713	14,522	5,809	199,540	214,062			
27	May-2023	869	130	184	0.4780260	54,003	76,434	22,431	200,232	276,666			
28	Apr-2023	866	367	415	0.4780260	151,927	171,798	19,871	200,001	371,799			
29	Total	10,430	3,187	3,729		1,326,063	1,551,590	225,527	2,378,258	3,929,848	24,953	6,347	31,300

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Multiple Customers at Common Addresses

As of March 31, 2024

		DC		Net
MCACA_RES_HTG/CLG	SACA_RES_HTG/CLG	42,392	8,434	33,958 1
MCACA_RES_NONHTG/NONCLG	SACA_RES_NONHTG/NONCLG	10,444	1,043	9,401 A
MCACA_OTHER	SACA_OTHER	482	119	363 B
MCACA_C&I_HTG/CLG	SACA_C&I_HTG/CLG	2,932	963	1,969 C
MCACA_C&I_NONHTG/NONCLG	SACA_C&I_NONHTG/NONCLG	1,116	309	807 1
MCACA_C&I_CHP	SACA_C&I_CHP	-	-	-
MCACA_GMA_HTG/CLG	SACA_GMA_HTG/CLG	888	282	606 1
MCACA_GMA_NONHTG/NONCLG	SACA_GMA_NONHTG/NONCLG	436	142	294 ↓
MCACA_NONFIRM	SACA_NONFIRM	85	34	51
MCACA_SPECCON	SACA_SPECCON	-	-	-
MCACA_TOTAL	**SACA_TOTAL**	**58,775**	**11,326**	**47,449**

A+B = 9,764 1
2/ 57.28% x C = 1,128
↓ 42.72% x C = 841

Washington Gas Light Company
District of Columbia Jurisdiction

Calculation of Average Cost per Service

As of March 31, 2024

Retirement Unit	Unitized Activity Cost	Non-Unitized Activity Cost	Total
380101-Service Pipe Iron 3/4"	$ 10/ 14,940,992.24	$ 11/ 5,394,986.82	$ 20,335,979.06
380102-Service Pipe Iron 1 "	1,319,994.62	525,548.20	1,845,542.82
380103-Service Pipe Iron 1-1/4"	7,742,275.07	2,275.80	7,744,550.87
380121-Service Pipe Iron 1/2"	-	-	-
380201-Service Pipe Plastic 3/4"	59,303,657.71	24,778,222.85	84,081,880.56
380202-Service Pipe Plastic 1 "	38,176,053.72	3,693,967.29	41,870,021.01
380203-Service Pipe Plastic 1-1/4"	72,189,867.26	8,713,708.18	80,903,575.44
380221-Service Pipe Plastic 1/2"	36,698,723.49	6,419,020.52	43,117,744.01
380301-Service Pipe Copper 3/4"	10,719.18	-	10,719.18
380302-Service Pipe Copper 1 "	722,026.73	-	722,026.73
380303-Service Pipe Copper 1-1/4"	990,973.61	-	990,973.61
380321-Service Pipe Copper 1/2"	1,284,741.52	-	1,284,741.52
Total	$ 233,380,025.15	$ 49,527,729.66	$ 282,907,754.81
Number of Services 1.25 inch or smaller			15/ 102,865
Average Cost Per Service			$ 2,750.28 1

Washington Gas Light Company
District of Columbia Jurisdiction

Distribution Services by Size (Unitized)

As of March 31, 2024

company	01 DC Washington Gas Light Company		
retirement_unit	**Sum of activity_cost**		
380101-Service Pipe Iron 3/4"	$	**14,940,992.24**	A 9
380102-Service Pipe Iron 1 "	$	**1,319,994.62**	A
380103-Service Pipe Iron 1-1/4"	$	**7,742,275.07**	A
380104-Service Pipe Iron 1-1/2"	$	5,676,651.43	
380105-Service Pipe Iron 2 "	$	5,932,016.97	
380106-Service Pipe Iron 3 "	$	2,401,433.66	
380107-Service Pipe Iron 4 "	$	1,169,556.62	
380108-Service Pipe Iron 6 "	$	960,171.76	
380109-Service Pipe Iron 8 "	$	392,061.74	
380111-Service Pipe Iron 12 "	$	501,121.66	
380120-Service Pipe Iron 2-1/2"	$	-	
380121-Service Pipe Iron 1/2"	$	-	A 9
380201-Service Pipe Plastic 3/4"	$	**59,303,657.71**	A
380202-Service Pipe Plastic 1 "	$	**38,176,053.72**	A
380203-Service Pipe Plastic 1-1/4"	$	**72,189,867.26**	A
380204-Service Pipe Plastic 1-1/2"	$	897,765.67	
380205-Service Pipe Plastic 2 "	$	53,781,598.70	
380206-Service Pipe Plastic 3 "	$	5,543,827.50	
380207-Service Pipe Plastic 4 "	$	8,627,117.79	
380208-Service Pipe Plastic 6 "	$	1,383,208.84	
380209-Service Pipe Plastic 8 "	$	425,124.13	
380211-Service Pipe Plastic 12 "	$	28,923.42	
380220-Service Pipe Plastic 2-1/2"	$	120,784.38	
380221-Service Pipe Plastic 1/2"	$	**36,698,723.49**	A 9
380225-Service Sleeves -6" & Under	$	53,047.09	
380301-Service Pipe Copper 3/4"	$	**10,719.18**	A 9
380302-Service Pipe Copper 1 "	$	**722,026.73**	A
380303-Service Pipe Copper 1-1/4"	$	**990,973.61**	A
380304-Service Pipe Copper 1-1/2"	$	6,292.51	
380305-Service Pipe Copper 2 "	$	863.27	
380307-Service Pipe Copper 4 "	$	-	
380321-Service Pipe Copper 1/2"	$	**1,284,741.52**	A 9
Non-unitized	$	102,284,425.71	
Special Conversion and VA Res Imbal	$	-	
Grand Total	$	423,566,018.00	

Unitized Pipe 1.25 Inch and Smaller $ $\boxed{233,380,025.15}$ = Sum A 9

Washington Gas Light Company
District of Columbia Jurisdiction

Allocation of Non-Unitized Amounts by Retirement Unit

As of March 31, 2024

Non-Unitized Services (Identifiable by Retirement Unit)

utility_account	retirement_unit	Sum of amount	Ratio	Allocation of Non Unitized		
380100 - Distr - Services - Steel	380103-Service Pipe Iron 1-1/4"	969.00	0.01%	2,275.80	A	9
	380107-Service Pipe Iron 4 "	214,707.42	3.29%	504,263.20		
	380108-Service Pipe Iron 6 "	78,527.30	1.20%	184,429.71		
	380104-Service Pipe Iron 1-1/2"	30,840.70	0.47%	72,432.66		
	380105-Service Pipe Iron 2 "	2,452,301.30	37.56%	5,759,490.30		
	380106-Service Pipe Iron 3 "	958,431.30	14.68%	2,250,977.80		
	380109-Service Pipe Iron 8 "	32,868.50	0.50%	77,195.17		
	380102-Service Pipe Iron 1 "	223,770.24	3.43%	525,548.20	A	9
	380111-Service Pipe Iron 12 "	239,216.70	3.66%	561,825.85		
	380101-Service Pipe Iron 3/4"	2,297,101.39	35.18%	5,394,986.82	A	9
380100 - Distr - Services - Steel Total		**6,528,733.85**	**100.00%**	**15,333,425.51**		
380200 - Distr - Services - Plastic	380208-Service Pipe Plastic 6 "	161,052.92	0.41%	352,289.24		
	380203-Service Pipe Plastic 1-1/4"	3,983,568.06	10.02%	8,713,708.18	A	9
	380202-Service Pipe Plastic 1 "	1,688,738.00	4.25%	3,693,967.29	A	
	380221-Service Pipe Plastic 1/2"	2,934,526.22	7.38%	6,419,020.52	A	
	380205-Service Pipe Plastic 2 "	14,788,959.04	37.21%	32,349,559.85		
	380207-Service Pipe Plastic 4 "	4,407,328.43	11.09%	9,640,647.08		
	380201-Service Pipe Plastic 3/4"	11,327,638.60	28.50%	24,778,222.85	A	9
	380206-Service Pipe Plastic 3 "	441,990.04	1.11%	966,814.72		
	380209-Service Pipe Plastic 8 "	7,885.62	0.02%	17,249.11		
380200 - Distr - Services - Plastic Total		**39,741,686.93**	**100.00%**	**86,931,478.83**		
				12/ 102,264,904.34		
Non-unitized Pipe 1.25 inch and Smaller	**sum A**			**49,527,729.66**		9

Washington Gas Light Company
District of Columbia Jurisdiction

Non-unitized Plant by Group

As of March 31, 2024

company	utility_account	ferc_activity_code	activity_quantity	activity_cost	
01 DC Washington Gas Light Company	369002 - Trans-Meas Reg Sta Spur	Addition	-	-	
01 DC Washington Gas Light Company	376100 - Distr - Mains - Steel	Addition	677	9,538,842	
01 DC Washington Gas Light Company	376200 - Distr - Mains - Plastic	Addition	2,275	72,658,230	
01 DC Washington Gas Light Company	376200 - Distr - Mains - Plastic	Addition	39	3,365,989	
01 DC Washington Gas Light Company	376300 - Distr - Mains - Cast Iron	Addition	-	-	
01 DC Washington Gas Light Company	378002 - Distr - Meas & Reg Sta	Addition	-	-	
01 DC Washington Gas Light Company	**380100 - Distr - Services - Steel**	**Addition**	**2,821**	**15,333,426**	A
01 DC Washington Gas Light Company	**380200 - Distr - Services - Plastic**	**Transfer**	**-**	**-**	A
01 DC Washington Gas Light Company	**380200 - Distr - Services - Plastic**	**Addition**	**12,935**	**86,913,265**	A
01 DC Washington Gas Light Company	**380200 - Distr - Services - Plastic**	**Adjustment**	**-**	**18,213**	A
01 DC Washington Gas Light Company	**380300 - Distr - Services - Copper**	**Addition**	**3**	**19,521** C	A
01 DC Washington Gas Light Company	381200 - Distr - Meters - HardCase	Addition	13	(220,616)	
01 DC Washington Gas Light Company	381300 - Distr - Meters -Index Corr	Addition	19	18,973	
01 DC Washington Gas Light Company	382000 - Distr - Meter Install	Addition	4,372	8,075,784	
01 DC Washington Gas Light Company	383000 - Distr - House Regulator	Addition	1,007	974,971	
01 DC Washington Gas Light Company	384000 - Distr - House Reg Install	Addition	1,384	895,437	
01 DC Washington Gas Light Company	386200 - Distr - Gas Light	Addition	7	7,495	
01 DC Washington Gas Light Company	397201 - Distr-Meters - Enscan Unit	Addition	-	-	
			Total Non Unitized Services	**102,284,426** B	sum A
				19,521	

B-C = 102,264,905 11

Washington Gas Light Company
Depreciable Gas Plant In Service
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - EOP
EOP Rate Base

	Description	Reference: Sc-Pg-Ln	Reference: Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Depreciable Gas Plant in Service**							
2	Capitalized Software	AL:2:23	Non_Genl_Plnt	$ 177,259,639	$ 33,746,559	$ 64,748,626	$ 78,764,453	$ -
3	Storage	AL:1:19	Total_Weather_All_NW	76,912,897	$ 12,672,965	$ 32,680,649	$ 31,559,283	$ -
4	Storage - AFUDC		Financial Stmt.	(522,068)	-	-	(522,068)	0
5	Total Storage	=3+4		$ 76,390,829	$ 12,672,965	$ 32,680,649	$ 31,037,215	$ -
6	Transmission							
7	Spurlines and Related Regulating							
8	Equipment and Structures		Financial Stmt.	$ 436,532,236	$ 56,268,888	$ 122,515,225	$ 221,975,898	$ 35,772,225
9	WSSC			-	-	-	-	-
10	ChalkPoint		Financial Stmt.	13,995,741	-	13,995,741	-	-
11	Panda		Financial Stmt.	2,037,807	-	2,037,807	-	-
12	Other	AL:1:28	Comp_Peak_Ann_NW	707,046,848	110,251,880	308,958,335	287,836,633	-
13	Transmission Mains - ARO			6,866,762	2,515	3,893,364	2,970,883	-
14	Post 1989 MD Interruptible Customers		Financial Stmt.	2,477,416	-	2,477,416	-	-
15	AFUDC		Financial Stmt.	(5,454,592)	-	-	(5,454,592)	0
16	Total Transmission	=8>13		$ 1,163,502,217	$ 166,523,282	$ 453,877,889	$ 507,328,821	$ 35,772,225
17	Distribution							
18	Compressor Station Equipment	AL:1:19	Total_Weather_All_NW	$ 2,735,941	$ 450,802	$ 1,162,514	$ 1,122,625	$ -
19	Mains		Financial Stmt.	2,657,582,180	569,615,674	909,030,303	1,178,936,203	-
20	Distribution Mains - ARO			60,526,224	1,069,747	34,074,639	25,381,838	-
21	Measuring and Regulator Station Equipment		Financial Stmt.	18,043,946	10,775,367	4,334,902	2,933,676	-
22	Services		Financial Stmt.	2,382,937,789	423,566,018 (1)	902,686,214	1,056,685,558	-
23	Distribution Services - ARO			60,759,908	949,665	34,884,224	24,926,019	-
24	Meters		Financial Stmt.	141,784,320	27,417,006	54,472,946	59,894,368	-
25	Meter Installations		Financial Stmt.	253,495,668	35,481,807	91,416,024	126,597,837	-
26	House Regulators		Financial Stmt.	45,427,074	4,799,334	16,028,705	24,599,035	-
27	House Regulator Installations		Financial Stmt.	15,289,594	3,731,028	6,598,182	4,960,385	-
28	Gas Light Services		Financial Stmt.	5,083,869	107,165	1,983,646	2,993,058	-
29	Post 1989 MD Interruptible Customers		Financial Stmt.	2,917,888	-	2,917,888	-	-
30	AFUDC		Financial Stmt.	(17,294)	-	-	(17,294)	-
31	Total Distribution	=16>26		$ 5,646,567,107	$ 1,077,963,612	$ 2,059,590,187	$ 2,509,013,309	$ -
32	General							
33	Transportation	AL:2:23	Non_Genl_Plnt	$ 42,408,687	$ 7,889,157	$ 15,486,831	$ 18,839,192	$ 193,507
34	POE	AL:2:23	Non_Genl_Plnt	4,738,176	881,428	1,730,290	2,104,838	21,620
35	Other - Direct		Financial Stmt.	67,131,345	11,901,295	37,825,530	17,404,520	-
36	Other - Allocable	AL:2:23	Non_Genl_Plnt	286,876,733	53,366,790	104,761,829	127,439,124	1,308,990
37	AFUDC		Financial Stmt.	(5,104,995)	-	-	(5,104,995)	-
38	Total General	=29>33		$ 396,049,945	$ 74,038,670	$ 159,804,481	$ 160,682,679	$ 1,524,116
39	CNG Equipment		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
40	CIAC - GPIS		Financial Stmt.	-	-	-	-	
41	CIAC - Liability		Financial Stmt.	-	-	-	-	
42	Total Depreciable Gas Plant in Service	=2+5+14+27+3 4+35+36+37		$ 7,459,769,738	$ 1,364,945,088	$ 2,770,701,832	$ 3,286,826,477	$ 37,296,341

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper 2.3 - Estimated Interruptible & Special Contracts Service Investment by Size

As of Mar 31, 2024

ON	On
Billing_Class	(All)

Retirement Unit	Pipe Footage	Ave Cost per Foot	Total Cost = Feet * Ave Cost	
380104-Service Pipe Iron 1-1/2"	24	$ 11.05	$ 265.32	
380105-Service Pipe Iron 2 "	746	$ 57.28	$ 23,971.24	
380106-Service Pipe Iron 3 "	528	$ 70.01	$ 22,779.76	
380107-Service Pipe Iron 4 "	1,810	$ 86.33	$ 83,377.05	
380108-Service Pipe Iron 6 "	1,717	$ 61.57	$ 110,987.62	
380109-Service Pipe Iron 8 "	3,755	$ 78.85	$ 218,340.49	
380201-Service Pipe Plastic 3/4"	119	$ 133.92	$ 9,455.40	A
380203-Service Pipe Plastic 1-1/4"	54	$ 29.10	$ 1,571.38	A
380205-Service Pipe Plastic 2 "	3,449	$ 214.68	$ 622,685.37	
380206-Service Pipe Plastic 3 "	2,036	$ 83.34	$ 94,722.58	
380207-Service Pipe Plastic 4 "	4,320	$ 321.46	$ 838,319.72	
380208-Service Pipe Plastic 6 "	885	$ 178.56	$ 457,830.05	
380209-Service Pipe Plastic 8 "	368	$ 166.09	$ 93,845.44	
380102-Service Pipe Iron 1 "	4	$ 76.26	$ 305.02	A
380111-Service Pipe Iron 12 "	1,044	$ 20.44	$ 21,335.22	
Grand Total	20,859	$ 151.91	$ 2,599,791.65	

Services 1.25 inches or Smaller	177	$ 11,331.80	1

Washington Gas Light Company
District of Columbia Jurisdiction

Number of Services 1.25 inch or smaller

as of March 31, 2024

Services	Count
.25	44
.5	22,107
.75	19,823
1	25,240
1.25	32,718
Unknown	2,933
Grand Total	**102,865** 9

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper 2.1 - Estimated Service Investment by Class

As of Mar 31, 2024

Billing_Class	(All)
ON	On

Category	Pipe Footage	Ave Cost per Foot	Total Cost = Feet * Ave Cost
Interruptible	19,590	$ 134	$ 2,291,879
C&I CHP	120	$ 63	$ 7,605
Special Contract	546	$ 88	$ 49,723
CNG/NGV	562	$ 533	$ 164,496
Grand Total	20,818	$ 140	$ 2,513,704

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper 2.2 - Estimated Interruptible & Special Contracts Service Investment

As of Mar 31, 2024

Billing_Class	(All)
ON	On

YEAR_INST	Retirement Unit	Pipe Footage	Ave Cost per Foot	Total Cost = Feet * Ave Cost
1970	380201-Service Pipe Plastic 3/4"	111	66	7,293
1970 Total		111	66	7,293
1983	380106-Service Pipe Iron 3 "	29	180	5,220
1983 Total		29	180	5,220
2010	380205-Service Pipe Plastic 2 "	5	66	328
2010 Total		5	66	328
2011	380207-Service Pipe Plastic 4 "	91	1,468	133,552
2011 Total		91	1,468	133,552
2012	380207-Service Pipe Plastic 4 "	54	990	53,475
2012 Total		54	990	53,475
2015	380201-Service Pipe Plastic 3/4"	8	270	2,163
2015 Total		8	270	2,163
2019	380207-Service Pipe Plastic 4 "	140	699	97,924
2019 Total		140	699	97,924
2022	380205-Service Pipe Plastic 2 "	17	1,510	25,673
2022 Total		17	1,510	25,673
1945	380107-Service Pipe Iron 4 "	919	3	2,346
1945 Total		919	3	2,346
1954	380108-Service Pipe Iron 6 "	133	9	1,145
1954 Total		133	9	1,145
1955	380108-Service Pipe Iron 6 "	57	27	1,536
1955 Total		57	27	1,536
1958	380106-Service Pipe Iron 3 "	45	10	462
1958	380107-Service Pipe Iron 4 "	139	11	1,563
1958 Total		184	11	2,025
1960	380106-Service Pipe Iron 3 "	63	11	694
1960 Total		63	11	694

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper 2.2 - Estimated Interruptible & Special Contracts Service Investment

As of Mar 31, 2024

Billing_Class	(All)
ON	On

YEAR_INST	Retirement Unit	Pipe Footage	Ave Cost per Foot	Total Cost = Feet * Ave Cost
1961	380107-Service Pipe Iron 4 "	34	9	318
1961 Total		34	9	318
1965	380108-Service Pipe Iron 6 "	20	12	236
1965 Total		20	12	236
1966	380105-Service Pipe Iron 2 "	149	9	1,392
1966	380106-Service Pipe Iron 3 "	69	13	875
1966 Total		218	10	2,266
1967	380106-Service Pipe Iron 3 "	32	22	713
1967 Total		32	22	713
1968	380104-Service Pipe Iron 1-1/2"	24	11	265
1968	380106-Service Pipe Iron 3 "	48	11	524
1968 Total		72	11	789
1969	380106-Service Pipe Iron 3 "	53	17	914
1969	380111-Service Pipe Iron 12 "	1,044	20	21,335
1969 Total		1,097	19	22,249
1970	380105-Service Pipe Iron 2 "	431	21	9,149
1970	380106-Service Pipe Iron 3 "	137	19	2,544
1970 Total		568	20	11,694
1971	380107-Service Pipe Iron 4 "	323	28	8,998
1971	380108-Service Pipe Iron 6 "	216	46	9,928
1971 Total		539	34	18,925
1972	380205-Service Pipe Plastic 2 "	27	66	1,774
1972 Total		27	66	1,774
1973	380206-Service Pipe Plastic 3 "	900	26	23,589
1973 Total		900	26	23,589
1980	380105-Service Pipe Iron 2 "	55	83	4,573
1980	380107-Service Pipe Iron 4 "	221	171	37,774

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper 2.2 - Estimated Interruptible & Special Contracts Service Investment

As of Mar 31, 2024

Billing_Class	(All)
ON	On

YEAR_INST	Retirement Unit	Pipe Footage	Ave Cost per Foot	Total Cost = Feet * Ave Cost
1980	380108-Service Pipe Iron 6 "	816	86	70,155
1980	380205-Service Pipe Plastic 2 "	249	46	11,574
1980	380206-Service Pipe Plastic 3 "	308	64	19,746
1980	380207-Service Pipe Plastic 4 "	622	100	62,249
1980 Total		2,271	93	206,073
1981	380106-Service Pipe Iron 3 "	28	206	5,761
1981	380107-Service Pipe Iron 4 "	11	446	4,903
1981	380108-Service Pipe Iron 6 "	42	64	2,691
1981	380205-Service Pipe Plastic 2 "	748	26	19,470
1981	380206-Service Pipe Plastic 3 "	335	38	12,846
1981	380207-Service Pipe Plastic 4 "	102	71	7,258
1981 Total		1,266	68	52,929
1982	380106-Service Pipe Iron 3 "	24	211	5,072
1982	380107-Service Pipe Iron 4 "	74	204	15,124
1982	380203-Service Pipe Plastic 1-1/4"	54	29	1,571
1982	380206-Service Pipe Plastic 3 "	437	75	32,563
1982 Total		589	119	54,330
1983	380105-Service Pipe Iron 2 "	19	126	2,385
1983	380107-Service Pipe Iron 4 "	28	294	8,246
1983	380108-Service Pipe Iron 6 "	199	35	7,042
1983	380109-Service Pipe Iron 8 "	2,761	45	125,422
1983	380207-Service Pipe Plastic 4 "	937	54	50,533
1983 Total		3,944	93	193,628
1984	380205-Service Pipe Plastic 2 "	100	61	6,136
1984	380208-Service Pipe Plastic 6 "	49	57	2,809
1984 Total		149	59	8,945
1985	380105-Service Pipe Iron 2 "	19	89	1,699

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper 2.2 - Estimated Interruptible & Special Contracts Service Investment

As of Mar 31, 2024

Billing_Class	(All)
ON	On

YEAR_INST	Retirement Unit	Pipe Footage	Ave Cost per Foot	Total Cost = Feet * Ave Cost
1985	380108-Service Pipe Iron 6 "	10	202	2,016
1985	380109-Service Pipe Iron 8 "	176	144	25,326
1985	380206-Service Pipe Plastic 3 "	28	89	2,488
1985 Total		233	131	31,528
1986	380109-Service Pipe Iron 8 "	410	99	40,788
1986	380206-Service Pipe Plastic 3 "	20	115	2,304
1986 Total		430	105	43,092
1987	380105-Service Pipe Iron 2 "	50	66	3,285
1987	380205-Service Pipe Plastic 2 "	507	59	29,696
1987	380207-Service Pipe Plastic 4 "	65	176	11,460
1987 Total		622	72	44,442
1988	380205-Service Pipe Plastic 2 "	104	64	6,631
1988	380208-Service Pipe Plastic 6 "	6	74	443
1988 Total		110	66	7,074
1989	380206-Service Pipe Plastic 3 "	3	286	858
1989	380207-Service Pipe Plastic 4 "	503	148	74,520
1989 Total		506	217	75,378
1990	380205-Service Pipe Plastic 2 "	120	63	7,605
1990 Total		120	63	7,605
1991	380205-Service Pipe Plastic 2 "	637	64	40,633
1991	380207-Service Pipe Plastic 4 "	127	169	21,526
1991 Total		764	90	62,158
1992	380205-Service Pipe Plastic 2 "	113	107	12,131
1992 Total		113	107	12,131
1993	380205-Service Pipe Plastic 2 "	57	64	3,628
1993	380208-Service Pipe Plastic 6 "	45	59	2,656
1993 Total		102	61	6,284

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper 2.2 - Estimated Interruptible & Special Contracts Service Investment

As of Mar 31, 2024

Billing_Class	(All)
ON	On

YEAR_INST	Retirement Unit	Pipe Footage	Ave Cost per Foot	Total Cost = Feet * Ave Cost
1994	380108-Service Pipe Iron 6 "	175	56	9,763
1994	380207-Service Pipe Plastic 4 "	71	186	13,215
1994 Total		246	121	22,978
1995	380107-Service Pipe Iron 4 "	19	71	1,346
1995	380207-Service Pipe Plastic 4 "	93	246	22,840
1995 Total		112	129	24,186
1997	380207-Service Pipe Plastic 4 "	52	164	8,524
1997 Total		52	164	8,524
1998	380102-Service Pipe Iron 1 "	4	76	305
1998	380105-Service Pipe Iron 2 "	23	65	1,489
1998 Total		27	70	1,794
1999	380205-Service Pipe Plastic 2 "	144	111	16,018
1999	380209-Service Pipe Plastic 8 "	347	266	92,466
1999 Total		491	150	108,484
2001	380207-Service Pipe Plastic 4 "	61	310	18,935
2001 Total		61	310	18,935
2002	380108-Service Pipe Iron 6 "	49	132	6,476
2002	380207-Service Pipe Plastic 4 "	410	66	26,936
2002	380208-Service Pipe Plastic 6 "	28	66	1,840
2002 Total		487	88	35,252
2003	380207-Service Pipe Plastic 4 "	77	94	7,257
2003 Total		77	94	7,257
2004	380207-Service Pipe Plastic 4 "	910	243	220,778
2004 Total		910	243	220,778
2005	380205-Service Pipe Plastic 2 "	61	66	4,008
2005 Total		61	66	4,008
2006	380205-Service Pipe Plastic 2 "	2	50	100

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper 2.2 - Estimated Interruptible & Special Contracts Service Investment

As of Mar 31, 2024

Billing_Class	(All)
ON	On

YEAR_INST	Retirement Unit	Pipe Footage	Ave Cost per Foot	Total Cost = Feet * Ave Cost
2006 Total		2	50	100
2007	380205-Service Pipe Plastic 2 "	7	82	573
2007 Total		7	82	573
2008	380208-Service Pipe Plastic 6 "	93	66	6,110
2008 Total		93	66	6,110
2009	380109-Service Pipe Iron 8 "	408	66	26,805
2009	380209-Service Pipe Plastic 8 "	21	66	1,380
2009 Total		429	66	28,185
2010	380208-Service Pipe Plastic 6 "	224	66	14,716
2010 Total		224	66	14,716
2011	380206-Service Pipe Plastic 3 "	5	66	328
2011	380207-Service Pipe Plastic 4 "	5	1,468	7,338
2011 Total		10	767	7,667
2012	380205-Service Pipe Plastic 2 "	357	473	169,026
2012 Total		357	473	169,026
2013	380208-Service Pipe Plastic 6 "	440	976	429,257
2013 Total		440	976	429,257
2014	380107-Service Pipe Iron 4 "	42	66	2,759
2014 Total		42	66	2,759
2019	380205-Service Pipe Plastic 2 "	61	699	42,654
2019 Total		61	699	42,654
2022	380205-Service Pipe Plastic 2 "	92	1,510	138,938
2022 Total		92	1,510	138,938
Grand Total		20,818	140	2,513,704

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper No. 3 - Directly Assigned Revenues

For the Twelve Months Ended March 31, 2024

Class	Allocation %	Forfeited Discounts Non POR By Tariff Class	Forfeited Discounts Non POR (Assigned)	Class Ratio	Forfeited Discounts Non POR Adj Assigned _1/ _2/	Forfeited Discounts Non POR Total	Forfeited Discounts POR By Tariff Class	Forfeited Discounts POR Assigned	Forfeited Discounts POR Eliminated _2/
	A	B (from SAP)	C = A * B	D	E = Adj Tot * D	F = C + E	G (from SAP)	H = A * G	I = - H
Res H/C	4/ 96.17%	3/ 2,240,772	2,154,956	66.40%	358,104	2,513,060	2 243,638	234,307	(234,307)
Res Non-Htg IMA	1.85%	2,240,772	41,506	1.28%	6,897	48,403	243,638	4,513	(4,513)
Res Non-Htg Other	1.98%	2,240,772	44,310	1.37%	7,363	51,673	243,638	4,818	(4,818)
C&I H/C <3075	9.52%	476,126	45,311	1.40%	7,530	52,841	79,202	7,537	(7,537)
C&I H/C >3075	78.73%	476,126	374,831	11.55%	62,288	437,119	79,202	62,352	(62,352)
C&I CHP	1.11%	476,126	5,272	0.16%	876	6,148	79,202	877	(877)
C&I Non-Htg	10.65%	476,126	50,711	1.56%	8,427	59,138	79,202	8,436	(8,436)
GMA H/C <3075	2.81%	381,013	10,717	0.33%	1,781	12,498	37,303	1,049	(1,049)
GMA H/C >3075	85.03%	381,013	323,978	9.98%	53,838	377,815	37,303	31,719	(31,719)
GMA Non-Htg	12.16%	381,013	46,318	1.43%	7,697	54,015	37,303	4,535	(4,535)
NGV Sales	100.00%	11,398	11,398	0.35%	1,894	13,292	-	-	-
Interruptible	100.00%	136,145	136,145	4.19%	22,624	158,769	-	-	-
Special Contract	100.00%	-	-	0.00%	-	-	-	-	-
Total			3/ 3,245,453 A	100.00%	5/ 539,319	6/ 3,784,772		3/ 360,143 A	5/ (360,143)

6/ Sum of A: 3,605,596

Class	Allocation %	Reconnect Revenue By Tariff Class	Reconnect Revenue Assigned	Class Ratio	Reconnect Revenue Assigned	Reconnect Revenue Total	Returned Check Charge By Tariff Class	Returned Check Charge Assigned
	J	K (from SAP)	L = J * K	M	N = Adj Tot * M	O = L + N	P (from SAP)	Q = J * P
Res H/C	4/ 96.17%	3/ 169,362	162,876	93.42%	-	162,876	2 40,303	38,759 2
Res Non-Htg IMA	1.85%	169,362	3,137	1.80%	-	3,137	40,303	747
Res Non-Htg Other	1.98%	169,362	3,349	1.92%	-	3,349	40,303	797
C&I H/C <3075	9.52%	4,633	441	0.25%	-	441	3,563	339
C&I H/C >3075	78.73%	4,633	3,647	2.09%	-	3,647	3,563	2,805
C&I CHP	1.11%	4,633	51	0.03%	-	51	3,563	39
C&I Non-Htg	10.65%	4,633	493	0.28%	-	493	3,563	379
GMA H/C <3075	2.81%	(45)	(1)	0.00%	-	(1)	819	23
GMA H/C >3075	85.03%	(45)	(38)	-0.02%	-	(38)	819	696
GMA Non-Htg	12.16%	(45)	(5)	0.00%	-	(5)	819	100
Interruptible	100.00%	405	405	0.23%	-	405	54	54
Special Contract	100.00%	-	-	0.00%	-	-	-	-
Total			3/ 174,354	100.00%	-	174,354		3/ 44,738 7/

Class	Allocation %	Service Initiation Charge By Tariff Class	Service Initiation Charge Assigned	Class Ratio	Service Initiation Charge Assigned _1/	Service Initiation Charge Total	Field Collection Charge By Tariff Class	Field Collection Charge Assigned
	R	S (from SAP)	T = R * S	U	V = Adj Tot * U	W = T + V	X (from SAP)	Y = R * X
Res H/C	4/ 96.17%	3/ 806,596	775,705	92.50%	-	775,705 2	3/ 144	139 2
Res Non-Htg IMA	1.85%	806,596	14,941	1.78%	-	14,941	144	3
Res Non-Htg Other	1.98%	806,596	15,950	1.90%	-	15,950	144	3
C&I H/C <3075	9.52%	27,334	2,601	0.31%	-	2,601	289	27
C&I H/C >3075	78.73%	27,334	21,518	2.57%	-	21,518	289	227
C&I CHP	10.65%	27,334	303	0.04%	-	303	289	3
C&I Non-Htg	1.11%	27,334	2,911	0.35%	-	2,911	289	31
GMA H/C <3075	2.81%	4,303	121	0.01%	-	121	-	-
GMA H/C >3075	85.03%	4,303	3,658	0.44%	-	3,658	-	-
GMA Non-Htg	12.16%	4,303	523	0.06%	-	523	-	-
Interruptible	100.00%	338	338	0.04%	-	338	-	-
Special Contract	100.00%	-	-	0.00%	-	-	-	-
Total			3/ 838,570	100.00%	-	7/ 838,570		3/ 433 7/

_1/ Adjustment was calculated by jurisdiction (not by class) and is included in both Adjustment 1 - Revenues for which workpaper is included in Exhibit WG (D)-5. In class cost study, the adjustment was assigned to each customer class based on the proportion of the class per book revenues to total per book revenues.

_2/ Forfeited discount for POR customers is excluded from the cost of service via Adjustment 7D.

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Revenues

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	— Reference — Sc-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	M	N	O	P	Q	R	S
1	Operating Revenues																	
2	Sales of Gas to Customers _1/	Financial Stmt.	Revenue Study	Comp TCS	$ 217,846,912	$ 90,772,884	$ 2,149,044	$ 1,990,531	$ 6,011,562	$ 51,788,411	$ 937,789	$ 6,353,589		$ 915,815	$ 22,542,271	$ 3,077,583	$ 16,025,194	$ 15,287,409
3	Line 2 - Percentage of Total		Gas_Sales_Revenue		1.0000	0.4167	0.0099	0.0091	0.0276	0.2377	0.0043	0.0292	-	0.0042	0.1035	0.0141	0.0736	0.0702
4	Total Gas Sales Revenue excluding Non Firm	Ln. 3 - Ln. 3 Col. N.			$ 186,534,309	90,772,884	2,149,044	1,990,531	6,011,562	51,788,411	937,789	6,353,589	-	915,815	22,542,271	3,077,583	-	-
5	Line 4 - Percentage of Total		Gas_Sales_Ex_Non_Firm		1.0000	0.4866	0.0115	0.0107	0.0322	0.2776	0.0050	0.0341	-	0.0049	0.1209	0.0165	-	-
6	Rate Adjustment Due Customers	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Unbilled Gas Accrual/Reversal	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Provision for Rate Refunds	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total Gas Sales	Lns. 6 > 8			$ 217,846,912	$ 90,772,884	$ 2,149,044	$ 1,990,531	$ 6,011,562	$ 51,788,411	$ 937,789	$ 6,353,589	$ -	$ 915,815	$ 22,542,271	$ 3,077,583	$ 16,025,194	$ 15,287,409
10	Other Operating Revenues				2/													
11	Forfeited Discounts (Non POR)	Billing System	Direct	Comp TCS	3,784,772	2,513,080	48,403	51,873	52,841	437,119	8,146	59,130	13,282	12,486	377,815	54,015	158,788	-
12	Forfeited Discounts (POR)	Billing System	Direct	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rent from Gas Property	RV 1:3	Gas_Sales_Revenue	Comp TCS	98,579	41,084	973	901	2,721	23,430	424	2,876	-	415	10,203	1,380	7,253	6,919
14	Rental Income from WGCC/Maritime/ACI	AL:14	Annual_Firm_NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	
15	Miscellaneous Service Revenues				2/													
16	Reconnect Revenues	Billing System	Direct	Customer	174,364	162,876	3,137	3,349	441	3,847	51	483		(1)	(38)	(5)	405	-
17	Dishonored Check Charge	Billing System	Direct	Customer	44,746	38,759	747	787	330	2,605	38	379		23	686	100	54	-
18	Service Initiation Charge	Billing System	Direct	Customer	838,879	775,706	14,841	15,950	2,801	21,518	303	2,811		121	3,658	523	336	-
19	Field Collection Charge	Billing System	Direct	Customer	433	138	3	3	27	227	3	31		-	-	-	-	-
20	IRATE Non Compliance MTR Charge	Billing System	Direct	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Other Gas Revenues																	
22	Watergate Revenues	Financial Stmt.	Direct	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Third Party Balancing Charges	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	CNG Sales for Natural Gas Vehicles	AL:6:48	C&I Other	Customer	847,960	-	-	-	-	-	-	-	847,960	-	-	-	-	-
25	Off System Sales Revenue Net of Gas Cost	RV 1:5	Gas_Sales_Ex_Non_Firm	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Miscellaneous Revenues																	
27	Other Allocable Miscellaneous	RV 1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Oth Gas Rev - MD RM-35	RV 1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Third Party Billing	AL 2:20	Dely_Cust	Customer	114,447	77,016.80	3,874	2,820	3,862	7,541	7,541	3,303	-	703	4,891	1,086	593	16
30	Firm Margin Sharing Adjustment	RV 1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total Other Operating Revenues	Ln. 22 > Ln. 30			5,983,875	$ 3,608,840	$ 72,077	$ 75,593	$ 62,922	$ 496,287	$ 14,510	$ 69,132	$ 861,251	$ 13,757	$ 397,326	$ 58,021	$ 167,413	$ 6,935
32	Total Operating Revenues	Ln. 9 + Ln. 31			$ 223,763,787	$ 94,381,333	$ 2,221,121	$ 2,066,124	$ 6,074,484	$ 52,282,708	$ 952,299	$ 6,422,731	$ 861,251	$ 929,572	$ 22,939,597	$ 3,135,614	$ 16,192,607	$ 15,294,344
33	Line 32 Percentage of Total Revenues		Total_Revenues		1.0000	0.4218	0.0099	0.0092	0.0271	0.2337	0.0043	0.0287	0.0038	0.0042	0.1025	0.0140	0.0724	0.0684

_1/ Transportation Sales, which are reported separately in the PSCOSA, are included in the "Sales of Gas to Customers" line in the class cost study for purposes of determining allocation factor "Gas_Sales_Revenue".

Washington Gas Light Company
District of Columbia Jurisdiction

Rate Category Allocation

For the Twelve Months Ended March 31, 2024

				Finance Amount	
G/L Account		**Rate Category**	**PS - Resource Type**	**$**	
WGL/487100	Forfeited discounts	Not assigned	Commercial Customer	476,125.61	1
			Group Meter Apartments	381,012.66	
			Interruptible Customers	136,145.08	
			NGV Sales	11,397.58	
			No-Rate Category	895.18	A
			Residential Customer	2,239,877.06	A
			Result	**3,245,453.17**	1
WGL/487107	Late Charges POR	Not assigned	Commercial Customer	79,201.52	1
			Group Meter Apartments	37,303.03	
			Residential Customer	243,638.02	
			Result	**360,142.57**	
WGL/488110	Reconnect Revenue	Not assigned	Commercial Customer	4,632.94	1
			Group Meter Apartments	-44.98	
			Interruptible Customers	404.82	
			Residential Customer	169,361.68	
			Result	**174,354.46**	
WGL/488150	Returned Check Charg	Not assigned	Commercial Customer	3,562.59	1
			Group Meter Apartments	819.00	
			Interruptible Customers	54.00	
			No-Rate Category	-90.00	B
			Residential Customer	40,392.59	B
			Result	**44,738.18**	
WGL/488160	Service Initiation C	Not assigned	Commercial Customer	27,333.57	1
			Group Meter Apartments	4,302.51	
			Interruptible Customers	338.34	
			No-Rate Category	-33.00	C
			Residential Customer	806,629.00	C
			Result	**838,570.42**	
WGL/488180	Field Collection Ch	Not assigned	Commercial Customer	288.64	1
			Residential Customer	144.32	
			Result	**432.96**	
Overall Result			6/	**4,663,691.76**	

Sum of A: 2,240,772.24 1
Sum of B: 40,302.59 1
Sum of C: 806,596 1

Washington Gas Light Company
District of Columbia Jurisdiction

Rate Category Allocation

For the Twelve Months Ended March 31, 2024

				Finance Amount
Jurisdiction Code	**Grid in Util.Indust.**	**Rate Category**	**System Level**	$
DISTRICT OF COLUMBIA	DC	Gas DC CI-Delivery CHP	1	822,359.80
		Gas DC CI-Delivery Heating	1	925,075.39
			2	26,205,937.77
			Result	**27,131,013.16**
		Gas DC CI-Delivery Heating and Cooling	1	4,148.31
			2	174,937.37
			Result	**179,085.68**
		Gas DC CI-Delivery Non-Heating/Cooling	1	611,352.78
			2	2,831,255.71
			Result	**3,442,608.49**
		Gas DC CI-Sales Heating	1	5,970,915.65
			2	31,687,360.58
			Result	**37,658,276.23**
		Gas DC CI-Sales Heating and Cooling	1	167,937.52
			2	401,190.94
			Result	**569,128.46**
		Gas DC CI-Sales Non Heating/Cooling	1	1,849,938.90
			2	2,617,826.26
			Result	**4,467,765.16**
		Gas DC GMA-Delivery Heating	1	257,293.21
			2	12,480,364.29
			Result	**12,737,657.50**
		Gas DC GMA-Delivery Heating and Cooling	2	33,202.75
		Gas DC GMA-Delivery Non-Heating/Cooling	1	211,676.96
			2	1,348,973.77
			Result	**1,560,650.73**
		Gas DC GMA-Sales Heating	1	557,112.33
			2	13,157,927.10
			Result	**13,715,039.43**
		Gas DC GMA-Sales Heating and Cooling	1	35,421.88
			2	19,603.35
			Result	**55,025.23**
		Gas DC GMA-Sales Non Heating/Cooling	1	828,897.38
			2	1,283,443.97
			Result	**2,112,341.35**
		Gas DC Res-Delivery Heating	1	9,270,109.27
			2	-102,829.30
			Result	**9,167,279.97**
		Gas DC Res-Delivery Heating and Cooling	1	15,224.62
			2	-1,110.24
			Result	**14,114.38**
		Gas DC Res-Delivery Non Heat/Cool IMA	1	148,147.61
		Gas DC Res-Delivery Non Heat/Cool Other	1	234,166.00
		Gas DC Res-Sales Heating	1	105,567,431.23
			2	-709,367.44
			Result	**104,858,063.79**
		Gas DC Res-Sales Heating and Cooling	1	561,955.22
			2	-18,092.92
			Result	**543,862.30**
		Gas DC Res-Sales Non Heat/Cool IMA	1	2,054,114.35
			2	4,691.12
			Result	**2,058,805.47**
		Gas DC Res-Sales Non Heat/Cool Other	1	2,121,883.37
		Result		**223,630,476.86**

	Amount ($)	% of Total
Res H/C	$114,583,320	96.17%
Res Non-Htg IMA	2,206,953	1.85%
Res Non-Htg Other	2,356,049	1.98%
	119,146,323	100.00%
	-	

①

C&I H/C <3075	$ 7,068,077	9.52%
C&I H/C >3075	58,469,427	78.73%
C&I Non-Htg	7,910,374	10.65%
C&I CHP	822,360	1.11%
	74,270,237	100.00%
	-	

GMA H/C <3075	$ 849,827	2.81%
GMA H/C >3075	25,691,097	85.03%
GMA Non-Htg	3,672,992	12.16%
	30,213,917	100.00%
	-	
	-	

Period	**March 31, 2024**	
	Mar-2024	

RA NOTE: Both AFO tabs must be rolled forward for current period.

Other Operating Revenues		
Late Payment Charges (POR)	**$** 6/ **(360,143)** 1	*Adj #7D*
Late Payment Adjustment	**$** 6/ **536,674** 1	*CCOSS WP #7*

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 - Ratemaking Revenues and Related Expenses Summary

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Book Amount C	Distribution Adjustments D	Distribution-Only Amount E = C + D	Ratemaking Adjustments F	Ratemaking Amount 2/ G = E + F
1	**Operating Revenues**						
2	Base Revenues						
3	Base Rate Revenues (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	$ 127,731,965	$ -	$ 127,731,965	$ 30,796,647	$ 158,528,612
4	Distribution Charge & Plant Recovery Adjustments	Rev WP 1 + Adj 1 WP 7	(8,444,784)	-	(8,444,784)	8,444,784	-
5	Peak Usage Charge	Rev WP 1 + Adj 1 WP 7	4,254,611	-	4,254,611	76,807	4,331,418
6	Fuel Revenues _1/	Rev WP 1 + Adjs 1D, 2D, 4D	69,417,982	(69,417,982)	-	-	-
7	Revenue Taxes						
8	DC Right of Way Tax (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	12,367,741	-	12,367,741	(2,457,862)	9,909,879
9	Delivery Tax (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	19,243,088	-	19,243,088	1,978,792	21,221,880
10	Sustainable Energy Trust Fund (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	16,438,143	-	16,438,143	4,900,753	21,338,896
11	Energy Assistance Trust Fund (excl CNG customers)	Rev WP 1 + Adj 1 WP 7	2,109,146	-	2,109,146	257,838	2,366,984
12	Non-District of Columbia Tariff Rates & Revenue Taxes	Rev WP 1 + Adj 1 WP 7	(50,138)	-	(50,138)	50,138	-
13	Off-System Sales Revenue (Asset Optimization)	Rev WP 1 + Adj 5D	14,177,234	(14,177,234)	-		-
14	PROJECTpipes	Rev WP 1 + Adj 1 WP 7	13,157,184	-	13,157,184	(13,157,184)	-
15	Sales of Gas to Customers (excl. CNG customers)	Sum Lns. 2 to 14	$ 270,402,172	$ (83,595,216)	$ 186,806,956	$ 30,890,713	$ 217,697,669
16	Late Payment Fees	Rev WP 1 + Adj 7D + Adj 1 WP 8	3,605,596 1 A	(360,143) 5	3,245,453	536,674 5	3,782,127 1
17	Other Operating Revenues	Adj No. 1, Page 2, Line 40	2,897,112	(736,920)	2,160,192	(41,088)	2,119,103
18	**Total Operating Revenues (RV 1:35)**	**Sum Lns. 15 to 17**	**$ 276,904,880**	**$ (84,692,279)**	**$ 192,212,601**	**$ 31,386,299**	**$ 223,598,900**
19	**Revenue Related Expenses**						
20	Uncollectible Accounts Expense	EX 7:19 + Adj 2D + Adj 1 WP 9	$ 6,226,265	$ (1,694,830)	$ 4,531,435	$ 1,356,416	$ 5,887,851
21	Delivery Tax Expense Expense (excl. PSC assessment)	EX 8:8 + Adj 1 WP 10	18,979,968	-	18,979,968	2,241,912	21,221,880
22	Rights of Way Fee Expense	EX 8:9 + Adj 1 WP 11	12,518,268	-	12,518,268	(2,608,389)	9,909,879
23	Sustainable Energy Trust Fund	EX 8:17 + Adj 1 WP 12	16,761,017	-	16,761,017	4,577,879	21,338,896
24	Energy Assistance Trust Fund Fee	EX 8:17 + Adj 2 WP 13	2,156,914	-	2,156,914	210,070	2,366,984
25	**Total Revenue Related Expenses**	**Sum Lns. 20 to 24**	**$ 56,642,432**	**$ (1,694,830)**	**$ 54,947,602**	**$ 5,777,888**	**$ 60,725,490**

26 **Adjustment Description:** To adjust Operating Revenues to a Ratemaking basis.

1/ Includes purchased gas costs, storage gas, ACA carrying costs, and gas administrative charge.
2/ Special contracts are shown within amount shown. For further detail, see the Revenue by Class tab.

A 3,605,596
7/ 1,058,097
4,663,693 3

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment No. 1 - Other Operating Revenues Breakout

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Book Amount C	Distribution Adjustments D	Distribution-Only Amount E = C + D	Ratemaking Adjustments F	Ratemaking Amount _3/ G = E + F
27	**Other Operating Revenues**						
28	Miscellaneous Service Revenues						
29	Reconnect Revenues	RV 1:19	$ A 174,354	$ -	$ 174,354	$ -	$ 174,354 (1)
30	Reconnect Revenue Premium	RV 1:20	-	-	-	-	-
31	Dishonored Check Charge	RV 1:21	44,740	-	44,740	-	44,740
32	Service Initiation Charge	RV 1:22	838,570	-	838,570	-	838,570
33	Field Collection Charge	RV 1:23	433	-	433	-	433
34	IRATE Non-Compliance Meter Charge	RV 1:24	-	-	-	-	-
35	Other Miscellaneous Revenues						
36	Rents	RV 1:17 + Adj 1 WP 5	$ 139,688	$ -	$ 139,688	$ (41,088)	$ 98,600
37	CNG Sales for Natural Gas Vehicles _3/	RV 1:28	847,959	-	847,959	-	847,959
38	Other Gas Revenues (POR)	RV 1:32 + Adj 7D	736,920	(736,920)	-	-	-
39	Third Party Billing	RV 1:33	114,447	-	114,447	-	114,447
40	**Total Other Operating Revenues**	**Sum Lns. 29 to 38**	**$ 2,897,112**	**$ (736,920)**	**$ 2,160,192**	**$ (41,088)**	**$ 2,119,103**

3/ For purposes of this adjustment, all components of CNG revenues (distribution revenues plus revenue taxes) are reflected in the Other Operating Revenues line. There are no ratemaking adjustments for CNG revenues or related expense.

Sum of A: 1,058,097 (6)

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost Study Workpaper 4.1 - Reconciliation of Therms and Months Billed

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	RES-HTG/CLG C	RES-NON H/C-IMA D	RES-NON H/C-OTH E	C&I H/C < 3075 F	C&I H/C > 3075 G	C&I CHP H	C&I NON H/C I	C&I NON H/C - NGV J	GMA H/C < 3075 K	GMA H/C >3075 L	GMA NON H/C M	NON FIRM N	Special Contract O	Total P = Sum (C>O)
1	Weather Gas Therms															
2	Normal Weather Study	NWS Sch 1A Col. D	2/ 70,729,615	309,352	1,287,100	4,057,018	39,197,035	1,127,791	2,745,262		586,702	20,493,631	1,551,590	15,911,005	10,878,939	168,855,040
3	Natural Gas Vehicles	Billing System	-	-	-	-	-	-	-	8/ 106,070	-	-	-	-	-	106,070
4	**Total All Weather Gas (AL:1:5)**	Ln. 2 + Ln. 3	70,729,615	309,352	1,287,100	4,057,018	39,197,035	1,127,791	2,745,262	106,070	586,702	20,493,631	1,551,590	15,911,005	10,878,939	168,961,110
5	Normal Weather Interruptible	NWS Sch 1A Col. D Ln. 19	-	-	-	-	-	-	-	-	-	-	-	(15,911,005)	(10,878,939)	(26,789,944)
6	**Total Firm Weather Gas (NW) (AL:1:1)**	Ln. 4 + Ln. 5	70,729,615	309,352	1,287,100	4,057,018	39,197,035	1,127,791	2,745,262	106,070	586,702	20,493,631	1,551,590	-	-	142,171,166
7	Total Gas Therms															
8	Normal Weather Study	NWS Sch 1A Col. H	2/ 84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732		999,179	29,674,103	3,929,848	-	-	206,081,756
9	Natural Gas Vehicles	Billing System	-	-	-	-	-	-	-	8/ 3,179,948	-	-	-	-	-	3,179,948
10	**Total Firm Sales (AL:1:3)**	Ln. 8 + Ln. 9	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	3,179,948	999,179	29,674,103	3,929,848	-	-	209,261,703
11	Normal Weather Interruptible	NWS Sch 1A Col. H Ln. 19	-	-	-	-	-	-	-	-	-	-	-	2/ 39,827,791	38,220,735	78,048,526
12	Interruptible Curtailment	NWS Support Workpaper	-	-	-	-	-	-	-	-	-	-	-	9/ (179,571)	-	(179,571)
13	**Total Annual Sales (AL:1:7)**	Ln. 10 + Ln. 11 + Ln. 12	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	3,179,948	999,179	29,674,103	3,929,848	39,648,220	38,220,735	287,130,658
14	Total Peak Day Therms - Normal Weather															
15	Normal Weather Study	NWS Sch 1A Col. I	2/ 1,138,887	4,978	20,770	65,270	633,771	18,146	44,047		9,042	330,407	24,953	254,561	175,043	2,719,875
16	Less: Interruptible & Special Contract Therms		-	-	-	-	-	-	-	-	-	-	-	(254,561)	(175,043)	(429,604)
17	**Total Weather Gas (AL:2:2)**	Ln. 15 + Ln. 16	1,138,887	4,978	20,770	65,270	633,771	18,146	44,047	-	9,042	330,407	24,953	-	-	2,290,271
18	Normal Weather Study	NWS Sch 1A Col. J	2/ 36,521	987	1,126	3,468	81,489	2,616	13,896		1,160	24,735	6,347	63,953	73,499	309,797
19	Special Contact	Analysis	-	-	-	-	-	-	-	-	-	-	-	-	3/ 11,492	11,492
20	Less: Interruptible Therms		-	-	-	-	-	-	-	-	-	-	-	(63,953)	(73,499)	(137,452)
21	**Total Base Gas (AL:2:3)**	Ln. 18 + Ln. 20	36,521	987	1,126	3,468	81,489	2,616	13,896	-	1,160	24,735	6,347	-	11,492	183,837
22	**Total Peak Day Therms**	Ln. 17 + Ln. 21	1,175,408	5,965	21,896	68,738	715,260	20,762	57,943	-	10,202	355,142	31,300	-	11,492	2,474,108
23	Months Billed															
24	Normal Weather Study	NWS Sch 2A Col. B	4/ 1,627,379	131,084	42,794	53,982	40,679	12	22,135		7,177	20,485	10,430	1,327	36	1,957,520
25	Natural Gas Vehicles	Billing System	-	-	-	-	-	-	-	8/ 32	-	-	-	-	-	32
26	**Annual Customer Bills (AL:3:1)**	Ln. 24 + Ln. 25	1,627,379	131,084	42,794	53,982	40,679	12	22,135	32	7,177	20,485	10,430	1,327	36	1,957,552
27	Total All Weather Gas	CCOSS AL:1 5	5/ 70,729,615	309,352	1,287,100	4,057,018	39,197,035	1,127,791	2,745,262	106,070	586,702	20,493,631	1,551,590	15,911,005	10,878,939	168,961,110
28	Total Firm Weather Gas (NW)	CCOSS AL:1 1	70,729,615	309,352	1,287,100	4,057,018	39,197,035	1,127,791	2,745,262	106,070	586,702	20,493,631	1,551,590	-	-	142,171,166
29	Total Firm Sales	CCOSS AL:1 3	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	3,179,948	999,179	29,674,103	3,929,848	-	-	209,261,703
30	Total Annual Sales	CCOSS AL:1 7	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	3,179,948	999,179	29,674,103	3,929,848	39,648,220	38,220,735	287,130,658
31	Total Peak Day Therms	CCOSS AL 2 4	6/ 1,175,408	5,965	21,896	68,738	715,260	20,762	57,943	-	10,202	355,142	31,300	-	11,492	2,474,108
32	Annual Customer Bills	CCOSS AL 3 1	7/ 1,627,379	131,084	42,794	53,982	40,679	12	22,135	32	7,177	20,485	10,430	1,327	36	1,957,552
33	**Variance (Total All Weather Gas)**	Ln. 27 - Ln. 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	**Variance (Total Firm Weather Gas (NW))**	Ln. 28 - Ln. 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	**Variance (Total Firm Sales)**	Ln. 29 - Ln. 10	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	**Variance (Total Annual Sales)**	Ln. 30 - Ln. 13	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	**Variance (Total Peak Day Therms)**	Ln. 22 - Ln. 31	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	**Variance (Annual Customer Bills)**	Ln. 32 - Ln. 26	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Washington Gas Light Company
District of Columbia Jurisdiction

Summary of Therm Sales Statistics Total

Based on 12 Months Ending Mar 2024

Line No.	Class Of Service	Actual Therms a/	<——Weather Gas——> Actual b/	Normal c/	Weather Adjustment	<——Base Gas——> Actual	Normal d/	Total Normal Weather Therm Sales	<——Peak Day——> Weather Gas e/	Base Gas f/	Total
	A	B	C	D	E=D-C	F=B-C	G	H=D+G	I	J	K=I+J
1	Residential										
2	Heating and Cooling	74,124,105	60,453,429	70,729,615	10,276,186	13,670,676	14,063,551	84,793,166	1,138,887	36,521	1,175,408
3	Non Heating and Non Cooling - IMA's	624,411	264,394	309,352	44,958	360,017	368,268	677,620	4,978	987	5,965
4	Non Heating and Non Cooling	1,480,156	1,100,079	1,287,100	187,021	380,077	416,434	1,703,534	20,770	1,126	21,896
5	Total - Residential	76,228,671	61,817,902	72,326,067	10,508,165	14,410,769	14,848,253	87,174,320	1,164,635	38,634	1,203,269
6											
7	Commercial and Industrial										
8	Heating and Cooling										
9	Less than 3075	4,671,124	3,467,503	4,057,018	589,515	1,203,621	1,279,120	5,336,138	65,270	3,468	68,738
10	More than 3075	61,303,846	33,508,268	39,197,035	5,688,767	27,795,578	29,657,369	68,854,404	633,771	81,489	715,260
11	Non Heating and Non Cooling	8,145,664	2,346,071	2,745,262	399,191	5,799,593	5,267,470	8,012,732	44,047	13,896	57,943
12	CHP	1,814,088	963,870	1,127,791	163,921	850,218	973,241	2,101,032	18,146	2,616	20,762
13	Total - Commercial and Industrial	75,934,721	40,285,712	47,127,106	6,841,394	35,649,009	37,177,200	84,304,306	761,234	101,469	862,703
14											
15	Group Metered Apartments										
16	Heating and Cooling										
17	Less than 3075	1,092,958	484,154	566,702	82,548	608,804	432,477	999,179	9,042	1,160	10,202
18	More than 3075	26,578,961	17,517,359	20,493,631	2,976,272	9,061,602	9,180,472	29,674,103	330,407	24,735	355,142
19	Non Heating and Non Cooling	3,756,632	1,326,063	1,551,590	225,527	2,430,569	2,378,258	3,929,848	24,953	6,347	31,300
20	Total - Group Metered Apartments	31,428,552	19,327,576	22,611,923	3,284,347	12,100,976	11,991,207	34,603,130	364,402	32,242	396,644
21											
22	Total Firm	183,591,944	121,431,190	142,065,096	20,633,906	62,160,754	64,016,660	206,081,756	2,290,271	172,345	2,462,616
23	Interruptible	37,706,690	13,597,776	15,911,005	2,313,229	24,108,914	23,916,786	39,827,791	254,561	63,953	318,514
24	Special Contracts	36,175,445	9,297,721	10,878,939	1,581,218	26,877,724	27,341,796	38,220,735	175,043	73,499	248,542
25	Total Throughput	257,474,080	144,326,687	168,855,040	24,528,353	113,147,393	115,275,242	284,130,282	2,719,875	309,797	3,029,672

a/ Schedule 1B, Column B
b/ Schedule 2A, Column F
c/ Schedule 2A, Column G
d/ Schedule 2A, Column I
e/ Schedule 2B, Column K - For Allocation Purposes Only
f/ Schedule 2B, Column L - For Allocation Purposes Only

Dates	CCF	BTU	TOTAL DSBB Therm Usage	Firm Usage Allowed, IN THERMS
1/1/2024		1.038	50,135.4	11,457.7
1/2/2024		1.041	49,447.5	11,489.1
1/3/2024		1.037	47,494.6	11,447.3
1/4/2024		1.037	53,509.2	11,447.0
1/5/2024		1.036	52,007.2	11,438.9
1/6/2024		1.037	49,153.8	11,446.3
1/7/2024		1.033	37,704.5	11,407.6
1/8/2024		1.034	48,184.4	11,411.0
1/9/2024		1.033	44,315.7	11,401.6
1/10/2024		1.036	47,138.0	11,440.8
1/11/2024		1.037	46,146.5	11,453.9
1/12/2024		1.032	43,240.8	11,392.3
1/13/2024		1.031	48,044.6	11,386.6
1/14/2024		1.036	53,457.6	11,434.5
1/15/2024		1.039	55,482.6	11,473.1
1/16/2024		1.040	62,920.0	11,484.5
1/17/2024		1.035	60,146.0	11,422.5
1/18/2024		1.041	54,756.6	11,491.5 ①
1/19/2024		1.035	60,133.5	11,425.4
1/20/2024		1.039	63,067.3	11,469.0
1/21/2024		1.036	61,952.8	11,436.2
1/22/2024		1.035	57,546.0	11,427.3
1/23/2024		1.037	49,464.9	11,446.5
1/24/2024		1.034	46,013.0	11,417.0
1/25/2024		1.027	42,004.3	11,341.1
1/26/2024		1.026	39,808.8	11,329.4
1/27/2024		1.031	41,549.3	11,381.7
1/28/2024		1.033	44,315.7	11,401.8
1/29/2024		1.033	47,827.9	11,408.5
1/30/2024		1.035	49,369.5	11,431.4
1/31/2024		1.034	50,045.6	11,415.0

Washington Gas Light Company
District of Columbia Jurisdiction

Summary of Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Class Of Service	Meters	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual a/	Normal Weather b/	Weather Adjustment	Base Gas c/	Total
	A	B	C	D	E	F	G	H=G-F	I	J=H+I
1	Residential									
2	Heating and Cooling	1,627,379 ①	3,187	3,729	0.1397740	60,453,429	70,729,615	10,276,186	14,063,551	84,793,166
3	Non Heating and Non Cooling - IMA's	131,084	3,187	3,729	0.0076190	264,394	309,352	44,958	368,268	677,620
4	Non Heating and Non Cooling	42,794	3,187	3,729	0.0965330	1,100,079	1,287,100	187,021	416,434	1,703,534
5	Total - Residential	1,801,257				61,817,902	72,326,067	10,508,165	14,848,253	87,174,320
6										
7	Commercial and Industrial									
8	Heating and Cooling									
9	Less than 3075	53,982	3,187	3,729	0.2397700	3,467,503	4,057,018	589,515	1,279,120	5,336,138
10	More than 3075	40,679	3,187	3,729	3.0813470	33,508,268	39,197,035	5,688,767	29,657,369	68,854,404
11	Non Heating and Non Cooling	22,135	3,187	3,729	0.3998460	2,346,071	2,745,262	399,191	5,267,470	8,012,732
12	CHP	12	3,187	3,729	302.4376000	963,870	1,127,791	163,921	973,241	2,101,032
13	Total - Commercial and Industrial	116,808				40,285,712	47,127,106	6,841,394	37,177,200	84,304,306
14										
15	Group Metered Apartments									
16	Heating and Cooling									
17	Less than 3075	7,177	3,187	3,729	0.2524320	484,154	566,702	82,548	432,477	999,179
18	More than 3075	20,485	3,187	3,729	3.2184570	17,517,359	20,493,631	2,976,272	9,180,472	29,674,103
19	Non Heating and Non Cooling	10,430	3,187	3,729	0.4780260	1,326,063	1,551,590	225,527	2,378,258	3,929,848
20	Total - Group Metered Apartments	38,092				19,327,576	22,611,923	3,284,347	11,991,207	34,603,130
21										
22	Total Firm	1,956,157				121,431,190	142,065,096	20,633,906	64,016,660	206,081,756
23	Interruptible	1,327	3,187	3,729	38.56989	13,597,776	15,911,005	2,313,229	23,916,786	39,827,791
24	Special Contracts	36	3,187	3,729	d/	9,297,721	10,878,939	1,581,218	27,341,796	38,220,735
25	Total Throughput	1,957,520				144,326,687	168,855,040	24,528,353	115,275,242	284,130,282
		163,127								

a/ Schedule 2B, Column F
b/ Schedule 2B, Column G
c/ Schedule 2B, Column I
d/ Schedule 2B for noted classes

Washington Gas Light Company
Normal Weather Therm Sales Analysis

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Sc-Pg-Ln	—— Reference —— Class Allocator	Cost Category	District of Columbia Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH
	A	B	C	D	E	F	G	H
1	TOTAL FIRM WEATHER GAS - NW	NW Study + SAP			142,171,186	70,729,615	309,352	1,287,100
2			Firm_Weather_NW	Demand	1.0000	0.4975	0.0022	0.0091
3	TOTAL FIRM THERM SALES - NW	NW Study + SAP			209,261,703	84,793,186	677,820	1,703,534
4			Annual_ Firm_ NW	Demand	1.0000	0.4052	0.0032	0.0081
5	TOTAL ALL WEATHER GAS	NW Study + SAP			168,961,130	70,729,615	309,352	1,287,100
6			Total_Weather_All_NW	Demand	1.0000	0.4186	0.0018	0.0076
7	TOTAL ANNUAL THERM SALES	Revenue Study + SAP			287,130,658	84,793,186	677,820	1,703,534
8	Factor for Total Annual Therms		Annual_Total_NW	Demand	1.0000	0.2953	0.0024	0.0060
9	Deductions for Pipeline:							
10	Propane Holding	AL 1 2	Firm _Weather_NW		-	-	-	-
11	Propane Gasified	AL 1 2	Firm _Weather_NW		-	-	-	-
12	Total Pipeline Deductions	Ln. 10 + Ln. 11			-	-	-	-
13	ANNUAL THERMS ADJUSTED	Ln. 7 - Ln. 12			287,130,658	84,793,186	677,820	1,703,534
14	Factor for Annual Therms Adj.		Pipeline_NW	Demand	1.0000	0.2953	0.0024	0.0060
15	FIRM ANNUAL PIPELINE	Ln. 3 - Ln. 12			209,261,703	84,793,186	677,820	1,703,534
16	Factor for Firm Annual Pipeline		Firm_Pipe_ Ann_ Adj	Demand	1.0000	0.40520	0.00324	0.00814

	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NOV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	I	J	K	K	L	M	N	O	P	Q
1	4,057,018	39,197,036	1,127,791	2,745,262	108,070	566,702	20,483,831	1,551,980	-	-
2	0.0286	0.2757	0.0079	0.0193	0.0007	0.0040	0.1441	0.0109	-	-
3	5,338,138	68,854,404	2,101,032	8,012,732	3,179,946	999,179	29,674,103	3,929,846	-	-
4	0.0255	0.3290	0.0100	0.0383	0.0152	0.0048	0.1418	0.0188	-	-
5	4,057,018	39,197,036	1,127,791	2,745,262	108,070	566,702	20,483,831	1,551,980	15,911,006	10,878,938
6	0.0240	0.2320	0.0067	0.0162	0.0006	0.0034	0.1213	0.0092	0.0942	0.0644
7	5,338,138	68,854,404	2,101,032	8,012,732	3,179,946	999,179	29,674,103	3,929,846	39,648,220	38,220,735
8	0.0186	0.2398	0.0073	0.0279	0.0111	0.0036	0.1033	0.0137	0.1381	0.1331
9										
10	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-
13	5,338,138	68,854,404	2,101,032	8,012,732	3,179,946	999,179	29,674,103	3,929,846	39,648,220	38,220,735
14	0.0186	0.2398	0.0073	0.0279	0.0111	0.0036	0.1033	0.0137	0.1381	0.1331
15	5,338,138	68,854,404	2,101,032	8,012,732	3,179,946	999,179	29,674,103	3,929,846	-	-
16	0.02550	0.32903	0.01004	0.03829	0.01520	0.00477	0.14180	0.01878	-	-

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Washington Gas Light Company
Normal Weather Therm Sales Analysis

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Sc-Pg-Ln	------ Reference ----- Class Allocator	Cost Category	District of Columbia Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	E	F	G	H	I	J	K	K	L	M	N	O	P	Q
1	Peak Day Therm Sales- Normal Weather																	
2	Weather Gas	NW Study			2,290,271	1,138,887	4,978	20,770	65,270	633,771	18,146	44,047		9,042	330,407	24,953	-	-
3	Base Gas	NW Study			183,837	36,521	987	1,126	3,468	81,489	2,616	13,896		1,160	24,735	6,347	-	11,492
4	Total Peak Day Therms	Ln. 2 + Ln. 3			2,474,108	1,175,408	5,965	21,896	68,738	715,260	20,762	57,943	-	10,202	355,142	31,300	-	11,492
5			Peak_Day_Total	Demand	1.0000	0.4751	0.0024	0.0089	0.0278	0.2891	0.0084	0.0234	-	0.0041	0.1435	0.0127	-	0.0046
6	**PEAK DAY AND ANNUAL SALES**																	
7	**Factor for Peak Day & Annual Sales (Firm)**	1/	**Comp_Peak_ Ann_NW**	**Demand**	**1.0000**	**0.3510**	**0.0023**	**0.0068**	**0.0212**	**0.2464**	**0.0073**	**0.0246**	**0.0060**	**0.0035**	**0.1138**	**0.0125**	**0.1036**	**0.1010**
8	**Development of Non-Firm Peak Day Usage:**																	
9	Therm Sales in the Peak Month				6,677,977												4,517,811	2,160,167
10	Number of Customers in Peak Month				108												105	3
11	Average Therm Sales in Peak Month	Ln. 9 / Ln. 10			61,833												43,027	720,056
12	Number of Days in Peak Month				31												31	31
13	Average therms per Day	Ln. 11 / Ln. 12			1,995												1,388	23,228
14	Average Number of Customers				114												111	3
15	**Total Non-Firm Peak Day Usage**	Ln. 13 * Ln. 14			226,555												153,485	69,683
16	Residential - Peak Day Therms				1,203,269	1,175,408	27,861											
17	Residential Customers in Peak Month				150,277	135,801	14,476											
18	Peak Usage Per Customer Per Day	Ln. 16 / Ln. 17			8	9	2											
19	Peak Day Therms Firm Non-Residential	NW Study			1,259,347				68,738	715,260	20,762	57,943	-	10,202	355,142	31,300		
20	Peak Day Therms - Non-Firm	NW Study			223,168												153,485	69,683
21	Total Peak Day Therms Firm N/R & Non-Firm	Ln. 19 + Ln. 20			1,482,515				68,738	715,260	20,762	57,943	-	10,202	355,142	31,300	153,485	69,683
22	Average Customer Bills Non Res. or Non-Firm				13,025				4,499	3,390	1	1,845	3	598	1,707	869	111	3
23	Peak Usage Per Customer Per Day	Ln. 18			8				8	8	8	8	8	8	8	8	8	8
24	Peak Day Adjustment	Ln. 22 * Ln. 23			104,288			-	36,020	27,143	8	14,770	21	4,789	13,669	6,959	885	24
25	Peak Day Adjustec	Ln. 21 - Ln. 24			1,135,236			-	32,718	688,117	-	43,173	-	5,413	341,473	24,341	-	-
26	**Peak Day Adjusted**		**Peak Day Adjusted**	**Demand**	**1.0000**			**-**	**0.0288**	**0.6061**	**-**	**0.0380**	**-**	**0.0048**	**0.3008**	**0.0214**	**-**	**-**
27	Delivery Customers (12 Month Total)	NWS			255,936	172,231	8,664	6,531	8,837	16,864	16,864	7,386		1,571	11,162	4,463	1,327	36
28	Delivery Customers (12 Month Average)	Ln. 27 / 12			21,328	14,353	722	544	736	1,405	1,405	616	-	131	930	372	111	3
29	**Delivery Customers Only Factor**		**Delv_Cust**	**Customer**	**1.0000**	**0.6729**	**0.0339**	**0.0255**	**0.0345**	**0.0659**	**0.0659**	**0.0289**	**-**	**0.0061**	**0.0436**	**0.0174**	**0.0052**	**0.0001**

1/ For interruptible and special contract classes, the split is 25% peak usage and 75% annual usage. For all firm classes, the composite peak & annual factor is a 50/50 split between peak and annual after considering the amounts allocated to interruptible and special contract classes.
Interruptible & Special Contract Factors = [75% * annual usage peak usage by class] + [25% peak usage by class]
Firm Factors = [1 - Interruptible Factor - Special Contract Factor] * [(Class Annual Therms /(Total Annual Therms - Interruptilbe Annual Therms - Special Contract Annual Therms)*.5) + (Class Peak Therms /(Total Peak Therms - Interruptilbe Peak Therms - Special Contract Peak Therms)*.5)]

Schedule AL Page 2

Washington Gas Light Company
Allocation Factors Based on Other Elements

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Sc-Pg-Ln	—— Reference —— Class Allocator	Cost Category	District of Columbia Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	E	F	G	H	I	J	K	K	L	M	N	O	P	Q
1	Annual Customer Bills	MW Study			1,957,552	1,627,379	131,084	42,794	53,862	40,679	12	22,136	32	7,177	20,486	10,430	1,327	36
2	Months				12	12	12	12	12	12	12	12	12	12	12	12	12	12
3	Annual Average Customers Bills	Ln. 1 / Ln. 2			163,129	135,615	10,924	3,566	4,489	3,390	1	1,845	3	598	1,707	869	111	3
4	Annual Average Customers Bill Allocators		Ave_Customer _Bill	Customer	1.0000	0.8313	0.0670	0.0219	0.0275	0.0208	0.0000	0.0113	0.0000	0.0037	0.0105	0.0053	0.0007	0.0000
5	Multiple Customers at Common Address				58,775	42,392	10,444	482	1,672	1,260	-	1,116	-	509	379	436	85	-
6	Services Applicable to Common Address Customers				11,326	8,434	1,043	119	549	414	-	309	-	73	209	142	34	0
7	Net Customers at Common Addresses	Ln. 5 - Ln. 6			47,449	33,958	9,401	363	1,123	846	-	807	-	436	170	294	51	-
8	Aver. No. of Customers adjusted for multiple bills (All)	Ln. 3 - Ln. 7			115,681	101,657	1,523	3,203	3,376	2,544	1	1,038	3	162	1,537	575	60	3
9	Allocators for Aver # of Customers after Adj'nt (All)		Ave_Customer _Bill_Adj	Customer	1.0000	0.8788	0.0132	0.0277	0.0292	0.0220	0.0000	0.0090	0.0000	0.0014	0.0133	0.0050	0.0005	0.0000
10	Aver. No. of Customers adjusted for multiple bills (Firm)	Ln. 8 Excl Col. O & P			115,617	101,657	1,523	3,203	3,376	2,544	-	1,038	3	162	1,537	575	-	-
11	Allocators for Aver # of Customers after Adj'nt (Firm)		Firm_Cust_Bill_Adj	Customer	1.0000	0.8793	0.0132	0.0277	0.0292	0.0220	-	0.0090	0.0000	0.0014	0.0133	0.0050	-	-
12	Fee Free Credit By Tariff Class Allocator	Analysis				0.9650	0.9650	0.9650	0.0298	0.0298	0.0298	0.0256	0.0298	0.0083	0.0083	0.0083	0.0002	-
13	Fee Free Credit By Rate Class	Ln. 12 * Ratio Ln. 9				0.8986	0.0143	0.0301	0.4649	0.3855	0.0001	0.1461	0.0004	0.0714	0.6756	0.2530	1.0000	-
14	Fee Free Credit Allocator	Ln. 12 * Ln. 13	Fee_Free_Credit	Customer	1.0000	0.8230	0.0136	0.0291	0.0124	0.0084	0.0000	0.0036	0.0000	0.0006	0.0064	0.0021	0.0002	-

1

- Non-Rate Class Analysis

CUBE:	**tm1serv:Rate Statistics DB**
RS_ACTUAL_AREA	**DC**
RS_ACTUAL_TYPE	*Obtained Below*
RS_ACTUAL_CLASS	*Obtained Below*
RS_ACTUAL_LEVEL	**Total System Level**
RS_ACTUAL_PERIOD	*Obtained Below*

	Apr-2023	May-2023	Jun-2023	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024
Winter Month Indicator	X							X	X	X	X	X
Therms Delivered Adjusted												
NGV_D	274,004	230,311	274,106	301,340	68,465	537,256	248,358	267,804	241,983	260,199	235,674	240,448
NGV_S	-	-	-	-	-	-	-	-	-	-	-	-
Billing Adjustment												
DC TOTAL	274,004	230,311	274,106	301,340	68,465	537,256	248,358	267,804	241,983	260,199	235,674	240,448
Months Billed Adjusted												
NGV_D	2	2	1	2	3	1	3	2	2	1	10	3
NGV_S	-	-	-	-	-	-	-	-	-	-	-	0
Billing Adjustment												
DC TOTAL	2	2	1	2	3	1	3	2	2	1	10	3

Heating Season Therms (Nov - Apr)	1,520,112	**A**
Minimum Usage in Heating Season	235,674	**B**
Months in Heating Season	6	**C**
Base Gas in Heating Season	1,414,042	**D = B * C**
Weather Gas Therms	106,070	**E = A - D** 1
Total Therms (TME Mar-2024)	3,179,948	1
NGV Months Billed	32	1

Washington Gas Light Company
System

Interruptible Curtailment Calculation

Based on 12 Months Ending Mar 2024

		Base Gas					Weather Gas								Total
Line No.	Interruptible Customers	Base Gas Therms b/ Jan-2024	Base Gas Therms b/ Feb-2024	Base Gas Therms b/ Total	Curtailment Days /a	Curtailment Therms	Heating HDD's Jan-2024	Heating HDD's Feb-2024	Heating HDD's Total	Curtailment Days	Curtailment HDDs	Avg number Customers	Variation per HDD	Curtailment Therms	Total Curtailment Therms
	A	B	C	D=B+C	E	F= (E / 59) x D	G	H	I=G+H	J /a	K= (I / 59) x J	L	M	N=KxLxM	O=F+N
1	District of Columbia	1,982,552	1,964,529	3,947,081	1	66,900	763	811	1,574	1	26.6779661	109.50	38.5698900	112,672	**179,571** 1
2	Maryland	8,156,991	8,193,741	16,350,732	1	277,131	757	812	1,569	1	26.5932203	134.00	40.7933900	145,367	**422,498**
3	Virginia	2,537,942	2,545,671	5,083,614	1	86,163	757	812	1,569	1	26.5932203	108.00	28.4013200	81,571	**167,733**

/a : Curtailment days based on a Ten Year average
/b : Average of usage for July and August used for Shenandoah

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost Study Workpaper 4.2 - Reconciliation of Ratemaking Base Rate Revenues

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract	Total
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O = Sum (C>N)
1	Sales of Gas to Customers														
2	Revenue Study - Test Period	Adj. No. 1 3/	$ 90,772,700	$ 2,149,044	$ 1,990,531	$ 6,011,562	$ 51,786,411	$ 937,789	$ 6,353,599	$ 915,815	$ 22,542,271	$ 3,077,593	$ 16,025,194	$ 15,287,409	$ 217,849,918
3	Forecasted Growth (Interim Period & Rate Year)	Adj. No. 6	-	-	-	-	-	-	-	-	-	-	-	-	-
4	**Total Sales of Gas to Customers (RV:1:2)**	Ln. 2 + Ln. 3	**$ 90,772,700**	**$ 2,149,044**	**$ 1,990,531**	**$ 6,011,562**	**$ 51,786,411**	**$ 937,789**	**$ 6,353,599**	**$ 915,815**	**$ 22,542,271**	**$ 3,077,593**	**$ 16,025,194**	**$ 15,287,409**	**$ 217,849,918**
5	Total Sales of Gas to Customers	CCOSS RV:1:2 2/	$ 90,772,694	$ 2,149,044	$ 1,990,531	$ 6,011,562	$ 51,786,411	$ 937,789	$ 6,353,599	$ 915,815	$ 22,542,271	$ 3,077,593	$ 16,025,194	$ 15,287,409	
6	**Variance**	Ln. 5 - Ln. 4	(7)	-	-	-	-	-	-	-	-	-	-	-	

Exhibit WG (F)-5
Schedule F
Page 2 of 3

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Revenues

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	------ Reference ----- Sc-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	M	N	O	P	Q	R	S
1	**Operating Revenues**																	1
2	Sales of Gas to Customers _1/	Financial Stmt.	**Revenue Study**	Comp TCS	**$ 217,849,912**	$ 90,772,694	$ 2,149,044	$ 1,990,531	$ 6,011,562	$ 51,786,411	$ 937,789	$ 6,353,599		$ 915,815	$ 22,542,271	$ 3,077,593	$ 16,025,194	$ 15,287,409
3	**Line 2 - Percentage of Total**		**Gas_Sales_Revenue**		**1.0000**	**0.4167**	**0.0099**	**0.0091**	**0.0276**	**0.2377**	**0.0043**	**0.0292**	**-**	**0.0042**	**0.1035**	**0.0141**	**0.0736**	**0.0702**
4	Total Gas Sales Revenue excluding Non Firm	Ln. 3 - Ln. 3 Col. N.			**$ 186,537,309**	90,772,694	2,149,044	1,990,531	6,011,562	51,786,411	937,789	6,353,599	-	915,815	22,542,271	3,077,593	-	-
5	**Line 4 - Percentage of Total**		**Gas_Sales_Ex_Non_Firm**		**1.0000**	**0.4866**	**0.0115**	**0.0107**	**0.0322**	**0.2776**	**0.0050**	**0.0341**	**-**	**0.0049**	**0.1208**	**0.0165**	**-**	**-**
6	Rate Adjustment Due Customers	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Unbilled Gas Accrual/Reversal	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Provision for Rate Refunds	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total Gas Sales	Lns. 6 > 8			**$ 217,849,912**	$ 90,772,694	$ 2,149,044	$ 1,990,531	$ 6,011,562	$ 51,786,411	$ 937,789	$ 6,353,599	$ -	$ 915,815	$ 22,542,271	$ 3,077,593	$ 16,025,194	$ 15,287,409
10	Other Operating Revenues																	
11	Forfeited Discounts (Non POR)	Billing System	Direct	Comp TCS	**3,784,772**	2,513,060	48,403	51,673	52,841	437,119	6,148	59,138	13,292	12,498	377,815	54,015	158,769	-
12	Forfeited Discounts (POR)	Billing System	Direct	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rent from Gas Property	RV:1:3	Gas_Sales_Revenue	Comp TCS	**98,600**	41,084	973	901	2,721	23,439	424	2,876	-	415	10,203	1,393	7,253	6,919
14	Rental Income from WGCC/Maritime/ACI	AL:1:4	Annual_ Firm_ NW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Miscellaneous Service Revenues																	
16	Reconnect Revenues	Billing System	Direct	Customer	**174,354**	162,876	3,137	3,349	441	3,647	51	493		(1)	(38)	(5)	405	-
17	Dishonored Check Charge	Billing System	Direct	Customer	**44,740**	38,759	747	797	339	2,805	39	379		23	696	100	54	-
18	Service Initiation Charge	Billing System	Direct	Customer	**838,570**	775,705	14,941	15,950	2,601	21,518	303	2,911		121	3,658	523	338	-
19	Field Collection Charge	Billing System	Direct	Customer	**433**	139	3	3	27	227	3	31		-	-	-	-	-
20	IRATE Non Compliance MTR Charge	Billing System	Direct	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Other Gas Revenues																	
22	Watergate Revenues	Financial Stmt.	Direct	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Third Party Balancing Charges	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	CNG Sales for Natural Gas Vehicles	AL:6:46	C&I Other	Customer	**847,959**	-	-	-	-	-	-	-	847,959	-	-	-	-	-
25	Off System Sales Revenue Net of Gas Cost	RV:1:5	Gas_Sales_Ex_Non_Firm	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Miscellaneous Revenues																	
27	Other Allocable Miscellaneous	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Oth Gas Rev - MD RM-35	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Third Party Billing	AL:2:29	Delv_Cust	Customer	**114,447**	77,016.60	3,874	2,920	3,952	7,541	7,541	3,303	-	703	4,991	1,996	593	16
30	Firm Margin Sharing Adjustment	RV:1:3	Gas_Sales_Revenue	Comp TCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total Other Operating Revenues	Ln. 22 > Ln. 30			**5,903,875**	$ 3,608,640	$ 72,077	$ 75,593	$ 62,922	$ 496,297	$ 14,510	$ 69,132	$ 861,251	$ 13,757	$ 397,326	$ 58,021	$ 167,413	$ 6,935
32	Total Operating Revenues	Ln. 9 + Ln. 31			**$ 223,753,787**	$ 94,381,333	$ 2,221,121	$ 2,066,124	$ 6,074,484	$ 52,282,708	$ 952,299	$ 6,422,731	$ 861,251	$ 929,572	$ 22,939,597	$ 3,135,614	$ 16,192,607	$ 15,294,344
33	**Line 32 Percentage of Total Revenues**		**Total_Revenues**		**1.0000**	**0.4218**	**0.0099**	**0.0092**	**0.0271**	**0.2337**	**0.0043**	**0.0287**	**0.0038**	**0.0042**	**0.1025**	**0.0140**	**0.0724**	**0.0684**

_1/ Transportation Sales, which are reported separately in the PBCOSA, are included in the "Sales of Gas to Customers" line in the class cost study for purposes of determining allocation factor "Gas_Sales_Revenue".

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment 1 Workpaper 7 - Ratemaking Revenues

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Total DC	Residential			Commercial & Industrial				Group Metered Apartments			Non-Firm	Special Contracts
				Htg/Clg	Non-htg-IMA	Non-htg-Other	H/C < 3075	H/C > 3075	CHP	Non-htg	H/C < 3075	H/C >3075	Non-htg		
	A	B	C=D...M	D	E	F	G	H	I	J	K	L	M	N	O
1	Normal Weather Therms	Norm Wthr 1/	283,950,711	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	999,179	29,674,103	3,929,848	39,648,220 5/	38,220,735
2	Distribution Charge Revenues														
3	Distribution Charges	DC Tariff		$ 0.5638	$ 0.6610	$ 0.6390	$ 0.5821	$ 0.4796	$ 0.1033	$ 0.4811	$ 0.4930	$ 0.4863	$ 0.4641	6/	4/
4	Distribution Charge Revenues	Line 1 x Line 3	$ 122,242,327	$ 47,806,387	$ 447,907	$ 1,088,558	$ 3,106,166	$ 33,022,572	$ 217,037	$ 3,854,925	$ 492,595	$ 14,430,516	$ 1,902,440	$ 8,087,394	$ 7,785,830
5	Customer Charge Revenues														
6	Customer Bills or Units	Analysis 3/	1,957,520	1,627,379	131,084	42,794	53,982	40,679	12	22,135	7,177	20,485	10,430	1,327	36
7	Customer Charges	DC Tariff		$ 16.55	$ 12.00	$ 13.55	$ 29.90	$ 70.05	$ 343.75	$ 28.50	$ 28.50	$ 70.05	$ 28.50	$ 121.00	$ 121.00
8	Customer Charge Revenues	Line 6 x Line 7	$ 36,286,285	$ 26,933,122	$ 1,573,008	$ 579,859	$ 1,614,062	$ 2,849,564	$ 4,125	$ 630,848	$ 204,545	$ 1,434,974	$ 297,255	$ 160,567	$ 4,356
9	Peak Usage Charge Revenues														
10	Therms from Maximum Usage Month	Norm Wthr 1/	16,621,656	N/A	N/A	N/A	785,545	9,533,168	280,694	1,166,597	115,023	4,209,429	531,201	N/A	-
11	Peak Usage Charge per Therm	DC Tariff		$ -	$ -	$ -	$ 0.0519	$ 0.0421	$ 0.0904	$ 0.0423	$ 0.0431	$ 0.0422	$ 0.0423	$ -	$ -
12	November through April Charge	6 Months		-	-	-	6	6	12	6	6	6	6	-	6
13	Peak Usage Charge Revenues	Line 10 x Line 11 x Line 12	$ 4,483,667	$ -	$ -	$ -	$ 244,619	$ 2,406,078	$ 304,497	$ 296,082	$ 29,745	$ 1,065,827	$ 134,819	$ -	$ -
14	Total Base Rate Revenues	Sum of Lines 4, 8, and 13	$ 163,012,279	$ 74,739,509	$ 2,020,915	$ 1,668,417	$ 4,964,847	$ 38,280,214	$ 525,659	$ 4,781,855	$ 726,885	$ 16,931,317	$ 2,334,514	$ 8,247,961	$ 7,790,186
15	DC Rights of Way Fee Revenues														
16	DC Rights of Way Fee per Therm	Analysis		$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349
17	DC Rights of Way Fee Revenues	Line 1 x Line 16	$ 9,909,879	$ 2,959,281	$ 23,649	$ 59,453	$ 186,231	$ 2,403,019	$ 73,326	$ 279,644	$ 34,871	$ 1,035,626	$ 137,152	$ 1,383,723	$ 1,333,904
18	Delivery Tax Revenues														
19	Delivery Tax Rate Per Therm			$ 0.07070	$ 0.07070	$ 0.07070	$ 0.07777	$ 0.07777	$ 0.07777	$ 0.07777	$ 0.07070	$ 0.07070	$ 0.07070	$ 0.07777	$ 0.07777
20	Delivery Tax Revenues	Line 1 x Line 19	$ 21,221,880	$ 5,994,877	$ 47,908	$ 120,440	$ 414,991	$ 5,354,807	$ 163,397	$ 623,150	$ 70,642	$ 2,097,959	$ 277,840	$ 3,083,442	$ 2,972,427
21	Sustainable Energy Trust Fund Revenues														
22	Sustainable Energy Trust Fund Rate Per Therm			$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515
23	Sustainable Energy Trust Fund Revenues	Line 1 x Line 22	$ 21,338,896	$ 6,372,206	$ 50,923	$ 128,021	$ 401,011	$ 5,174,408	$ 157,893	$ 602,157	$ 75,088	$ 2,230,009	$ 295,328	$ 2,979,564	$ 2,872,288
24	Energy Assistance Trust Fund Revenues														
25	Energy Assistance Trust Fund Rate Per Therm			$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834
26	Energy Assistance Trust Fund Revenues	Line 1 x Line 25	$ 2,366,984	$ 706,827	$ 5,649	$ 14,200	$ 44,482	$ 573,963	$ 17,514	$ 66,793	$ 8,329	$ 247,360	$ 32,759	$ 330,504	$ 318,604
27	Total Non-gas Revenues	Sum of Lines 14, 17, 20, 23, and 26	$ 217,849,916	$ 90,772,700	$ 2,149,044	$ 1,990,531	$ 6,011,562	$ 51,786,411	$ 937,789	$ 6,353,599	$ 915,815	$ 22,542,271	$ 3,077,593	$ 16,025,194	$ 15,287,409 1
28	Purchased Gas Charge Revenues	2/													
29	Purchased Gas Charge	Page 23, Line 12		$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ -	$ 0.6018
30	Purchased Gas Charge Revenues	DC Rev by Class, Line 20 x Line 29	$ 73,743,790	$ 44,727,004	$ 359,630	$ 888,042	$ 2,624,191	$ 15,630,650	$ -	$ 1,983,757	$ 404,664	$ 6,187,304	$ 938,548	$ -	$ -
31	Total Sales/Delivery of Gas Revenues	Line 27 + Line 30	$ 291,593,706	$ 135,499,704	$ 2,508,674	$ 2,878,573	$ 8,635,753	$ 67,417,061	$ 937,789	$ 8,337,356	$ 1,320,479	$ 28,729,575	$ 4,016,141	$ 16,025,194	$ 15,287,409

1/ Amounts referenced as "Norm Wthr" come from the Normal Weather Study.
2/ Purchased gas revenues are not carried forward for ratemaking purposes.
3/ Amounts referenced as "Norm Wthr" come from the Normal Weather Study and are the meter totals for the referenced period.
4/ Includes AOC and GSA distribution revenues.
5/ Includes a curtailment amount of 179571 therms.
6/ Distribution charge revenue for interruptible customers are outlined below.

Exhibit WG (F)-5
Schedule F
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Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost Study Workpaper 5 - Reconciliation of Class Cost Rate Making Amount to Rate Making Pro Forma (RMPF) File

Twelve Months Ended March 31, 2024

Line No.	Desciption A	Reference B	90.90% RMPF C	100% RMPF D	Variance E = C - D	Class Cost F	Variance CC to RMPF G = F - D
1	**Operating Revenues**		2/ **211,627,531**	4/ **223,753,787**	6/ **12,126,256**	5/ **223,753,787**	-
2	Operating Expenses						
3	Operation		56,816,665	57,139,031	322,366	57,139,032	1
4	Maintenance		25,925,811	25,925,811	-	25,925,812	1
5	Depreciation		31,830,254	31,830,254	-	31,830,254	0
6	Amortization of General Plant		1,878,281	1,878,281	-	1,878,281	-
7	Amortization of Capitalized Software		3,659,183	3,659,183	-	3,659,183	-
8	Amortization of Unrecovered Plant Loss		100,274	100,274	-	100,274	-
9	Interest on Customer Deposits		77,084	77,084	-	77,084	-
10	Interest on Supplier Refunds		-	-	-	-	-
11	General Taxes		63,436,331	63,436,331	-	63,436,330	(1)
12	**Expenses Before Income Taxes**	**Ln. 2 > Ln. 11**	**183,723,884**	**184,046,250**	**322,366**	**184,046,251**	**1**
13	Income Taxes		614,762	3,857,393	3,242,630	3,857,393	0
14	**Total Operating Expenses**	**Ln. 12 + Ln. 13**	**184,338,646**	**187,903,642**	**3,564,996**	**187,903,644**	**2**
15	**Net Operating Income**	**Ln. 1 - Ln. 14**	**27,288,885**	**35,850,145**	**8,561,260**	**35,850,143**	**(2)**
16	Net Income Adjustments						
17	AFUDC		467,443	467,443	-	467,443	-
18	LCP Equity Accrual		-	-	-	-	-
19	**Net Operating Income - Adjusted**	**Ln. 15 > Ln. 18**	**27,756,328**	**36,317,588**	**8,561,260**	**36,317,586**	**(2)**
20	**Net Rate Base**		**760,992,964**	**761,839,660**	**846,696**	**761,839,660**	-

Notes:
_1/ For purposes of calculating revenues from firm customers and the revenue requirement, 90.9% of interruptible customer revenues is included. For purposes of determining class returns for all customer classes in the class cost study, 100% of interruptible revenue is included.

Washington Gas Light Company
District of Columbia Jurisdiction

Income Statement and Rate of Return Summary

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Books C	Distribution Adjustments D	Distribution Amounts E = C + D	Ratemaking Adjustments F	Ratemaking Amounts G = E + F	Revenue Deficiency H	ROE Amounts I = G + H
1	Operating Revenues	Adj List Pg 1, Ln. 11	$ 276,904,880 3/	$ (84,692,285)	$ 192,212,595	$ 19,414,936	$ 211,627,531 1	$ 45,572,411	$ 257,199,942
2	Operating Expenses								
3	Operation	Adj List Pg 1, Ln. 41	$ 125,293,859	$ (68,209,263)	$ 57,084,597	$ (267,932)	$ 56,816,665	$ 1,200,094	$ 58,016,759
4	Maintenance	Adj List Pg 1, Ln. 20	25,568,839	-	25,568,839	356,972	25,925,811	-	25,925,811
5	Depreciation	Adj List Pg 1, Ln. 44	23,907,431	-	23,907,431	7,922,823	31,830,254	-	31,830,254
6	Amortization of General Plant	Per Books	1,878,281	-	1,878,281	-	1,878,281	-	1,878,281
7	Amortization of Capitalized Software	Adj List Pg 1, Ln. 45	3,757,163	(97,980)	3,659,183	-	3,659,183	-	3,659,183
8	Amortization of Unrecovered Plant Loss	Per Books	100,274	-	100,274	-	100,274	-	100,274
9	Interest on Customer Deposits	Adj List Pg 1, Ln. 48	41,769	-	41,769	35,315	77,084	-	77,084
10	Interest on Supplier Refunds	Per Books	11,533	(11,533)	-	-	-	-	-
11	General Taxes	Adj List Pg 2, Ln. 7	58,992,535	-	58,992,535	4,443,796	63,436,331	-	63,436,331
12	Expenses Before Income Taxes	Sum of Lns. 3 > 11	$ 239,551,685	$ (68,318,776)	$ 171,232,910	$ 12,490,974	$ 183,723,884	$ 1,200,094	$ 184,923,978
13	Income Taxes	Adj List Pg 2, Ln. 10	3,537,493	(3,089,477)	448,015	166,747	614,762	12,210,152	12,824,914
14	Total Operating Expenses	Sum of Lns. 12 + 13	$ 243,089,178	$ (71,408,253)	$ 171,680,925	$ 12,657,721	$ 184,338,646	$ 13,410,246	$ 197,748,892
15	Net Operating Income	Ln. 1 - Ln. 14	$ 33,815,702	$ (13,284,032)	$ 20,531,669	$ 6,757,215	$ 27,288,885	$ 32,162,165	$ 59,451,050
16	Net Income Adjustments								
17	AFUDC	Per Books	467,443	-	467,443	-	467,443	-	467,443
18	Net Operating Income - Adjusted	Sum of Ln.s 15 > 17	$ 34,283,145	$ (13,284,032)	$ 20,999,112	$ 6,757,215	$ 27,756,328	$ 32,162,165	$ 59,918,493
19	Net Rate Base	Rate Base Stmt, Ln.23	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (35,183,527)	$ 760,992,964	$ -	$ 760,992,964
20	Return Earned	Ln. 18 / Ln. 19	4.22%		2.64%		3.65%		7.87%
21	Return on Common Equity								
22	Interest Expense		$ 19,142,496	$ (330,939)	$ 18,811,557	$ (831,295)	$ 17,980,262		$ 17,980,262
23	Net Income Available for Common Equity	Ln. 18 - Ln. 22	$ 15,140,649		$ 2,187,555		$ 9,776,066		$ 41,938,231
24	Common Equity Ratio	Cost of Capital, Ln. 3	52.49%		52.49%		52.49%		52.49%
25	Common Equity Capital	Ln. 19 * Ln. 24	$ 426,291,579		$ 417,878,033		$ 399,411,746		$ 399,411,746
26	Return Earned on Common Equity	Ln. 23 / Ln. 25	3.55%		0.52%		2.45%		10.50%

Washington Gas Light Company
Income Statement Summary -- Combined
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG

	Description	------ Reference ------ Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Operating Revenues**	RV:1:34		$ 1,608,715,831	$ 276,904,880 2	$ 677,942,095	$ 650,536,019	$ 3,332,837
2	Operating Expenses							
3	Gas Purchased	EX:2:2		$ 454,828,378	$ 64,262,645 A	$ 200,704,535	$ 189,861,198	$ -
4	Operation - Other than Gas Purchased	EX:2:3>44		322,051,962	61,031,214 A.	137,950,468	122,960,170	110,110
5	Maintenance	EX:4:26		114,413,313	25,568,839 2	46,799,501	41,961,616	83,356
6	Depreciation	EX:6:22		135,410,640	23,907,431	41,034,291	70,456,187	12,731
7	Amortization of Capitalized Software		Financial Stmt.	21,433,284	3,757,163	8,810,769	8,785,972	79,380
8	Amortization of Chalk Point / MD Post 1989 Inter		Financial Stmt.	94,718	-	94,718	-	-
9	Amortization of General Plant			14,127,280	1,878,281	5,415,781	6,833,217	-
10	Amortization of Unrecovered Plant Loss Chillum		Financial Stmt.	-	-	-	-	-
11	Interest on Customer Deposits	EX:1:6		528,578	41,769	128,646	358,163	-
12	Interest on Supplier Refunds	EX:1:7		73,600	11,533	31,581	30,486	-
13	General Taxes	EX:8:24		171,665,153	58,992,535	88,254,140	24,335,027	83,452
14	Other Income Taxes	EX:10:23	Financial Stmt.	13,182,317	756,509 B.	5,234,557	7,027,005	164,246
15	Expenses Before Federal Income Taxes	=3>14		$ 1,247,809,223	$ 240,207,920	$ 534,458,986	$ 472,609,042	$ 533,275
16	Federal Income Tax Expense	EX:10:22		$ 50,043,363	$ 2,871,897 B	$ 19,871,685	$ 26,676,264	$ 623,518
17	ITC Adjustment	EX:10:22		(305,994)	(90,913) B.	(108,018)	(107,064)	-
18	Loss- Disposition of Utility Plant		Financial Stmt.	451,758	100,274 2	351,484	-	-
19	Total Operating Expenses	=15 > 17		$ 1,297,998,351	$ 243,089,178	$ 554,574,138	$ 499,178,242	$ 1,156,793
20	Net Operating Income	=1-18		$ 310,717,480	$ 33,815,702	$ 123,367,957	$ 151,357,777	$ 2,176,044
21	Net Income Adjustments							
22	AFUDC	AL:3:14	ADJ_CWIP	1,259,101	467,443	791,658	-	-
23	LCP Equity Accrual			-	-	-	-	-
24	Net Operating Income - Adjusted	19+21-22+23		$ 311,976,581	$ 34,283,145	$ 124,159,615	$ 151,357,777	$ 2,176,044
25	Net Rate Base	RB:1:26		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952
26	Return Earned	=24 / 25		7.28%	4.22%	7.83%	8.14%	7.84%

sum of A. = 125,293,859 2
sum of B. = 3,537,492 2

Exhibit WG (F)-5
Schedule G
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Washington Gas Light Company
District of Columbia Jurisdiction

Income Statement and Rate of Return Summary

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	Per Books C	Distribution Adjustments D	Distribution Amounts E = C + D	Ratemaking Adjustments F	Ratemaking Amounts G = E + F	Revenue Deficiency H	ROE Amounts I = G + H
1	Operating Revenues	Adj List Pg 1, Ln. 11	$ 276,904,880	$ (84,692,285)	$ 192,212,595	$ 31,541,193	$ 223,753,787	$ 33,535,937	$ 257,289,724
2	Operating Expenses								
3	Operation	Adj List Pg 1, Ln. 41	$ 125,293,859	$ (68,209,263)	$ 57,084,597	$ 54,434	$ 57,139,031	$ 883,128	$ 58,022,159
4	Maintenance	Adj List Pg 1, Ln. 20	25,568,839	-	25,568,839	356,972	25,925,811	-	25,925,811
5	Depreciation	Adj List Pg 1, Ln. 44	23,907,431	-	23,907,431	7,922,823	31,830,254	-	31,830,254
6	Amortization of General Plant	Per Books	1,878,281	-	1,878,281	-	1,878,281	-	1,878,281
7	Amortization of Capitalized Software	Adj List Pg 1, Ln. 45	3,757,163	(97,980)	3,659,183	-	3,659,183	-	3,659,183
8	Amortization of Unrecovered Plant Loss	Per Books	100,274	-	100,274	-	100,274	-	100,274
9	Interest on Customer Deposits	Adj List Pg 1, Ln. 48	41,769	-	41,769	35,315	77,084	-	77,084
10	Interest on Supplier Refunds	Per Books	11,533	(11,533)	-	-	-	-	-
11	General Taxes	Adj List Pg 2, Ln. 7	58,992,535	-	58,992,535	4,443,796	63,436,331	-	63,436,331
12	Expenses Before Income Taxes	Sum of Lns. 3 > 11	$ 239,551,685	$ (68,318,776)	$ 171,232,910	$ 12,813,340	$ 184,046,250	$ 883,128	$ 184,929,378
13	Income Taxes	Adj List Pg 2, Ln. 10	3,537,493	(3,089,477)	448,015	3,409,377	3,857,393	8,985,237	12,842,630
14	Total Operating Expenses	Sum of Lns. 12 + 13	$ 243,089,178	$ (71,408,253)	$ 171,680,925	$ 16,222,717	$ 187,903,642	$ 9,868,365	$ 197,772,007
15	Net Operating Income	Ln. 1 - Ln. 14	$ 33,815,702	$ (13,284,032)	$ 20,531,669	$ 15,318,475	$ 35,850,145	$ 23,667,572	$ 59,517,717
16	Net Income Adjustments								
17	AFUDC	Per Books	467,443	-	467,443	-	467,443	-	467,443
18	Net Operating Income - Adjusted	Sum of Ln.s 15 > 17	$ 34,283,145	$ (13,284,032)	$ 20,999,112	$ 15,318,475	$ 36,317,588	$ 23,667,572	$ 59,985,160
19	Net Rate Base	Rate Base Stmt, Ln.23	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (34,336,831)	$ 761,839,660	$ -	$ 761,839,660
20	Return Earned	Ln. 18 / Ln. 19	4.22%		2.64%		4.77%		7.87%
21	Return on Common Equity								
22	Interest Expense		$ 19,142,496	$ (330,939)	$ 18,811,557	$ (811,289)	$ 18,000,268		$ 18,000,268
23	Net Income Available for Common Equity	Ln. 18 - Ln. 22	$ 15,140,649		$ 2,187,555		$ 18,317,320		$ 41,984,892
24	Common Equity Ratio	Cost of Capital, Ln. 3	52.49%		52.49%		52.49%		52.49%
25	Common Equity Capital	Ln. 19 * Ln. 24	$ 426,291,579		$ 417,878,033		$ 399,856,140		$ 399,856,140
26	Return Earned on Common Equity	Ln. 23 / Ln. 25	3.55%		0.52%		4.58%		10.50%

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Income Statement Summary

Twelve Months Ended March 31, 2024 - Average Rate Base

	Description	Reference: Sc-Pg-Ln	Reference: Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-MMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	C&I NON H/C - NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	B	C	D	G	H	I	J	K	L	M	N	N	O	P	Q	R	S
1	Operating Revenues	RV 1:32			$ 223,783,79 (1)	$ 94,391,333	$ 2,221,121	$ 2,088,124	$ 8,074,484	$ 52,282,708	$ 952,299	$ 6,422,731	$ 861,251	$ 929,572	$ 22,939,987	$ 3,128,814	$ 16,182,607	$ 15,294,344
2	Operating Expenses																	
3	Gas Purchased	EX 2:2			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Operation - Other than Gas Purchased				57,150,032	29,606,687	1,080,828	760,978	1,787,327	10,236,000	482,563	1,321,177	151,015	248,880	4,813,756	675,348	3,213,709	2,770,733
5	Maintenance	EX 4:25			25,826,012	12,840,525	272,434	347,252	978,094	5,266,850	83,473	679,512	69,748	133,159	2,531,505	355,265	1,225,375	1,134,631
6	Depreciation	EX 6:20			31,830,264	14,795,151	214,109	380,073	914,781	6,846,949	140,085	746,149	114,178	122,763	3,258,856	380,522	1,986,405	1,913,425
7	Amortization of General Plant	AL 4:30	Tot_Plnt_Ex_Genl	Comp TPE	1,879,291	867,415	12,401	22,163	53,603	405,399	8,417	44,057	6,844	7,227	182,795	22,987	119,886	114,887
8	Amortization of Capitalized Software	AL 4:30	Tot_Plnt_Ex_Genl	Comp TPE	3,660,183	1,689,650	24,150	43,178	104,427	780,160	16,207	85,630	13,333	14,080	375,984	44,783	233,957	223,618
9	Amortization of Unrecovered Plant Loss	AL 1:6	Total_Weather_All_MW	Demand	100,274	41,976	184	784	2,408	23,282	880	1,629	63	338	12,182	921	9,443	6,490
10	Interest on Customer Deposits	RV 1:5	Gas_Sales_Ex_Non_Firm	Comp TCB	77,084	37,511	890	823	2,484	21,400	398	2,620	-	378	9,315	1,272	-	-
11	Interest on Supplier Refunds	AL 1:4	Annual_Firm_MW	Demand	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	General Taxes	EX 8:21			63,436,330	19,308,800	184,458	400,630	1,272,988	15,450,085	508,442	1,194,016	821,473	222,720	6,443,519	853,883	8,853,311	8,321,944
13	Expenses Before Income Taxes	Ln. 2 > Ln. 12			$ 184,046,251	$ 79,198,934	$ 1,769,461	$ 1,365,860	$ 8,116,082	$ 39,040,284	$ 1,250,464	$ 4,074,888	$ 975,852	$ 749,544	$ 17,636,303	$ 2,344,061	$ 15,451,864	$ 14,465,885
14	Income Taxes	EX 1:10			3,957,393	907,680	73,887	(52,003)	61,943	2,100,582	(108,329)	471,939	(56,189)	22,123	732,285	129,513	(235,895)	(189,731)
15	Total Operating Expenses	Ln. 13 + Ln. 14			$ 187,903,644	$ 80,104,584	$ 1,843,349	$ 1,303,857	$ 8,178,025	$ 41,140,857	$ 1,142,135	$ 4,546,533	$ 919,463	$ 771,667	$ 18,367,544	$ 2,473,584	$ 15,215,919	$ 14,276,164
16	Net Operating Income	Ln. 1 - Ln. 15			$ 35,880,143	$ 14,276,739	$ 377,773	$ 182,267	$ 896,459	$ 11,141,851	$ (189,836)	$ 1,876,198	$ (58,213)	$ 157,905	$ 4,572,009	$ 682,030	$ 976,789	$ 998,180
17	Net Income Adjustments																	
18	AFUDC	AL 5:2	Net_Rate_Base	Comp NRB	$ 467,443	$ 214,915	$ 3,246	$ 5,468	$ 13,265	$ 100,336	$ 2,112	$ 10,946	$ 1,811	$ 1,800	$ 47,633	$ 5,703	$ 31,290	$ 28,916
19	LCP Equity Accrual	AL 4:26	Tot_Dist_Plnt	Comp TDP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Net Operating Income - Adjusted				$ 36,317,586	$ 14,491,654	$ 381,021	$ 187,736	$ 909,724	$ 11,242,187	$ (187,724)	$ 1,887,143	$ (56,402)	$ 159,706	$ 4,619,642	$ 687,723	$ 1,008,078	$ 1,027,096
21	Net Rate Base	RB 1:26			$ 761,839,660	$ 350,084,408	$ 5,230,745	$ 9,870,552	$ 21,500,941	$ 163,735,866	$ 3,239,098	$ 17,812,622	$ 2,942,134	$ 2,919,859	$ 77,703,888	$ 9,278,720	$ 51,180,821	$ 47,331,405
22	Return Earned	Ln. 20 / Ln. 21			4.77%	4.14%	7.29%	1.89%	4.23%	6.87%	-5.80%	10.59%	-1.92%	5.47%	5.95%	7.20%	1.97%	2.17%
23	Uniform Rate of Return				1.00	0.87	1.53	0.40	0.89	1.44	(1.22)	2.22	(0.40)	1.15	1.25	1.51	0.41	0.46

From RMPF

		RMPF Inter at 90.9% Study#292 Mar-2024 Mar-2024 (Full Inter)	RMPF Inter at 100% Study#292 Mar-2024 (Full Inter) Mar-2024 (Full Inter)		Difference
Revenue Adjustments	**Adj No.**				
DC PF Adj - Revenues	Adj. No. 1	19,456,025	31,582,281		12,126,256 (1)
Changes in Revenues				**A**	**12,126,256**
Expense Adjustments	**Adj No.**				
Uncollectible Gas Accounts Adjustment	Adj. No. 2D	1,038,168	1,360,534	**D**	322,366
DC PF Adj - Income Taxes	Adj. No. 10D & Adj. No. 30	(2,922,730)	319,900		3,242,630
Change in Expenses				**B**	**3,564,996**
Change in NOI				**C = A - B**	**8,561,260**
				Sum of D	**322,366**
Ratebase Adjustments	**Adj No.**				
DC PF Adj - Cash Working Capital	Adj. No. 9D & Adj. No. 29	854,471	1,701,167		846,696
Change in Rate Base					**846,696**

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost Study Workpaper 5.2 - Reconciliation of Class Cost Rate Making Amount to Rate Making Pro Forma (RMPF) File

Twelve Months Ended March 31, 2024

Line No.	Description A	Reference B	90.90% RMPF C	100% RMPF D	Variance E = C - D	Class Cost F	Variance CC to RMPF G = F - D	
1	Gas Plant in Service		$ 2/ 1,343,519,841	$ 4/ 1,343,519,841	$ -	$ 5/ 1,341,462,626	$ 2,057,216	b/
2	Construction Work in Progress	Pg. 7, Ln. 20	6,884,577	6,884,577	-	6,884,577	-	
3	Materials & Supplies	Pg. 7, Ln. 19	2,941,148	2,941,148	-	2,941,148	0	
4	Non-Plant ADIT		(3,355,922)	(3,355,922)	-	(3,355,922)	-	
5	FC 1027 - Rate Base CWIP (Reg Asset) _a/		(0)	(0)	-	0	(0)	
6	Unamortized East Station _a/		1,766,327	1,766,327	-	1,766,327	-	
7	Cloud Computing - Prepaid	Per Books	-	-	-	-	-	
8	Sub-Total	Sum of Lns. 1 > 3	$ 1,351,755,971	$ 1,351,755,971	$ -	$ 1,349,698,755	$ 2,057,216	
9	Cash Working Capital	Pg. 7, Ln. 20	40,826,325	41,673,021	6/ (846,696)	41,673,021	-	
10	Gross Rate Base	Ln. 8 + Ln. 9	$ 1,392,582,296	$ 1,393,428,992	$ (846,696)	$ 1,391,371,776	$ 2,057,216	
11	LESS:							
12	Reserve for Depreciation	Per Books	$ 456,197,363	$ 456,197,363	$ -	$ 454,140,147	$ 2,057,216	b/
13	ADIT: M.A.C.R.S. Depreciation	Per Books	216,026,702	216,026,702	-	216,026,702	-	
14	ADIT: Gains/Losses on Reaquired Debt (Federal)	Per Books	29,300	29,300	-	29,300	-	
15	ADIT: Gains/Losses on Reaquired Debt (State)	Per Books	10,143	10,143	-	10,143	-	
16	NOL Carryforward Federal	Per Books	(35,762,077)	(35,762,077)	-	(35,762,077)	-	
17	NOL Carryforward State	Per Books	(12,237,900)	(12,237,900)	-	(12,237,900)	-	
18	NOL Federal Benefit of State	Per Books	2,569,959	2,569,959	-	2,569,959	-	
19	Customer Advances for Construction	Per Books	305,769	305,769	-	305,769	-	
20	Customer Deposits	Per Books	1,432,785	1,432,785	-	1,432,785	-	
21	Supplier Refunds	Pg. 7, Ln. 32	-	-	-	-	-	
22	Deferred Tenant Allowance	Per Books	3,017,287	3,017,287	-	3,017,287	-	
23	Total Rate Base Deductions	Sum of Lns. 12 > 21	$ 631,589,332	$ 631,589,332	$ -	$ 629,532,116	$ 2,057,216	
24	Net Rate Base	Ln. 10 - Ln. 23	$ 760,992,964	$ 761,839,660	$ (846,696)	$ 761,839,660	$ (0)	

a/ Net of deferred taxes

b/ ARO amounts are included in the PBCOSA and RMPF, but not in the CCOSS.

GPIS ARO - Situs Distribution (Mains)	$ 7/ 1,086,978
GPIS ARO - Situs Distribution (Services)	967,723
GPIS ARO - Allocable Transmission (Mains)	2,515
	$ 2,057,216
Variance Noted Above	2,057,216
Unreconciled Variance	$ 0
Reserve ARO - Situs Distribution (Mains)	$ 8/ (2,054,701)
Reserve ARO - Allocable Transmission (Mains)	(2,515)
	$ (2,057,216)
Variance Noted Above	(2,057,216)
Unreconciled Variance	$ 0

Washington Gas Light Company
District of Columbia Jurisdiction

Average Rate Base Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Books Amount	Distribution Adjustments	Distribution Amount	Ratemaking Adjustments	Ratemaking Amount
	A	B	C	D	E = C + D	F	G = E + F
1	Gas Plant in Service		$ 3/ 1,317,182,832	$ (770,154)	$ 1,316,412,678	$ 27,107,163	$ 1,343,519,841 1
2	Construction Work in Progress		79,322,274	-	79,322,274	(72,437,698)	6,884,577
3	Materials & Supplies	Adj List Pg 2, Ln. 14	19,836,447	(16,895,300)	2,941,148	-	2,941,148
4	Non-Plant ADIT		(3,062,666)		(3,062,666)	(293,256)	(3,355,922)
5	FC 1027 - Rate Base CWIP (Reg Asset) _a/		(0)	-	(0)	-	(0)
6	Unamortized East Station _a/	Adj List Pg 2, Ln. 19	1,075,846	-	1,075,846	690,481	1,766,327
7	Sub-Total	Sum of Lns. 1 > 3	$ 1,414,354,734	$ (17,665,454)	$ 1,396,689,281	$ (44,933,310)	$ 1,351,755,971
8	Cash Working Capital	Adj List Pg 2, Ln. 17	39,219,091	652,610	39,871,701	954,625	40,826,325
9	Gross Rate Base	Ln. 7 + Ln. 8	$ 1,453,573,825	$ (17,012,844)	$ 1,436,560,981	$ (43,978,685)	$ 1,392,582,296
10	LESS:						
11	Reserve for Depreciation	Per Books	$ 449,057,859	$ (356,329)	$ 448,701,530	$ 7,495,833	$ 456,197,363
12	ADIT: M.A.C.R.S. Depreciation	Per Books	212,149,665	-	212,149,665	3,877,037	216,026,702
13	ADIT: Gains/Losses on Reaquired Debt (Federal)	Per Books	29,300	-	29,300	-	29,300
14	ADIT: Gains/Losses on Reaquired Debt (State)	Per Books	10,143	-	10,143	-	10,143
15	NOL Carryforward Federal	Per Books	(14,916,809)	-	(14,916,809)	(20,845,267)	(35,762,077)
16	NOL Carryforward State	Per Books	(13,095,164)	-	(13,095,164)	857,264	(12,237,900)
17	NOL Federal Benefit of State	Per Books	2,749,985	-	2,749,985	(180,026)	2,569,959
18	Customer Advances for Construction	Per Books	305,769	-	305,769	-	305,769
19	Customer Deposits	Per Books	1,432,785	-	1,432,785	-	1,432,785
20	Supplier Refunds	Adj List Pg 2, Ln. 25	626,315	(626,315)	-	-	-
21	Deferred Tenant Allowance	Per Books	3,017,287	-	3,017,287	-	3,017,287
22	Total Rate Base Deductions	Sum of Lns. 11 > 21	$ 641,367,135	$ (982,644)	$ 640,384,490	$ (8,795,158)	$ 631,589,332
23	Net Rate Base	Ln. 9 - Ln. 22	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (35,183,527)	$ 760,992,964

a/ Net of deferred taxes

Washington Gas Light Company
Rate Base Summary
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	— Reference — Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	Gas Plant in Service	RB:3:17		$ 7,249,016,177	$1,317,182,832 (2)	$ 2,711,617,252	$ 3,190,657,625	$ 29,558,468
2	Gas Plant Held for Future Use	RB:4:13		-	-	-	-	-
3	Unrecovered Plant - Peaking Facility		Total_Weather_All_NW	-	-	-	-	-
4	Construction Work in Progress	RB:5:29		397,111,025	79,322,274	134,339,566	183,449,185	-
5	Materials & Supplies	RB:6:12		123,327,981	19,836,447	52,379,031	51,112,503	-
6	Non Plant - ADIT	RB:12:18	Financial Stmt.	(34,509,521)	(3,062,666)	(21,491,098)	(9,955,757)	0
7	FC 1027 - Rate Base CWIP (Reg Asset)			(0)	(0)			
8	Unamortized East Station Cost (Net of Deferred Taxes)		Financial Stmt.	1,075,846	1,075,846	-	-	-
9	Sub-Total	=1>10		$ 7,736,021,508	$1,414,354,734	$ 2,876,844,750	$ 3,415,263,556	$ 29,558,468
10	Cash Working Capital	RB:7>9:17		$ 121,292,100	$ 39,219,091	$ 67,230,077	$ 14,826,433	$ 16,500
11	Total Rate Base Additions	= 12 + 11		$ 7,857,313,609	$1,453,573,825	$ 2,944,074,827	$ 3,430,089,989	$ 29,574,968
12	LESS:							
13	Reserve for Depreciation	RB:10:35		$ 2,370,279,045	$ 449,057,859	$ 864,931,885	$ 1,054,487,285	$ 1,802,016
14	Accumulated DIT re Depreciation	RB:11:17		1,298,608,831	212,149,665	532,439,389	554,019,777	0
15	Accumulated DIT re Gains/Losses On Reacquired Debt							
16	Federal	RB:11:9	Net_Rate_Base	175,290	29,300	70,009	75,981	-
17	State	RB:11:9	Net_Rate_Base	57,829	10,143	22,631	25,055	-
18	NOL Carryforward Federal		Net_Rate_Base	(78,173,336)	(14,916,809)	(29,119,631)	(34,136,895)	-
19	NOL Carryforward State		Net_Rate_Base	(68,626,785)	(13,095,164)	(25,563,533)	(29,968,088)	-
20	NOL Federal Benefit of State		Net_Rate_Base	14,411,625	2,749,985	5,368,342	6,293,298	-
21	Customer Advances for Construction		Financial Stmt.	2,698,381	305,769	244,862	2,147,750	-
22	Customer Deposits		Financial Stmt.	12,871,928	1,432,785	2,467,234	8,971,908	-
23	Supplier Refunds		Financial Stmt.	4,509,391	626,315	1,675,549	2,207,527	-
24	Deferred Tenant Allowance		Non_Genl_Plnt	16,261,534	3,017,287	6,000,718	7,243,529	-
25	Total Rate Base Deductions	=14>26		$ 3,573,073,733	$ 641,367,135	$ 1,358,537,454	$ 1,571,367,128	$ 1,802,016
26	Net Rate Base	= 13 - 27		$ 4,284,239,876	$ 812,206,690	$ 1,585,537,373	$ 1,858,722,862	$ 27,772,952

Exhibit WG (F)-5
Schedule H

Washington Gas Light Company
District of Columbia Jurisdiction

Average Rate Base Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Books Amount	Distribution Adjustments	Distribution Amount	Ratemaking Adjustments	Ratemaking Amount
	A	B	C	D	E = C + D	F	G = E + F
1	Gas Plant in Service		$ 1,317,182,832	$ (770,154)	$ 1,316,412,678	$ 27,107,163	$ 1,343,519,841 1
2	Construction Work in Progress		79,322,274	-	79,322,274	(72,437,698)	6,884,577
3	Materials & Supplies	Adj List Pg 2, Ln. 14	19,836,447	(16,895,300)	2,941,148	-	2,941,148
4	Non-Plant ADIT		(3,062,666)		(3,062,666)	(293,256)	(3,355,922)
5	FC 1027 - Rate Base CWIP (Reg Asset) _a/		(0)	-	(0)	-	(0)
6	Unamortized East Station _a/	Adj List Pg 2, Ln. 19	1,075,846	-	1,075,846	690,481	1,766,327
7	Sub-Total	Sum of Lns. 1 > 3	$ 1,414,354,734	$ (17,665,454)	$ 1,396,689,281	$ (44,933,310)	$ 1,351,755,971
8	Cash Working Capital	Adj List Pg 2, Ln. 17	39,219,091	652,610	39,871,701	1,801,320	41,673,021
9	Gross Rate Base	Ln. 7 + Ln. 8	$ 1,453,573,825	$ (17,012,844)	$ 1,436,560,981	$ (43,131,989)	$ 1,393,428,992
10	LESS:						
11	Reserve for Depreciation	Per Books	$ 449,057,859	$ (356,329)	$ 448,701,530	$ 7,495,833	$ 456,197,363
12	ADIT: M.A.C.R.S. Depreciation	Per Books	212,149,665	-	212,149,665	3,877,037	216,026,702
13	ADIT: Gains/Losses on Reaquired Debt (Federal)	Per Books	29,300	-	29,300	-	29,300
14	ADIT: Gains/Losses on Reaquired Debt (State)	Per Books	10,143	-	10,143	-	10,143
15	NOL Carryforward Federal	Per Books	(14,916,809)	-	(14,916,809)	(20,845,267)	(35,762,077)
16	NOL Carryforward State	Per Books	(13,095,164)	-	(13,095,164)	857,264	(12,237,900)
17	NOL Federal Benefit of State	Per Books	2,749,985	-	2,749,985	(180,026)	2,569,959
18	Customer Advances for Construction	Per Books	305,769	-	305,769	-	305,769
19	Customer Deposits	Per Books	1,432,785	-	1,432,785	-	1,432,785
20	Supplier Refunds	Adj List Pg 2, Ln. 25	626,315	(626,315)	-	-	-
21	Deferred Tenant Allowance	Per Books	3,017,287	-	3,017,287	-	3,017,287
22	Total Rate Base Deductions	Sum of Lns. 11 > 21	$ 641,367,135	$ (982,644)	$ 640,384,490	$ (8,795,158)	$ 631,589,332
23	Net Rate Base	Ln. 9 - Ln. 22	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (34,336,831)	$ 761,839,660

a/ Net of deferred taxes

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Rate Base Summary

Twelve Months Ended March 31, 2024 - Average Rate Base
Average Rate Base

	Description A	— Reference — Sch-Pg-Ln B	Class Allocator C	Cost Category D	District of Columbia Rate Making Total G	RES-HTG/CLG H	RES-NON H/C-MMA I	RES-NON H/C-OTH J	C&I H/C < 3075 K
1	Gas Plant in Service	RB 3 15			$ 1,341,462,626	$ 618,344,340	$ 8,640,138	$ 15,769,389	$ 38,211,282
2	Gas Plant Held for Future Use	RB 4 12			-	-	-	-	-
3	Construction Work in Progress	RB 5 27			6,004,677	3,043,569	45,814	102,323	177,488
4	Materials & Supplies	RB 6 12			2,041,148	985,503	8,979	18,412	60,361
5	Non Plant ADIT	RB 9 19			(3,365,922)	(2,051,237)	(71,143)	(66,030)	(186,208)
6	Unamortized East Station Cost (Net of Deferred Taxes)	AL 1 6	Total_Weather_All_NW	Demand	1,766,327	739,411	3,234	13,455	42,412
7	FC 1027 - Rate Base CWIP (Reg Asset)	AL 4 20	Dist_Mains_Plnt	Demand	0	0	0	0	0
8	Cloud Computing - Prepaid	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	-	-	-	-	-
9	Sub-Total	Ln. 1 > Ln. 7			$ 1,339,698,757	$ 621,061,485	$ 8,625,022	$ 15,868,550	$ 38,306,317
10	Cash Working Capital	AL 6 37	O&M Adjusted	Comp OMA	A 40,920,257	22,181,003	778,547	587,892	1,400,293
11	Cash Working Capital - Multi-Family Unit Contributions	AL 9 46	Residential Heating	Customer	A 752,764	752,764	-	-	-
12	Total Rate Base Additions	Ln. 9 + Ln. 10			$ 1,381,371,778	$ 644,595,252	$ 9,603,569	$ 16,457,242	$ 39,706,610
13	LESS:								
14	Reserve for Depreciation	RB 7 33			$ 464,140,147	$ 213,656,194	$ 3,140,182	$ 5,537,854	$ 13,224,940
15	Accumulated DIT re Depreciation	AL 5 2	Net_Rate_Base	Comp NRB	216,038,762	99,321,945	1,500,834	2,527,176	6,130,546
16	ADIT re Gains/Losses On Reacquired Debt (Federal)	AL 5 2	Net_Rate_Base	Comp NRB	28,389	13,471	204	343	831
17	ADIT re Gains/Losses On Reacquired Debt (State)	AL 5 2	Net_Rate_Base	Comp NRB	10,143	4,664	70	119	288
18	NOL Carryforward Federal	AL 5 2	Net_Rate_Base	Comp NRB	(36,762,077)	(16,442,222)	(248,459)	(416,381)	(1,014,880)
19	NOL Carryforward State	AL 5 2	Net_Rate_Base	Comp NRB	(12,237,980)	(5,628,582)	(85,022)	(143,164)	(347,285)
20	NOL Federal Benefit of State	AL 5 2	Net_Rate_Base	Comp NRB	2,686,980	1,161,582	17,885	30,085	72,832
21	Customer Advances for Construction	AL 4 20	Dist_Mains_Plnt	Demand	366,766	107,322	886	2,071	6,488
22	Customer Deposits	RV 1 5	Gas_Sales_Ex_Non_Firm	Comp TCS	1,433,795	697,221	16,507	15,388	46,175
23	Supplier Refunds	AL 1 4	Annual_Firm_NW	Demand	-	-	-	-	-
24	Deferred Tenant Allowance	AL 5 2	Net_Rate_Base	Comp NRB	3,017,287	1,387,248	20,982	35,288	85,627
25	Total Rate Base Deductions	Ln. 14 > Ln. 24			$ 629,532,116	$ 294,500,843	$ 4,372,824	$ 7,586,690	$ 18,205,670
26	Net Rate Base	Ln. 12 - Ln. 25			$ 751,839,662	$ 350,094,409	$ 5,230,745	$ 8,870,552	$ 21,500,941

	C&I H/C > 3075 L	C&I CHP M	C&I NON H/C N	C&I NON H/C - NGV O	GMA H/C < 3075 P	GMA H/C >3075 Q	GMA NON H/C R	NON FIRM S	Special Contract T
1	$ 289,134,304	$ 6,007,651	$ 31,406,404	$ 5,043,291	$ 5,152,087	$ 137,436,364	$ 16,368,760	$ 87,753,756	$ 81,947,929
2	-	-	-	-	-	-	-	-	-
3	1,383,625	21,403	136,044	17,677	18,243	669,884	72,564	301,726	284,248
4	716,588	21,412	75,434	22,450	10,386	323,981	37,931	336,310	325,452
5	(281,649)	(219,122)	(74,028)	(13,604)	(23,877)	(228,353)	(43,154)	(37,480)	38,863
6	400,768	11,790	28,088	1,108	5,934	214,241	16,220	166,334	113,729
7	0	0	0	0	0	0	0	0	0
8	-	-	-	-	-	-	-	-	-
9	$ 291,367,815	$ 5,843,133	$ 31,571,943	$ 5,070,324	$ 5,163,782	$ 138,414,106	$ 16,470,331	$ 88,518,869	$ 82,720,208
10	7,169,676	121,216	945,459	96,749	190,195	3,446,670	480,486	1,878,086	1,633,974
11	-	-	-	-	-	-	-	-	-
12	$ 298,432,491	$ 5,964,352	$ 32,517,102	$ 5,167,073	$ 5,353,957	$ 141,860,776	$ 16,950,817	$ 90,397,755	$ 84,354,181
13									
14	$ 88,946,985	$ 1,832,316	$ 10,581,888	$ 1,550,664	$ 1,757,316	$ 48,253,635	$ 5,535,826	$ 27,581,274	$ 30,249,773
15	48,380,917	875,912	5,058,466	838,880	832,073	22,013,422	2,835,809	14,460,372	13,363,314
16	6,288	132	686	114	113	2,986	357	1,981	1,812
17	2,177	46	238	38	38	1,034	124	679	627
18	(7,676,294)	(161,557)	(837,408)	(130,543)	(137,745)	(3,844,208)	(436,344)	(2,393,838)	(2,212,226)
19	(2,626,853)	(55,280)	(288,563)	(47,410)	(47,137)	(1,247,058)	(149,318)	(819,178)	(757,031)
20	551,820	11,610	60,176	9,968	9,888	261,882	31,357	172,028	158,977
21	75,336	2,248	7,516	1,848	1,084	34,703	3,628	31,888	30,881
22	397,769	7,303	48,802	-	7,034	173,148	23,638	-	-
23	-	-	-	-	-	-	-	-	-
24	647,856	13,631	70,853	11,688	11,622	307,486	36,815	201,871	188,646
25	$ 134,696,622	$ 2,726,254	$ 14,704,480	$ 2,225,540	$ 2,434,298	$ 64,157,090	$ 7,682,098	$ 39,216,934	$ 37,022,777
26	$ 163,735,868	$ 3,238,098	$ 17,812,622	$ 2,942,134	$ 2,919,659	$ 77,703,686	$ 9,278,720	$ 51,180,821	$ 47,331,405

sum of A. = 41,673,021 1

		RMPF Inter at 90.9% Study#292 Mar-2024 Mar-2024 (Full Inter)	RMPF Inter at 100% Study#292 Mar-2024 (Full Inter) Mar-2024 (Full Inter)		Difference
Revenue Adjustments	**Adj No.**				
DC PF Adj - Revenues	Adj. No. 1	19,456,025	31,582,281		12,126,256
Changes in Revenues				**A**	**12,126,256**
Expense Adjustments	**Adj No.**				
Uncollectible Gas Accounts Adjustment	Adj. No. 2D	1,038,168	1,360,534	**D**	322,366
DC PF Adj - Income Taxes	Adj. No. 10D & Adj. No. 30	(2,922,730)	319,900		3,242,630
Change in Expenses				**B**	**3,564,996**
Change in NOI				**C = A - B**	**8,561,260**
				Sum of D	**322,366**
Ratebase Adjustments	**Adj No.**				
DC PF Adj - Cash Working Capital	Adj. No. 9D & Adj. No. 29	854,471	1,701,167		846,696
Change in Rate Base					**846,696** 1

Washington Gas Light Company
Depreciable Gas Plant In Service
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	Reference: Sc-Pg-Ln	Reference: Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Depreciable Gas Plant In Service**							
2	Capitalized Software	AL:2:23	Non_Genl_Plnt	$ 168,881,787	$ 31,956,957	$ 62,038,051	$ 74,886,780	$ -
3	Storage	AL:1:19	Total_Weather_All_NW	76,262,465	$ 12,565,793	$ 32,404,277	$ 31,292,394	$ -
4	Storage - AFUDC		Financial Stmt.	(511,776)	-	-	(511,776)	0
5	Total Storage	=3+4		$ 75,750,689	$ 12,565,793	$ 32,404,277	$ 30,780,618	$ -
6	Transmission							
7	Spurlines and Related Regulating							
8	Equipment and Structures		Financial Stmt.	$ 414,164,974	$ 56,197,740	$ 120,198,620	$ 209,444,575	$ 28,324,039
9	WSSC			5,547	-	5,547	-	-
10	ChalkPoint		Financial Stmt.	13,995,741	-	13,995,741	-	-
11	Panda		Financial Stmt.	2,034,808	-	2,034,808	-	-
12	Other	AL:1:32	Comp_Peak_ Ann_NW	696,637,349	108,628,696	304,409,695	283,598,957	-
13	Transmission Mains - ARO			6,956,762	2,515 1	3,954,742	2,999,506	-
14	Post 1989 MD Interruptible Customers		Financial Stmt.	2,477,416	-	2,477,416	-	-
15	AFUDC		Financial Stmt.	(5,268,645)	-	-	(5,268,645)	0
16	Total Transmission	=8>13		$ 1,131,003,953	$ 164,828,951	$ 447,076,569	$ 490,774,393	$ 28,324,039
17	Distribution							
18	Compressor Station Equipment	AL:1:19	Total_Weather_All_NW	$ 2,735,941	$ 450,802	$ 1,162,514	$ 1,122,625	$ -
19	Mains		Financial Stmt.	2,573,799,925	549,032,913	887,779,494	1,136,987,518	-
20	Distribution Mains - ARO			61,255,520	1,086,978 1	34,552,539	25,616,002	-
21	Measuring and Regulator Station Equipment		Financial Stmt.	17,875,325	10,637,047	4,323,013	2,915,266	-
22	Services		Financial Stmt.	2,297,650,823	399,729,625	873,174,680	1,024,746,517	-
23	Distribution Services - ARO			61,635,355	967,723 1	35,467,125	25,200,508	-
24	Meters		Financial Stmt.	138,243,994	26,892,685	53,287,464	58,063,846	-
25	Meter Installations		Financial Stmt.	252,239,013	35,970,717	91,047,414	125,220,882	-
26	House Regulators		Financial Stmt.	43,226,309	4,731,358	15,452,640	23,042,310	-
27	House Regulator Installations		Financial Stmt.	15,195,671	3,744,785	6,522,287	4,928,599	-
28	Gas Light Services		Financial Stmt.	5,022,656	107,137	1,977,956	2,937,563	-
29	Post 1989 MD Interruptible Customers		Financial Stmt.	2,917,888	-	2,917,888	-	-
30	AFUDC		Financial Stmt.	(17,294)	-	-	(17,294)	-
31	Total Distribution	=16>26		$ 5,471,781,126	$1,033,351,770	$ 2,007,665,014	$ 2,430,764,342	$ -
32	General							
33	Transportation	AL:2:23	Non_Genl_Plnt	$ 42,991,069	$ 7,947,207	$ 15,805,240	$ 19,078,670	$ 159,953
34	POE	AL:2:23	Non_Genl_Plnt	4,988,314	922,126	1,833,904	2,213,725	18,560
35	Other - Direct		Financial Stmt.	65,528,429	11,564,934	36,619,764	17,343,732	-
36	Other - Allocable	AL:2:23	Non_Genl_Plnt	283,802,687	52,462,958	104,337,239	125,946,573	1,055,916
37	AFUDC		Financial Stmt.	(5,105,363)	-	-	(5,105,363)	-
38	Total General	=29>33		$ 392,205,136	$ 72,897,224	$ 158,596,147	$ 159,477,337	$ 1,234,428
39	CNG Equipment		Financial Stmt.	$ -	$ -	$ -	$ -	$ -
40	CIAC - GPIS		Financial Stmt.	-	-	-	-	
41	CIAC - Liability		Financial Stmt.	-	-	-	-	
42	Total Depreciable Gas Plant in Service	=2+5+14+27+34+35+36+37		$ 7,239,622,691	$1,315,600,695	$ 2,707,780,058	$ 3,186,683,470	$ 29,558,468

Washington Gas Light Company
Reserve For Depreciation
Allocated on Normal Weather Therm Sales
Twelve Months Ended March 2024 - AVG
AVG Rate Base

	Description	——Reference—— Sc-Pg-Ln	Allocator	WG	DC	MD	VA	FERC
	A	B	C	D	E	F	G	H
1	**Reserve for Depreciation**							
2	Capitalized Software	AL:2:23	Non_Genl_Plnt	$ 93,226,573	$ 17,297,958	$ 34,401,819	$ 41,526,796	$ -
3	Capitalized Software Reserve Deficiency		Financial Stmt.	-	-	-	-	-
4	Capitalized Software Amort Res Def		Financial Stmt.	(632,048)	-	(632,048)	-	-
5	Total Capitalized Software	=2>4		$ 92,594,525	$ 17,297,958	$ 33,769,771	$ 41,526,796	$ -
	Storage							
6	Storage		Financial Stmt.	52,670,681	8,251,328	22,503,733	21,915,620	
7	AFUDC		Financial Stmt.	(120,084)	-	-	(120,084)	
8	Total Storage	=6+7		$ 52,550,597	$ 8,251,328	$ 22,503,733	$ 21,795,536	
	Transmission							
9	Spurlines and Related Regulating Equip		Financial Stmt.	97,106,167	5,147,487	42,913,619	49,045,060	
10	Depreciation Res - Trans - ARO		Comp_Peak_Ann_NW	6,956,762	2,515 1	3,954,741	2,999,506	-
11	21.5 Mile Loop RE: Save Amendment		Financial Stmt.	700,103	-	-	379,096	321,006
12	New 21.5 Mile loop		Financial Stmt.	-	-	-	-	-
	17.44 Miles of the 19.44 Serving							
13	Shen/Spurlines & Reg Equip		Financial Stmt.	1,663,719	-	-	1,663,719	
14	2.00 Miles of the 19.44 Serving Mountaineer		Financial Stmt.	32,515	-	-	-	32,515
15	Ninevah/Clearbrook Gate Stations		Financial Stmt.	1,067,637	-	-	578,111	489,525
16	Chalk Point		Financial Stmt.	14,153,002	-	14,153,002	-	
17	Post 1989 MD Interr Customers		Financial Stmt.	2,477,416	-	2,477,416	-	
18	Panda Cogeneration		Financial Stmt.	1,897,999	-	1,897,999	-	
19	AFUDC		Financial Stmt.	(484,314)	-	-	(484,314)	
20	Other - Allocable		Financial Stmt.	106,037,142	16,493,465	46,174,133	43,007,895	361,650
21	Total Transmission	=9>20		$ 231,608,146	$ 21,643,467	$ 111,570,910	$ 97,189,074	$ 1,204,696
	Distribution							
22	Distribution - Situs		Financial Stmt.	$ 1,716,026,917	$ 376,928,298	$ 563,332,270	$ 775,766,349	
23	Depreciation Res - Dist - ARO			122,890,875	2,054,701 1	70,019,664	50,816,510	-
24	Post 1989 MD Interr Customers		Financial Stmt.	2,865,602	-	2,865,602	-	
25	AFUDC		Financial Stmt.	(9,853)	-	-	(9,853)	
26	Other - Allocable		Financial Stmt.	174,161	27,373	74,145	72,643	
27	Total Distribution	22>26		$ 1,841,947,702	$ 379,010,372	$ 636,291,681	$ 826,645,649	
	General Plant							
28	Direct		Financial Stmt.	$ 38,579,720	$ (115,289)	$ 22,510,263	$ 16,049,785	$ 134,961
29	AFUDC		Financial Stmt.	(3,868,312)	-	-	(3,868,312)	
30	Allocable		Non_Genl_Plnt	124,269,880	22,972,177	45,686,587	55,148,758	462,359
31	General Plant - Reserve Deficiency		Financial Stmt.	-	-	-	-	-
32	General Plant - Amort Res Def		Financial Stmt.	(7,381,009)	-	(7,381,009)	-	-
33	Total General Plant	28>32		$ 151,600,279	$ 22,856,888	$ 60,815,842	$ 67,330,230	$ 597,320
34	CNG Equipment		Financial Stmt.	(22,205)	(2,154)	(20,051)	-	
35	Total Reserve for Depreciation	=5+8+21+27+32+34		$ 2,370,279,045	$ 449,057,859	$ 864,931,885	$ 1,054,487,285	$ 1,802,016

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper No. 6 - Services and Mains Split for Gas Distribution CWIP

For the Twelve Months Ended March 31, 2024

Line No.	Description	Percentage
	A	B
1	Gas Distribution CWIP	
2	Mains	2/ 40.87%
3	Services	55.71%
4	Other	3.42%
5	Total	100.00%

gl_account	(All)
company_c	01 DC Washington Gas Light Company

Sum of amount	Column Labels			
	Gas Distribution			Gas Distribution Total
Row Labels	Mains	Services	Other	
4/1/2023	3,929,529.72	4,569,899.44	198,536.95	8,697,966.11
11/1/2023	(1,666,340.33)	6,864,057.13	104,178.01	5,301,894.81
6/1/2023	5,351,033.99	2,811,595.02	403,483.48	8,566,112.49
5/1/2023	2,558,847.97	5,505,152.13	170,613.06	8,234,613.16
12/1/2023	2,733,893.86	5,661,996.34	258,781.78	8,654,671.98
2/1/2024	4,755,847.60	2,506,867.44	382,269.49	7,644,984.53
3/1/2023	3,525,822.21	2,501,985.66	307,804.46	6,335,612.33
9/1/2023	3,474,573.37	3,751,542.86	213,883.58	7,439,999.81
7/1/2023	3,601,087.05	3,686,197.94	389,348.51	7,676,633.50
3/1/2024	3,545,225.10	3,167,488.33	377,102.26	7,089,815.69
10/1/2023	3,945,747.79	8,111,069.49	411,379.24	12,468,196.52
8/1/2023	4,825,158.72	6,099,562.91	372,470.65	11,297,192.28
1/1/2024	2,696,926.95	3,751,118.59	33,025.57	6,481,071.11
Grand Total	**43,277,354.00**	**58,988,533.28**	**3,622,877.04**	**105,888,764.32**
13M Avg	3,329,027	4,537,579	278,683	8,145,290
% Split	40.87%	55.71%	3.42%	100.00%

1

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment 1 Workpaper 7 - Ratemaking Revenues

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Total DC	Residential			Commercial & Industrial				Group Metered Apartments			Non-Firm	Special Contracts
				Htg/Clg	Non-htg-IMA	Non-htg-Other	H/C < 3075	H/C > 3075	CHP	Non-htg	H/C < 3075	H/C >3075	Non-htg		
	A	B	C=D...M	D	E	F	G	H	I	J	K	L	M	N	O
1	Normal Weather Therms	Norm Wthr 1/	283,950,711	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	999,179	29,674,103	3,929,848	39,648,220 5/	38,220,735
2	Distribution Charge Revenues														
3	Distribution Charges	DC Tariff		$ 0.5638	$ 0.6610	$ 0.6390	$ 0.5821	$ 0.4796	$ 0.1033	$ 0.4811	$ 0.4930	$ 0.4863	$ 0.4841	6/	4/
4	Distribution Charge Revenues	Line 1 x Line 3	$ 122,242,327	$ 47,806,387	$ 447,907	$ 1,088,558	$ 3,106,166	$ 33,022,572	$ 217,037	$ 3,854,925	$ 492,595	$ 14,430,516	$ 1,902,440	$ 8,087,394	$ 7,785,830
5	Customer Charge Revenues														
6	Customer Bills or Units	Analysis 3/	1,957,520	1,627,379	131,084	42,794	53,982	40,679	12	22,135	7,177	20,485	10,430	1,327	36
7	Customer Charges	DC Tariff		$ 16.55	$ 12.00	$ 13.55	$ 29.90	$ 70.05	$ 343.75	$ 28.50	$ 28.50	$ 70.05	$ 28.50	$ 121.00	$ 121.00
8	Customer Charge Revenues	Line 6 x Line 7	$ 36,286,285	$ 26,933,122	$ 1,573,008	$ 579,859	$ 1,614,062	$ 2,849,564	$ 4,125	$ 630,848	$ 204,545	$ 1,434,974	$ 297,255	$ 160,567	$ 4,356
9	Peak Usage Charge Revenues														
10	Therms from Maximum Usage Month	Norm Wthr 1/	16,621,656	N/A	N/A	N/A	785,545	9,533,168	280,694	1,166,597	115,023	4,209,429	531,201	N/A	-
11	Peak Usage Charge per Therm	DC Tariff		$ -	$ -	$ -	$ 0.0519	$ 0.0421	$ 0.0904	$ 0.0423	$ 0.0431	$ 0.0422	$ 0.0423	$ -	$ -
12	November through April Charge	6 Months		-	-	-	6	6	12	6	6	6	6	-	6
13	Peak Usage Charge Revenues	Line 10 x Line 11 x Line 12	$ 4,483,667	$ -	$ -	$ -	$ 244,619	$ 2,406,078	$ 304,497	$ 296,082	$ 29,745	$ 1,065,827	$ 134,819	$ -	$ -
14	Total Base Rate Revenues	Sum of Lines 4, 8, and 13	$ 163,012,279	$ 74,739,509	$ 2,020,915	$ 1,668,417	$ 4,964,847	$ 38,280,214	$ 525,659	$ 4,781,855	$ 726,885	$ 16,931,317	$ 2,334,514	$ 8,247,961	$ 7,790,186
15	DC Rights of Way Fee Revenues														
16	DC Rights of Way Fee per Therm	Analysis		$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349
17	DC Rights of Way Fee Revenues	Line 1 x Line 16	$ 9,909,879	$ 2,959,281	$ 23,649	$ 59,453	$ 186,231	$ 2,403,019	$ 73,326	$ 279,644	$ 34,871	$ 1,035,626	$ 137,152	$ 1,383,723	$ 1,333,904
18	Delivery Tax Revenues														
19	Delivery Tax Rate Per Therm			$ 0.07070	$ 0.07070	$ 0.07070	$ 0.07777	$ 0.07777	$ 0.07777	$ 0.07777	$ 0.07070	$ 0.07070	$ 0.07070	$ 0.07777	$ 0.07777
20	Delivery Tax Revenues	Line 1 x Line 19	$ 21,221,880	$ 5,994,877	$ 47,908	$ 120,440	$ 414,991	$ 5,354,807	$ 163,397	$ 623,150	$ 70,642	$ 2,097,959	$ 277,840	$ 3,083,442	$ 2,972,427
21	Sustainable Energy Trust Fund Revenues														
22	Sustainable Energy Trust Fund Rate Per Therm			$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515
23	Sustainable Energy Trust Fund Revenues	Line 1 x Line 22	$ 21,338,896	$ 6,372,206	$ 50,923	$ 128,021	$ 401,011	$ 5,174,408	$ 157,893	$ 602,157	$ 75,088	$ 2,230,009	$ 295,328	$ 2,979,564	$ 2,872,288
24	Energy Assistance Trust Fund Revenues														
25	Energy Assistance Trust Fund Rate Per Therm			$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834
26	Energy Assistance Trust Fund Revenues	Line 1 x Line 25	$ 2,366,984	$ 706,827	$ 5,649	$ 14,200	$ 44,482	$ 573,983	$ 17,514	$ 66,793	$ 8,329	$ 247,360	$ 32,759	$ 330,504	$ 318,604
27	Total Non-gas Revenues	Sum of Lines 14, 17, 20, 23, and 26	$ 217,849,918	$ 90,772,700	$ 2,149,044	$ 1,990,531	$ 6,011,562	$ 51,786,411	$ 937,789	$ 6,353,599	$ 915,815	$ 22,542,271	$ 3,077,593	$ 16,025,194	$ 15,287,409
28	Purchased Gas Charge Revenues	2/													
29	Purchased Gas Charge	Page 23, Line 12		$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ -	$ 0.6018
30	Purchased Gas Charge Revenues	DC Rev by Class, Line 20 x Line 29	$ 73,743,790	$ 44,727,004	$ 359,630	$ 888,042	$ 2,624,191	$ 15,630,650	$ -	$ 1,983,757	$ 404,664	$ 6,187,304	$ 938,548	$ -	$ -
31	Total Sales/Delivery of Gas Revenues	Line 27 + Line 30	$ 291,593,708	$ 135,499,704	$ 2,508,674	$ 2,878,573	$ 8,635,753	$ 67,417,061	$ 937,789	$ 8,337,356	$ 1,320,479	$ 28,729,575	$ 4,016,141	$ 16,025,194	$ 15,287,409

1/ Amounts referenced as "Norm Wthr" come from the Normal Weather Study.
2/ Purchased gas revenues are not carried forward for ratemaking purposes.
3/ Amounts referenced as "Norm Wthr" come from the Normal Weather Study and are the meter totals for the referenced period.
4/ Includes AOC and GSA distribution revenues.
5/ Includes a curtailment amount of 179571 therms.
6/ Distribution charge revenue for interruptible customers are outlined below.

Description	Blocked Therms (TME	Block Percentage	Blocked Therms (TME	Rate	Distribution Charge
Block 1	26,499,608	66.54%	26,380,129	$ 0.2094	$ 5,523,999
Block 2	13,328,184	33.46%	13,268,091	$ 0.1932	2,563,395
Total	39,827,791	100.00%	39,648,220		$ 8,087,394

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Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment 1 Workpaper 7 - Class Cost Allocation of Ratemaking Pipeline Gas Cost

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Total DC	Residential			Commercial & Industrial				Group Metered Apartments			Non-Firm	Special Contracts
				Htg/Clg	Non-htg-IMA	Non-htg-Other	H/C < 3075	H/C > 3075		Non-htg	H/C < 3075	H/C >3075	Non-htg		
	A	B	C=D...M	D	E	F	G	H		I	J	K	L	M	N
1	Commodity														
2	Allocable - Firm	Page 19, Line 2	$ 31,673,000	$ 19,210,276	$ 154,469	$ 381,406	$ 1,127,084	$ 6,713,377	$ -	$ 852,035	$ 173,790	$ 2,657,460	$ 403,102	$ -	$ -
3	Non-Firm	Page 19, Line 3	-											-	-
4	Total Commodity	Line 2 + Line 3	$ 31,673,000	$ 19,210,276	$ 154,469	$ 381,406	$ 1,127,084	$ 6,713,377	$ -	$ 852,035	$ 173,790	$ 2,657,460	$ 403,102	$ -	$ -
5	Firm Transportation Demand:														
6	Base Gas	Page 19, Line 6	$ 2,192,298	$ (470,372)	$ 12,555	$ 14,322	$ 44,113	$ 1,036,573	$ 33,277	$ 176,763	$ 14,756	$ 314,639	$ 80,736	$ -	$ 934,936
7	Weather Gas	Page 19, Line 7	18,134,074	8,377,287	36,613	152,780	480,100	4,661,817	133,485	324,002	66,516	2,430,365	183,553	-	1,287,556
8	Total Firm Transportation Demand	Line 6 + Line 7	$ 20,326,372	$ 7,906,915	$ 49,168	$ 167,102	$ 524,213	$ 5,698,390	$ 166,762	$ 500,765	$ 81,272	$ 2,745,004	$ 264,289	$ -	$ 2,222,492
9	Storage Service Demand														
10	Demand	Page 19, Line 10	$ 10,818,879	$ 4,997,932	$ 21,843	$ 91,149	$ 286,430	$ 2,781,263	$ 79,638	$ 193,301	$ 39,684	$ 1,449,968	$ 109,509	$ -	$ 768,162
11	Capacity	Page 19, Line 11	6,416,808	780,004	14,078	41,998	132,064	1,538,487	45,867	154,202	22,228	706,568	78,510	801,272	2,101,530
12	Injection/Withdrawal	Page 19, Line 12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Total Storage Service Demand	Sum of Lines 10 - 12	$ 17,235,687	$ 5,777,936	$ 35,921	$ 133,147	$ 418,494	$ 4,319,750	$ 125,505	$ 347,503	$ 61,912	$ 2,156,536	$ 188,019	$ 801,272	$ 2,869,692
14	Peaking Service Demand	Page 19, Line 14	$ 2,702,500	$ 1,249,783	$ 5,467	$ 22,742	$ 71,687	$ 692,608	$ 19,928	$ 48,507	$ 10,013	$ 362,119	$ 27,417	$ -	$ 192,229
15	Total Ratemaking Pipeline Cost	Sum of Lines 4, 8, 13 & 14	$ 71,937,559	$ 34,144,910	$ 245,025	$ 704,397	$ 2,141,478	$ 17,424,125	$ 312,195	$ 1,748,810	$ 326,987	$ 7,921,119	$ 882,827	$ 801,272	$ 5,284,413

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Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment 1 Workpaper 7 - Normal Weather Therm Allocation Factors

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Total DC	Residential			Commercial & Industrial				Group Metered Apartments				
				Htg/Clg	Non-htg-IMA	Non-htg-Other	H/C < 3075	H/C > 3075		Non-htg	H/C < 3075	H/C >3075	Non-htg	Non-Firm	Special Contracts
	A	B	C=D...M	D	E	F	G	H		I	J	K	L	M	N
1	**Firm Annual Weather Gas**														
2	TOTAL FIRM WEATHER GAS - NW	NW Study	152,944,035	70,729,615	309,352	1,287,100	4,057,018	39,197,035	1,127,791	2,745,262	566,702	20,493,631	1,551,590	-	10,878,939
3	TOTAL FIRM WEATHER GAS -Allocation Factors		1.00000	0.462454	0.002023	0.008415	0.026526	0.256284	0.007374	0.017949	0.003705	0.133994	0.010145	-	0.071130
4	TOTAL FIRM THERM SALES - NW	NW Study	244,302,491	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	999,179	29,674,103	3,929,848	-	38,220,735
5	TOTAL FIRM THERM SALES -Allocation Factors		1.00000	0.347083	0.002774	0.006973	0.021842	0.281841	0.008600	0.032798	0.004090	0.121465	0.016086	-	0.156448
6	**Non-Firm Annual Weather Gas**														
7	June Sales	Financial Stmt.	4,878,086											4,878,086	
8	July Sales	Financial Stmt.	4,144,577											4,144,577	
9	Aug. Sales	Financial Stmt.	4,074,410											4,074,410	
10	Total Summer Usage	=7+8+9	13,097,073											13,097,073	
11	Annualization Factor	Constant	4											4	
12	Annualized Summer Usage	=10*11	52,388,293											52,388,293	
13	Watergate Usage		0											0	
14	Calculated Base Usage	=12+13	52,388,293											52,388,293	
15	Actual Usage	NW Study	73,882,136											73,882,136	
16	Weather Usage	=15-14	21,493,843											21,493,843	
17	Calculated Normal Weather Non-Firm Weather Gas		15,911,005											15,911,005	
18	TOTAL ALL WEATHER GAS	=2+16	168,855,040	70,729,615	309,352	1,287,100	4,057,018	39,197,035	1,127,791	2,745,262	566,702	20,493,631	1,551,590	15,911,005	10,878,939
19	TOTAL ALL WEATHER GAS -Allocation Factors		1.000000	0.418878	0.001832	0.007623	0.024027	0.232134	0.006679	0.016258	0.003356	0.121368	0.009189	0.094229	0.064428
20	TOTAL FIRM THERMS SALES ONLY	NW Study	122,542,753	74,324,500	597,610	1,475,692	4,360,714	25,974,024	0	3,296,481	672,445	10,281,670	1,559,619	-	-
21	Deductions for Pipeline :														
22	Propane Holding		-	-	-	-	-	-	-	-	-	-	-	-	-
23	Propane Gasified		-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Pipeline Deductions	=21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
25	SALES FIRM THERMS ADJUSTED FOR PIPELINE	=19-23	122,542,753	74,324,500	597,610	1,475,692	4,360,714	25,974,024	0	3,296,481	672,445	10,281,670	1,559,619	-	-
26															
27															
28	FIRM ANNUAL PIPELINE ADJ FOR ANNUALIZATION AND 2PSI	24+25	122,542,753	74,324,500	597,610	1,475,692	4,360,714	25,974,024	0	3,296,481	672,445	10,281,670	1,559,619	-	-
29	FIRM ANNUAL PIPELINE ADJ FOR ANNUALIZATION AND 2PSI-Allocation Factors		1.000000	0.606519	0.004877	0.012042	0.035585	0.211959	0.000000	0.026901	0.005487	0.083903	0.012727	-	-
30	**Peak Day Therm Sales- Normal Weather**														
31	Weather Gas	NW Study	2,465,314	1,138,887	4,978	20,770	65,270	633,771	18,146	44,047	9,042	330,407	24,953	-	175,043
32	Weather Gas - Allocation Factors		1.000000	0.461964	0.002019	0.008425	0.026475	0.257076	0.007361	0.017867	0.003668	0.134022	0.010122	-	0.071002
33	Base Gas	NW Study	172,345	36,521	987	1,126	3,468	81,489	2,616	13,896	1,160	24,735	6,347		73,499
34	Base Gas - Allocation Factors		1.426460	0.211906	0.005727	0.006533	0.020122	0.472825	0.015179	0.080629	0.006731	0.143520	0.036827	-	0.426464
35	Total Peak Day Therms	=29+31	2,711,158	1,175,408	5,965	21,896	68,738	715,260	20,762	57,943	10,202	355,142	31,300	-	248,542
36	**Total Winter Therm Sales**														
37	Firm Winter Gas	NW Study	187,796,304	72,590,924	470,893	1,404,479	4,416,478	51,450,620	1,533,963	5,156,890	743,401	23,629,251	2,625,593		23,773,812
38	Non-Firm Winter Gas	NW Study	26,796,365											26,796,365	
39	Watergate		0											0	
40	Less:														
41	Propane Holding		-	-	-	-	-	-	-	-	-	-	-	-	-
42	Propane Gasified		-	-	-	-	-	-	-	-	-	-	-	-	-
43	Total Winter Pipeline Therms	=35+36-38-39	214,592,669	72,590,924	470,893	1,404,479	4,416,478	51,450,620	1,533,963	5,156,890	743,401	23,629,251	2,625,593	26,796,365	23,773,812
44	Total Winter Pipeline Therms -Allocation Factors		1.216720	0.338273	0.002194	0.006545	0.020581	0.239759	0.007148	0.024031	0.003464	0.110112	0.012235	0.124871	0.327504

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Washington Gas Light Company
District of Columbia Jurisdiction

Income Statement and Rate of Return Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Books	Distribution Adjustments	Distribution Amounts	Ratemaking Adjustments	Ratemaking Amounts	Revenue Deficiency	ROE Amounts
	A	B	C	D	E = C + D	F	G = E + F	H	I = G + H
1	Operating Revenues	Adj List Pg 1, Ln. 11	$ 276,904,880	$ (84,692,285)	$ 192,212,595	$ 31,541,193	$ 223,753,787	$ 33,535,937	$ 257,289,724
2	Operating Expenses								
3	Operation	Adj List Pg 1, Ln. 41	$ 125,293,859	$ (68,209,263)	$ 57,084,597	$ 54,434	$ 57,139,031	$ 883,128	$ 58,022,159
4	Maintenance	Adj List Pg 1, Ln. 20	25,568,839	-	25,568,839	356,972	25,925,811	-	25,925,811
5	Depreciation	Adj List Pg 1, Ln. 44	23,907,431	-	23,907,431	7,922,823	31,830,254	-	31,830,254
6	Amortization of General Plant	Per Books	1,878,281	-	1,878,281	-	1,878,281	-	1,878,281
7	Amortization of Capitalized Software	Adj List Pg 1, Ln. 45	3,757,163	(97,980)	3,659,183	-	3,659,183	-	3,659,183
8	Amortization of Unrecovered Plant Loss	Per Books	100,274	-	100,274	-	100,274	-	100,274
9	Interest on Customer Deposits	Adj List Pg 1, Ln. 48	41,769	-	41,769	35,315	77,084	-	77,084
10	Interest on Supplier Refunds	Per Books	11,533	(11,533)	-	-	-	-	-
11	General Taxes	Adj List Pg 2, Ln. 7	58,992,535	-	58,992,535	4,443,796	63,436,331	-	63,436,331
12	Expenses Before Income Taxes	Sum of Lns. 3 > 11	$ 239,551,685	$ (68,318,776)	$ 171,232,910	$ 12,813,340	$ 184,046,250	$ 883,128	$ 184,929,378
13	Income Taxes	Adj List Pg 2, Ln. 10	3,537,493	(3,089,477)	448,015	3,409,377	3,857,393	8,985,237	12,842,630
14	Total Operating Expenses	Sum of Lns. 12 + 13	$ 243,089,178	$ (71,408,253)	$ 171,680,925	$ 16,222,717	$ 187,903,642	$ 9,868,365	$ 197,772,007
15	Net Operating Income	Ln. 1 - Ln. 14	$ 33,815,702	$ (13,284,032)	$ 20,531,669	$ 15,318,475	$ 35,850,145	$ 23,667,572	$ 59,517,717
16	Net Income Adjustments								
17	AFUDC	Per Books	467,443	-	467,443	-	467,443	-	467,443
18	Net Operating Income - Adjusted	Sum of Ln.s 15 > 17	$ 34,283,145	$ (13,284,032)	$ 20,999,112	$ 15,318,475	$ 36,317,588	$ 23,667,572	$ 59,985,160
19	Net Rate Base	Rate Base Stmt, Ln.23	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (34,336,831)	$ 761,839,660	$ -	$ 761,839,660
20	Return Earned	Ln. 18 / Ln. 19	4.22%		2.64%		4.77%		7.87%
21	Return on Common Equity								
22	Interest Expense		$ 19,142,496	$ (330,939)	$ 18,811,557	$ (811,289)	$ 18,000,268		$ 18,000,268
23	Net Income Available for Common Equity	Ln. 18 - Ln. 22	$ 15,140,649		$ 2,187,555		$ 18,317,320		$ 41,984,892
24	Common Equity Ratio	Cost of Capital, Ln. 3	52.49%		52.49%		52.49%		52.49%
25	Common Equity Capital	Ln. 19 * Ln. 24	$ 426,291,579		$ 417,878,033		$ 399,856,140		$ 399,856,140
26	Return Earned on Common Equity	Ln. 23 / Ln. 25	3.55%		0.52%		4.58%		10.50%

Washington Gas Light Company
District of Columbia Jurisdiction

Average Rate Base Summary

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	Per Books Amount	Distribution Adjustments	Distribution Amount	Ratemaking Adjustments	Ratemaking Amount
	A	B	C	D	E = C + D	F	G = E + F
1	Gas Plant in Service		$ 1,317,182,832	$ (770,154)	$ 1,316,412,678	$ 27,107,163	$ 1,343,519,841
2	Construction Work in Progress		79,322,274	-	79,322,274	(72,437,698)	6,884,577
3	Materials & Supplies	Adj List Pg 2, Ln. 14	19,836,447	(16,895,300)	2,941,148	-	2,941,148
4	Non-Plant ADIT		(3,062,666)		(3,062,666)	(293,256)	(3,355,922)
5	FC 1027 - Rate Base CWIP (Reg Asset) _a/		(0)	-	(0)	-	(0)
6	Unamortized East Station _a/	Adj List Pg 2, Ln. 19	1,075,846	-	1,075,846	690,481	1,766,327
7	Sub-Total	Sum of Lns. 1 > 3	$ 1,414,354,734	$ (17,665,454)	$ 1,396,689,281	$ (44,933,310)	$ 1,351,755,971
8	Cash Working Capital	Adj List Pg 2, Ln. 17	39,219,091	652,610	39,871,701	1,801,320	41,673,021
9	Gross Rate Base	Ln. 7 + Ln. 8	$ 1,453,573,825	$ (17,012,844)	$ 1,436,560,981	$ (43,131,989)	$ 1,393,428,992
10	LESS:						
11	Reserve for Depreciation	Per Books	$ 449,057,859	$ (356,329)	$ 448,701,530	$ 7,495,833	$ 456,197,363
12	ADIT: M.A.C.R.S. Depreciation	Per Books	212,149,665	-	212,149,665	3,877,037	216,026,702
13	ADIT: Gains/Losses on Reaquired Debt (Federal)	Per Books	29,300	-	29,300	-	29,300
14	ADIT: Gains/Losses on Reaquired Debt (State)	Per Books	10,143	-	10,143	-	10,143
15	NOL Carryforward Federal	Per Books	(14,916,809)	-	(14,916,809)	(20,845,267)	(35,762,077)
16	NOL Carryforward State	Per Books	(13,095,164)	-	(13,095,164)	857,264	(12,237,900)
17	NOL Federal Benefit of State	Per Books	2,749,985	-	2,749,985	(180,026)	2,569,959
18	Customer Advances for Construction	Per Books	305,769	-	305,769	-	305,769
19	Customer Deposits	Per Books	1,432,785	-	1,432,785	-	1,432,785
20	Supplier Refunds	Adj List Pg 2, Ln. 25	626,315	(626,315)	-	-	-
21	Deferred Tenant Allowance	Per Books	3,017,287	-	3,017,287	-	3,017,287
22	Total Rate Base Deductions	Sum of Lns. 11 > 21	$ 641,367,135	$ (982,644)	$ 640,384,490	$ (8,795,158)	$ 631,589,332
23	Net Rate Base	Ln. 9 - Ln. 22	$ 812,206,690	$ (16,030,199)	$ 796,176,491	$ (34,336,831)	$ 761,839,660

a/ Net of deferred taxes

Washington Gas Light Company
District of Columbia

Determination of Revenue Deficiency

Twelve Months Ended March 31, 2024

Line No.	Description	Reference	DC Distribution Amount	DC Ratemaking Amount	Per Book Proof	After Increase Proof
	A	B	C	D	E	F
1	Revenue Deficiency					
2	Net Rate Base	Rate Base Stmt, Ln.23	$ 796,176,491	$ 761,839,660	$ 812,206,690	$ 761,839,660
3	Overall Rate of Return	Cost of Capital, Ln. 4	7.87%	7.87%	7.87%	7.87%
4	Required Return	Line 2 x Line 3	$ 62,688,747	$ 59,985,160	$ 63,950,921	$ 59,985,160
5	Net Utility Operating Income	DC Inc Stmt, Ln. 18	20,999,112	36,317,588	34,283,145	59,985,160
6	Return Deficiency	Line 4 - Line 5	$ 41,689,635	$ 23,667,572	$ 29,667,776	$ (0)
7	DC Income Taxes	Line 9 x footnote a/	4,745,138	2,693,857	3,376,803	-
8	Federal Income Taxes	Line 9 x footnote b/	11,082,055	6,291,380	7,886,371	-
9	Revenue Deficiency before Uncollectibles	Line 6 / footnote c/	$ 57,516,828	$ 32,652,809	$ 40,930,950	$ -
10	Allowance for Uncollectible Accounts	Line 9 x footnote d/	1,555,600	883,128	1,107,018	-
11	Total Revenue Deficiency	Line 9 + Line 10	$ 59,072,428	$ 33,535,937	$ 42,037,968	$ -
a/	DC Income Tax Rate		8.2500%	8.2500%	8.2500%	8.2500%
b/	Federal Income Tax Rate (1 - 8.25%)*21%		19.2675%	19.2675%	19.2675%	19.2675%
	Composite Tax Rate		27.5175%	27.5175%	27.5175%	27.5175%
c/	Complement of Composite Tax Rate (1 - 27.518%)		72.483%	72.483%	72.483%	72.483%
d/	Uncollectible Rate		2.7046%	2.7046%	2.7046%	2.7046%

Washington Gas Light Company
District of Columbia Jurisdiction

Utility Cost of Capital

Twelve Months Ended March 31, 2024

Line No.	Description	Ratio	Cost	Weighted Cost
	A	C	D	E = C x D
1	Long-term Debt	42.88%	4.84%	2.08%
2	Short-term Debt	4.63%	6.20%	0.29%
3	Common Equity	52.49%	10.50%	5.51%
4	Total	100.00%		7.87%

ATTESTATION

I, TRACEY M. SMITH, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Tracey M. Smith

TRACEY M. SMITH

7/25/2024

DATE

WITNESS WHITE
EXHIBIT WG (G)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF RONALD E. WHITE, PH.D.
Exhibit WG (G)

Table of Contents

Exhibits

WASHINGTON GAS LIGHT COMPANY
DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF
RONALD E. WHITE, PH.D.

I. INTRODUCTION AND QUALIFICATION

Q. PLEASE STATE YOUR NAME, EMPLOYER AND BUSINESS ADDRESS.

A. My name is Ronald E. White. I serve as President of Foster Associates Consultants, LLC. Foster Associates is a public utility economics consulting firm. My business address is 17595 S. Tamiami Trail, Suite 260, Fort Myers, Florida 33908. A summary of my formal education, employment history and other professional qualifications is provided in Exhibit WG (G) –1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Foster Associates was engaged by Washington Gas Light Company ("Washington Gas" or "Company") to conduct a 2024 depreciation study for gas properties subject to the jurisdiction of the Public Service Commission of the District of Columbia. The scope of the engagement included a 2024 Technical Update of plant subject to the jurisdiction of the Virginia State Corporation Commission and a 2024 Technical Update of plant subject to the jurisdiction of the Maryland Public Service Commission.[1] The purpose of my testimony is to sponsor the study conducted by Foster Associates for the District of Columbia. My testimony supports the reasonableness of the Company's proposed depreciation rates for use in this proceeding.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. A summary of my professional qualifications is contained in Exhibit WG (G)–1. I also sponsor Exhibit WG (G)–2, a document titled "2024 Depreciation

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[1] The need to conduct updates is derived from cross–allocations of plant among jurisdictions.

Rate Study." These exhibits were prepared by me or under my direction and supervision.

IV. SUMMARY

Q. PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS RECOMMENDED FOR WASHINGTON GAS IN THE 2024 STUDY

A. Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of service lives and net salvage parameters recommended for Washington Gas the 2024 Study.

Function	Accrual Rates			2024 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Storage	2.14%	1.90%	-0.24%	$ 321,671	$ 229,278	$ (92,393)
Transmission	1.57%	2.22%	0.65%	1,007,377	1,424,404	417,027
Distribution	2.01%	2.60%	0.59%	21,217,984	27,432,452	6,214,468
General	5.57%	5.56%	-0.01%	4,006,201	4,000,927	(5,274)
Total	2.21%	2.75%	0.54%	$26,553,233	$33,087,061	$6,533,828

Table 1. Current and Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.75 percent. Depreciation expense is currently accrued at an equivalent composite rate of 2.21 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.54 percentage points.

A continued application of currently approved rates would provide annualized depreciation expense of $26,553,233 compared with an annualized expense of $33,087,061 using the rates developed in this study.

The 2024 increase in rates and accruals is largely attributable to: a) Settlement of *Formal Case No. 1162* in which the settling parties agreed to retain depreciation rates developed in a 2015 depreciation study; b) A prescribed "present value method" of accruing for net salvage with no provision for adjusting annual accrual rates; and c) A growth rate of 80 percent in jurisdictional plant investment over the period 2014–2023.

Of the 50 primary accounts included in the 2024 study, Foster Associates is recommending rate reductions for 15 accounts, rate increases for 23 accounts and no change for 12 accounts.

V. DEVELOPMENT OF DEPRECIATION RATES

Q. PLEASE EXPLAIN THE GOAL OF DEPRECIATION ACCOUNTING AND WHY DEPRECIATION STUDIES ARE CONDUCTED PERIODICALLY.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. The service potential (or future economic benefit) of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other noncash expenses) or cash inflows attributable to the use of that asset alone. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life system) of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life become more certain. Future net salvage rates and projection curves, which describe the future distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of an accounting disclosure of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or timing of depreciation expense for an unregulated entity. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues which, in turn, are dependent upon approved levels of depreciation expense. Appropriate depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation can be a significant source of internally generated funds used to finance plant replacements, new capacity additions or other cash expenditures. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.[2]

Q. PLEASE DESCRIBE THE PRINCIPAL ACTIVITIES UNDERTAKEN IN CONDUCTING A DEPRECIATION STUDY.

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is

[2] I do not discuss nor have I considered whether other regulatory or public policy goals should influence or be reflected in establishing depreciation rates. Such considerations remain the prerogative of the regulatory agency responsible for prescribing appropriate depreciation rates

used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The probability distributions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the estimated projection–life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy (or inadequacy) of recorded depreciation reserves. The purpose of such an analysis is to compare current recorded reserve balances with balances required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between required (or theoretical) reserves and recorded reserves provides an estimate of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish reserve imbalances.

Although reserve records are typically maintained by various account classifications, the sum of all account reserves is the most important indicator of the adequacy (or inadequacy) of recorded depreciation reserves. Differences between theoretical (or computed) and recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise when depreciation rates are negotiated in settlements that shift the timing of depreciation expense to future accounting periods. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute or rebalance recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and net salvage rates. A redistribution of recorded reserves will initialize reserve balances for each primary account consistent with revised estimates of net salvage and service–life statistics, and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are entered into a formulation of an accrual rate using a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Figure 1 below.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Figure 1. Elements of a Depreciation System

The above elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

VI. 2024 DEPRECIATION RATE STUDY

Q. PLEASE DESCRIBE THE SOURCE OF DEPRECIATION RATES CURRENTLY USED BY WASHINGTON GAS.

A. Depreciation rates currently used by Washington Gas were approved by the Public Service Commission of the District of Columbia in *Formal Case No. 1162* (Order No. 20705, dated February 24, 2021). The 2021 Order approved a Non–unanimous Settlement Agreement in which the settling parties agreed to retain depreciation rates developed in a 2015 depreciation study and approved in *Formal Case No. 1137* (Order No. 18712, dated Match 3, 2017).

Q. DID WASHINGTON GAS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2024 DEPRECIATION STUDY?

A. Yes. The database used in conducting the 2024 study was assembled by appending plant and net salvage transactions recorded over the period 2020–2023 to the database used in conducting a 2020 Virginia depreciation study and update of the District of Columbia service–life parameters. The accuracy and completeness of the appended transactions was verified by comparisons to ledger activity recorded for activity years 2020–2023. Activity–year transactions prior to 2020 were validated in prior studies. Derived age distributions on December 31, 2023 were confirmed by comparisons to age distributions maintained in the Continuing Property Record (CPR) system currently used by Washington Gas.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR WASHINGTON GAS PLANT AND EQUIPMENT?

A. Yes. The 2024 study was conducted on plant and equipment physically located within the District (called *situs* property). A portion of these investments, however, is used to provide utility services to customers residing in other regulatory jurisdictions (*i.e.*, Maryland and Virginia). Similarly, a portion of the investments located in other jurisdictions directly benefits customers residing in the District and is allocated to District operations. Absent an agreement amongst these jurisdictions to allocate depreciation expense derived from the rates approved by the jurisdiction in which the plant is physically located, each jurisdiction is obligated to approve depreciation rates applied to plant allocated from a neighboring jurisdiction.

The terminology adopted by Washington Gas to describe plant allocated to or from another jurisdiction is *assigned* and *unassigned*. Assigned plant is plant located within a jurisdiction and devoted solely to serving customers residing within the jurisdiction. Assigned plant is not allocated to other jurisdictions.

Unassigned plant is pooled with similar property located in other jurisdictions and the pooled investment is allocated among jurisdictions based on annually adjusted use factors. A portion of the unassigned plant located within a jurisdiction is thereby "returned" to the jurisdiction in which the plant is located. The portion of a pooled account allocated to a jurisdiction is called *allocated property*.

As discussed in Exhibit WG (G)–2, all plant accounts were analyzed using a technique in which first, second- and third-degree polynomials were fitted to a set of observed retirement ratios. The resulting function was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life. Observed proportions surviving were then fitted by a weighted least–squares procedure to the Iowa–curve family (using projection lives derived from the polynomial hazard function) to obtain a mathematical description or classification of the dispersion characteristics of the data.

Service–life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life and curve for each plant category.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS FOR WASHINGTON GAS PLANT AND EQUIPMENT?

A. Yes. Five–year moving averages of the ratio of realized salvage and cost of removal to the associated retirements were used in the 2024 study to a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) obtain a quantitative basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from Washington Gas operating personnel were blended with judgment and historical net salvage indications in developing future net salvage estimates.

Q. ARE YOU FAMILIAR WITH A COMMISSION DIRECTIVE IN FORMAL CASE NO. 1137 REGARDING THE ESTIMATION OF FUTURE NET SALVAGE RATES FOR DISTRIBUTION MAINS AND SERVICES?

A. Yes. The Commission directed Washington Gas to "… revisit its policy to allocate 16.5% of the cost of main and service replacements to cost of removal in developing its new depreciation study."[3] As discussed in Exhibit WG (G)–2, in 2018 Washington Gas retained an independent contractor to conduct a review of its pipe replacement processes and practices, and provide a recommended allocation methodology and ratios to bifurcate the cost of pipe replacement projects between expenditures attributable to removal and new asset installations. Based on the findings and recommendations of the review, Washington Gas adopted a 7.6 percent cost of removal ratio for Mains and a 20.2 percent ratio for services located in the District of Columbia, The revised ratios were adopted at the end of 2019.

[3] *Formal Case No 1137* (Order No. 18712, ¶142.

Table 2 below provides a comparison of realized, current and proposed net salvage rates recommended in the 2024 depreciation study for distribution mains and services. It can be observed from this comparison that net salvage rates recommended in the 2024 study (Column D), tempered to mitigate otherwise significantly higher revenue requirements, are relatively modest increases from current rates (Column C) and far lower than 2015–2023 average realized rates (Column B) that will likely persist into the future.

Account Description	Realized	Current	Proposed
A	B	C	D
Distribution Plant			
376.10 Mains - Steel	-748%	-50%	-75%
376.20 Mains - Plastic	-215%	-50%	-75%
380.10 Services - Steel	-1340%	-60%	-75%
380.20 Services - Plastic	-170%	-60%	-75%

Table 2. Comparative Net Salvage Rates (Realized 2015-2023)

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes. Exhibit WG (G)–2, Statement C provides a comparison of computed and recorded reserves for Washington Gas on December 31, 2023. The recorded reserve was $448,406,676, or 37.3 percent of the depreciable plant investment. The corresponding computed reserve is $428,284,104 or 35.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $20,122,572 will be amortized over the composite weighted–average remaining life of each rate category using the remaining–life depreciation rates proposed in this study.

Q. HOW ARE DEPRECIATION RESERVES MAINTAINED FOR POOLED INVESTMENTS?

A. Reserves are maintained by primary account within each jurisdiction for both assigned and allocated property. Depreciation reserves associated with pooled investments are not allocated among jurisdictions. Depreciation accruals credited to the reserves associated with allocated plant are based on the depreciation rates approved by the jurisdiction in which the reserves are maintained. Unassigned plant retirements and realized net salvage are allocated to the jurisdictional reserves based on annually adjusted use factors. The portion of an allocated reserve attributable to plant located in a neighboring jurisdiction is not identifiable by jurisdiction.

Q. IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF DEPRECIATION RESERVES FOR WASHINGTON GAS?

A. Yes Offsetting reserve imbalances attributable to the passage of time, the use of SFAS 143 accrual rates for net salvage and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable assigned plant categories was achieved by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserves to the function total calculated reserve. The sum of the redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before the redistribution. Recorded reserves for allocated plant categories were redistributed within each primary account to obtain the portion of an allocated reserve attributable to plant physically located within each pooled jurisdiction. Depreciation reserves for amortizable categories were redistributed by setting recorded reserves for amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing residual imbalances to the remaining depreciable accounts within the appropriate function.

Q. PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED BY THE COMMISSION FOR WASHINGTON GAS.

A. Current depreciation rates were developed for each primary account as two–part rates using a) the currently approved system composed of the straight–

line method, vintage group procedure, remaining–life technique for investment accrual rates and b) the "present value method in SFAS–143" directed by the Commission in *Formal Case No. 1093* for net salvage accrual rates.[4]

The investment portion of accrual rates using the currently approved system is given by:

$$\text{Accrual Rate} = \frac{\text{1.0-Investment Reserve Ratio}}{\text{Remaining Life}}.$$

The net salvage portion of the accrual rate is the sum of a straight–line, whole–life rate applied to the Asset Retirement Cost and the accretion rate applied to the present value of future net salvage (PVFNS). The formulation of the net salvage accrual rate is given by:

$$\text{Accrual Rate} = \frac{\text{Asset Retirement Cost}}{\text{(Plant)(Average Life)}} + \frac{\text{(PVFNS)(Accretion Rate)}}{\text{Plant}}.$$

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM FOR WASHINGTON GAS?

A. No. Depreciation rates recommended in the 2024 study were developed using the currently approved system. With the exception of SFAS 143 accrual rates for net salvage, it is the opinion of Foster Associates that this system will remain appropriate for Washington Gas, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance-based regulation may ultimately encourage abandonment of the straight–line method, no consideration was given in the

[4] The Commission found that "... consistent with our depreciation rulings in *Formal Case No. 1076*, going forward, depreciation rates for WGL shall use the present value method in SFAS–143 (recodified in ASC410) for collecting for future net removal costs using the formulas ordered by the Commission in Order No. 15710 in *Formal Case No. 1076*, which are the formulas from Maryland Case No. 9092; net salvage shall be calculated as described in this Opinion and Order; an inflation–based discount rate and the remaining–life depreciation method shall be used to calculate WGL's depreciation rates going forward and WGL is directed not to transfer monies out of its depreciation reserve into income without prior Commission Approval."

current study to address this concern. It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

RONALD E. WHITE, PH.D.

EDUCATION

1961 – 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated with the Service Life of Industrial Property

EMPLOYMENT

2015 – Present: Foster Associates Consultants, LLC, President

2007 – 2015 Foster Associates, Inc., Chairman

1996 – 2007 Foster Associates, Inc., Executive Vice President

1988 – 1996 Foster Associates, Inc., Senior Vice President

1979 – 1988 Foster Associates, Inc., Vice President

1978 – 1979 Northern States Power Company, Assistant Treasurer

1974 – 1978 Northern States Power Company, Manager, Corporate Economics

1972 – 1974 Northern States Power Company, Corporate Economist

1970 – 1972 Iowa State University, Graduate Student and Instructor

1968 – 1970 Northern States Power Company, Valuation Engineer

1965 – 1968 Iowa State University, Graduate Student and Teaching Assistant

PUBLICATIONS

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem with AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

TESTIFYING WITNESS

- Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.
- Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.
- Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.
- Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.
- Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.
- Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.
- Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.
- Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–16–0036, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–19–0236, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–22–0144, Arizona Public Service Company; rebuttal testimony to Staff advocated treatment of net salvage accrual rates.

- Arizona Corporation Commission, Docket No. E–04204A–22–0251, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01933A–12–0126, Tucson Electric Power Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01933A–15–0322, Tucson Electric Power Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01933A–19–0028, Tucson Electric Power Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc.; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–04204A–15–0142, UNS Electric, Inc.; testimony supporting proposed depreciation rates.
- Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.
- California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.
- California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.
- California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.
- California Public Utilities Commission. Application No. A.16–09–001 Southern California Edison; testimony regarding estimation of service lives and net salvage rates.
- Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.
- State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.
- State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.
- State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.
- State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.
- Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.
- Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.
- Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

- Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1093, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1115, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1137, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1162, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.
- Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.
- Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.
- Federal Energy Regulatory Commission, Docket No. RP14-118-000, WBI Energy Transmission, Inc.; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC *Transmission*; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

- Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.
- Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.
- Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.
- Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.
- Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.
- Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.
- Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.
- Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.
- Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.
- Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.
- Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.
- Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.
- Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.
- Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.
- Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.
- Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.
- Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.
- Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

- Kansas Corporation Commission, Docket No. 23-EKCE-775-RTS, Evergy Kansas Central, Evergy Kansas South and Evergy Kansas Metro; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 24-KGSG-610-RTS, Kansas Gas Service, a Division of ONE Gas, Inc, testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 16-KGSG-491-RTS, Kansas Gas Service, a Division of ONE Gas, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 12-KGSG-835-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 12-WSEE-328-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 18-WSEE-328-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.
- Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.
- Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 18–KGSG–560–RTS, Kansas Gas Service, a Division of ONE Gas, Inc.; testimony supporting proposed depreciation rates.
- Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9424, Delmarva Power and Light Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9385, Potomac Electric Power Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9481, Washington Gas Light Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

- Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.
- Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 15–155, Massachusetts Electric Company/Nantucket Electric Company; testimony supporting proposed depreciation rates.
- Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.
- Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.
- Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.
- Michigan Public Service Commission, Case No. U–18150, DTE Electric Company; testimony supporting proposed depreciation rates.
- Michigan Public Service Commission, Case No. U–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.
- Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.
- Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.
- Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.
- Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates
- Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.
- Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.
- Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.
- Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.
- Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

- Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.
- Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.
- Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.
- Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.
- Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.
- Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.
- Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.
- Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.
- Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.
- Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.
- Montana Public Service Commission, Docket No. D2018.2.12, NorthWestern Energy –Montana; testimony supporting proposed depreciation rates.
- Montana Public Service Commission, Docket No. D2022.07.078, NorthWestern Energy – Montana; testimony supporting proposed depreciation rates.
- Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.
- Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.
- Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.
- New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.
- New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.
- New Jersey Board of Public Utilities, Docket No. GR87060552, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

- New Jersey Board of Public Utilities, Docket No. GR21030679, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.
- New Jersey Board of Public Utilities, Docket No. GR19030420, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.
- New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony supporting depreciation rates.
- New Jersey Board of Regulatory Commissioners, Docket No. GR15111304, New Jersey Natural Gas Company; testimony supporting depreciation rates.
- New York Public Service Commission, Case No. 12–G–0202. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.
- New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.
- North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.
- North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.
- North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.
- North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- Oklahoma Corporation Commission, Cause No. PUD 202100063, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.
- Oklahoma Corporation Commission, Cause No. PUD 201500213, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.
- Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.
- Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.
- Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.
- Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.
- Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.
- Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.
- Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

- Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.
- Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.
- Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.
- Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.
- Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.
- Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.
- Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.
- Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.
- Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.
- South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.
- South Dakota Public Utilities Commission, Docket No. EL14–106, NorthWestern Energy; testimony supporting revised depreciation rates.
- Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.
- Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

- Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.
- The Railroad Commission of Texas, GUD Docket No. 9896, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 9988, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10488, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10506, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10656, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10526, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10928, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 14399, Texas Gas Service, testimony supporting recommended depreciation rates.
- State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.
- State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.
- Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.
- Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

Other Consulting Engagements

Arbitrator in a Technical Dispute relating to classification of Capital Budget expenditures.

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

SR International Business Insurance Co. vs. WTC Properties et. al., 01,CV–9291 (JSM) and other related cases.

BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, et. al. File No. 394126; testimony concerning depreciation and engineering economics.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee).

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

SPEAKER

Depreciation Training Seminar, Kansas Gas Service, October 2018.

Depreciation Workshop, Oklahoma Corporation Commission, Public Utility Division, March 2015.

Depreciation Workshop, ONE Gas, Inc. January 2015.

Depreciation Training Seminar, Florida Public Service Commission, March 2013.

Depreciation and Obsolescence (Isness and Oughtness), Ninety–Fifth Annual Arizona Tax Conference, August 2012.

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation? American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

HONORS AND AWARDS

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

July 2024

EXHIBIT WG (G)–2

2024 Depreciation Rate Study

Washington Gas™

A WGL Company

– District of Columbia

foster associates

CONTENTS

DISTRIBUTION

380.10 – SERVICES – STEEL

EXECUTIVE SUMMARY

INTRODUCTION

This report presents findings and recommendations developed in a 2024 Depreciation Rate Study conducted by Foster Associates Consultants, LLC (Foster Associates) for gas plant owned and operated by Washington Gas Light Company – District of Columbia (Washington Gas). Work on the study commenced in January 2024 and progressed through July, at which time the project was completed.

Foster Associates is a public utility economics consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers Florida office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by Washington Gas were approved by the Public Service Commission of the District of Columbia in *Formal Case No. 1162* (Order No. 20705, dated February 24, 2021). The 2021 Order approved a Non–unanimous Settlement Agreement in which the settling parties agreed to retain depreciation rates developed in a 2015 depreciation study and approved in *Formal Case No. 1137* (Order No. 18712, dated Match 3, 2017).

The current depreciation study was conducted on plant and equipment physically located within the District (called *situs* property). A portion of these investments, however, is used to provide utility services to customers residing in other regulatory jurisdictions (*i.e.*, Maryland and Virginia). Similarly, a portion of the investments located in other jurisdictions directly benefits customers residing in the District and is allocated to District operations. Absent an agreement amongst these jurisdictions to allocate depreciation expense derived from the rates approved by the jurisdiction in which the plant is physically located, each jurisdiction is obligated to approve depreciation rates applied to plant allocated from a neighboring jurisdiction.

The terminology adopted by Washington Gas to describe plant allocated to or from another jurisdiction is *assigned* and *unassigned*. Assigned plant is plant located within a jurisdiction and devoted solely to serving customers residing within the jurisdiction. Assigned plant is not allocated to other jurisdictions.

Unassigned plant is pooled with similar property located in other jurisdictions and the pooled investment is allocated among all jurisdictions based on annually adjusted use factors. A portion of the unassigned plant located within a jurisdiction is thereby "returned" to the jurisdiction in which the plant is located. The portion of a pooled account allocated to a jurisdiction is called *allocated property*.

Depreciation reserves associated with pooled investments are not allocated among jurisdictions. Reserves are maintained by primary account within each jurisdiction for both assigned and allocated property. Depreciation accruals credited to the reserves associated with allocated plant are based on depreciation rates approved by the jurisdiction in which the reserves are maintained. Unassigned plant retirements and realized net salvage are allocated to the jurisdictional reserves based on annually adjusted use factors. The portion of an allocated reserve attributable to plant located in a neighboring jurisdiction is not identifiable by jurisdiction.

Depreciation rates and accruals for plant allocated to District operations from neighboring jurisdictions were derived in the 2024 study using the parameters (*i.e.*, projection curves, projection lives and future net salvage rates) estimated for the jurisdiction in which the plant is physically located. Proposed accrual rates for allocated property, however, were derived using the age distributions of surviving plant and depreciation reserves specific to District operations. Average service lives, remaining lives and average net salvage rates were derived from 2024 technical updates for Maryland and Virginia.

In April 2006, Washington Gas migrated to a new plant accounting system that incorporated a change in the treatment of general amortizable plant from prior depreciation studies. The change in treatment was necessitated by differing Commission orders approving, modifying or denying amortization accounting as requested by the Company.

The District of Columbia, for example, initially prescribed depreciation accounting for selected general asset categories for which Maryland and Virginia had approved amortization accounting—although over differing amortization periods.[1] The plant accounting effort required to comply with these jurisdictional differences necessitated an unbundling of previously pooled investments such that each jurisdiction is now assigned a static portion of each vintage addition. The portion assigned to a jurisdiction receives the prescribed accounting treatment of that jurisdiction. The 2024 study retains the current accounting treatment of amortizable categories.

The principal findings and recommendations of the District of Columbia Depreciation Rate Study are summarized in the Statements section of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and

[1]The Commission subsequently approved amortization accounting in *Formal Case No. 1054* (Order No. 14694 dated December 27, 2007). Depreciation accounting was not requested for ENSCAN Equipment.

proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides the ordered computation of a SFAS 143 formulation of accrual rates for net salvage. Statement E provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and future net salvage rates.

Scope of Study

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Discussions with Washington Gas plant accounting and regulatory personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Estimation of future net salvage ratios;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

Depreciation System

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of accruals for net salvage and amortization of several general plant categories, Washington Gas is currently using a depreciation system composed of the straight–line method, vintage group procedure and remaining–life technique. The so–called "present value method" of accruing for net salvage was ordered by the Commission in *Formal Case No. 1093*.[2] Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.*, credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period.

[2]*Formal Case No. 1093* (Order No. 17204), ¶ 340(w).

Depreciation theory provides that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the approved amortization categories.

PROPOSED DEPRECIATION RATES

Table 1 below provides a summary of the changes in annual rates and accruals resulting from the recommended parameters and depreciation system used in this study.

	Accrual Rates			2024 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Storage	2.14%	1.90%	-0.24%	$ 321,671	$ 229,278	$ (92,393)
Transmission	1.57%	2.22%	0.65%	1,007,377	1,424,404	417,027
Distribution	2.01%	2.60%	0.59%	21,217,984	27,432,452	6,214,468
General	5.57%	5.56%	-0.01%	4,006,201	4,000,927	(5,274)
Total	2.21%	2.75%	0.54%	$26,553,233	$33,087,061	$6,533,828

Table 1. Current and Proposed Rates and Accruals

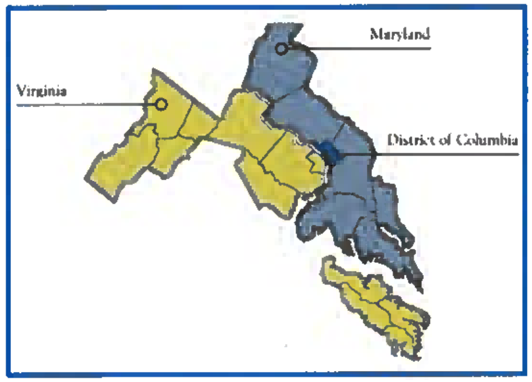
Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.75 percent. Depreciation expense is currently accrued at an equivalent composite rate of 2.21 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.54 percentage points.

A continued application of currently approved rates would provide annualized depreciation expense of $26,553,233 compared with an annualized expense of $33,087,061 using the rates developed in the 2024 study. The increase in rates and accruals is largely attributable to: a) Settlement of *Formal Case No. 1162* in which the settling parties agreed to retain depreciation rates developed in a 2015 depreciation study; b) A prescribed "present value method" of accruing for net salvage with no provision for adjusting annual accrual rates; and c) A growth rate 80 percent in jurisdictional plant investment over the period 2014–2023.

Of the 50 primary accounts included in the 2024 study, Foster Associates is recommending rate reductions for 15 accounts, rate increases for 23 accounts and no change for 12 accounts.

COMPANY PROFILE

GENERAL



Washington Gas is a public utility that delivers and sells natural gas to customers in Washington D.C. and adjoining areas in Maryland and Virginia. The Company has been in the natural gas business for 172 years, originally incorporated by an Act of Congress in 1848. Washington Gas became a domestic corporation of Virginia in 1953 and a corporation of the District of Columbia in 1957.

On November 1, 2000, a corporate restructuring occurred in which Washington Gas and its subsidiaries became separate subsidiaries of WGL Holdings, Inc., a newly formed holding company incorporated in the Commonwealth of Virginia. As of October 31, 2018, all of the outstanding shares common stock of WGL Holdings are held by Wrangler 1 LLC, and indirect wholly owned subsidiary of AltaGas Ltd.

Rates the Company is allowed to charge for its distribution services are set separately by regulatory commissions in Virginia, Maryland and the District of Columbia. All information referred to as the Company's Virginia Territory includes the operations of the former Shenandoah Division.

GAS UTILITY OPERATIONS

At December 31, 2023, Washington Gas owned and operated approximately 621 miles of transmission mains, 13,777 miles of distribution mains and 13,756 miles of distribution services. Of this total, approximately 31 miles of transmission mains, 1,244 miles of distribution mains and 1,167 miles of distribution services are located in the Company's District of Columbia Territory. Washington Gas owns approximately 20 acres of land and two buildings (completed in 2012) at 6801 and 6803 Industrial Road in Springfield, Virginia. The Springfield site houses both operating and certain administrative functions of the utility.

In addition, the Company has title to land and buildings used as substations for its utility operations. These buildings are common facilities that serve customers in each of the Company's three jurisdictions. Washington Gas also has peaking facilities consisting of propane air plants in West Springfield, Virginia (Ravensworth Plant) and Rockville, Maryland (Rockville Plant). At December 31, 2023, Washington Gas has the storage capacity for approximately 15.0 million gallons of propane for peak–shaving.

Customer Base

On December 31, 2023, Washington Gas had approximately 1,390,903 customers (as defined as connected customer meters) in its three jurisdictions with 184,395 located in the District of Columbia Territory. Approximately 164,600 of these customers in the Company's District of Columbia Territory purchase both natural gas and distribution services as a bundled service from Washington Gas, with an additional 19,795 customers receiving distribution services from Washington Gas and purchasing the natural gas commodity from a third–party marketer. The Company's retail sales are seasonal and temperature–sensitive as the majority of gas sold by the Company is used for residential heating.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This study provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Washington Gas for the District of Columbia. The proposed rates are subject to approval by the Public Service Commission of the District of Columbia.

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2024 study included consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing the plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. The data are processed by a computer program and transaction summary reports are created in a format reconcilable to the Company's official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system currently used by Washington Gas provides aged transactions over the period 1986–2018 for all plant accounts.

In 1984, Washington Gas converted its plant records from a manual card system to an in–house electronic CPR where records were maintained until conversion to a PeopleSoft asset management system in 1999. Plant accounting records prior to 1999 were retained in a magnetic tape medium. The PeopleSoft system was converted to PowerPlant in 2006 in three stages: 1) October 2004–September 2005; 2) October 2005–February 2006; and 3) March 2006–April 2006. The new system was uploaded with age distributions at September 30, 2004. PeopleSoft was operational until the conversion was completed in April 2006.

Databases used in conducting depreciation studies are assembled by assigning codes to accounting transactions recorded by the Company. Transaction codes for plant additions, for example, are used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes are used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes are also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity relevant to conducting a depreciation study.

The database used in conducting the 2024 study was assembled by appending plant and net salvage transactions recorded over the period 2020–2023 to the database used in conducting a 2020 Virginia depreciation study and update of the District of Columbia service–life parameters. The accuracy and completeness of the appended transactions was verified by comparisons to ledger activity recorded for activity years 2020–2023. Transactions for prior activity years were validated in prior studies. Derived age distributions on December 31, 2023 were confirmed by comparisons to age distributions maintained in the current CPR system.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of service life known as the *projection life* of the account. Mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve. The amount of weight given to the life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available.

An actuarial life analysis program designed and developed by Foster Associates was used in conducting the 2024 study. The first step in an actuarial analysis involves a systematic treatment of available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally contains the age of each survivor and the age of each retirement from a group of property units installed in a given accounting year.

A life table can be constructed in any one of at least five alternative methods. The annual–rate or retirement–rate method was used in the 2024 study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ratio (or set of ratios) is commonly referred to as retirement ratios. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age–interval by the proportion of the original group surviving at the beginning of that interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in the 2024 study are the Iowa–type curves which are mathematically described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second and third degree polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function, which is numerically integrated to obtain an estimate of average service life. The observed proportions surviving were then fitted by a weighted least–squares procedure to the Iowa–curve family (using the projection life derived from the polynomial hazard function) to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in the 2024 study provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined for a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the actuarial life analysis program include the width and location of both placement and observation bands; the interval of years included in a selected rolling or shrinking band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis and algorithms for calculating depreciation rates and accruals.

While actuarial and semi–actuarial statistical methods are well–suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters and services), these methods are not well–suited to plant categories composed of major items of plant that will most likely be retired as a single unit. Property units retired from an integrated system prior to the retirement of the entire facility are more properly viewed as interim retirements that will be replaced in order to maintain the integrity of the system. A proper depreciation rate can be developed for an integrated system using a life–span method. All plant accounts were treated as full mortality categories in the current study.

While the current study recognizes that the Company has no immediate or long–range plans for abandoning its gas storage facilities, it is the opinion of Foster Associates that a life–span treatment should be adopted if and when a coterminous retirement date is estimated for gas supply planning purposes.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage that reflects both realized and future net salvage rates.

An estimate of the net salvage rate applicable to future retirements is most often obtained from an analysis of gross salvage and removal expense realized in the past. An analysis of past experience (including an examination of trends over time) provides an appropriate basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

Average net salvage rates are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

Five–year moving averages of the ratio of realized salvage and cost of removal to the associated retirements were used in the 2024 study to a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from Company engineers were blended with judgment and historical net salvage indications in developing estimates of the future.

As can be observed from Table 2 below, average realized net salvage rates for distribution mains and services (constituting 80 percent of jurisdictional plant investments) have increased precipitously over the past ranges of calendar years.

Account Description	2006-2014	2015-2023
A	B	C
Distribution Plant		
376.10 Mains - Steel	-461%	-748%
376.20 Mains - Plastic	-175%	-215%
380.10 Services - Steel	-108%	-1340%
380.20 Services - Plastic	-62%	-170%

Table 2. Average Realized Net Salvage Rates

The cause of increasing net salvage ratios is partially attributable to cost of removal stated in current dollars divided by retirements stated in dollars at the year of installation. This increase is predictable when older pipe is retired and replaced at current costs. The extent to which past inflation is captured in the ratio of removal expense to retirements is a function of both the rate of change in the cost of labor required to remove plant from service and the rate of change in the installed unit cost of plant removed. Labor costs are also impacted by increasingly stringent governmental regulations.

As previously reported in *Formal Case No. 1137*, a contributing cause for increasing recorded net salvage was a policy adopted by Washington Gas in 2009 to allocate 16.5 percent of the cost of mains and services replacement projects to cost of removal and the remaining 83.5 percent to the replacement addition. Replacement construction contracts are designed to pay a contractor on a per foot basis for the installation of the replacement pipe. Contractors include the cost to abandon existing facilities in the bid price per foot for installing new pipe. Cost of removal is not identified as a bid item or a pay item on contractor invoices.

In 2018 Washington Gas retained an independent contractor to conduct a review of its pipe replacement processes and practices, and provide a recommended allocation methodology and ratios to separate the cost of pipe replacement projects between expenditures attributable to removal and new asset installations. Based on the findings and recommendations of the review, Washington Gas adopted a 7.6 percent cost of removal ratio for Mains and a 20.2 percent ratio for services located in the District of Columbia, The revised ratios were adopted at the end of 2019.

Table 3 below provides a comparison of Realized, Current and Proposed net salvage rates recommended in the 2024 depreciation study. It can be observed from this comparison that net salvage rates recommended in the 2024 study (Column D), tempered to mitigate otherwise significantly higher revenue requirements, are relatively modest increases from current rates (Column C) and far lower than 2015–2023 average realized rates (Column B) that will likely persist into the future.

Account Description	Realized	Current	Proposed
A	B	C	D
Distribution Plant			
376.10 Mains - Steel	-748%	-50%	-75%
376.20 Mains - Plastic	-215%	-50%	-75%
380.10 Services - Steel	-1340%	-60%	-75%
380.20 Services - Plastic	-170%	-60%	-75%

Table 3. Comparative Net Salvage Rates (Realized 2015-2023)

Depreciation Reserve Analysis

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant currently in service and the sum of the depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important indicator of the adequacy (or inadequacy) of recorded depreciation reserves. While differences between theoretical and recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of conducting depreciation reviews, significant reserve imbalances are often created from negotiated settlements that shift the timing of depreciation expense to future accounting periods. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A redistribution of recorded reserves is considered appropriate for Washington Gas at this time. Offsetting reserve imbalances attributable to the passage of time, the use of SFAS 143 accrual rates for net salvage and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable assigned plant categories was achieved by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserves to the function total calculated reserve. The sum of the redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before the redistribution. Recorded reserves for allocated plant categories were redistributed within each primary account to obtain the portion of an allocated reserve attributable to plant physically located within each pooled jurisdiction. Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the appropriate function.

Statement C provides a comparison of the computed and recorded reserves for Washington Gas on December 31, 2023. The recorded reserve was $448,406,676, or 37.3 percent of the depreciable plant investment. The corresponding computed reserve is $428,284,104 or 35.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $20,122,572 will be amortized over the composite weighted–average remaining life of each rate category using the remaining–life depreciation rates proposed in this study.

Development of Accrual Rates

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time, rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of a time–based method is that it does not require an estimate of the remaining amount of service potential an asset will provide or the amount of service potential actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole–life and remaining–life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2024 study were developed as two–part rates using a) the currently approved system composed of the straight–line method, vintage group procedure, remaining–life technique for investment accrual rates and b) the "present value method" ordered by the Commission in *Formal Case No. 1093* for net salvage accrual rates.[4] The derivation of an "inflation–based discount rate" advocated by the Office of the People's Counsel (OPC) in *Formal Case No. 1093* and approved by the Commission was used in the current study to derive a discount rate of 3.35 percent.[5]

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general plant categories is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories. With the exception of ENSCAN equipment (Account 397.20) which the Commission ordered to remain depreciable, rates shown in Statement A (Column G) are the reciprocal of the reported amortization periods.

[4]*ibid.* The Commission found that "… consistent with our depreciation rulings in *Formal Case No. 1076*, going forward, depreciation rates for WGL shall use the present value method in SFAS–143 (recodified in ASC410) for collecting for future net removal costs using the formulas ordered by the Commission in Order No. 15710 in *Formal Case No. 1076*, which are the formulas from Maryland Case No. 9092; net salvage shall be calculated as described in this Opinion and Order; an inflation–based discount rate and the remaining–life depreciation method shall be used to calculate WGL's depreciation rates going forward and WGL is directed not to transfer monies out of its depreciation reserve into income without prior Commission Approval."

[5]The discount rate used by OPC was the implied rate of inflation over the period 1988–2009 derived from the Handy–Whitman Cost Trends of Gas Utility Construction, Production Plant (S.N.G. Equipment), North Atlantic Region. This derivation was replicated in the current study using S.N.G. Equipment, North Atlantic Region Indexes from Handy–Whitman Bulletin No. 198

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded, computed and redistributed depreciation reserves, and current and proposed service life and net salvage parameters recommended for Washington Gas. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and updated annual depreciation rates using the vintage group procedure, remaining–life technique combined with the Commission ordered SFAS 143 formulation of accrual rates for net salvage.
- Statement B provides a comparison of current and proposed annualized 2024 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves at December 31, 2023.
- Statement D provides the computation of a SFAS 143 formulation of accrual rates for net salvage.
- Statement E provides a comparative summary of current and proposed parameters including projection life, projection curve, average service life, average remaining life, and future net salvage rates.

The investment portion of accrual rates (Statement A) is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Investment Reserve Ratio}}{\text{Remaining Life}}.$$

The net salvage portion of the accrual rate is the sum of a straight–line, whole–life rate applied to the Asset Retirement Cost and the accretion rate applied to the present value of future net salvage (PVFNS). The formulation of the net salvage accrual rate is given by:

$$\text{Accrual Rate} = \frac{\text{Asset Retirement Cost}}{(\text{Plant})(\text{Average Life})} + \frac{(\text{PVFNS})(\text{Accretion Rate})}{\text{Plant}}.$$

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA Statement A

Comparison of Current and SFAS 143 Accrual Rates
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.35 Percent

	Current			SFAS 143		
Account Description	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
STORAGE AND PROCESSING PLANT						
Allocated Property						
361.00 Structures and Improvements						
Maryland (Rockville)	2.39%	0.76%	3.15%	2.06%	0.44%	2.50%
Virginia (Ravensworth)	2.47%	0.50%	2.97%	2.11%	0.42%	2.53%
Total Account 361.00	2.43%	0.64%	3.06%	2.08%	0.43%	2.51%
362.00 Gas Holders						
Maryland (Rockville)	1.69%	0.57%	2.26%	1.11%	0.27%	1.38%
Virginia (Ravensworth)	1.79%	0.34%	2.13%	1.51%	0.29%	1.80%
Total Account 362.00	1.74%	0.47%	2.20%	1.29%	0.28%	1.57%
363.50 Other Equipment						
Maryland (Rockville)	5.37%	0.11%	5.48%	2.24%	0.05%	2.29%
Virginia (Ravensworth)	1.97%	1.54%	3.51%	2.90%	0.42%	3.32%
Total Account 363.50	3.93%	0.72%	4.64%	2.52%	0.21%	2.73%
Total Allocated Property	2.14%	0.53%	2.67%	1.60%	0.30%	1.90%
Total Storage and Processing Plant	2.14%	0.53%	2.67%	1.60%	0.30%	1.90%
TRANSMISSION PLANT						
Assigned Property						
365.20 Rights of Way						
366.00 Meas. and Reg. Station Structures						
367.10 Mains - Steel	0.50%	0.10%	0.60%	1.09%	0.14%	1.23%
369.00 Measuring and Regulating Equipment	1.09%	0.20%	1.29%	1.18%	0.26%	1.44%
Total Assigned Property	0.88%	0.16%	1.05%	1.15%	0.22%	1.37%
Allocated Property						
365.20 Rights of Way						
District	0.33%		0.33%	-4.47%		-4.47%
Maryland	1.60%		1.60%	1.40%		1.40%
Virginia	1.15%		1.15%	0.73%		0.73%
Total Account 365.20	1.45%		1.45%	1.17%		1.17%
366.00 Meas. and Reg. Station Structures						
Maryland	0.33%	1.24%	1.57%	2.13%	1.01%	3.14%
Virginia	1.33%	0.02%	1.35%	2.06%	0.21%	2.27%
Total Account 366.00	1.19%	0.19%	1.38%	2.00%	0.39%	2.39%
367.10 Mains - Steel						
District	1.05%	0.10%	1.15%	1.66%	0.14%	1.80%
Maryland	1.44%	-0.03%	1.41%	1.67%	-0.11%	1.56%
Virginia	1.47%	0.10%	1.57%	1.67%	0.08%	1.75%
Total Account 367.10	1.43%	0.05%	1.48%	1.67%	0.01%	1.68%
369.00 Measuring and Regulating Equipment						
District	-0.18%	0.20%	0.02%	-1.06%	0.26%	-0.80%
Maryland	0.29%	2.40%	2.69%	-0.70%	7.49%	6.79%
Virginia	0.55%		0.55%	-0.92%	-4.95%	-5.87%
Total Account 369.00	0.33%	1.79%	2.13%	-0.76%	4.49%	3.73%
Total Allocated Property	1.04%	0.66%	1.69%	0.85%	1.57%	2.42%
Total Transmission Plant	1.01%	0.56%	1.57%	0.91%	1.32%	2.22%
DISTRIBUTION PLANT						
Assigned Property						
375.00 Structures and Improvements						
376.10 Mains - Steel	0.87%	0.39%	1.26%	1.22%	0.62%	1.84%
376.20 Mains - Plastic	1.53%	0.57%	2.10%	1.80%	0.86%	2.66%
376.30 Mains - Cast Iron	-1.78%	1.14%	-0.64%	0.86%	1.88%	2.74%
378.00 Measuring and Regulating Equipment	1.08%	0.11%	1.19%	2.00%	0.24%	2.24%

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA Statement A

Comparison of Current and SFAS 143 Accrual Rates
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.35 Percent

Account Description	Current Investment	Current Net Salvage	Current Total	SFAS 143 Investment	SFAS 143 Net Salvage	SFAS 143 Total
A	B	C	D=B+C	E	F	G=E+F
380.10 Services - Steel	1.18%	0.91%	2.09%	1.63%	0.69%	2.32%
380.20 Services - Plastic	1.42%	0.73%	2.15%	1.79%	0.92%	2.71%
380.30 Services - Copper	-1.86%	1.46%	-0.40%	1.34%	1.39%	2.73%
381.20 Meters - Hard Case	3.13%		3.13%	3.80%		3.80%
381.30 Meters - Electronic Devices	2.39%		2.39%	4.99%		4.99%
381.50 Meters - Electronic Demand Recorders	-0.33%		-0.33%	2.18%		2.18%
382.00 Meter Installations	1.42%	0.12%	1.54%	2.09%	0.16%	2.25%
383.00 House Regulators	1.76%	1.52%	3.28%	2.59%	1.87%	4.46%
384.00 House Regulator Installations	1.51%		1.51%	1.75%	0.12%	1.87%
386.20 Gas Lights	-0.10%	2.49%	2.39%	1.92%	2.74%	4.66%
Total Assigned Property	1.41%	0.60%	2.01%	1.80%	0.81%	2.60%
Allocated Property						
375.00 Structures and Improvements						
District						
Maryland						
Virginia						
Total Account 375.00						
377.00 Compressor Station Equipment						
District						
Maryland						
Virginia						
Total Account 377.00						
378.00 Measuring and Regulating Equipment						
District						
Maryland	3.85%	-0.10%	3.75%	3.37%	0.35%	3.72%
Virginia	5.21%	0.55%	5.76%	3.35%	0.33%	3.68%
Total Account 378.00	4.04%	-0.01%	4.03%	3.37%	0.35%	3.71%
Total Allocated Property	4.04%	-0.01%	4.03%	3.37%	0.35%	3.71%
Total Distribution Plant	1.41%	0.60%	2.01%	1.80%	0.81%	2.60%
GENERAL PLANT						
Allocated Property (Depreciable)						
390.00 Structures and Improvements						
District	2.14%	0.21%	2.35%	2.06%	0.14%	2.20%
Maryland	2.27%	0.14%	2.41%	1.99%	0.23%	2.22%
Virginia	1.96%	0.20%	2.16%	1.99%	0.20%	2.19%
Total Account 390.00	2.03%	0.19%	2.22%	1.99%	0.20%	2.20%
Total Allocated Property (Depreciable)	2.03%	0.19%	2.22%	1.99%	0.20%	2.20%
Assigned Property (Amortizable)						
303.05 Software - 5 year	20.00%		20.00%	← 5 Year Amortization →		20.00%
303.06 Software (DC POR) - 10 year	10.00%		10.00%	← 10 Year Amortization →		10.00%
303.10 Software - 10 year	10.00%		10.00%	← 10 Year Amortization →		10.00%
391.10 Office Furniture and Equipment (DC POR)	5.00%		5.00%	← 20 Year Amortization →		5.00%
391.11 Office Furniture and Equipment	5.00%		5.00%	← 20 Year Amortization →		5.00%
391.21 Computer Equipment	14.29%		14.29%	← 7 Year Amortization →		14.29%
393.00 Stores Equipment	5.00%		5.00%	← 20 Year Amortization →		5.00%
394.00 Tools, Shop & Garage Equipment	5.00%		5.00%	← 20 Year Amortization →		5.00%
395.00 Laboratory Equipment	5.00%		5.00%	← 15 Year Amortization →		5.00%
397.10 Communication Equipment - Telephones						
397.20 ENSCAN Equipment	5.93%		5.93%	← 18 Year Amortization →		5.93%
398.00 Miscellaneous Equipment	6.67%		6.67%	← 15 Year Amortization →		6.67%
Total Assigned Property (Amortizable)	7.49%		7.49%	7.49%		7.49%
Total General Plant	5.50%	0.07%	5.57%	5.49%	0.07%	5.56%
TOTAL JURISDICTION	1.64%	0.56%	2.21%	1.97%	0.79%	2.75%

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA

Comparison of Current and SFAS 143 Accruals
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.35 Percent

Account Description	12/31/23 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Investment	SFAS 143 Net Salvage	SFAS 143 Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STORAGE AND PROCESSING PLANT								
Allocated Property								
361.00 Structures and Improvements								
Maryland (Rockville)	$ 1,311,110	$ 31,336	$ 9,965	$ 41,301	$ 27,009	$ 5,769	$ 32,778	$ (8,523)
Virginia (Ravensworth)	1,183,946	29,243	5,919	35,162	24,981	4,973	29,954	(5,208)
Total Account 361.00	$ 2,495,056	$ 60,579	$ 15,884	$ 76,463	$ 51,990	$ 10,742	$ 62,732	$ (13,731)
362.00 Gas Holders								
Maryland (Rockville)	$ 4,460,885	$ 75,389	$ 25,427	$ 100,816	$ 49,516	$ 12,044	$ 61,560	$ (39,256)
Virginia (Ravensworth)	3,676,243	65,805	12,500	78,305	55,511	10,661	66,172	(12,133)
Total Account 362.00	$ 8,137,128	$ 141,194	$ 37,927	$ 179,121	$ 105,027	$ 22,705	$ 127,732	$ (51,389)
363.50 Other Equipment								
Maryland (Rockville)	$ 818,973	$ 43,979	$ 900	$ 44,879	$ 18,345	$ 409	$ 18,754	$ (26,125)
Virginia (Ravensworth)	604,207	11,903	9,305	21,208	17,522	2,538	20,060	(1,148)
Total Account 363.50	$ 1,423,180	$ 55,882	$ 10,205	$ 66,087	$ 35,867	$ 2,947	$ 38,814	$ (27,273)
Total Allocated Property	$ 12,055,364	$ 257,655	$ 64,016	$ 321,671	$ 192,884	$ 36,394	$ 229,278	$ (92,393)
Total Storage and Processing Plant	$ 12,055,364	$ 257,655	$ 64,016	$ 321,671	$ 192,884	$ 36,394	$ 229,278	$ (92,393)
TRANSMISSION PLANT								
Assigned Property								
365.20 Rights of Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
366.00 Meas. and Reg. Station Structures								
367.10 Mains - Steel	4,258,093	21,290	4,258	25,548	46,413	5,961	52,374	26,826
369.00 Measuring and Regulating Equipment	7,874,665	85,834	15,749	101,583	92,921	20,474	113,395	11,812
Total Assigned Property	$ 12,132,758	$ 107,124	$ 20,007	$ 127,131	$ 139,334	$ 26,435	$ 165,769	$ 38,638
Allocated Property								
365.20 Rights of Way								
District	$ 470	$ 2	$ -	$ 2	$ (21)	$ -	$ (21)	$ (23)
Maryland	803,227	12,852		12,852	11,245		11,245	(1,607)
Virginia	401,040	4,612		4,612	2,928		2,928	(1,684)
Total Account 365.20	$ 1,204,737	$ 17,466	$ -	$ 17,466	$ 14,152	$ -	$ 14,152	$ (3,314)
366.00 Meas. and Reg. Station Structures								
Maryland	$ 499,988	$ 1,650	$ 6,200	$ 7,850	$ 10,650	$ 5,050	$ 15,700	$ 7,850
Virginia	3,153,657	41,944	631	42,575	64,965	6,623	71,588	29,013
Total Account 366.00	$ 3,653,645	$ 43,594	$ 6,831	$ 50,425	$ 75,615	$ 11,673	$ 87,288	$ 36,863

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA Statement B

Comparison of Current and SFAS 143 Accruals
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.35 Percent

Account Description	12/31/23 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Investment	SFAS 143 Net Salvage	SFAS 143 Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
367.10 Mains - Steel								
District	$ 1,833,775	$ 19,255	$ 1,834	$ 21,089	$ 30,441	$ 2,567	$ 33,008	$ 11,919
Maryland	11,899,374	171,351	(3,570)	167,781	198,720	(13,089)	185,631	17,850
Virginia	15,473,955	227,467	15,473	242,940	258,415	12,379	270,794	27,854
Total Account 367.10	$ 29,207,104	$ 418,073	$ 13,737	$ 431,810	$ 487,576	$ 1,857	$ 489,433	$ 57,623
369.00 Measuring and Regulating Equipment								
District	$ 599,848	$ (1,080)	$ 1,200	$ 120	$ (6,358)	$ 1,560	$ (4,798)	$ (4,918)
Maryland	13,331,810	38,662	319,963	358,625	(93,323)	998,553	905,230	546,605
Virginia	3,963,721	21,800		21,800	(36,466)	(196,204)	(232,670)	(254,470)
Total Account 369.00	$ 17,895,379	$ 59,382	$ 321,163	$ 380,545	$ (136,147)	$ 803,909	$ 667,762	$ 287,217
Total Allocated Property	$ 51,960,865	$ 538,515	$ 341,731	$ 880,246	$ 441,196	$ 817,439	$ 1,258,635	$ 378,389
Total Transmission Plant	$ 64,093,623	$ 645,639	$ 361,738	$ 1,007,377	$ 580,530	$ 843,874	$ 1,424,404	$ 417,027
DISTRIBUTION PLANT								
Assigned Property								
375.00 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
376.10 Mains - Steel	96,886,105	842,909	377,856	1,220,765	1,182,010	600,694	1,782,704	561,939
376.20 Mains - Plastic	454,106,167	6,947,824	2,588,405	9,536,229	8,173,911	3,905,313	12,079,224	2,542,995
376.30 Mains - Cast Iron	6,002,962	(106,853)	68,434	(38,419)	51,625	112,856	164,481	202,900
378.00 Measuring and Regulating Equipment	11,225,235	121,233	12,348	133,581	224,505	26,941	251,446	117,865
380.10 Services - Steel	53,992,928	637,117	491,336	1,128,453	880,085	372,551	1,252,636	124,183
380.20 Services - Plastic	357,615,007	5,078,133	2,610,590	7,688,723	6,401,309	3,290,058	9,691,367	2,002,644
380.30 Services - Copper	3,030,970	(56,376)	44,252	(12,124)	40,615	42,130	82,745	94,869
381.20 Meters - Hard Case	23,438,610	733,628		733,628	890,667		890,667	157,039
381.30 Meters - Electronic Devices	2,491,253	59,541		59,541	124,314		124,314	64,773
381.50 Meters - Electronic Demand Recorders	852,990	(2,815)		(2,815)	18,595		18,595	21,410
382.00 Meter Installations	35,599,234	505,509	42,719	548,228	744,024	56,959	800,983	252,755
383.00 House Regulators	4,735,146	83,339	71,974	155,313	122,640	88,547	211,187	55,874
384.00 House Regulator Installations	3,728,682	56,303		56,303	65,252	4,474	69,726	13,423
386.20 Gas Lights	107,165	(107)	2,668	2,561	2,058	2,936	4,994	2,433
Total Assigned Property	$ 1,053,812,454	$ 14,899,385	$ 6,310,582	$ 21,209,967	$ 18,921,610	$ 8,503,459	$ 27,425,069	$ 6,215,102

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA

Statement B

Comparison of Current and SFAS 143 Accruals
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.35 Percent

	12/31/23	Current			SFAS 143			
Account Description	Plant	Investment	Net Salvage	Total	Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Allocated Property								
375.00 Structures and Improvements								
District	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maryland								
Virginia								
Total Account 375.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
377.00 Compressor Station Equipment								
District	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maryland								
Virginia								
Total Account 377.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
378.00 Measuring and Regulating Equipment								
District	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maryland	170,682	6,571	(171)	6,400	5,752	597	6,349	(51)
Virginia	28,078	1,463	154	1,617	941	93	1,034	(583)
Total Account 378.00	$ 198,760	$ 8,034	$ (17)	$ 8,017	$ 6,693	$ 690	$ 7,383	$ (634)
Total Allocated Property	$ 198,760	$ 8,034	$ (17)	$ 8,017	$ 6,693	$ 690	$ 7,383	$ (634)
Total Distribution Plant	$ 1,054,011,214	$ 14,907,419	$ 6,310,565	$ 21,217,984	$ 18,928,303	$ 8,504,149	$ 27,432,452	$ 6,214,468
GENERAL PLANT								
Allocated Property (Depreciable)								
390.00 Structures and Improvements								
District	$ 607,056	$ 12,991	$ 1,275	$ 14,266	$ 12,505	$ 850	$ 13,355	$ (911)
Maryland	5,474,473	124,271	7,664	131,935	108,942	12,591	121,533	(10,402)
Virginia	20,131,767	394,583	40,264	434,847	400,622	40,264	440,886	6,039
Total Account 390.00	$ 26,213,296	$ 531,845	$ 49,203	$ 581,048	$ 522,069	$ 53,705	$ 575,774	$ (5,274)
Total Allocated Property (Depreciable)	$ 26,213,296	$ 531,845	$ 49,203	$ 581,048	$ 522,069	$ 53,705	$ 575,774	$ (5,274)

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA Statement B

Comparison of Current and SFAS 143 Accruals

Current: VG Procedure / RL Technique

Updated: VG Procedure / RL Technique

Accretion Rate: 3.35 Percent

Account Description	12/31/23 Plant	Current Investment	Current Net Salvage	Current Total	SFAS 143 Investment	SFAS 143 Net Salvage	SFAS 143 Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Assigned Property (Amortizable)								
303.05 Software - 5 year	$ 3,181,844	$ 636,369	$ -	$ 636,369	636,369	$ -	$ 636,369	$ -
303.06 Software (DC POR) - 10 year	762,920	76,292		76,292	76,292		76,292	
303.10 Software - 10 year	14,210,276	1,421,028		1,421,028	1,421,028		1,421,028	
391.10 Office Furniture and Equipment (DC POR)	7,234	362		362	362		362	
391.11 Office Furniture and Equipment	3,831,631	191,582		191,582	191,582		191,582	
391.21 Computer Equipment	1,902,016	271,798		271,798	271,798		271,798	
393.00 Stores Equipment	31,298	1,565		1,565	1,565		1,565	
394.00 Tools, Shop & Garage Equipment	2,286,711	114,336		114,336	114,336		114,336	
395.00 Laboratory Equipment	18,011	901		901	901		901	
397.10 Communication Equipment - Telephones	7,532,335							
397.20 ENSCAN Equipment	11,521,899	683,249		683,249	683,249		683,249	
398.00 Miscellaneous Equipment	414,859	27,671		27,671	27,671		27,671	
Total Assigned Property (Amortizable)	$ 45,701,034	$ 3,425,153	$ -	$ 3,425,153	$ 3,425,153	$ -	$ 3,425,153	$ -
Total General Plant	$ 71,914,330	$ 3,956,998	$ 49,203	$ 4,006,201	$ 3,947,222	$ 53,705	$ 4,000,927	$ (5,274)
TOTAL JURISDICTION	$ 1,202,074,531	$ 19,767,711	$ 6,785,522	$ 26,553,233	$ 23,648,939	$ 9,438,122	$ 33,087,061	$ 6,533,828

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
Depreciation Reserve Summary - SFAS 143
Vintage Group Procedure
Accretion Rate: 3.35 Percent
December 31, 2023

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
STORAGE AND PROCESSING PLANT										
Allocated Property										
361.00 Structures and Improvements										
Maryland (Rockville)	$ 1,311,110	$ -		$ 409,445	$ 71,971	$ 481,416	$ 431,068	$ 75,771	$ 506,839	38.66%
Virginia (Ravensworth)	1,183,946			406,797	79,805	486,602	428,280	84,020	512,300	43.27%
Total Account 361.00	$ 2,495,056	$ 1,019,139	40.85%	$ 816,242	$ 151,776	$ 968,018	$ 859,348	$ 159,791	$ 1,019,139	40.85%
362.00 Gas Holders										
Maryland (Rockville)	$ 4,460,885	$ -		$ 2,683,388	$ 488,685	$ 3,172,073	$ 3,310,114	$ 602,821	$ 3,912,935	87.72%
Virginia (Ravensworth)	3,676,243			2,011,003	413,857	2,424,860	2,480,688	510,517	2,991,205	81.37%
Total Account 362.00	$ 8,137,128	$ 6,904,140	84.85%	$ 4,694,391	$ 902,542	$ 5,596,933	$ 5,790,802	$ 1,113,338	$ 6,904,140	84.85%
363.50 Other Equipment										
Maryland (Rockville)	$ 818,973	$ -		$ 131,303	$ (5,501)	$ 125,802	$ 271,149	$ (11,361)	$ 259,789	31.72%
Virginia (Ravensworth)	604,207			122,186	(24,583)	97,603	252,321	(50,766)	201,555	33.36%
Total Account 363.50	$ 1,423,180	$ 461,344	32.42%	$ 253,489	$ (30,084)	$ 223,405	$ 523,470	$ (62,126)	$ 461,344	32.42%
Total Allocated Property	$ 12,055,364	$ 8,384,623	69.55%	$ 5,764,122	$ 1,024,234	$ 6,788,355	$ 7,173,620	$ 1,211,003	$ 8,384,623	69.55%
Total Storage and Processing Plant	$ 12,055,364	$ 8,384,623	69.55%	$ 5,764,122	$ 1,024,234	$ 6,788,355	$ 7,173,620	$ 1,211,003	$ 8,384,623	69.55%
TRANSMISSION PLANT										
Assigned Property										
365.20 Rights of Way	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	
366.00 Meas. and Reg. Station Structures		(617)								
367.10 Mains - Steel	4,258,093	2,358,062	55.38%	753,626	72,479	826,105	1,960,776	72,479	2,033,255	47.75%
369.00 Measuring and Regulating Equipment	7,874,665	2,890,627	36.71%	1,146,821	159,349	1,306,170	3,055,468	159,349	3,214,817	40.82%
Total Assigned Property	$ 12,132,758	$ 5,248,072	43.26%	$ 1,900,447	$ 231,828	$ 2,132,275	$ 5,016,244	$ 231,828	$ 5,248,072	43.26%
Allocated Property										
365.20 Rights of Way										
District	$ 470	$ -		$ 440	$ -	$ 440	$ 579	$ -	$ 579	123.27%
Maryland	803,227			261,069		261,069	343,965		343,965	42.82%
Virginia	401,040			236,277		236,277	311,302		311,302	77.62%
Total Account 365.20	$ 1,204,737	$ 655,846	54.44%	$ 497,786	$ -	$ 497,786	$ 655,846	$ -	$ 655,846	54.44%
366.00 Meas. and Reg. Station Structures										
Maryland	$ 499,988	$ -		$ 210,177	$ (6,804)	$ 203,373	$ 189,066	$ (6,121)	$ 182,946	36.59%
Virginia	3,153,657			765,286	76,529	841,814	688,418	68,842	757,260	24.01%
Total Account 366.00	$ 3,653,645	$ 940,206	25.73%	$ 975,463	$ 69,724	$ 1,045,187	$ 877,485	$ 62,721	$ 940,206	25.73%
367.10 Mains - Steel										
District	$ 1,833,775	$ -		$ 324,554	$ 31,214	$ 355,767	$ 320,056	$ 31,214	$ 351,270	19.16%
Maryland	11,899,374			2,052,711	3,015,739	5,068,450	2,026,762	2,977,615	5,004,376	42.06%
Virginia	15,473,955			2,160,476	2,068,137	4,228,613	2,133,163	2,041,992	4,175,156	26.98%
Total Account 367.10	$ 29,207,104	$ 9,530,802	32.63%	$ 4,537,741	$ 5,115,090	$ 9,652,831	$ 4,479,981	$ 5,050,821	$ 9,530,802	32.63%
369.00 Measuring and Regulating Equipment										
District	$ 599,848	$ -		$ 87,358	$ 12,138	$ 99,497	$ 930,595	$ 12,138	$ 942,733	157.16%
Maryland	13,331,810			1,919,340	(2,619,690)	(700,350)	18,185,773	(24,821,597)	(6,635,824)	-49.77%
Virginia	3,963,721			615,399	616,553	1,231,952	5,830,916	5,841,851	11,672,767	294.49%
Total Account 369.00	$ 17,895,379	$ 5,979,676	33.41%	$ 2,622,097	$ (1,990,998)	$ 631,099	$ 24,947,283	$ (18,967,607)	$ 5,979,676	33.41%
Total Allocated Property	$ 51,960,865	$ 17,106,530	32.92%	$ 8,633,087	$ 3,193,816	$ 11,826,903	$ 30,960,596	$ (13,854,066)	$ 17,106,530	32.92%
Total Transmission Plant	$ 64,093,623	$ 22,354,602	34.88%	$ 10,533,534	$ 3,425,644	$ 13,959,179	$ 35,976,840	$ (13,622,238)	$ 22,354,602	34.88%

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA Statement C

Depreciation Reserve Summary - SFAS 143
Vintage Group Procedure
Accretion Rate: 3.35 Percent
December 31, 2023

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
DISTRIBUTION PLANT										
Assigned Property										
375.00 Structures and Improvements	$ -	$ 6,901,348		$ -	$ -	$ -	$ -	$ -	$ -	
376.10 Mains - Steel	96,886,105	57,624,364	59.48%	34,422,294	12,630,394	47,052,688	35,683,114	12,630,394	48,313,508	49.87%
376.20 Mains - Plastic	454,106,167	115,809,363	25.50%	96,115,003	43,607,092	139,722,095	99,858,984	43,607,092	143,466,076	31.59%
376.30 Mains - Cast Iron	6,002,962	6,301,728	104.98%	5,108,889	3,139,458	8,248,347	5,329,911	3,139,458	8,469,369	141.09%
378.00 Measuring and Regulating Equipment	11,225,235	7,022,939	62.56%	3,570,837	302,193	3,873,030	3,674,618	302,193	3,976,811	35.43%
380.10 Services - Steel	53,992,928	(7,227,772)	-13.39%	8,772,631	3,623,181	12,395,813	9,104,788	3,623,181	12,727,970	23.57%
380.20 Services - Plastic	357,615,007	173,693,884	48.57%	92,890,385	41,783,616	134,674,000	96,499,097	41,783,616	138,282,713	38.67%
380.30 Services - Copper	3,030,970	4,798,254	158.31%	2,550,977	1,084,915	3,635,892	2,648,404	1,084,915	3,733,319	123.17%
381.20 Meters - Hard Case	23,438,610	3,965,240	16.92%	9,583,989		9,583,989	9,840,800		9,840,800	41.99%
381.30 Meters - Electronic Devices	2,491,253	50,039	2.01%	768,377		768,377	788,967		788,967	31.67%
381.50 Meters - Electronic Demand Recorders	852,990	592,306	69.44%	772,685		772,685	793,390		793,390	93.01%
382.00 Meter Installations	35,599,234	12,346,701	34.68%	8,646,065	505,374	9,151,439	8,891,286	505,374	9,396,660	26.40%
383.00 House Regulators	4,735,146	1,870,032	39.49%	1,954,308	1,194,630	3,148,938	2,038,686	1,194,630	3,233,317	68.28%
384.00 House Regulator Installations	3,728,682	1,078,046	28.91%	974,797	54,447	1,029,244	1,002,377	54,447	1,056,824	28.34%
386.20 Gas Lights	107,165	118,482	110.56%	72,534	59,148	131,681	76,062	59,148	135,210	126.17%
Total Assigned Property	$1,053,812,454	$ 384,944,954	36.53%	$ 266,203,771	$ 107,984,449	$ 374,188,220	$ 276,230,486	$ 107,984,449	$ 384,214,935	26.21%
Allocated Property										
375.00 Structures and Improvements										
District	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	
Maryland										
Virginia										
Total Account 375.00	$ -	$ (39,753)		$ -	$ -	$ -	$ -	$ -	$ -	
377.00 Compressor Station Equipment										
District	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	
Maryland										
Virginia										
Total Account 377.00	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	
378.00 Measuring and Regulating Equipment										
District	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	
Maryland	170,682			62,354	4,935	67,289	24,949	1,975	26,923	15.77%
Virginia	28,078			9,065	849	9,914	3,627	340	3,967	14.13%
Total Account 378.00	$ 198,760	$ 70,643	35.54%	$ 71,419	$ 5,785	$ 77,203	$ 28,575	$ 2,315	$ 30,890	15.54%
Total Allocated Property	$ 198,760	$ 30,890	15.54%	$ 71,419	$ 5,785	$ 77,203	$ 28,575	$ 2,315	$ 30,890	15.54%
Total Distribution Plant	$1,054,011,214	$ 384,975,844	36.52%	$ 266,275,190	$ 107,990,233	$ 374,265,423	$ 276,259,061	$ 107,986,763	$ 384,245,825	36.46%
GENERAL PLANT										
Allocated Property (Depreciable)										
390.00 Structures and Improvements										
District	$ 607,056	$ -		$ 124,411	$ 19,966	$ 144,377	$ 128,280	$ 19,966	$ 148,246	24.42%
Maryland	5,474,473			1,198,158	350,737	1,548,894	1,230,263	360,135	1,590,398	29.05%
Virginia	20,131,767			3,595,964	326,525	3,922,489	3,692,321	335,274	4,027,595	20.01%
Total Account 390.00	$ 26,213,296	$ 4,836,555	18.45%	$ 4,918,533	$ 697,227	$ 5,615,760	$ 5,050,864	$ 715,375	$ 5,766,239	22.00%
Total Allocated Property (Depreciable)	$ 26,213,296	$ 4,836,555	18.45%	$ 4,918,533	$ 697,227	$ 5,615,760	$ 5,050,864	$ 715,375	$ 5,766,239	22.00%

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA

Statement C

Depreciation Reserve Summary - SFAS 143
Vintage Group Procedure
Accretion Rate: 3.35 Percent
December 31, 2023

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Investment	Computed Reserve Net Salvage	Computed Reserve Total	Redistributed Reserve Investment	Redistributed Reserve Net Salvage	Redistributed Reserve Total	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F	G=E+F	H	I	J=H+I	K=J/B
Assigned Property (Amortizable)										
303.05 Software - 5 year	$ 3,181,844	$ 2,432,114	76.44%	$ 2,585,951	$ -	$ 2,585,951	$ 2,585,951	$ -	$ 2,585,951	81.27%
303.06 Software (DC POR) - 10 year	762,920	371,918	48.75%	343,314		343,314	343,314		343,314	45.00%
303.10 Software - 10 year	14,210,276	12,569,180	88.45%	9,236,680		9,236,680	9,236,680		9,236,680	65.00%
391.10 Office Furniture and Equipment (DC POR)	7,234	3,501	48.40%	1,628		1,628	1,628		1,628	22.50%
391.11 Office Furniture and Equipment	3,831,631	1,290,530	33.68%	1,705,647		1,705,647	1,705,647		1,705,647	44.51%
391.21 Computer Equipment	1,902,016	1,615,555	84.94%	1,610,056		1,610,056	1,610,056		1,610,056	84.65%
393.00 Stores Equipment	31,298	22,803	72.86%	23,435		23,435	23,435		23,435	74.88%
394.00 Tools, Shop & Garage Equipment	2,286,711	559,414	24.46%	1,211,963		1,211,963	1,211,963		1,211,963	53.00%
395.00 Laboratory Equipment	18,011	15,852	88.01%	17,211		17,211	17,211		17,211	95.56%
397.10 Communication Equipment - Telephones	7,532,335	2,926,614	38.85%	3,919,733		3,919,733	3,919,733		3,919,733	52.04%
397.20 ENSCAN Equipment	11,521,899	5,784,387	50.20%	6,754,352		6,754,352	6,754,352		6,754,352	58.62%
398.00 Miscellaneous Equipment	414,859	263,184	63.44%	245,417		245,417	245,417		245,417	59.16%
Total Assigned Property (Amortizable)	$ 45,701,034	$ 27,855,052	60.95%	$ 27,655,387	$ -	$ 27,655,387	$ 27,655,387	$ -	$ 27,655,387	60.51%
Total General Plant	$ 71,914,330	$ 32,691,607	45.46%	$ 32,573,920	$ 697,227	$ 33,271,147	$ 32,706,251	$ 715,375	$ 33,421,626	46.47%
TOTAL JURISDICTION	$1,202,074,531	$ 448,406,676	37.30%	$ 315,146,766	$ 113,137,339	$ 428,284,104	$ 352,115,772	$ 96,290,904	$ 448,406,676	37.30%

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA Statement D

Net Salvage Accrual Rates - SFAS 143

Accretion Rate (r): 3.35 Percent

Account Description	12/31/23 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
STORAGE AND PROCESSING PLANT							
Allocated Property							
361.00 Structures and Improvements							
Maryland (Rockville)	$ 1,311,110	$ -	$ -	47.36	0.44%		0.44%
Virginia (Ravensworth)	1,183,946			46.13	0.42%		0.42%
Total Account 361.00	$ 2,495,056	$ -	$ -	46.77	0.43%		0.43%
362.00 Gas Holders							
Maryland (Rockville)	$ 4,460,885	$ -	$ -	58.55	0.27%		0.27%
Virginia (Ravensworth)	3,676,243			47.42	0.29%		0.29%
Total Account 362.00	$ 8,137,128	$ -	$ -	52.94	0.28%		0.28%
363.50 Other Equipment							
Maryland (Rockville)	$ 818,973	$ -	$ -	35.49	0.05%		0.05%
Virginia (Ravensworth)	604,207			25.17	0.42%		0.42%
Total Account 363.50	$ 1,423,180	$ -	$ -	30.23	0.21%		0.21%
Total Allocated Property	$ 12,055,364	$ -	$ -	47.43	0.30%		0.30%
Total Storage and Processing Plant	$ 12,055,364	$ -	$ -	47.43	0.30%		0.30%
TRANSMISSION PLANT							
Assigned Property							
365.20 Rights of Way	$ -	$ -	$ -				
366.00 Meas. and Reg. Station Structures							
367.10 Mains - Steel	4,258,093	88,415	145,313	60.40	0.03%	0.11%	0.14%
369.00 Measuring and Regulating Equipment	7,874,665	327,021	441,139	60.70	0.07%	0.19%	0.26%
Total Assigned Property	$ 12,132,758	$ 415,436	$ 586,452	60.59	0.06%	0.16%	0.22%
Allocated Property							
365.20 Rights of Way							
District	$ 470	$ -	$ -	80.96		$ -	$ -
Maryland	803,227			60.58			
Virginia	401,040			74.92			
Total Account 365.20	$ 1,204,737	$ -	$ -	64.71			
366.00 Meas. and Reg. Station Structures							
Maryland	$ 499,988	$ 17,250	$ 93,326	50.48	0.38%	0.63%	1.01%
Virginia	3,153,657			50.11	0.21%		0.21%
Total Account 366.00	$ 3,653,645	$ 17,250	$ 93,326	50.16	0.23%	0.09%	0.32%
367.10 Mains - Steel							
District	$ 1,833,775	$ 38,077	$ 62,580	60.40	0.03%	0.11%	0.14%
Maryland	11,899,374			59.94	-0.11%		-0.11%
Virginia	15,473,955			60.02	0.08%		0.08%
Total Account 367.10	$ 29,207,104	$ 38,077	$ 62,580	60.01	0.00%	0.01%	0.01%
369.00 Measuring and Regulating Equipment							
District	$ 599,848	$ 24,911	$ 33,603	60.70	0.07%	0.19%	0.26%
Maryland	13,331,810			60.50	7.49%		7.49%
Virginia	3,963,721			60.48	-4.95%		-4.95%
Total Account 369.00	$ 17,895,379	$ 24,911	$ 33,603	60.50	4.49%	0.01%	4.49%
Total Allocated Property	$ 51,960,865	$ 80,238	$ 189,509	59.46	1.56%	0.01%	1.57%
Total Transmission Plant	$ 64,093,623	$ 495,674	$ 775,961	59.67	1.28%	0.04%	1.32%
DISTRIBUTION PLANT							
Assigned Property							
375.00 Structures and Improvements	$ -	$ -	$ -				
376.10 Mains - Steel	96,886,105	5,203,378	15,982,376	80.02	0.07%	0.55%	0.62%
376.20 Mains - Plastic	454,106,167	55,591,123	87,376,599	54.90	0.22%	0.64%	0.86%
376.30 Mains - Cast Iron	6,002,962	448,249	3,214,995	87.15	0.09%	1.79%	1.88%
378.00 Measuring and Regulating Equipment	11,225,235	382,123	581,849	49.26	0.07%	0.17%	0.24%
380.10 Services - Steel	53,992,928	5,605,574	8,352,353	60.87	0.17%	0.52%	0.69%
380.20 Services - Plastic	357,615,007	43,778,793	74,225,197	55.13	0.22%	0.70%	0.92%
380.30 Services - Copper	3,030,970	247,365	1,126,872	59.61	0.14%	1.25%	1.39%
381.20 Meters - Hard Case	23,438,610			25.85			
381.30 Meters - Electronic Devices	2,491,253			19.81			
381.50 Meters - Electronic Demand Recorders	852,990			33.99			
382.00 Meter Installations	35,599,234	807,899	1,138,831	47.35	0.05%	0.11%	0.16%
383.00 House Regulators	4,735,146	1,049,095	1,812,984	37.41	0.59%	1.28%	1.87%
384.00 House Regulator Installations	3,728,682	62,901	102,198	56.42	0.03%	0.09%	0.12%
386.20 Gas Lights	107,165	28,677	69,361	46.85	0.57%	2.17%	2.74%
Total Assigned Property	$1,053,812,454	$113,205,176	$ 193,983,614	54.86	0.19%	0.62%	0.81%

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
Net Salvage Accrual Rates - SFAS 143
Accretion Rate (r): 3.35 Percent

Statement D

Account Description	12/31/23 Plant	ARC	ARO	ASL	Net Salvage Accrual Rate ARC	Accretion	Total
A	B	C	D	E	F=C/E/B	G=D*r/B	H=F+G
Allocated Property							
375.00 Structures and Improvements							
District	$ -	$ -	$ -			$ -	$ -
Maryland							
Virginia							
Total Account 375.00	$ -	$ -	$ -			$ -	$ -
377.00 Compressor Station Equipment							
District	$ -	$ -	$ -			$ -	$ -
Maryland							
Virginia							
Total Account 377.00	$ -	$ -	$ -			$ -	$ -
378.00 Measuring and Regulating Equipment							
District	$ -	$ -	$ -				
Maryland	170,682			39.91	0.35%		0.35%
Virginia	28,078			38.44	0.33%		0.33%
Total Account 378.00	$ 198,760	$ -	$ -	39.70	0.35%		0.35%
Total Allocated Property	$ 198,760	$ -	$ -	39.70	0.35%		0.35%
Total Distribution Plant	$1,054,011,214	$113,205,176	$ 193,983,614	54.86	0.19%	0.62%	0.81%
GENERAL PLANT							
Allocated Property (Depreciable)							
390.00 Structures and Improvements							
District	$ 607,056	$ 11,684	$ 17,438	48.16	0.04%	0.10%	0.14%
Maryland	5,474,473	72,902	214,202	49.94	0.10%	0.13%	0.23%
Virginia	20,131,767			50.05	0.20%		0.20%
Total Account 390.00	$ 26,213,296	$ 84,586	$ 231,641	49.98	0.18%	0.03%	0.20%
Total Allocated Property (Depreciable)	$ 26,213,296	$ 84,586	$ 231,641	49.98	0.18%	0.03%	0.20%
Assigned Property (Amortizable)							
303.05 Software - 5 year	$ 3,181,844	$ -	$ -	5.00			
303.06 Software (DC POR) - 10 year	762,920			10.00			
303.10 Software - 10 year	14,210,276			10.00			
391.10 Office Furniture and Equipment (DC POR)	7,234			20.00			
391.11 Office Furniture and Equipment	3,831,631			20.00			
391.21 Computer Equipment	1,902,016			7.00			
393.00 Stores Equipment	31,298			20.00			
394.00 Tools, Shop & Garage Equipment	2,286,711			20.00			
395.00 Laboratory Equipment	18,011			15.00			
397.10 Communication Equipment - Telephones	7,532,335			18.00			
397.20 ENSCAN Equipment	11,521,899			18.00			
398.00 Miscellaneous Equipment	414,859			15.00			
Total Assigned Property (Amortizable)	$ 45,701,034	$ -	$ -	12.02			
Total General Plant	$ 71,914,330	$ 84,586	$ 231,641	16.63	0.06%	0.01%	0.07%
TOTAL JURISDICTION	$1,202,074,531	$113,785,436	$ 194,991,215	48.34	0.24%	0.54%	0.79%

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA

Statement E

Parameter Summary - SFAS 143
Vintage Group Procedure
Accretion Rate: 3.35 Percent

	Current Parameters						SFAS 143					
											Fut. Net Sal.	
Account Description	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Sf	Sf'
A	B	C	D	E	F	G	H	I	J	K	L	M
STORAGE AND PROCESSING PLANT												
Allocated Property												
361.00 Structures and Improvements												
Maryland (Rockville)	45.00	R3	46.05	31.91	-32.2	-31.0	45.00	R4	47.36	32.57	-20.0	-20.0
Virginia (Ravensworth)	45.00	R4	45.97	28.58	-20.3	-20.0	45.00	R4	46.13	30.28	-20.0	-20.0
Total Account 361.00									46.77	31.47	-20.0	-20.0
362.00 Gas Holders												
Maryland (Rockville)	45.00	R3	48.61	23.71	-32.6	-31.0	45.00	R4	58.55	23.33	-20.0	-20.0
Virginia (Ravensworth)	45.00	R4	46.32	23.08	-19.1	-20.0	45.00	R4	47.42	21.48	-20.0	-20.0
Total Account 362.00									52.94	22.40	-20.0	-20.0
363.50 Other Equipment												
Maryland (Rockville)	15.00	O3	15.78	14.61	-0.6		35.00	L0	35.49	29.80		
Virginia (Ravensworth)	35.00	L0	35.73	30.92	-19.0		25.00	L1.5	25.17	20.08		
Total Account 363.50									30.23	24.84		-0.2
Total Allocated Property									47.43	24.75	-17.6	-16.6
Total Storage and Processing Plant									47.43	24.75	-17.6	-16.6
TRANSMISSION PLANT												
Assigned Property												
365.20 Rights of Way												
366.00 Meas. and Reg. Station Structures												
367.10 Mains - Steel	80.00	R3	80.51	58.54	97.3	-15.0	60.00	R4	60.40	49.71	-15.0	-8.9
369.00 Measuring and Regulating Equipment	50.00	S3	50.14	39.30	-72.9	-15.0	60.00	L0.5	60.70	51.86	-30.0	-15.5
Total Assigned Property									60.59	51.10	-21.3	-13.1
Allocated Property												
365.20 Rights of Way												
District	60.00	R3	73.48	7.71			60.00	R3	80.96	5.21		0.0
Maryland	60.00	R3	60.39	42.77			60.00	R3	60.58	40.89		-0.1
Virginia	60.00	R3	77.71	34.78			60.00	R4	74.92	30.78		-0.1
Total Account 365.20									64.71	37.97		1.0

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA — Statement E

Parameter Summary - SFAS 143

Vintage Group Procedure

Accretion Rate: 3.35 Percent

	Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	SFAS 143 P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Fut. Net Sal. Sf	Sf'
	A	B	C	D	E	F	G	H	I	J	K	L	M
366.00	Meas. and Reg. Station Structures												
	Maryland	43.00	S4	43.01	28.20	-20.2		50.00	R3	50.48	29.26	-10.0	-28.5
	Virginia	50.00	R3	50.06	41.61	-7.7	-10.0	50.00	R3	50.11	37.95	-10.0	-10.2
	Total Account 366.00									50.16	36.77	-10.0	-13.6
367.10	Mains - Steel												
	District	80.00	R3	80.51	58.54	97.3	-15.0	60.00	R4	60.40	49.71	-15.0	-8.6
	Maryland	60.00	R3	59.98	44.15	1.5		60.00	R4	59.94	49.60	-15.0	-19.4
	Virginia	60.00	R4	60.04	45.70	-7.3	-15.0	60.00	R4	60.02	51.64	-15.0	-17.3
	Total Account 367.10									60.01	50.69	-15.0	-17.6
369.00	Measuring and Regulating Equipment												
	District	50.00	S3	50.14	39.30	-72.9	-15.0	60.00	L0.5	60.70	51.86	-30.0	-15.7
	Maryland	45.00	R2	45.32	36.51	-33.3	-11.0	60.00	L0.5	60.50	51.79	-30.0	-201.9
	Virginia	60.00	L0.5	60.39	50.89	-28.3	-30.0	60.00	L0.5	60.48	51.09	-30.0	105.4
	Total Account 369.00									60.50	51.64	-30.0	-126.1
	Total Allocated Property									59.46	49.58	-19.5	-53.0
	Total Transmission Plant									59.67	49.86	-19.5	-45.7
DISTRIBUTION PLANT													
Assigned Property													
375.00	Structures and Improvements												
376.10	Mains - Steel	80.00	R3	79.92	49.16	-69.3	-50.0	80.00	R3	80.02	51.59	-75.0	-44.8
376.20	Mains - Plastic	55.00	R4	54.84	41.69	-51.6	-50.0	55.00	R4	54.90	43.28	-75.0	-46.7
376.30	Mains - Cast Iron	70.00	R2.5	83.43	15.19	-43.6	-50.0	70.00	R2.5	87.15	12.98	-75.0	-76.7
378.00	Measuring and Regulating Equipment	80.00	L1.5	80.46	61.49	-20.1	-20.0	45.00	L0	49.26	33.59	-15.0	-10.7
380.10	Services - Steel	50.00	SC	54.49	32.85	-82.9	-60.0	60.00	S-.5	60.87	50.98	-75.0	-41.8
380.20	Services - Plastic	55.00	L2	54.95	39.03	-60.1	-60.0	55.00	L2	55.13	40.81	-75.0	-49.3
380.30	Services - Copper	55.00	R3	57.48	12.72	-53.0	-60.0	55.00	R3	59.61	9.44	-50.0	-48.9
381.20	Meters - Hard Case	24.00	S1	23.90	14.63	0.8		25.00	R1	25.85	15.28		-0.1
381.30	Meters - Electronic Devices	18.00	L3	19.10	8.09			19.00	L2	19.81	13.70		0.0
381.50	Meters - Electronic Demand Recorders	22.00	R3	24.55	6.62			22.00	R3	33.99	3.20		0.0
382.00	Meter Installations	63.00	R0.5	63.92	52.26	-15.1	-15.0	45.00	L0	47.35	35.85	-10.0	-7.1

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA

Parameter Summary - SFAS 143
Vintage Group Procedure
Accretion Rate: 3.35 Percent

		Current Parameters						SFAS 143					
		P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Fut. Net Sal. Sf	Fut. Net Sal. Sf'
	Account Description A	B	C	D	E	F	G	H	I	J	K	L	M
383.00	House Regulators	40.00	R4	40.14	27.32	-75.9	-75.0	37.00	R4	37.41	21.97	-75.0	-66.3
384.00	House Regulator Installations	54.00	SC	56.63	41.74	-1.0		54.00	SC	56.42	41.67	-10.0	-6.3
386.20	Gas Lights	40.00	R1	44.53	17.99	-169.5	-100.0	40.00	R1	46.85	15.14	-100.0	-96.7
	Total Assigned Property									54.86	41.00	-68.2	-32.9
Allocated Property													
375.00	Structures and Improvements												
	District												
	Maryland												
	Virginia												
	Total Account 375.00												
377.00	Compressor Station Equipment												
	District												
	Maryland												
	Virginia												
	Total Account 377.00												
378.00	Measuring and Regulating Equipment												
	District												
	Maryland	55.00	L1.5	56.30	36.52	-7.6	-1.0	35.00	L0	39.91	25.33	-10.0	-10.0
	Virginia	35.00	L0	38.18	26.16	-9.1	-10.0	35.00	L0	38.44	26.03	-10.0	-10.0
	Total Account 378.00									39.70	25.43	-10.0	-10.0
	Total Allocated Property									39.70	25.43	-10.0	-10.0
	Total Distribution Plant									54.86	41.00	-10.0	-43.2
GENERAL PLANT													
Allocated Property (Depreciable)													
390.00	Structures and Improvements												
	District	40.00	S4	36.58	26.17	-50.4	-10.0	50.00	R2	48.16	38.29	-10.0	-8.7
	Maryland	37.00	R1	37.56	27.47	-4.0		50.00	R2	49.94	39.01	-10.0	-15.7
	Virginia	50.00	R2	49.97	47.58	-10.2	-10.0	50.00	R2	50.05	41.11	-10.0	-10.0
	Total Account 390.00									49.98	40.60	-10.0	-11.2
	Total Allocated Property (Depreciable)									49.98	40.60	-10.0	-11.2

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA Statement E

Parameter Summary - SFAS 143

Vintage Group Procedure

Accretion Rate: 3.35 Percent

		Current Parameters						SFAS 143					
		P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Fut. Net Sal. Sf	Sf'
	Account Description A	B	C	D	E	F	G	H	I	J	K	L	M
Assigned Property (Amortizable)													
303.05	Software - 5 year	5.00	SQ	5.00	2.86			5.00	SQ	5.00	1.00		
303.06	Software (DC POR) - 10 year	10.00	SQ	10.00	3.36			10.00	SQ	10.00	5.50		
303.10	Software - 10 year	10.00	SQ	10.00	3.36			10.00	SQ	10.00	3.50		
391.10	Office Furniture and Equipment (DC POR)	20.00	SQ	20.00	12.17			20.00	SQ	20.00	15.50		
391.11	Office Furniture and Equipment	20.00	SQ	20.00	12.17			20.00	SQ	20.00	11.10		
391.21	Computer Equipment	7.00	SQ	7.00	3.32			7.00	SQ	7.00	1.07		
393.00	Stores Equipment	20.00	SQ	20.00	8.59			20.00	SQ	20.00	5.02		
394.00	Tools, Shop & Garage Equipment	20.00	SQ	20.00	9.71			20.00	SQ	20.00	9.40		
395.00	Laboratory Equipment	20.00	SQ	20.00	6.58			15.00	SQ	15.00	2.74		
397.10	Communication Equipment - Telephones	15.00	SQ	15.00	9.72			18.00	SQ	18.00	8.63		
397.20	ENSCAN Equipment	18.00	SQ	18.00	8.36			18.00	SQ	18.00	7.45		-2.8
398.00	Miscellaneous Equipment	15.00	SQ	15.00	10.94			15.00	SQ	15.00	6.13		
	Total Assigned Property (Amortizable)									12.02	4.76		
	Total General Plant									16.63	9.11	-3.6	
	TOTAL JURISDICTION									48.34	35.67	-10.9	-35.5

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the 2024 study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 380.10 Services –Steel. Documentation for all other plant accounts is contained in the study work papers. The supporting schedules developed in the Washington Gas study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column H) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 2. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged data is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce either a rolling, shrinking or progressive–band analysis depending upon the movement of the beginning or end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between observed proportions surviving and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – NET SALVAGE HISTORY

An Unadjusted Net Salvage History contains recorded activity–year retirements, salvage, cost of removal and other depreciation reserve activity appropriately recognized in the computation of average net salvage rates. This schedule provides a moving–average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving–average analysis of the components of unadjusted net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

An Adjusted Net Salvage History contains recorded activity–year total retirements, salvage, cost of removal and other depreciation reserve activity appropriately adjusted in the estimation of future net salvage rates. The moving–average adjusted net salvage analysis and component analysis are displayed in columns corresponding to an unadjusted net salvage analysis.

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant
Account: 380.10 Services - Steel

Dispersion: 60 - S-.5
Procedure: Vintage Group

Generation Arrangement

Vintage	Age	Surviving Plant (December 31, 2023)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2023	0.5	10,744,977	60.00	59.63	0.9938	1.0000	10,678,663	179,079
2022	1.5	6,508,133	60.01	58.91	0.9817	1.0000	6,388,826	108,459
2021	2.5	2,238,715	60.01	58.20	0.9697	1.0000	2,170,857	37,303
2020	3.5	1,470,743	60.03	57.50	0.9579	1.0000	1,408,765	24,500
2019	4.5	4,660,988	60.05	56.82	0.9462	1.0000	4,410,042	77,620
2018	5.5	6,727,798	60.07	56.14	0.9345	1.0000	6,287,439	111,992
2017	6.5	2,100,315	60.10	55.48	0.9230	1.0000	1,938,629	34,944
2016	7.5	794,222	60.14	54.82	0.9116	1.0000	723,989	13,206
2015	8.5	1,053,130	60.18	54.18	0.9002	1.0000	948,005	17,498
2014	9.5	654,450	60.23	53.54	0.8889	1.0000	581,745	10,866
2013	10.5	683,075	60.25	52.91	0.8781	1.0000	599,786	11,336
2012	11.5	249,619	60.35	52.28	0.8663	1.0000	216,252	4,136
2011	12.5	189,407	60.42	51.67	0.8551	1.0000	161,966	3,135
2010	13.5	144,086	60.50	51.06	0.8440	1.0000	121,603	2,382
2009	14.5	121,852	60.57	50.45	0.8330	1.0000	101,498	2,012
2008	15.5	94,524	60.54	49.85	0.8235	1.0000	77,839	1,561
2007	16.5	25,903	60.68	49.26	0.8119	1.0000	21,031	427
2006	17.5	17,681	60.87	48.67	0.7996	1.0000	14,138	290
2005	18.5	31,691	60.99	48.09	0.7886	1.0000	24,992	520
2004	19.5	327,767	60.17	47.52	0.7897	1.0000	258,840	5,447
2003	20.5	421,400	57.72	46.94	0.8133	1.0000	342,738	7,301
2002	21.5	210,384	61.09	46.38	0.7591	1.0000	159,701	3,444
2001	22.5	696,150	61.51	45.81	0.7448	1.0000	518,526	11,318
2000	23.5	459,357	61.19	45.25	0.7396	1.0000	339,729	7,507
1999	24.5	618,646	61.80	44.70	0.7234	1.0000	447,504	10,011
1998	25.5	971,010	61.31	44.15	0.7201	1.0000	699,217	15,837
1997	26.5	385,320	61.67	43.60	0.7070	1.0000	272,440	6,248
1996	27.5	116,880	58.54	43.06	0.7356	1.0000	85,976	1,997
1995	28.5	167,164	60.31	42.52	0.7050	1.0000	117,857	2,772
1994	29.5	104,225	59.97	41.99	0.7001	1.0000	72,967	1,738
1993	30.5	97,748	57.99	41.45	0.7148	1.0000	69,874	1,686
1992	31.5	61,679	56.13	40.93	0.7291	1.0000	44,970	1,099
1991	32.5	76,445	60.54	40.40	0.6673	1.0000	51,013	1,263
1990	33.5	26,733	48.36	39.88	0.8246	1.0000	22,043	553
1989	34.5	25,199	58.80	39.36	0.6694	1.0000	16,868	429
1988	35.5	19,495	48.03	38.84	0.8088	1.0000	15,767	406
1987	36.5	12,509	119.09	38.33	0.3219	1.0000	4,026	105

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant
Account: 380.10 Services - Steel

Dispersion: 60 - S-.5
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2023 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1986	37.5	111,857	56.36	37.82	0.6711	1.0000	75,067	1,985
1985	38.5	80,917	55.55	37.31	0.6716	1.0000	54,348	1,457
1984	39.5	162,067	52.57	36.81	0.7002	1.0000	113,472	3,083
1983	40.5	362,944	57.37	36.30	0.6328	1.0000	229,657	6,326
1982	41.5	398,392	54.11	35.80	0.6617	1.0000	263,598	7,362
1981	42.5	332,134	57.20	35.31	0.6173	1.0000	205,025	5,807
1980	43.5	615,773	62.08	34.81	0.5608	1.0000	345,317	9,920
1979	44.5	90,045	55.72	34.32	0.6159	1.0000	55,458	1,616
1978	45.5	59,932	57.65	33.83	0.5867	1.0000	35,164	1,040
1977	46.5	92,061	56.86	33.34	0.5863	1.0000	53,974	1,619
1976	47.5	30,504	52.27	32.85	0.6285	1.0000	19,173	584
1975	48.5	131,474	58.32	32.37	0.5550	1.0000	72,971	2,254
1974	49.5	238,533	61.91	31.89	0.5150	1.0000	122,853	3,853
1973	50.5	218,868	58.05	31.41	0.5410	1.0000	118,407	3,770
1972	51.5	268,702	59.74	30.93	0.5177	1.0000	139,107	4,498
1971	52.5	434,297	62.55	30.45	0.4868	1.0000	211,434	6,944
1970	53.5	423,232	64.24	29.98	0.4666	1.0000	197,493	6,588
1969	54.5	363,460	63.36	29.50	0.4656	1.0000	169,232	5,736
1968	55.5	276,286	62.55	29.03	0.4642	1.0000	128,240	4,417
1967	56.5	356,708	64.88	28.56	0.4402	1.0000	157,028	5,498
1966	57.5	314,567	63.06	28.09	0.4455	1.0000	140,146	4,989
1965	58.5	330,191	65.11	27.63	0.4243	1.0000	140,096	5,071
1964	59.5	404,154	65.92	27.16	0.4120	1.0000	166,522	6,131
1963	60.5	430,150	67.38	26.70	0.3962	1.0000	170,430	6,384
1962	61.5	301,727	66.63	26.24	0.3937	1.0000	118,803	4,528
1961	62.5	329,565	67.29	25.78	0.3831	1.0000	126,244	4,898
1960	63.5	389,095	68.86	25.32	0.3677	1.0000	143,056	5,651
1959	64.5	443,343	67.12	24.86	0.3703	1.0000	164,191	6,605
1958	65.5	718,954	70.88	24.40	0.3443	1.0000	247,503	10,143
1957	66.5	400,708	71.37	23.95	0.3355	1.0000	134,445	5,615
1956	67.5	276,594	69.87	23.49	0.3362	1.0000	92,997	3,959
1955	68.5	356,082	70.03	23.04	0.3290	1.0000	117,138	5,085
1954	69.5	215,984	68.19	22.59	0.3312	1.0000	71,533	3,167
1953	70.5	121,220	70.45	22.13	0.3142	1.0000	38,086	1,721
1952	71.5	74,230	69.49	21.68	0.3121	1.0000	23,163	1,068
1951	72.5	85,960	69.29	21.24	0.3065	1.0000	26,343	1,241
1950	73.5	91,545	71.87	20.79	0.2892	1.0000	26,478	1,274

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant
Account: 380.10 Services - Steel

Dispersion: 60 - S-.5
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2023 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1949	74.5	71,324	74.88	20.34	0.2716	1.0000	19,374	952
1948	75.5	54,310	74.01	19.89	0.2688	1.0000	14,598	734
1947	76.5	60,052	76.19	19.45	0.2553	1.0000	15,329	788
1946	77.5	50,337	74.58	19.00	0.2548	1.0000	12,827	675
1945	78.5	20,188	74.91	18.56	0.2478	1.0000	5,002	270
1944	79.5	15,372	78.45	18.12	0.2309	1.0000	3,550	196
1943	80.5	14,841	78.32	17.67	0.2257	1.0000	3,349	190
1942	81.5	24,673	77.19	17.23	0.2233	1.0000	5,508	320
1941	82.5	23,146	74.85	16.79	0.2243	1.0000	5,192	309
1940	83.5	16,497	70.67	16.35	0.2314	1.0000	3,817	233
1939	84.5	511	71.12	15.91	0.2237	1.0000	114	7
Total	16.0	$53,992,928	60.87	50.98	0.8375	1.0000	$45,218,974	$886,983

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

Age Distribution

Vintage	Age as of 12/31/2023	Derived Additions	1986 Opening Balance	Experience to 12/31/2023 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2023	0.5	10,744,977		10,744,977	1.0000	0.5000
2022	1.5	6,508,133		6,508,133	1.0000	1.5000
2021	2.5	2,238,715		2,238,715	1.0000	2.5000
2020	3.5	1,470,743		1,470,743	1.0000	3.5000
2019	4.5	4,660,988		4,660,988	1.0000	4.5000
2018	5.5	6,727,798		6,727,798	1.0000	5.5000
2017	6.5	2,100,315		2,100,315	1.0000	6.5000
2016	7.5	794,222		794,222	1.0000	7.5000
2015	8.5	1,053,130		1,053,130	1.0000	8.5000
2014	9.5	655,244		654,450	0.9988	9.4958
2013	10.5	689,846		683,075	0.9902	10.4656
2012	11.5	249,619		249,619	1.0000	11.5000
2011	12.5	189,407		189,407	1.0000	12.5000
2010	13.5	144,086		144,086	1.0000	13.5000
2009	14.5	122,606		121,852	0.9939	14.4908
2008	15.5	119,937		94,524	0.7881	15.3707
2007	16.5	26,884		25,903	0.9635	16.4089
2006	17.5	17,681		17,681	1.0000	17.5000
2005	18.5	31,691		31,691	1.0000	18.5000
2004	19.5	413,971		327,767	0.7918	18.5629
2003	20.5	514,119		421,400	0.8197	16.9833
2002	21.5	213,760		210,384	0.9842	21.2237
2001	22.5	698,425		696,150	0.9967	22.4919
2000	23.5	472,509		459,357	0.9722	23.0228
1999	24.5	622,405		618,646	0.9940	24.4668
1998	25.5	1,001,158		971,010	0.9699	24.8141
1997	26.5	398,438		385,320	0.9671	25.9950
1996	27.5	140,122		116,880	0.8341	23.6778
1995	28.5	191,193		167,164	0.8743	26.2554
1994	29.5	119,215		104,225	0.8743	26.7134
1993	30.5	146,298		97,748	0.6681	25.5203
1992	31.5	136,109		61,679	0.4532	24.4390
1991	32.5	84,130		76,445	0.9087	29.6186
1990	33.5	76,274		26,733	0.3505	18.1998
1989	34.5	30,083		25,199	0.8377	29.3884
1988	35.5	95,845		19,495	0.2034	19.3589
1987	36.5	14,094		12,509	0.8875	91.1522
1986	37.5	239,438		111,857	0.4672	29.1449

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

Age Distribution

Vintage	Age as of 12/31/2023	Derived Additions	1986 Opening Balance	Experience to 12/31/2023 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1985	38.5		172,473	80,917	0.4692	29.0569
1984	39.5		349,579	162,067	0.4636	26.7796
1983	40.5		570,004	362,944	0.6367	32.2802
1982	41.5		706,755	398,392	0.5637	29.7056
1981	42.5		581,433	332,134	0.5712	33.4644
1980	43.5		861,219	615,773	0.7150	39.0123
1979	44.5		234,256	90,045	0.3844	33.3164
1978	45.5		128,482	59,932	0.4665	35.8968
1977	46.5		203,122	92,061	0.4532	35.7455
1976	47.5		257,413	30,504	0.1185	31.7787
1975	48.5		446,251	131,474	0.2946	38.4471
1974	49.5		400,219	238,533	0.5960	42.6477
1973	50.5		454,090	218,868	0.4820	39.3879
1972	51.5		495,769	268,702	0.5420	41.6651
1971	52.5		658,654	434,297	0.6594	45.0523
1970	53.5		620,877	423,232	0.6817	47.3137
1969	54.5		572,187	363,460	0.6352	46.9975
1968	55.5		457,988	276,286	0.6033	46.7308
1967	56.5		530,076	356,708	0.6729	49.6049
1966	57.5		526,528	314,567	0.5974	48.3116
1965	58.5		562,541	330,191	0.5870	50.8871
1964	59.5		682,319	404,154	0.5923	52.2062
1963	60.5		717,057	430,150	0.5999	54.1683
1962	61.5		538,058	301,727	0.5608	53.9066
1961	62.5		505,712	329,565	0.6517	55.0422
1960	63.5		558,402	389,095	0.6968	57.0810
1959	64.5		718,871	443,343	0.6167	55.8044
1958	65.5		984,784	718,954	0.7301	60.0155
1957	66.5		565,823	400,708	0.7082	60.9436
1956	67.5		481,618	276,594	0.5743	59.8731
1955	68.5		663,260	356,082	0.5369	60.4581
1954	69.5		456,123	215,984	0.4735	59.0312
1953	70.5		239,212	121,220	0.5067	61.6873
1952	71.5		211,191	74,230	0.3515	61.1187
1951	72.5		183,921	85,960	0.4674	61.3025
1950	73.5		145,169	91,545	0.6306	64.2500
1949	74.5		99,757	71,324	0.7150	67.6234
1948	75.5		93,471	54,310	0.5810	67.1061

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

Age Distribution

Vintage	Age as of 12/31/2023	Derived Additions	1986 Opening Balance	Experience to 12/31/2023 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1947	76.5		99,219	60,052	0.6053	69.6243
1946	77.5		80,963	50,337	0.6217	68.3482
1945	78.5		41,356	20,188	0.4882	68.9988
1944	79.5		25,469	15,372	0.6036	72.8566
1943	80.5		22,623	14,841	0.6560	73.0277
1942	81.5		39,880	24,673	0.6187	72.1897
1941	82.5		66,902	23,146	0.3460	70.1409
1940	83.5		55,969	16,497	0.2948	66.2360
1939	84.5		56,957	511	0.0090	66.9508
1938	85.5		55,295		0.0000	62.5778
1937	86.5		68,960		0.0000	61.7874
1936	87.5		62,864		0.0000	58.6962
1935	88.5		36,478		0.0000	58.4846
1934	89.5		22,711		0.0000	60.9801
1933	90.5		3,747		0.0000	53.4006
1932	91.5		20,652		0.0000	66.2262
1931	92.5		9,173		0.0000	69.0685
1930	93.5		7,275		0.0000	64.9197
1929	94.5		3,762		0.0000	64.4025
1928	95.5		4,284		0.0000	64.8158
1927	96.5		7,716		0.0000	67.6097
1926	97.5		19,260		0.0000	76.5489
1925	98.5		27,032		0.0000	71.1017
1924	99.5		13,612		0.0000	66.8689
1923	100.5		5,937		0.0000	64.5436
1922	101.5		1,016		0.0000	74.5814
1921	102.5		711		0.0000	78.0993
1920	103.5		984		0.0000	77.8395
1919	104.5		601		0.0000	78.1170
1918	105.5		1,244		0.0000	78.3402
1916	107.5		49		0.0000	74.9441
1915	108.5		71		0.0000	75.4408
1914	109.5		44		0.0000	78.8351
1913	110.5		1,517		0.0000	88.8202
1912	111.5		101		0.0000	81.6295
1911	112.5		152		0.0000	83.0728
1910	113.5		683		0.0000	86.6767
1909	114.5		2		0.0000	75.7643

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA
Distribution Plant
Account: 380.10 Services - Steel

Age Distribution

Vintage	Age as of 12/31/2023	Derived Additions	1986 Opening Balance	Experience to 12/31/2023 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1908	115.5		154		0.0000	81.5204
1907	116.5		111		0.0000	86.0928
1906	117.5		159		0.0000	90.5244
1905	118.5		326		0.0000	103.2515
1904	119.5		1,721		0.0000	98.6444
1903	120.5		1,459		0.0000	94.5720
1902	121.5		1,360		0.0000	90.0206
1901	122.5		880		0.0000	86.3106
1900	123.5		(105)		0.0000	86.0000
1899	124.5		89		0.0000	90.6163
Total	16.0	$44,153,608	$18,506,089	$53,992,928	0.8617	

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1986	18,668,470	298,747	320,756		18,646,461
1987	18,646,461	(36,150)	189,131	(49,278)	18,371,903
1988	18,371,903	105,029	249,271		18,227,660
1989	18,227,660	41,878	364,105		17,905,433
1990	17,905,433	101,093	329,183		17,677,344
1991	17,677,344	68,439	281,696		17,464,087
1992	17,464,087	184,594	142,701		17,505,980
1993	17,505,980	110,702	108,920		17,507,763
1994	17,507,763	179,384	185,112	(567)	17,501,468
1995	17,501,468	145,743	142,359		17,504,853
1996	17,504,853	155,509	272,072		17,388,289
1997	17,388,289	428,740	338,254		17,478,775
1998	17,478,775	535,580	257,862		17,756,493
1999	17,756,493	491,104	252,901		17,994,697
2000	17,994,697	581,066	307,780		18,267,982
2001	18,267,982	475,235	252,592		18,490,625
2002	18,490,625	43,427	222,544		18,311,509
2003	18,311,509	909,565	170,905		19,050,169
2004	19,050,169	465,264	178,092		19,337,341
2005	19,337,341	384,764	32,053	924	19,690,976
2006	19,690,976	16,828	167,889		19,539,915
2007	19,539,915	(17,020)	280,480		19,242,416
2008	19,242,416	89,543	231,917	273	19,100,315
2009	19,100,315	105,130	216,618		18,988,826
2010	18,988,826	160,818	200,235		18,949,409
2011	18,949,409	94,118	175,999		18,867,528
2012	18,867,528	190,179	278,455		18,779,253
2013	18,779,253	507,308	188,396		19,098,165
2014	19,098,165	340,739	420,558		19,018,346
2015	19,018,346	573,095	373,153		19,218,289
2016	19,218,289	398,616	263,129		19,353,776
2017	19,353,776	864,398	397,707		19,820,467
2018	19,820,467	825,742	146,059		20,500,151
2019	20,500,151	9,794,942	297,847		29,997,246
2020	29,997,246	2,974,656	123,190		32,848,712
2021	32,848,712	3,218,315	110,127		35,956,901
2022	35,956,901	7,065,413	194,795		42,827,519
2023	42,827,519	11,311,508	146,099		53,992,928

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1986	18,700,105	239,438	320,756		18,618,787
1987	18,618,787	14,094	189,131	(49,278)	18,394,473
1988	18,394,473	95,845	249,271		18,241,046
1989	18,241,046	30,083	364,105		17,907,024
1990	17,907,024	76,274	329,183		17,654,115
1991	17,654,115	84,130	281,696		17,456,548
1992	17,456,548	136,109	142,701		17,449,957
1993	17,449,957	146,298	108,920		17,487,335
1994	17,487,335	119,215	185,112	(567)	17,420,870
1995	17,420,870	191,193	142,359		17,469,705
1996	17,469,705	140,122	272,072		17,337,755
1997	17,337,755	398,438	338,254		17,397,939
1998	17,397,939	1,001,158	257,862		18,141,235
1999	18,141,235	622,405	252,901		18,510,739
2000	18,510,739	472,509	307,780		18,675,468
2001	18,675,468	698,425	252,592		19,121,301
2002	19,121,301	213,760	222,544		19,112,518
2003	19,112,518	514,119	170,905		19,455,731
2004	19,455,731	413,971	178,092		19,691,611
2005	19,691,611	31,691	32,053		19,691,249
2006	19,691,249	17,681	167,889		19,541,041
2007	19,541,041	26,884	280,480		19,287,445
2008	19,287,445	119,937	231,917		19,175,464
2009	19,175,464	122,606	216,618		19,081,452
2010	19,081,452	144,086	200,235		19,025,303
2011	19,025,303	189,407	175,999		19,038,710
2012	19,038,710	249,619	278,455		19,009,875
2013	19,009,875	689,846	188,396		19,511,325
2014	19,511,325	655,244	276,387	(144,171)	19,746,011
2015	19,746,011	1,053,130	373,153		20,425,989
2016	20,425,989	794,222	263,129		20,957,082
2017	20,957,082	2,100,315	397,707		22,659,691
2018	22,659,691	6,727,798	146,059		29,241,430
2019	29,241,430	4,660,988	297,847		33,604,571
2020	33,604,571	1,470,743	123,190		34,952,124
2021	34,952,124	2,238,715	110,127		37,080,712
2022	37,080,712	6,508,133	194,795		43,394,050
2023	43,394,050	10,744,977	146,099		53,992,928

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

T-Cut: None
Placement Band: 1899-2023
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1986-1990	9.2	81.2	O4*	11.56	43.8	O2	6.80	43.4	O2	6.54
1987-1991	0.0	89.9	O4*	13.08	42.7	O2	4.54	43.5	O2 *	4.85
1988-1992	0.0	86.1	O4*	12.00	40.3	O2	5.58	40.8	O2 *	5.95
1989-1993	0.0	70.1	O3	13.34	41.6	SC	2.70	41.2	SC	2.51
1990-1994	0.0	61.9	L0	11.82	45.9	SC	2.91	45.5	SC	2.70
1991-1995	0.0	65.7	L1	12.69	49.4	R0.5	2.82	48.6	R0.5 *	3.50
1992-1996	7.0	64.7	L1.5*	11.24	52.2	R1	3.47	51.7	R1	3.49
1993-1997	7.7	60.1	L1.5*	8.28	50.8	R1	3.16	50.5	R1	3.26
1994-1998	1.5	57.7	L1	7.80	48.8	R0.5	3.08	48.8	R0.5	3.00
1995-1999	0.0	56.5	L0.5	7.21	48.7	R0.5	3.46	48.8	R0.5	3.08
1996-2000	-0.3	53.4	L0	8.48	47.0	SC	4.45	46.6	SC	3.48
1997-2001	0.0	54.0	O2	8.81	49.8	L0	6.43	48.0	SC	4.45
1998-2002	3.0	58.9	O2	10.21	55.3	L0	8.94	50.0	SC	5.53
1999-2003	3.7	63.3	O2	12.29	73.0	O3 *	13.41	51.9	SC *	7.32
2000-2004	2.9	75.6	O3	15.22	64.1	O2	13.54	52.8	SC	8.63
2001-2005	7.6	89.5	O2	16.11	71.0	SC	12.88	60.7	R0.5	8.32
2002-2006	17.1	104.6	O3	15.35	81.6	SC	12.83	64.7	R0.5	7.96
2003-2007	19.1	87.9	O2	10.82	74.4	SC	8.55	66.5	R0.5	6.75
2004-2008	21.3	78.4	L0	6.14	69.6	S-.5	4.31	79.1	O2 *	4.76
2005-2009	22.2	72.9	L1	8.28	83.8	O2 *	9.01	69.4	S0 *	7.86
2006-2010	17.7	67.6	L0.5	7.43	98.2	O3 *	9.75	65.1	S-.5 *	6.76
2007-2011	12.2	67.6	L1	4.80	82.8	O3 *	6.19	65.2	L1 *	4.03
2008-2012	6.0	68.2	L1*	3.84	82.3	O2 *	4.85	65.9	L1 *	3.18
2009-2013	6.9	70.0	L1.5*	4.55	73.6	L1 *	4.88	67.0	S0 *	4.02
2010-2014	0.0	68.5	L1.5*	5.64	81.5	O2 *	7.64	65.1	S0 *	4.28
2011-2015	0.0	64.4	L1.5*	5.67	66.4	L1.5 *	6.10	62.5	L1.5 *	4.73
2012-2016	0.0	62.7	L1.5*	6.60	63.7	L1.5 *	6.88	62.1	L1.5 *	6.24
2013-2017	0.0	60.5	L2*	5.19	60.3	L2 *	5.07	60.4	L2 *	5.13
2014-2018	0.0	61.2	L1.5*	8.42	61.2	L1.5 *	8.42	60.8	L1.5 *	8.23
2015-2019	0.0	60.8	L1.5*	6.95	61.4	L1 *	6.45	58.8	L1 *	6.08
2016-2020	20.9	67.2	L1	7.84	75.7	O2 *	6.06	81.9	O3 *	6.17
2017-2021	21.5	73.1	L1	12.69	95.0	O3 *	9.55	102.2	O3 *	9.89
2018-2022	25.9	83.5	L1	17.85	117.0	SC *	12.99	120.8	SC *	13.59
2019-2023	18.3	85.4	L1	21.78	118.5	SC *	15.56	122.7	SC *	16.80

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

T-Cut: None

Placement Band: 1899-2023

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1986-2023	0.0	65.5	L0.5	2.02	69.7	O2	2.90	61.6	S-.5	1.94
1988-2023	0.0	66.0	L0.5	2.03	70.1	L0	2.86	62.4	S-.5	1.87
1990-2023	0.0	66.8	L0.5	2.00	71.7	L0	2.90	64.0	S-.5	1.76
1992-2023	0.0	67.8	L1	2.00	72.5	L0.5	2.86	65.5	L1 *	1.77
1994-2023	0.0	67.5	L0.5	2.15	76.0	O2 *	3.42	65.0	L1 *	1.84
1996-2023	0.0	67.5	L0.5	2.39	79.7	O2 *	4.04	64.8	S-.5 *	1.91
1998-2023	0.0	68.8	L1	2.65	79.9	O2 *	4.30	65.9	S-.5 *	2.05
2000-2023	0.0	69.7	L1	2.86	82.5	O2 *	4.57	67.8	L0.5 *	2.56
2002-2023	0.0	70.9	L1	2.95	81.1	O2 *	4.50	72.2	L0.5 *	3.62
2004-2023	0.0	70.9	L1	2.83	80.4	O2 *	4.29	90.9	O3 *	5.35
2006-2023	0.0	69.3	L1*	3.33	87.9	O3 *	5.93	92.6	O3 *	6.77
2008-2023	0.0	69.5	L1*	3.33	85.4	O3 *	5.89	96.8	O3 *	8.24
2010-2023	0.0	69.9	L1*	3.94	87.5	O3 *	6.30	98.4	O3 *	8.86
2012-2023	0.0	69.4	L1*	6.40	87.5	O3 *	9.38	102.0	O3 *	13.48
2014-2023	0.0	69.8	L1*	11.45	90.1	O3 *	14.52	105.7	O3 *	19.46
2016-2023	19.9	74.1	L1*	7.37	97.1	O3 *	4.34	112.6	O3 *	5.84
2018-2023	20.2	85.5	L1	16.89	119.4	SC *	11.59	123.7	SC *	12.57
2020-2023	24.1	91.4	L1*	17.02	126.0	SC *	11.64	134.6	SC *	14.15
2022-2023	22.2	85.4	L1*	16.57	116.9	O3 *	10.05	124.9	SC *	12.67

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

T-Cut: None
Placement Band: 1899-2023
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1986-1987	12.2	57.2	O2	6.10	50.6	L0	3.69	48.6	SC	3.60
1986-1989	0.1	90.3	O4*	18.72	44.2	O2	10.21	44.1	O2	10.13
1986-1991	0.0	77.0	O4*	10.11	43.6	O2	3.72	43.4	O2	3.70
1986-1993	0.1	69.2	O3	10.63	44.6	SC	3.71	44.6	SC	3.71
1986-1995	0.0	65.8	O3	10.69	45.6	SC	3.54	45.6	SC	3.55
1986-1997	8.2	59.4	O2	9.00	45.3	SC	2.87	45.3	SC	2.83
1986-1999	0.0	58.4	O2	9.23	46.0	SC	2.64	46.0	SC	2.63
1986-2001	5.4	58.4	O2	8.13	47.3	SC	2.68	47.2	SC	2.79
1986-2003	6.5	60.4	O2	8.05	50.0	SC	3.20	49.2	SC	3.31
1986-2005	5.9	65.7	O2	9.10	52.3	SC	3.44	51.0	SC	3.40
1986-2007	9.9	65.6	O2	7.76	54.5	SC	3.47	52.6	SC	3.58
1986-2009	11.6	64.5	O2	6.65	55.3	SC	3.19	53.6	SC	3.63
1986-2011	8.7	65.1	O2	6.22	57.0	SC	3.04	55.0	SC	3.26
1986-2013	4.5	64.5	O2	5.32	57.6	SC	2.72	55.8	SC	3.10
1986-2015	0.0	62.6	L0	4.69	57.1	SC	2.36	55.5	SC	2.64
1986-2017	0.0	61.3	L0	3.93	56.3	S-.5	2.11	55.2	R0.5	2.66
1986-2019	0.0	62.1	L0	3.37	58.8	L0.5	2.03	56.4	S-.5	2.58
1986-2021	0.0	64.1	L0	2.55	63.6	L0.5	2.38	59.0	S-.5	2.39
1986-2023	0.0	65.5	L0.5	2.02	69.7	O2	2.90	61.6	S-.5	1.94

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

T-Cut: None

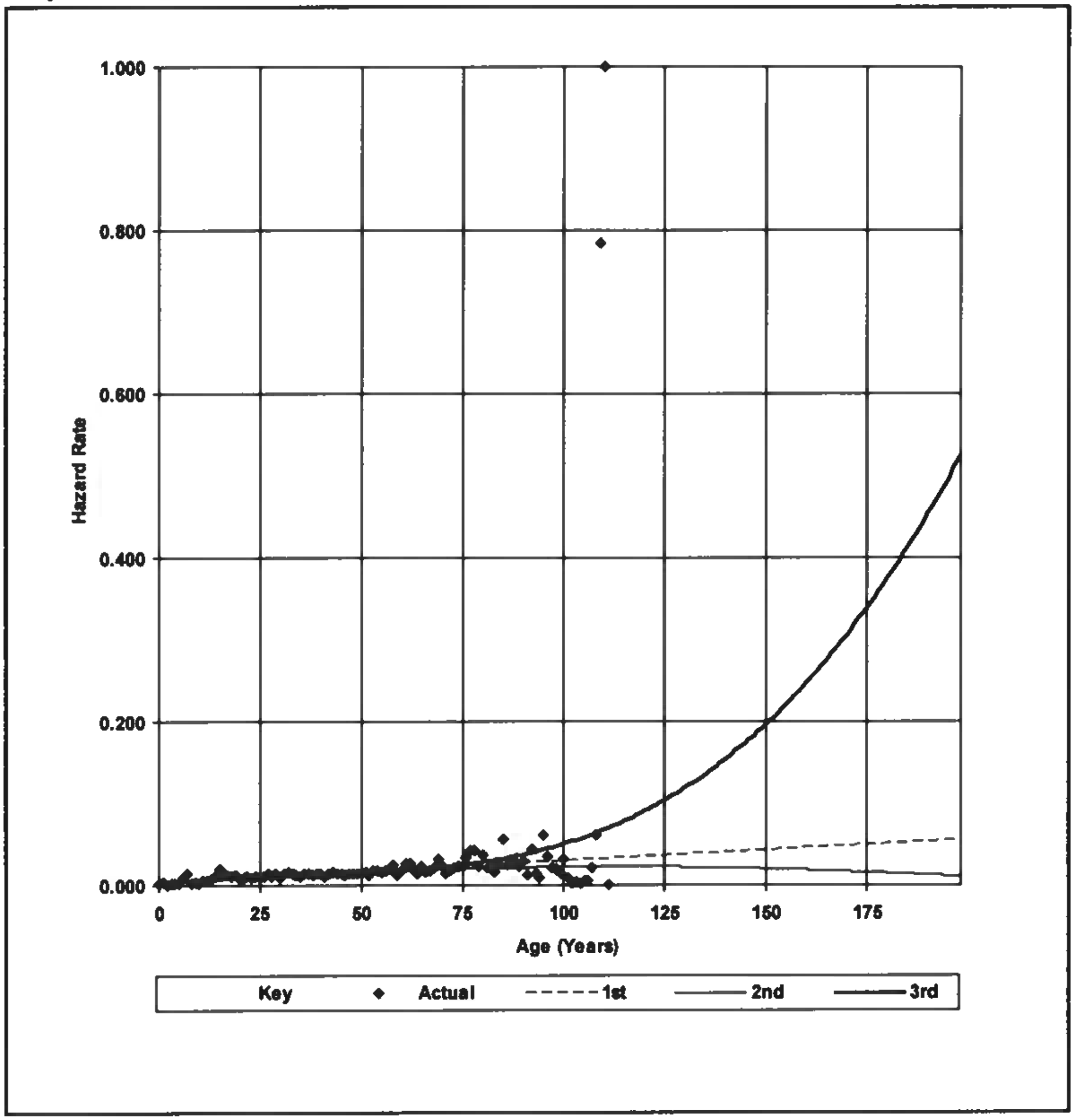
Placement Band: 1899-2023 Observation Band: 1986-2023

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Functions

1st: 65.5-L0.5 2nd: 69.7-O2 3rd: 61.6-S-.5



WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

T-Cut: None

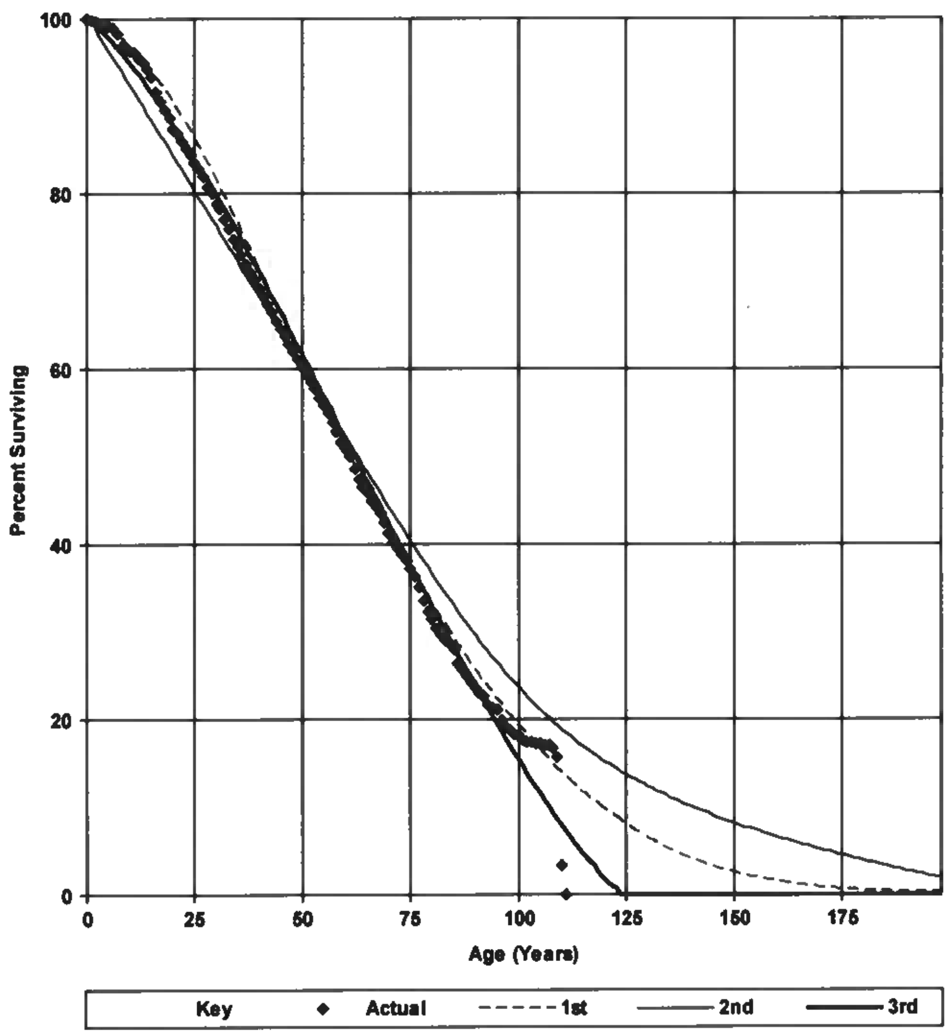
Placement Band: 1899-2023 Observation Band: 1986-2023

Hazard Function: Proportion Retired

Weighting: Exposures

Survivorship Functions

1st: 65.5-L0.5 2nd: 69.7-O2 3rd: 61.6-S-.5



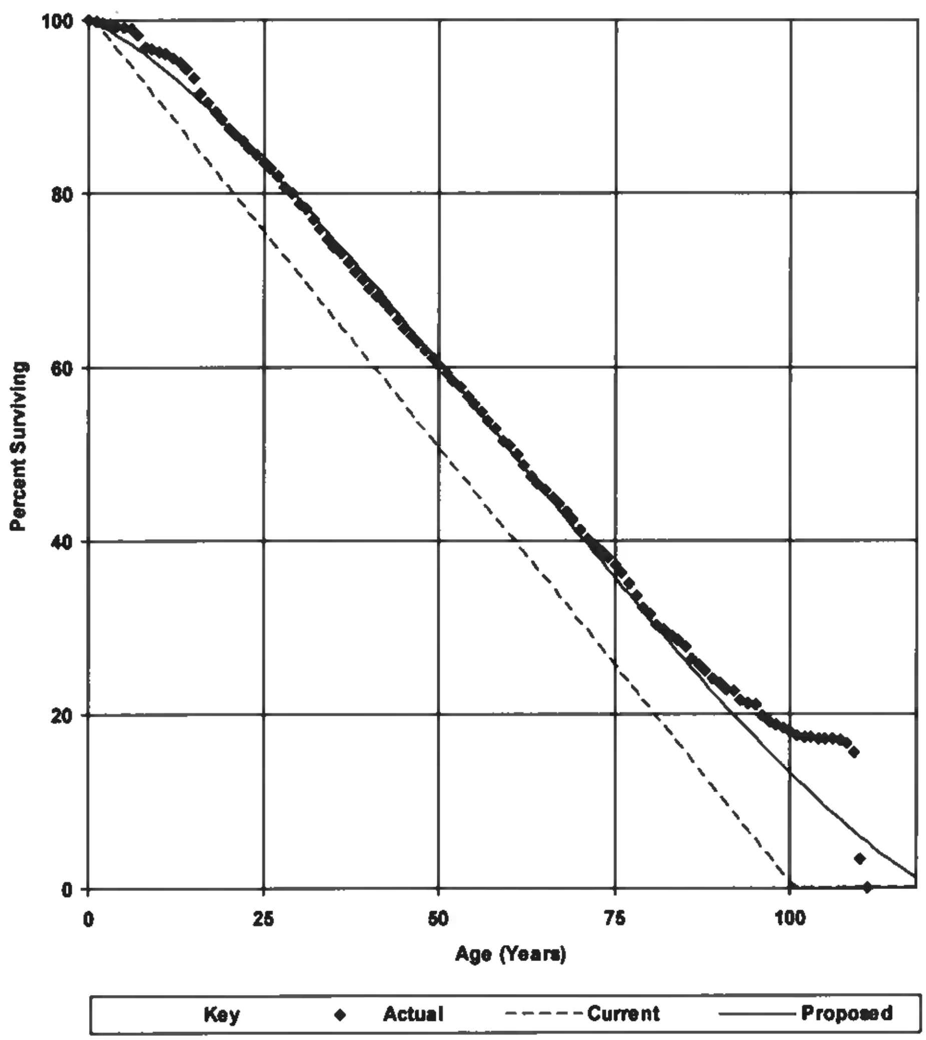
WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

Distribution Plant

Account: 380.10 Services - Steel

T-Cut: None
Placement Band: 1899-2023
Observation Band: 1986-2023

Projection Life Curves Current: 50.0-SC Proposed: 60.0-S-.5



WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA
Distribution Plant
Account: 380.10 Services - Steel

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
2006	167,889		0.0			0.0			0.0	
2007	280,480		0.0			0.0			0.0	
2008	231,917		0.0			0.0			0.0	
2009	216,618		0.0		2,002	0.9		(2,002)	-0.9	
2010	200,235		0.0	0.0	268,066	133.9	24.6	(268,066)	-133.9	-24.6
2011	175,999		0.0	0.0	628,653	357.2	81.3	(628,653)	-357.2	-81.3
2012	278,455		0.0	0.0	459,294	164.9	123.1	(459,294)	-164.9	-123.1
2013	188,396		0.0	0.0	416,962	221.3	167.5	(416,962)	-221.3	-167.5
2014	420,558		0.0	0.0	405,859	96.5	172.4	(405,859)	-96.5	-172.4
2015	373,153	584,271	156.6	40.7	2,728,847	731.3	323.0	(2,144,576)	-574.7	-282.3
2016	263,129	7,719	2.9	38.9	2,348,119	892.4	417.3	(2,340,399)	-889.4	-378.5
2017	397,707	20,515	5.2	37.3	2,295,048	577.1	498.8	(2,274,533)	-571.9	-461.5
2018	146,059		0.0	38.3	1,056,780	723.5	552.0	(1,056,780)	-723.5	-513.7
2019	297,847	27,465	9.2	43.3	1,828,486	613.9	694.0	(1,801,021)	-604.7	-650.7
2020	123,190		0.0	4.5	1,932,406	2e+3	770.5	(1,932,406)	-2e+3	-765.9
2021	110,127		0.0	4.5	3,705,219	3e+3	1e+3	(3,705,219)	-3e+3	-1e+3
2022	194,795	975,306	500.7	115.0	5,189,289	3e+3	2e+3	(4,213,983)	-2e+3	-1e+3
2023	146,099	263,467	180.3	145.2	6,416,640	4e+3	2e+3	(6,153,173)	-4e+3	-2e+3
Total	4,212,651	1,878,743	44.6		29,681,669	704.6		(27,802,926)	-660.0	

WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA
Distribution Plant
Account: 380.10 Services - Steel

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
2006	167,889		0.0			0.0			0.0	
2007	280,480		0.0			0.0			0.0	
2008	231,917		0.0			0.0			0.0	
2009	216,618		0.0		2,002	0.9		(2,002)	-0.9	
2010	200,235		0.0	0.0	268,066	133.9	24.6	(268,066)	-133.9	-24.6
2011	175,999		0.0	0.0	628,653	357.2	81.3	(628,653)	-357.2	-81.3
2012	278,455		0.0	0.0	459,294	164.9	123.1	(459,294)	-164.9	-123.1
2013	188,396		0.0	0.0	416,962	221.3	167.5	(416,962)	-221.3	-167.5
2014	276,387		0.0	0.0	405,859	146.8	194.6	(405,859)	-146.8	-194.6
2015	373,153		0.0	0.0	2,728,847	731.3	359.0	(2,728,847)	-731.3	-359.0
2016	263,129		0.0	0.0	2,348,119	892.4	461.0	(2,348,119)	-892.4	-461.0
2017	397,707		0.0	0.0	2,295,048	577.1	546.8	(2,295,048)	-577.1	-546.8
2018	146,059		0.0	0.0	1,056,780	723.5	606.6	(1,056,780)	-723.5	-606.6
2019	297,847		0.0	0.0	1,828,486	613.9	694.0	(1,828,486)	-613.9	-694.0
2020	123,190		0.0	0.0	1,932,406	2e+3	770.5	(1,932,406)	-2e+3	-770.5
2021	110,127		0.0	0.0	3,705,219	3e+3	1e+3	(3,705,219)	-3e+3	-1e+3
2022	194,795		0.0	0.0	5,189,289	3e+3	2e+3	(5,189,289)	-3e+3	-2e+3
2023	146,099		0.0	0.0	6,416,640	4e+3	2e+3	(6,416,640)	-4e+3	-2e+3
Total	4,068,480		0.0		29,681,669	729.6		(29,681,669)	-729.6	

ATTESTATION

I, DR. RONALD E. WHITE, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

DR. RONALD E. WHITE

July 26, 2024
DATE

WITNESS BELL
EXHIBIT WG (H)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF KIMBERLY M. BELL
Exhibit WG (H)
(Page 1 of 1)

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Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF KIMBERLY M. BELL

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Kimberly M. Bell. I am the Senior Manager of Tax Technology, Special Projects, and Regulatory Liaison for Washington Gas Light Company ("Washington Gas" or the "Company"). My business address is 1000 Maine Avenue SW, Washington, DC 20024.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I joined Washington Gas in 2015 as a Senior Tax Analyst. Since that time, I have held positions of increasing responsibilities, assuming my current role as Senior Tax Manager of Tax Technology, Special Projects, Regulatory Liaison. Prior to my role at Washington Gas, I worked over seven years in various tax leadership positions at Pepco Holdings Inc. ("PHI"). I have a degree in Accounting from Virginia State University, and I am a Certified Public Accountant.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. Yes, I testified before the Maryland Public Service Commission in Case No. 9704.

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I sponsor two (2) exhibits. The first is identified as Exhibit WG (H)-1, which provides the amount of the net operating loss carryforward on page one and the Deferred Tax Asset for Net Operating Loss Carryforwards ("DTA-NOLC") that must be restored on page two. The second is identified as Exhibit WG (H)-2 and includes the Private Letter Rulings from the Internal Revenue Service ("IRS").

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony provides support and detail for the Company's request to account for the recently issued Internal Revenue Service (the "IRS") private letter rulings ("PLR") 202462002, 202462003 and 202462004.

Q. WHAT IS THE SUBJECT MATTER OF THESE PRIVATE LETTER RULINGS?

A. The PLR's address how tax sharing payments received from other members of the consolidated group for the utilization of the regulated utility company DTA-NOLC cause a normalization violation under the tax rules.

Q. DOES THE COMPANY HAVE A NORMALIZATION VIOLATION AS A RESULT OF THESE RULINGS BY THE IRS?

A. Yes. As a result of these rulings, the Company has incurred a normalization violation by accounting for the receipts of the tax sharing payments as a reduction of the DTA-NOLC for rate making purposes.

Q. THESE RULINGS WERE ISSUED TO ANOTHER REGULATED UTILITY COMPANY. WHY ARE THEY RELEVANT TO WASHINGTON GAS?

A. The PLR'S were issued to a specific taxpayer and apply solely to that taxpayer; however, the rulings provide strong guidance as to how the IRS will rule in a similar fact pattern.

Q. DO THE FACTS IN THE PLR MATCH THE FACTS AT THE COMPANY?

A. Yes, the Company facts are the same as reflected for the taxpayer in the PLR.

Q. DOES THE COMPANY HAVE NET OPERATING LOSSES?

A. Yes, similar to the taxpayer in the PLR, the Company generated a net operating loss carryforward that was reduced by tax sharing payments received from other members of the consolidated group.

Q. If THE COMPANY IS PROFITABLE, HOW CAN IT HAVE A NET OPERATING LOSS CARRYFORWARD?

A. Yes, the Company is profitable; however, for tax reporting purposes, the Internal Revenue Code provides tax deductions that are different from book deductions. Similar to the taxpayer in the PLR, the Company generates a significant tax deduction from the use of accelerated tax depreciation that is greater than book depreciation. On an annual basis, the total tax deductions exceed our taxable income resulting in an annual net operating loss on the federal income tax return of the Company.

Q. HOW DOES WASHINGTON GAS ACCOUNT FOR AN NOLC?

A. On a stand-alone basis, the Company establishes a DTA – NOLC. This DTA- NOLC reflects the future benefit of using the NOLC to reduce taxable income of the Company in future years.

Q. IS THE COMPANY A MEMBER OF A TAX SHARING AGREEMENT?

A. Yes, like the taxpayer in the PLR, as a member of the consolidated group the Company has entered into a tax sharing agreement with AltaGas Services U.S., Inc ("ASUS") & subsidiaries. This agreement was approved by the Virginia State Corporation Commission as part of the affiliate agreements on December 11, 2023, and replaces the previous Tax Sharing Policy of the ASUS consolidated group that was in place since July 6, 2018.

Q. WHAT IS THE PURPOSE OF THIS TAX SHARING AGREEMENT?

A. Similar to the taxpayer in the PLR, the purpose of this tax sharing agreement is to establish the allocation of Liabilities and Benefits arising from the filing of the Consolidated Tax Returns Between AltaGas Services (U.S.) Inc. and its Subsidiary Companies. The agreement also establishes the payment mechanism for utilization of tax attributes (including net operating losses) by members of the consolidated group.

Q. IS A TAX SHARING AGREEMENT SUCH AS THE ONE USED BY THE COMPANY STANDARD INDUSTRY PRACTICE?

A. Yes, these tax sharing arrangements have been followed by many regulated utilities that are members of a consolidated group, including the taxpayer in the PLR.

Q. HAS THE COMPANY RECEIVED ANY PAYMENTS UNDER THIS TAX SHARING AGREEMENT?

A. Yes.

Q. WERE THESE PAYMENTS FOR THE UTILIZATION OF NOLCS BY OTHER MEMBERS OF THE CONSOLIDATED GROUP?

A. Yes.

Q. HOW DOES THE COMPANY ACCOUNT FOR THESE TAX SHARING PAYMENTS?

A. Similar to the taxpayer in the PLR, the cash payments received by the Company for the use of NOLC by other members of the consolidated group are used to reduce the balance of the DTA-NOLC on the books of the Company.

Q. IS THE ACCOUNTING FOR TAX SHARING PAYMENTS STANDARD INDUSTRY PRACTICE?

A. Yes, the method of reducing the stand-alone DTA–NOLC with cash payments from the consolidated group is typical within the utility industry, including the taxpayer in the PLR.

Q. DOES THE CURRENT PRACTICE OF ACCOUNTING FOR THE TAX SHARING PAYMENTS CONSTITUTE A VIOLATION OF THE NORMALIZATION RULES ACCORDING TO THE PRIVATE LETTER RULINGS?

A. Yes, per the IRS Private Letter Rulings (PLR) 202462002, 202462003 and 202462004, any payments reducing the DTA-NOLC for ratemaking purposes constitute a normalization violation.

Q. WHAT ARE THE IMPLICATIONS TO THE COMPANY OF A NORMALIZATION VIOLATION?

A. Congress established a penalty for normalization violations. The penalty imposed on regulated utilities that have a normalization violation is to preclude that regulated utility from claiming the benefit of accelerated tax depreciation deductions on its federal income tax return.

Q. DOES THE IRS PROVIDE AN AVENUE TO REMEDY A NORMALIZATION VIOLATION?

A. Yes, the IRS private letter rulings confirmed the safe harbor relief for inadvertent normalization violations under Revenue Procedure 2017-47 and Revenue Procedure 2020-39 applies in this instance. These private letter rulings allow the avoidance of the normalization penalties if the taxpayer and the rate-setting commission agree to correct the normalization violation at the next available opportunity after the inadvertent normalization violation is discovered. This rate proceeding provides an opportunity to remedy the normalization violation and avoid penalties.

Q. IS THE TAX SHARING PAYMENT RECEIVED BY THE COMPANY THAT WAS USED TO REDUCE THE DTA-NOLC AN INADVERTENT NORMALIZATION VIOLATION?

A. Yes, the rulings provide that the safe harbor for the inadvertent normalization would apply in this circumstance.

Q. WHAT IS THE REMEDY NEEDED TO CORRECT THIS INAVERTANT NORMALIZATION VIOLATION?

A. The Revenue Procedure indicates the Company should re-establish, for rate making purposes, the DTA–NOLC generated by the accelerated tax depreciation deductions reflected on the stand-alone company income tax returns that had been previously reduced by the tax sharing payments.

Q. WHAT IS THE AMOUNT OF THE DTA-NOLC THAT MUST BE RESTORED IN ORDER TO REMEDY THE NORMALIZATION VIOLATION?

A. The amount of DTA-NOLC on a system-wide basis that must be restored for rate making purposes due to these payments received under the terms of the tax sharing agreement from other members of the consolidated group for the use of the stand-alone NOLC and paid for under the terms of the tax sharing agreement to remedy the normalization violation is $181,640,605. Please refer to Exhibit WG (H)-1 for the calculation of this amount.

Q. IS THIS AMOUNT SOLELY RELATED TO THE ACCELERATED TAX DEPRECIATION TAKEN ON THE COMPANY'S TAX RETURNS?

A. Yes, to remedy the inadvertent normalization violation, the DTA-NOLC amount that needs to be re-established for rate making purposes is limited to the accelerated tax depreciation taken during those tax years reflecting net operating losses.

Q. WHY IS THIS ONLY LIMITED TO ACCELERATED TAX DEPRECIATION?

A. PLR201709008 indicates the with or without method should be used to determine the amount of NOL generated from accelerated tax depreciation taken on the Company tax return. If any portion of the DTA-NOLC that is a result of a NOL generated by accelerated tax depreciation is excluded from rate base, it violates the normalization requirements of § 168(i)(9) and § 1.167(l)-1[1].

Q. DOES THIS IMPACT ANY OF THE EXCESS DEFERRED TAXES RESULTING FROM THE INCOME TAX RATE REDUCTION AFTER THE PASSAGE OF THE TAX CUTS AND JOBS ACT ("TCJA")?

A. Yes, a DTA – NOLC existed at the time the TCJA was enacted. This DTA–NOLC was adjusted to reflect the reduction in the amount of the

[1] Interal Revenue Code of 1986.

carryforward as a result of the tax rate decrease from 35% to 21%. Formal Case No. 1162 established the ratemaking for excess deferred taxes. The ratemaking included a regulatory asset for the deficient deferred taxes associated with the NOLC that were required to be collected from customers in the future. The settlement reached in Formal Case No. 1162 set the amortization period for the recovery of this regulatory asset at 15 years. Because a portion of this regulatory asset is associated with deductions that arose from accelerated tax deductions, the amortization of the regulatory asset for the NOL derived by accelerated tax depreciation must be adjusted to reflect the Average Rate Assumption Method (ARAM) required by the normalization rules enacted by Congress.

Q. DID THIS SETTLEMENT REACHED IN FORMAL CASE NO. 1162 MAKE ANY ACCOMODATION FOR INADVERTENT NORMALIZATION VIOLATIONS?

A. Yes, in adopting this settlement, the Settling Parties intended to comply with federal normalization requirements and believed the Settlement Agreement did so. In the event a subsequent determination is made that an inadvertent normalization violation has occurred, the Settling Parties agreed that the calculation of ARAM and the qualification of temporary differences subject to federal normalization requirements provided for in the Settlement may be adjusted at the next available ratemaking opportunity, in accordance with Rev. Proc. 2017-47[2] and related guidance, in order to meet the safe harbor provisions of the Internal Revenue Service regarding normalization requirements.

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[2] IRS Revenue Procedure 2017-47.

Q. WHAT IS THE ANNUAL CHANGE IN THE AMORTIZATION OF THE REGULATORY ASSET ESTABLISHED UNDER THE SETTLEMENT IN FORMAL CASE NO. 1162 ASSOCIATED WITH THE DTA-NOLC?

A. The regulatory asset amortization calculated using ARAM decreases the annual amortization established under the Settlement by $815,584 on a system-wide basis.

Q. WHAT IS THE IMPACT TO CUSTOMER RATES AS A RESULT OF THESE CHANGES TO THE DTA-NOLC FOR RATE MAKING PURPOSES THAT ARE REQUIRED TO AVOID A NORMALIZATION VIOLATION?

A. The impact to customer rates is included in Company Witness Robert Tuoriniemi's direct testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Washington Gas Light

Exhibit WG (H)-1; Page 1 of 2

Filing Year	Tax Year	Carryback provision	Loss carryforward subject to normalization	
FYE 09/30/16	2015	2 year	(37,969,356)	
FYE 09/30/17	2016	2 year	(102,492,654)	
2018 SP 1 Ended 07/06/2018	2017	2 year	(3,961,270)	
2018 SP2 Ended 12/31/2018	2018	5 year	(193,522,249)	
CYE 12/31/19	2019	5 year	(102,532,653)	
CYE 12/31/20	2020	5 year	(93,928,893)	
CYE 12/31/21	2021	none	(103,333,533)	
CYE 12/31/22	2022	none	(100,213,895)	
CYE 12/31/23	2023	none	(127,000,757)	Note A
Total			(864,955,260)	

Note A: These amounts represent an estimate based on the year end provision calculation. These amounts will be updated after completion of the tax year 2023 federal income tax return.

Washington Gas Light

Calculation of Deferred Tax Asset

Exhibit WG (H)-1; Page 2 of 2

	NOLC	Tax Rate	DTA-NOL - System Wide		
NOLC at 12/31/2017	(120,154,521)	35%	42,054,082	DTA - NOL at 35%	(Per - Formal Case 1162)
NOLC generated after 12/31/2017	(744,800,739)	21%	156,408,155	DTA - NOL at 21%	
Total as of 12/31/2023	(864,955,260)		198,462,238	Total DTA before ASC740 adjustment to statutory rate	
Reconcile to Exhibit WG(H)-1 page 1	(864,955,260)	21%	181,640,605	DTA on NOL carryforward at statutory rate	
			16,821,633	Excess DTA on NOL Carryback - Agrees to previous filings for TCJA	

	Annual Amortization		
		16,821,633	Net APB11 Regulatory Asset
Original 15 Year Amortization	1,121,442	6,728,653	Previously Amortized Per Rate Orders
est. ARAM Amortization	305,848	10,092,980	Remaining APB11 Amount To Be Amortized Using ARAM as of 12/31/2023
Annual Amortization Difference	815,594		
		181,640,605	DTA-NOL Required To Be Restored Per PLR Under the Safe Harbor Provision of Rev Proc 2017-47 and Rev Proc 2020-39

Internal Revenue Service

Number: **202426002**
Release Date: 6/28/2024

Index Number: 168.24-01

Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.

Telephone Number:

Refer Reply To:
CC:PSI:B06
PLR-105951-22

Date:
March 08, 2024

Legend:

Parent	=
Taxpayer	=
Additional Subsidiary	=
Date 1	=
Date 2	=
Date 3	=
Date 4	=
Date 5	=
Date 6	=
Date 7	=
Date 8	=
Date 9	=
Date 10	=
Commission A	=
Commission B	=
Staff	=
a	=
b	=
c	=
d	=
e	=
f	=

g	=	
Year 1	=	
State	=	
System	=	
Form	=	
Form A	=	
Form B	=	
Rules	=	
Enforcement Matter	=	
Agency	=	
Opinion	=	

Dear :

On Date 1, on behalf of Parent and its wholly-owned subsidiary, Taxpayer, Parent's and Taxpayer's authorized representatives requested rulings under § 168(i)(9) regarding the potential implementation of a proposed ratemaking adjustment under the depreciation normalization provisions of the Internal Revenue Code of 1986, as amended ("Code") and the regulations thereunder. Taxpayer's request is made pursuant to, and in compliance with, Rev. Proc. 2022-1. Parent is simultaneously submitting a substantially identical letter ruling for another of its wholly-owned subsidiaries, Additional Subsidiary.

On Date 2, the Staff filed a written submission with the Internal Revenue Service, objecting to certain statements set forth in the Statement of Facts of the Date 1 submission that it believed were erroneous or potentially misleading. Parent and Taxpayer did not agree with the concerns but on Date 3, modified and resubmitted the ruling request with a modified Statement of Facts that addresses the Staff's stated factual concerns. In addition, Staff believed that the summaries of its position in the original ruling request submission did not adequately capture the entirety of its legal positions and analysis. Accordingly, Taxpayer's representatives removed its summaries of the Staff's positions and analyses from the ruling request and are willing for the Staff's positions and analyses reflected in its Date 2 submission to speak for themselves. Additionally, Staff submitted an addendum dated Date 4 to its original Date 2 filing attached to the Date 3 submission by Taxpayer. Later, in response to a request for additional information, Taxpayer submitted additional responses on Date 5.

Parent, through its operating subsidiaries, serves nearly a customers in b states. Taxpayer, a wholly owned subsidiary of Parent, is a regulated public utility serving more than c customers in d states. As a member of the Parent affiliated group, Taxpayer joins in the filing of a consolidated return with other Parent operating companies. As is relevant to this private letter ruling request, Taxpayer is subject to the ratemaking jurisdiction of Commission A.

Parent and each of its subsidiaries are accrual basis taxpayers. Parent is the common parent of an affiliated group of corporations filing a consolidated return on a calendar-year basis. Parent, as the common parent of the affiliated group, serves as the agent of Taxpayer for purposes of this private letter ruling request pursuant to § 1.1502-77(a) of the Income Tax Regulations.

On a separate return basis, Taxpayer had a federal income tax net operating loss carry-forward ("NOLC"). In its rate case filing in the instant case, Taxpayer reflected a total NOLC deferred tax asset ("DTA") attributable to tax losses for the years Year 1 through the Date 6 test year end by proposing an adjustment to its actual Generally Accepted Accounting Principles (GAAP) and Commission B books of account.

Under the Parent Tax Allocation Agreement ("TAA") amongst the Parent affiliated group members joining in the filing of a consolidated return, certain profitable members of the affiliated group were able to utilize the Taxpayer NOLC to offset their separate company taxable income. None of these profitable subsidiaries provided electric utility service to customers in State within the service territory of Taxpayer and their operations were either subject to the jurisdiction of Commission B and/or state public utility commissions other than Commission A, were separately subject to the jurisdiction of Commission A, or were unregulated businesses not subject to the jurisdiction of any public utility commission.

Pursuant to the TAA, the profitable members made cash payments to Parent for their separate return tax liability, and Parent remitted cash payments of $e to Taxpayer for the tax benefit derived by the affiliated group from the use of Taxpayer's losses. On its financial (GAAP) books and its annual and quarterly balance sheets reported on Commission B Form A and Form B, Taxpayer reduced its DTA for the NOLC to reflect the receipt of cash for the use of its loss by other members of the affiliated group, thereby recording an adjusted DTA balance of zero on its GAAP books. Similarly, in its annual reports filed with the Agency, the consolidated NOLC as of Date 6 and Date 7, reflected a balance of zero. In the rate base calculated for its General Rate Case ("GRC" filing), Taxpayer restored the DTA in order to reflect a separate return basis.

For ratemaking purposes, Taxpayer includes all used and useful public utility property in rate base, calculates depreciation expense thereon using a straight-line method, depreciates such property for federal income tax purposes using accelerated depreciation (MACRS), and makes an adjustment to the reserve for deferred taxes (at the statutory rate) to reflect the difference in tax liability attributable to the use of different depreciation methods for book and tax purposes. Tax expense for the test year of approximately $f was thus calculated on a fully-normalized basis to include both current and deferred taxes on a stand-alone basis unreduced for any NOL. All of these calculations were done on a separate return basis without regard to the property, tax attributes, or separate tax liability, of affiliates, or the non-State property of Taxpayer.

In accordance with section 13001 of Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act ("TCJA"), Taxpayer calculated its so-called excess deferred income taxes ("EDIT") as of December 31, 2017, representing the amount of accelerated depreciation-related taxes previously collected from customers that had not yet been paid by Taxpayer and became excess due to the reduction in tax rates in the TCJA. (Rev. Proc. 2020-39, Section 2.05.) The total EDIT so-calculated was based on the deferred tax balances on Taxpayer's actual financial (GAAP) books and as a result did not include any adjustment for the separate return NOLC DTA. Had the calculation of EDIT taken into account the separate return NOLC DTA, it would have resulted in a reduction to the balance of $g. Pursuant to TCJA § 13001(d)(1), Taxpayer began amortizing the unadjusted EDIT balance on its ratemaking books in accordance with the Average Rate Assumption Method ("ARAM") beginning as of January 1, 2018. In connection with the preparation of Taxpayer's current GRC, Taxpayer determined that amortization of its EDIT must take into account the $g related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized and seeks to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39.

In Taxpayer's current GRC, the Staff asserted that no DTA was allowable to Taxpayer because its GAAP books and Commission B Form A and Form B reflected a balance of zero. Staff's alternative positions are that if the DTA is restored to rate base, then either (i) the $e of used and useful property that Taxpayer purportedly acquired using the TAA payments should be removed from rate base, or (ii) the $e of TAA payments received by Taxpayer should be treated as additional zero-cost capital.

Taxpayer asserted that the adoption of Staff's proposal would violate the normalization rules of § 168(i)(9), and particularly the consistency rules of § 168(i)(9)(B). Specifically, Taxpayer contended that the adjustment to remove used and useful assets from rate base, while computing depreciation expense, tax expense and the reserve for deferred taxes by including such assets, would violate the consistency rules. Moreover, Taxpayer asserted that the Staff proposal would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2) by introducing a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate. Finally, Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue.

The administrative law judges presiding over the GRC recommended that Commission A adopt Staff's position, and Taxpayer filed its exceptions to that recommendation. The parties appeared at an open Commission A hearing held on Date 8. Commission A issued a final order on Date 9 adopting Staff's position, but it is aware that Taxpayer is filing this private letter ruling request.

In Staff's submission dated Date 2, Staff allege that Taxpayer's ratemaking regulated books of account did not reflect the NOLC DTA balance unreduced by the TAA payments. Staff note that Taxpayer confirmed in response to a discovery request (answered as if under oath) that the balance of its NOLC DTA at the Date 10 test year end on its books and records kept in accordance with the Commission 2 System and reported on its Commission 2 Form for that date, was zero. Staff assert that Commission A's Rules require a major electric utility like Taxpayer to maintain, for purposes of accounting and reporting to Commission A, its books and records in accordance with the uniform system of accounts adopted and amended by Commission B for all regulatory purposes. The term "all regulatory purposes" includes ratemaking. Thus, Taxpayer's regulatory books and records for the Commission B and State jurisdictions are the same as its ratemaking books which reflected the NOLC DTA actual balance of zero at the end of the test year.

In response to these concerns raised by Commission A on its submission dated Date 2, Taxpayer explained more in its additional submission dated Date 5 that journal entries are not made to the financial statements of Taxpayer to re-establish the NOLC DTA for ratemaking purposes. Taxpayer says the tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. Taxpayer represents that this methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Taxpayer explains that the "separate return method" terminology used by Agency is a method of allocating taxes amongst the members of an affiliate group. This methodology allocates current and deferred taxes to members of the group as if it were a separate taxpayer.

Regarding Commission B Financial Reporting, Taxpayer explains that Commission B issued Enforcement Matter to discuss the acceptable accounting for income taxes, addressing both a "separate return method" and a "stand alone method" of accounting. Commission B describes the "separate return method" as a method that allocates current and deferred taxes to members of the group as if each member were a separate taxpayer, which is similar to the definition of separate return used by the Agency. Under the "separate return method," the sum of the individual member's allocations will not align with the consolidated tax return. In Enforcement Matter, Commission B also defines the "stand alone method" and distinguishes it from the "separate return method". The "stand alone method" allocates the consolidated group tax expense to individual members through the recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under this method, the sum of the amounts allocated to individual members equals the consolidated amount. Commission B concludes in Enforcement Matter that Commission B requires the use of the "stand alone method" and expressly provides that the use of the "separate return method" will not be permitted for Commission B financial accounting and reporting (Commission B Form A and Form B.)

Commission B has issued several decisions rejecting the use of the "separate return method" for determining income tax expense when an entity files as part of a consolidated group. Instead, Commission B relies on the "stand alone method" of allocating income taxes between members of a consolidated group. Under the "stand alone method," the consolidated tax expense is allocated to individual members through recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under the "stand alone method," the sum of amounts allocated to individual members equal the consolidated amount.

Regarding Commission B Ratemaking, Opinion from Commission B describes the "stand alone method" as an income tax allowance "that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities ... " The "stand alone method" results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Based on this definition, for ratemaking purposes, the Commission B-approved tax allocation method for ratemaking purposes aligns with the Agency definition of "separate return method" despite using the term "stand alone method" in that the tax expense is only attributable to the cost of service and the activities involved in providing service to a utility's customers.

The receipt of cash from the Taxpayer's Parent Company for the consolidated utilization of the NOL results in the DTA being reduced to zero on Commission B Form A and Form B. Journal entries are not made to the financial statements of the subsidiary to re-establish the NOLC DTA for ratemaking purposes. The tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. This methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Because no journal entries are recorded to the financial statements to re-establish the DTA, Taxpayer represents that it is necessary to make adjustments for ratemaking purposes in order to comply with the normalization rules. Accordingly, these adjustments are incorporated into the filing package presented to the respective state regulatory bodies as part of the Taxpayer's rate requests. The filing packages include schedules that start with the financial information on Commission B's Form A and Form B and the financial information presented in Agency financial statements. Consistent with the "separate return methodology," however, adjustments are made to align the rate request with the revenues and costs entering into the regulated cost of service. These adjustments are where the NOLC DTA is re-established as a component of accumulated deferred income taxes.

Taxpayer emphasizes the role that Commission B Form A and Form B play (and do not play) in the ratemaking context. Taxpayer asserts that Commission B Form A and Form B are simply the starting point for the financial data included in ratemaking. Adjustments are then made to arrive at the end result of a tax allowance for the test year associated with the provision of utility service to the regulatory jurisdiction's customers. The financial statement data in Commission B Form A and Form B are first adjusted to remove items of income and expense that are not associated with the provision of utility service. An example of one of these items is the expense in the financial statements for lobbying which is removed along with the income tax associated with that expense. In addition to the adjustments to remove non-utility activity, there are also adjustments that are made to the Commission B Form A and Form B financial statements for ratemaking purposes. An example of these ratemaking adjustments is changes to payroll expenses for known increases/decreases in the expense relative to the expense reported on the Commission B Form A and Form B. After these adjustments are made, a further adjustment is made to the income and expense to allocate it to the customers within the respective regulatory jurisdiction to which the filing is being made.

Per Commission B's guidance in Opinion, Taxpayer asserts that the income tax allowance in ratemaking should reflect the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Taxpayer asserts this ratemaking aligns with the consistency requirement set forth in § 168(i)(9) such that any projections of tax expense, depreciation expense, rate base and the deferred tax reserve remain in synch. Taxpayer believes that setting rates based on the unadjusted Commission B financial statements would violate the consistency requirement of the normalization rules.

RULINGS REQUESTED

Taxpayer requests the following rulings:

1. The implementation of Staff's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Putting into effect a rate order reducing the used and useful public utility property includible in rate base in an amount equal to the TAA payments, treating the TAA payments as additional zero-cost capital or eliminating the DTA to reflect the TAA payments while computing book and tax depreciation, tax expense, and the deferred tax reserve with respect to Taxpayer's public utility property for ratemaking purposes would violate the consistency rules of § 168(i)(9)(B)
3. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.

4. Implementation of Staff's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property.

LAW & ANALYSIS

Section 168(f)(2) of the Code provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

Section 168(i)(10) defines, in part, public utility property as property used predominantly in the trade or business of the furnishing or sale of electrical energy if the rates for such furnishing or sale, as the case may be, have been established or approved by a State or political subdivision thereof.

Prior to The Revenue Reconciliation Act of 1990, the definition of public utility property was contained in § 167(l)(3)(A) and that definition is essentially unchanged in § 168(i)(10) and the regulations promulgated under former § 167(l) remain valid for application of the normalization rules.

In order to use a normalization method of accounting, § 168(i)(9)(A) of the Code requires that a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) provides that one way the requirements of § 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under § 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under § 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base (hereinafter referred to as the "Consistency Rule").

Former § 167(l) generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in § 168(i)(9)(A). Section 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under § 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under § 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under § 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under § 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under § 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under § 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under § 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Rev. Proc. 2020-39 provides guidance concerning the implementation of the EDIT normalization rules of TCJA § 13001 solely with respect to effects of tax rate reductions on timing differences related to accelerated depreciation. Sec. 4.01(6) of Rev. Proc. 2020-39 allows taxpayers that have amortized their EDIT in a manner not in accordance with the Revenue Procedure to prospectively correct the erroneous method at the next available opportunity. Taxpayers so correcting the erroneous method at such time and in such manner will not be treated as having violated the normalization rules of the TCJA.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. The deferred tax computation rules involve the method and life differences between book and tax depreciation and the statutory tax rate. In regard to request (1), Commission A's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would introduce a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate.

Section 168(i)(9)(B)(ii) provides that the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii) does not comply with the Consistency Rule unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its rate base by removing used and useful assets) without making similar adjustments to book and tax depreciation expense, tax expense, and the reserve for deferred taxes. Therefore, in regard to request (2), the Normalization Rules do not allow Taxpayer to adjust its rate base in an amount equal to the TAA payments, treat the TAA payments as additional zero-cost capital, or eliminate the DTA to reflect the TAA payments while computing book and tax depreciation, tax expense, and the deferred tax reserve with respect to Taxpayer's public utility property for ratemaking purposes. Doing so would violate the Consistency Rule of § 168(i)(9)(B).

Adjustment of Taxpayer's rate base in an amount equal to the TAA payments or treating the TAA payments as additional zero-cost capital would, in effect, flow through the tax benefits of accelerated depreciation deductions to rate payers. This is so even if the intent of such reduction is not specifically to mitigate the effects of the normalization rules. In general, taxpayers may not adopt any accounting treatment that directly or indirectly circumvents the normalization rules. See generally, § 1.46-6(b)(2)(ii) (In determining whether, or to what extent, the investment tax credit has been used to reduce cost of service, reference shall be made to any accounting treatment that affects cost of service); Rev. Proc. 88-12, 1988-1 C.B. 637, 638 (It is a violation of the normalization rules for taxpayers to adopt any accounting treatment that, directly or indirectly flows excess tax reserves to ratepayers prior to the time that the amounts in the vintage accounts reverse). Accordingly, any adjustment of rate base or treating amounts as zero cost capital that has the effect of offsetting some or all of the level of revenues that would flow through would violate the normalization requirements of § 168(i)(9) of the Code.

Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue. In regard to request (3), based on the response to requests (1) and (2), Taxpayer's amortization of its EDIT must take into account the $g related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized.

In the setting of utility rates, a utility's rate base is offset by its EDIT and/or ADIT balance. Taxpayer maintains that the amortization of its EDIT must take into account the $g related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized. The EDIT should be reduced because these are the amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers.

In regard to request (4), Taxpayer sought to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39. Our understanding is that Commission A is in agreement to follow the outcome of the letter ruling request.

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By reducing Taxpayer's stand-alone DTA by reason of the TAA payments (or achieving a similar result through other methods), this improperly involves amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. Taxpayer's failure to comply with the Normalization Rules was inadvertent. Because Commission A, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency

Rule or the deferred tax reserve computational rules constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

We are not providing a ruling on the overall merits of Commission A's policies towards separate return or consolidated return ratemaking. This ruling is solely with respect to the four normalization elements relevant to depreciation-related ratemaking. The treatment of non-ratemaking related payments as part of a TAA does not determine the normalization consequences of those arrangements. Ultimately, since depreciation normalization is based upon the construct of the extension of an interest free loan from the federal government to the utility in the form of deferred taxes, whether and how the group members allocate tax liabilities amongst themselves is irrelevant to the analysis. While under certain circumstances, the intercompany payments under a TAA might create an imputed loan between members, that is not a loan from the federal government, which is the *sine qua non* of depreciation normalization.

RULINGS

We rule as follows in response to Taxpayer's requested rulings:

1. The implementation of Staff's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Putting into effect a rate order reducing the used and useful public utility property includible in rate base in an amount equal to the TAA payments, treating the TAA payments as additional zero-cost capital or eliminating the DTA to reflect the TAA payments while computing book and tax depreciation, tax expense, and the deferred tax reserve with respect to Taxpayer's public utility property for ratemaking purposes would violate the consistency rules of § 168(i)(9)(B).
3. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
4. Implementation of Staff's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property. However, as described this disallowance of Taxpayer's right to claim accelerated depreciation would only occur under facts not present in this case.

Except as specifically set forth above, no opinion is expressed or implied concerning the federal income tax consequences of the above-described facts under any other provision of the Code or regulations.

This ruling is directed only to the taxpayer requesting it. Section 6110(k)(3) of the Code provides that it may not be used or cited as precedent.

The rulings contained in this letter are based upon information and representations submitted by the taxpayer and accompanied by a penalty of perjury statement executed by an appropriate party. While this office has not verified any of the material submitted in support of the request for rulings, it is subject to verification on examination.

In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative.

This letter is being issued electronically in accordance with Rev. Proc. 2020-29, 2020-21 I.R.B. 859. A paper copy will not be mailed to Taxpayer.

Sincerely,

/S/

Patrick S. Kirwan
Chief, Branch 6
Office of the Associate Chief Counsel
(Passthroughs and Special Industries)

Enclosure: Copy for § 6110 purposes

cc:

Internal Revenue Service

Number: **202426003**
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Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.

Telephone Number:

Refer Reply To:
CC:PSI:B06
PLR-105952-22

Date:
March 08, 2024

Legend:

Parent =

Taxpayer =

Additional Subsidiary =

Date 1 =
Date 2 =
Date 3 =
Date 4 =
Date 5 =
Commission A =
Commission B =

Staff =
<u>a</u> =
<u>b</u> =
<u>c</u> =
<u>d</u> =
<u>e</u> =
<u>f</u> =
<u>g</u> =
<u>h</u> =
Year 1 =
Year 2 =
State =

Intervenor A =

Intervenor B =
Form A =
Form B =
Enforcement Matter =
Agency =
Opinion =

Dear :

On Date 1, on behalf of Parent and its wholly-owned subsidiary, Taxpayer, Parent's and Taxpayer's authorized representatives requested rulings under § 168(i)(9) regarding the potential implementation of a proposed ratemaking adjustment under the depreciation normalization provisions of the Internal Revenue Code of 1986, as amended ("Code") and the regulations thereunder. In response to a request for additional information, Taxpayer submitted additional responses on Date 2. Taxpayer's request is made pursuant to, and in compliance with, Rev. Proc. 2022-1. Parent is simultaneously submitting a substantially identical letter ruling for another of its wholly-owned subsidiaries, Additional Subsidiary.

Parent, through its operating subsidiaries, serves nearly a customers in b states. Taxpayer, a wholly owned subsidiary of Parent, is a regulated public utility serving more than c customers in State. As a member of the Parent affiliated group, Taxpayer joins in the filing of a consolidated return with other Parent operating companies. As is relevant to this private letter ruling request, Taxpayer is subject to the ratemaking jurisdiction of Commission A.

Parent and each of its subsidiaries are accrual basis taxpayers. Parent is the common parent of an affiliated group of corporations filing a consolidated return on a calendar-year basis. Parent, as the common parent of the affiliated group, serves as the agent of Taxpayer for purposes of this private letter ruling request pursuant to § 1.1502-77(a) of the Regulations.

Staff refers to the employees of Commission A who participated in the rate proceeding culminating in the proposed rate order at issue in this private letter ruling request.

On a separate return basis, Taxpayer had a federal income tax net operating loss carry-forward ("NOLC"). In its rate case filing in the instant case, Taxpayer recorded a total NOLC deferred tax asset ("DTA") attributable to tax losses for the years Year 1 through the Date 3 test year end. In its current General Rate Case ("GRC") (which is the GRC to which this ruling request relates), Taxpayer originally included a DTA of $d, which was based on its NOLC balance through the end of the test year ended Date 3. In response to a discovery request, Taxpayer updated its DTA for ratemaking purposes to reflect additional net operating losses through Date 4, which resulted in Taxpayer presenting a DTA balance of $e as of Date 4. The updated amount included losses incurred by Taxpayer due to a winter storm that occurred in Year 2, with the increase in the DTA largely attributable to expenses associated with the storm. Subsequent to that, in its rebuttal testimony Taxpayer further adjusted the DTA balance presented in the GRC to remove the portion attributable to the winter storm losses. The final NOLC DTA that Taxpayer sought to include in its rate base in the current GRC was $f. Approximately g% of that balance is attributable to accelerated depreciation using the "with or without" approach pursuant to which an NOL is treated as being created first by accelerated tax depreciation and only to the extent the NOL is larger than the accelerated tax depreciation deductions is it considered to have been created by other tax deductions.

Under the Parent Tax Allocation Agreement ("TAA") amongst the Parent affiliated group members joining in the filing of a consolidated return, certain profitable members of the affiliated group were able to utilize the Taxpayer NOLC to offset their separate company taxable income. None of these profitable subsidiaries provided electric utility service to customers in State and their operations were either subject to the jurisdiction of Commission B and/or state public utility commissions other than Commission A or were unregulated businesses not subject to the jurisdiction of any public utility commission.

Pursuant to the TAA, the profitable members made cash payments to Parent for their separate return tax liability, and Parent remitted cash payments to Taxpayer for the tax benefit derived by the affiliated group from the use of Taxpayer's losses. On its financial (GAAP) books, Taxpayer reduced its DTA for the NOLC to reflect the receipt of cash for the use of its loss by other members of the affiliated group, thereby recording an adjusted DTA balance of zero.

For ratemaking purposes, Taxpayer includes all used and useful public utility property in rate base, calculates depreciation expense thereon using a straight-line method, depreciates such property for federal income tax purposes using accelerated depreciation (MACRS), and makes an adjustment to the reserve for deferred taxes (at the federal statutory tax rate) to reflect the difference in tax liability attributable to the use of different depreciation methods for book and tax purposes. All of these calculations were done on a separate return basis without regard to the property, tax attributes, or separate tax liability, of affiliates of Taxpayer.

In accordance with section 13001 of Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act ("TCJA"), Taxpayer calculated its so-called excess deferred income taxes ("EDIT") as of December 31, 2017, representing the amount of accelerated depreciation-related taxes previously collected from customers that had not yet been paid by Taxpayer and became excess due to the reduction in tax rates in the TCJA. See Rev. Proc. 2020-39, Section 2.05. The total EDIT so-calculated was based on the deferred tax balances on Taxpayer's financial (GAAP) books and as a result did not include any adjustment for the NOLC DTA. Had the calculation of EDIT taken into account the NOLC DTA, it would have resulted in a reduction to the balance of $h. Pursuant to TCJA § 13001(d)(1), Taxpayer began amortizing the unadjusted EDIT balance on its ratemaking books in accordance with the Average Rate Assumption Method ("ARAM") beginning as of January 1, 2018. In connection with the preparation of Taxpayer's current GRC, Taxpayer determined that amortization of its EDIT must take into account the $h related to the NOLC DTA as a reduction to the total EDIT available to be amortized and seeks to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39.

In the rate case at issue, the Staff did not initially take a position on whether Taxpayer's stand-alone DTA should be reduced by reason of the TAA payments. However, intervenors in the case, Intervenor A and Intervenor B, entered testimony advocating for elimination of Taxpayer's standalone NOLC DTA.

Intervenor A took the position that the payments received under the TAA were cost-free capital received by Taxpayer, and, therefore, must be reflected as an increase in Taxpayer's ADIT reserve in order to reduce rate base. Intervenor A's position it that it would be inappropriate to allow a utility holding company to be able to benefit from cost-free tax savings generated by its loss-generating utility subsidiaries. Intervenor A's expert witness testified that no normalization violation results from eliminating Taxpayer's standalone NOLC DTA because that balance is based on a hypothetical standalone return, rather than reflecting the actual utilization of Taxpayer's loss in the Parent consolidated tax return.

Intervenor B pointed to the elimination of the DTA on Taxpayer's financial (GAAP) books resulting from the TAA payments notwithstanding that Taxpayer's ratemaking regulated books of account continued to reflect the DTA unreduced by the TAA payments. Additionally, Intervenor B argued that the NOLC DTA should be excluded from rate base because Taxpayer has been compensated for the NOLC by affiliates.

Both Intervenor A and Intervenor B asserted that there was no authority that specifically mandated separate return ratemaking treatment for the four depreciation-related elements of normalization or prohibited the elimination of the DTA upon receipt of tax sharing payments from affiliates.

Following the introduction of testimony from Intervenor A and Intervenor B, Staff filed rebuttal testimony in which it recommended that Taxpayer's NOLC DTA should be included in rate base subject to refund if the IRS were to issue a PLR concluding that removal of the NOLC DTA did not constitute a normalization violation.

Taxpayer asserted that excluding Taxpayer's standalone NOLC DTA from rate base would violate the normalization rules of § 168(i)(9), and particularly the consistency rules of § 168(i)(9)(B). Taxpayer also asserted that excluding the NOLC DTA from rate base as advocated by the intervenors in the case would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2) by introducing a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life difference between book and tax depreciation and the statutory tax rate.

Taxpayer explained more in its additional submission dated Date 2 that journal entries are not made to the financial statements of Taxpayer to re-establish the NOLC DTA for ratemaking purposes. Taxpayer says the tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. Taxpayer represents that this methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Taxpayer explains that the "separate return method" terminology used by Agency is a method of allocating taxes amongst the members of an affiliate group. This methodology allocates current and deferred taxes to members of the group as if it were a separate taxpayer.

Regarding Commission B Financial Reporting, Taxpayer explains that Commission B issued Enforcement Matter to discuss the acceptable accounting for income taxes, addressing both a "separate return method" and a "stand alone method" of accounting. Commission B describes the "separate return method" as a method that allocates current and deferred taxes to members of the group as if each member were a separate taxpayer, which is similar to the definition of separate return used by the Agency. Under the "separate return method," the sum of the individual member's allocations will not align with the consolidated tax return. In Enforcement Matter, Commission B also defines the "stand alone method" and distinguishes it from the "separate return method". The "stand alone method" allocates the consolidated group tax expense to individual members through the recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under this method, the sum of the amounts allocated to individual members equals the consolidated amount. Commission B concludes in Enforcement Matter that Commission B requires the use of the "stand alone method" and expressly provides that the use of the "separate return method" will not be permitted for Commission B financial accounting and reporting (Commission B Form A and Form B.)

Commission B has issued several decisions rejecting the use of the "separate return method" for determining income tax expense when an entity files as part of a consolidated group. Instead, Commission B relies on the "stand alone method" of allocating income taxes between members of a consolidated group. Under the "stand alone method," the consolidated tax expense is allocated to individual members through recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under the "stand alone method," the sum of amounts allocated to individual members equal the consolidated amount.

Regarding Commission B Ratemaking, Opinion from Commission B describes the "stand alone method" as an income tax allowance "that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities ... " The "stand alone method" results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Based on this definition, for ratemaking purposes, the Commission B-approved tax allocation method for ratemaking purposes aligns with the Agency definition of "separate return method" despite using the term "stand alone method" in that the tax expense is only attributable to the cost of service and the activities involved in providing service to a utility's customers.

The receipt of cash from the Taxpayer's Parent Company for the consolidated utilization of the NOL results in the DTA being reduced to zero on Commission B Form A and Form B. Journal entries are not made to the financial statements of the subsidiary to re-establish the NOLC DTA for ratemaking purposes. The tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. This methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Because no journal entries are recorded to the financial statements to re-establish the DTA, Taxpayer represents that it is necessary to make adjustments for ratemaking purposes in order to comply with the normalization rules. Accordingly, these adjustments are incorporated into the filing package presented to the respective state regulatory bodies as part of the Taxpayer's rate requests. The filing packages include schedules that start with the financial information on Commission B's Form A and Form B and the financial information presented in Agency financial statements. Consistent with the "separate return methodology," however, adjustments are made to align the rate request with the revenues and costs entering into the regulated cost of service. These adjustments are where the NOLC DTA is re-established as a component of accumulated deferred income taxes.

Taxpayer emphasizes the role that Commission B Form A and Form B play (and do not play) in the ratemaking context. Taxpayer asserts that Commission B Form A and Form B are simply the starting point for the financial data included in ratemaking. Adjustments are then made to arrive at the end result of a tax allowance for the test year associated with the provision of utility service to the regulatory jurisdiction's customers. The financial statement data in Commission B Form A and Form B are first adjusted to remove items of income and expense that are not associated with the provision of utility service. An example of one of these items is the expense in the financial statements for lobbying which is removed along with the income tax associated with that expense. In addition to the adjustments to remove non-utility activity, there are also adjustments that are made to the Commission B Form A and Form B financial statements for ratemaking purposes. An example of these ratemaking adjustments is changes to payroll expenses for known increases/decreases in the expense relative to the expense reported on the Commission B Form A and Form B. After these adjustments are made, a further adjustment is made to the income and expense to allocate it to the customers within the respective regulatory jurisdiction to which the filing is being made.

Per Commission B's guidance in Opinion, Taxpayer asserts that the income tax allowance in ratemaking should reflect the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Taxpayer asserts this ratemaking aligns with the consistency requirement set forth in § 168(i)(9) such that any projections of tax expense, depreciation expense, rate base and the deferred tax reserve remain in synch. Taxpayer believes that setting rates based on the unadjusted Commission B financial statements would violate the consistency requirement of the normalization rules.

Taxpayer, Staff, and the intervenors in the case entered into a Joint Stipulation and Settlement Agreement (the "Settlement"). Pursuant to the terms of the Settlement, the stipulating parties agreed that the return on the NOLC DTA will be excluded from the base rate revenue requirement resulting from the rate case. Instead, the stipulating parties would request Commission A allow that amount to be deferred as a regulatory asset until rates are effective in Taxpayer's next base rate case. If Taxpayer obtains a PLR concluding that excluding Taxpayer's stand-alone NOLC DTA from rate base would constitute a normalization violation, such regulatory asset will be recovered over a 20 month period through an interim rate adjustment to the Excess Tax Reserve Rider following Taxpayer's receipt of a PLR. On Date 5, Commission A adopted the terms of the Settlement, including those relating to the NOLC DTA. Taxpayer is seeking this private letter ruling in accordance with the terms of the Settlement.

RULINGS REQUESTED

Taxpayer requests the following rulings:

1. The implementation of either Intervenor A's or Intervenor B's proposals to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).

2. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.

3. Implementation of either Intervenor A's or Intervenor B's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property.

LAW & ANALYSIS

Section 168(f)(2) of the Code provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

Section 168(i)(10) defines, in part, public utility property as property used predominantly in the trade or business of the furnishing or sale of electrical energy if the rates for such furnishing or sale, as the case may be, have been established or approved by a State or political subdivision thereof.

Prior to The Revenue Reconciliation Act of 1990, the definition of public utility property was contained in § 167(l)(3)(A) and that definition is essentially unchanged in § 168(i)(10) and the regulations promulgated under former § 167(l) remain valid for application of the normalization rules.

In order to use a normalization method of accounting, § 168(i)(9)(A) of the Code requires that a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) provides that one way the requirements of § 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under § 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under § 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base (hereinafter referred to as the "Consistency Rule").

Former § 167(l) generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in § 168(i)(9)(A). Section 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under § 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under § 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under § 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under § 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under § 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under § 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under § 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Rev. Proc. 2020-39 provides guidance concerning the implementation of the EDIT normalization rules of TCJA § 13001 solely with respect to effects of tax rate reductions on timing differences related to accelerated depreciation. Sec. 4.01(6) of Rev. Proc. 2020-39 allows taxpayers that have amortized their EDIT in a manner not in accordance with the Revenue Procedure to prospectively correct the erroneous method at the next available opportunity. Taxpayers so correcting the erroneous method at such time and in such manner will not be treated as having violated the normalization rules of the TCJA.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. The deferred tax computation rules involve the method and life differences between book and tax depreciation and the statutory tax rate. In regard to request (1), Commission A's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would introduce a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate.

Section 168(i)(9)(B)(ii) provides that the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii) does not comply with the Consistency Rule unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its rate base by removing used and useful assets) without making similar adjustments to book and tax depreciation expense, tax expense, and the reserve for deferred taxes.

Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue. In regard to request (2), based on the response to request (1), Taxpayer's amortization of its EDIT must take into account the $h related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized.

In the setting of utility rates, a utility's rate base is offset by its EDIT and/or ADIT balance. Taxpayer maintains that the amortization of its EDIT must take into account the $h related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized. The EDIT should be reduced because these are the amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers.

In regard to request (3), Taxpayer sought to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39. Our understanding is that Commission A is in agreement to follow the outcome of the letter ruling request.

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By reducing Taxpayer's stand-alone DTA by reason of the TAA payments (or achieving a similar result through other methods), this improperly involves amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers.

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. Taxpayer's failure to comply with the Normalization Rules was inadvertent. Because Commission A, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency Rule or the deferred tax reserve computational rules constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

We are not providing a ruling on the overall merits of Commission A's policies towards separate return or consolidated return ratemaking. This ruling is solely with respect to the four normalization elements relevant to depreciation-related ratemaking. The treatment of non-ratemaking related payments as part of a TAA does not determine the normalization consequences of those arrangements. Ultimately, since depreciation normalization is based upon the construct of the extension of an interest free loan from the federal government to the utility in the form of deferred taxes, whether and how the group members allocate tax liabilities amongst themselves is irrelevant to the analysis. While under certain circumstances, the intercompany payments under a TAA might create an imputed loan between members, that is not a loan from the federal government, which is the *sine qua non* of depreciation normalization.

RULINGS

We rule as follows in response to Taxpayer's requested rulings:

1. The implementation of either Intervenor A's or Intervenor B's proposals to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).

2. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Implementation of either Intervenor A's or Intervenor B's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property. However, as described this disallowance of Taxpayer's right to claim accelerated depreciation would only occur under facts not present in this case.

Except as specifically set forth above, no opinion is expressed or implied concerning the federal income tax consequences of the above-described facts under any other provision of the Code or regulations.

This ruling is directed only to the taxpayer requesting it. Section 6110(k)(3) of the Code provides that it may not be used or cited as precedent.

The rulings contained in this letter are based upon information and representations submitted by the taxpayer and accompanied by a penalty of perjury statement executed by an appropriate party. While this office has not verified any of the material submitted in support of the request for rulings, it is subject to verification on examination.

In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative.

This letter is being issued electronically in accordance with Rev. Proc. 2020-29, 2020-21 I.R.B. 859. A paper copy will not be mailed to Taxpayer.

Sincerely,

/S/

Patrick S. Kirwan
Chief, Branch 6
Office of the Associate Chief Counsel
(Passthroughs and Special Industries)

Enclosure: Copy for § 6110 purposes

cc:

Internal Revenue Service

Number: **202426004**
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Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.
Telephone Number:

Refer Reply To:
CC:PSI:B06
PLR-107770-22

Date:
March 08, 2024

Legend:

Parent =

Taxpayer =

Additional Subsidiary =

Date 1 =
Date 2 =
Date 3 =
Commission A =
Commission B =

Commission C =
Office =
Group =
a =
b =
c =
d =
e =
f =
Year 1 =
Year 2 =
Year 3 =
Year 4 =
State =
Form A =

Form B =
Enforcement Matter =
Agency =
Opinion =

Dear :

On Date 1, on behalf of Parent and its wholly-owned subsidiary, Taxpayer, Parent's and Taxpayer's authorized representatives requested rulings under § 168(i)(9) regarding the potential implementation of a proposed ratemaking adjustment under the depreciation normalization provisions of the Internal Revenue Code of 1986, as amended ("Code") and the regulations thereunder. In response to a request for additional information, Taxpayer submitted additional responses on Date 2. Taxpayer's request is made pursuant to, and in compliance with, Rev. Proc. 2022-1.

Parent, through its operating subsidiaries, serves nearly a customers in b states. Taxpayer, a wholly owned subsidiary of Parent, is a regulated public utility serving more than c customers in State. As a member of the Parent affiliated group, Taxpayer joins in the filing of a consolidated return with other Parent operating companies. As is relevant to this private letter ruling request, Taxpayer is subject to the ratemaking jurisdiction of Commission A.

Parent and each of its subsidiaries are accrual basis taxpayers. Parent is the common parent of an affiliated group of corporations filing a consolidated return on a calendar-year basis. Parent, as the common parent of the affiliated group, serves as the agent of Taxpayer for purposes of this private letter ruling request pursuant to § 1.1502-77(a) of the Income Tax Regulations.

On a separate return basis, Taxpayer had a federal income tax net operating loss carry-forward ("NOLC"). On its ratemaking books of account for purposes of its current rate case, Taxpayer recorded a total NOLC deferred tax asset ("DTA") attributable to tax losses for certain years during the period Year 1 through the Year 2. The projected NOLC DTA balance as of Date 3 (the end of the test period) is $d. The entire DTA balance is deemed to be attributable to accelerated depreciation, as determined using the "with or without" approach, pursuant to which an NOL is treated as being created first by accelerated tax depreciation deductions and only to the extent the NOL is larger than the accelerated tax depreciation deductions is it considered to have been created by other tax deductions.

Under the Parent Tax Allocation Agreement ("TAA") amongst the Parent affiliated group members joining in the filing of a consolidated return, certain profitable members of the affiliated group were able to utilize the Taxpayer NOLC to offset their separate company taxable income. None of these profitable subsidiaries provided electric utility service to customers in State within the service territory of Taxpayer and their operations were either subject to the jurisdiction of Commission B and/or state public utility commissions other than Commission A or were unregulated businesses not subject to the jurisdiction of any public utility commission.

Pursuant to the TAA, the profitable members made cash payments to Parent for their separate return tax liability, and Parent remitted cash payments of $e to Taxpayer for the tax benefit derived by the affiliated group from the use of Taxpayer's losses.

On its financial (GAAP) books, Taxpayer reduced its DTA for the NOLC to reflect the receipt of cash for the use of its loss by other members of the affiliated group, thereby recording an adjusted DTA balance of zero. For ratemaking purposes, Taxpayer includes all used and useful public utility property in rate base, calculates depreciation expense thereon using a straight-line method, depreciates such property for federal income tax purposes using accelerated depreciation (MACRS), and makes an adjustment to the reserve for deferred taxes (at the federal statutory rate) to reflect the difference in tax liability attributable to the use of different depreciation methods for book and tax purposes. All of these calculations were done on a separate return basis without regard to the property, tax attributes, or separate tax liability, of affiliates of Taxpayer.

In accordance with section 13001 of Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act ("TCJA"), Taxpayer calculated its so-called excess deferred income taxes ("EDIT") as of December 31, 2017, representing the amount of accelerated depreciation-related taxes previously collected from customers that had not yet been paid by Taxpayer and became excess due to the reduction in tax rates in the TCJA. (Rev. Proc. 2020-39, Section 2.05.) The total EDIT so-calculated was based on the deferred tax balances on Taxpayer's financial (GAAP) books and as a result did not include any adjustment for the NOLC DTA. Had the calculation of EDIT taken into account the NOLC DTA, it would have resulted in a reduction to the balance of $f. Pursuant to TCJA § 13001(d)(1), Taxpayer began amortizing the unadjusted EDIT balance on its ratemaking books in accordance with the Average Rate Assumption Method ("ARAM") beginning as of January 1, 2018. In connection with the preparation of Taxpayer's current General Rate Case ("GRC"), Taxpayer determined that consistent with its proposed changed in treatment of the NOLC DTA for ratemaking purposes prospectively to comply with the normalization provisions of the Code, that amortization of its EDIT must take into account the $f related to the NOLC DTA as a reduction to the total EDIT available to be amortized and seeks to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39.

In the rate case at issue, intervenors in the case – the Office, the Group, and certain Joint Municipalities (Joint Municipals) – entered testimony recommending elimination of Taxpayer's reinstatement of its standalone NOLC DTA, which does not exist on its GAAP books and records.

Office's witness testified that Taxpayer's proposed adjustment to reinstate its standalone NOLC for ratemaking purposes is improper because it would result in a double counting and allow Taxpayer to earn a return on cost-free capital at ratepayers' expense. The witness testified that reinstating Taxpayer's NOLC is improper for ratemaking purposes because: 1) Taxpayer received payments from the parent company for the use of its NOLC; 2) Taxpayer took those payments (non-investor cost-free capital) and used the funds to acquire additional rate base assets upon which Taxpayer is earning a full rate base return; 3) the parent company fully utilized the NOL, so there is no carryforward to reinstate; 4) a consolidated group is considered a single entity for tax purposes—thus, Taxpayer's NOLC is $0 because it has been fully utilized; and 5) the current ratemaking treatment has been followed for the last 12 years without triggering a normalization violation. The existing treatment is appropriate because it tracks with economic realities. Office's witness explained that to reinstate a hypothetical standalone NOLC at the subsidiary level, solely for ratemaking purposes, would violate consistency principles and be contrary to sound ratemaking policy. The witness also testified regarding a pending proceeding before Commission C in which Additional Subsidiary, a regulated utility within Parent's consolidated group, similarly proposed to reinstate its standalone NOLC for ratemaking purposes, but Commission C rejected the proposal based on its finding that such an adjustment would result in a double recovery for the utility at ratepayers' expense.

Group witness testified that utility income tax expenses should be reflected in cost of service in a manner that ensures that the utility's costs are no higher than what the utility could achieve on a stand-alone basis. However, the witness noted that the purpose of an affiliate agreement allows the utility to incur benefits for itself and its ratepayers that could not be achieved on a stand-alone basis. Taxpayer has been participating in the Parent tax agreement for many decades. Because of this agreement, Taxpayer and its ratepayers have benefitted under the tax agreement when Taxpayer has income tax deductions that exceed its taxable income, and those tax benefits can be used by affiliate companies to reduce consolidated taxable income. Under the Parent affiliate tax agreement, cash payments are made to Taxpayer if its tax deductions exceed its taxable income, which are then reflected in its cost of service for rate-setting purposes. Participation in the affiliate tax agreement benefits customers. This practice is consistent across all Parent utility affiliates that participate in the consolidated tax filing agreement, and this agreement maximizes the use of tax deductions available to the consolidated enterprises, and reallocates those affiliates' tax benefits to utility affiliates to reduce cost of service. Because income taxes are no higher for ratemaking purposes than what could be achieved on a stand-alone basis, participation in these affiliate agreements has the effect of benefitting all stakeholders, the utility and its end-use customers. The creation of these consolidated income tax benefits has been permitted under IRS normalization rules, and the reallocation of tax benefits across all participants in a consolidated filing ensures the affiliate that contributes the tax benefits, realizes the benefits, which in turn reduces its cost of service and retail rates. Taxpayer's proposal in this case would no longer pass the consolidated tax benefits on to customers but would retain the benefits for its shareholders.

The Joint Municipals' witness stated that Taxpayer admitted in discovery responses that its GAAP books accurately reflect it has already received cash payments from its parent, Parent, (the taxpayer) for its NOLC pursuant to the companies' tax sharing agreement and has thus been made whole. Taxpayer's GAAP books show the NOLC as having a $0 balance, both historically and as budgeted for Year 3 and Year 4, because those cash payments have eliminated the NOLC. By reinstating the NOLC on a standalone basis, however, Taxpayer fails to account for the cash payments from Parent, which it uses to increase its capital at no cost to the Company. Taxpayer is using this already refunded NOLC deferred tax asset solely for rate-making purposes to artificially increase its rate of return. In other words, in the real world, Taxpayer increases its level of capital with the use of the zero-cost NOLC cash payment from Parent, yet by reinstating a stand-alone NOLC deferred tax asset and deducting it from ADFIT solely for regulatory purposes, Taxpayer artificially increases the apparent overall Weighted Average Cost of Capital to be applied to the increased investment. The witness stated that Taxpayer is essentially double counting the impact of its tax burden, once by including a restated NOLC deferred tax asset, and then again by failing to account for the tax sharing payment it received from Parent. She explained that it would only be appropriate to include the NOLC deferred tax asset based on a Taxpayer stand-alone tax return if the payment from Parent for use of the NOLC in a consolidated tax return is credited to Taxpayer's ratepayers. Thus, the witness concluded that Taxpayer's claim that the adjustment to reinstate a stand-alone NOLC deferred tax asset is required by the IRS normalization rules is incorrect when no NOLC deferred tax asset is reported in accordance with GAAP. The witness also noted that Taxpayer did not claim a normalization violation existed in either of its last two State rate cases (both of which were finalized after the TCJA went into effect), and the cumulative effect of the company's proposal would be to reduce the customer refunds previously approved when Taxpayer's tax rate was reduced pursuant to the TCJA.

Taxpayer asserted that excluding Taxpayer's standalone NOLC DTA from the calculation of accumulated deferred income tax ("ADFIT") treated as cost-free capital in Taxpayer's capital structure would violate the normalization rules of § 168(i)(9), and particularly the consistency rules of § 168(i)(9)(B). Taxpayer also asserted that excluding the NOLC DTA from ADFIT as advocated by the intervenors in the case would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2) by introducing a variable, that is, the profits of affiliates and/or the TAA payments, other than the difference between book and tax depreciation and the statutory tax rate.

Taxpayer explained more in its additional submission dated Date 2 that journal entries are not made to the financial statements of Taxpayer to re-establish the NOLC DTA for ratemaking purposes. Taxpayer says the tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group.

Taxpayer represents that this methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Taxpayer explains that the "separate return method" terminology used by Agency is a method of allocating taxes amongst the members of an affiliate group. This methodology allocates current and deferred taxes to members of the group as if it were a separate taxpayer.

Regarding Commission B Financial Reporting, Taxpayer explains that Commission B issued Enforcement Matter to discuss the acceptable accounting for income taxes, addressing both a "separate return method" and a "stand alone method" of accounting. Commission B describes the "separate return method" as a method that allocates current and deferred taxes to members of the group as if each member were a separate taxpayer, which is similar to the definition of separate return used by the Agency. Under the "separate return method," the sum of the individual member's allocations will not align with the consolidated tax return. In Enforcement Matter, Commission B also defines the "stand alone method" and distinguishes it from the "separate return method". The "stand alone method" allocates the consolidated group tax expense to individual members through the recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under this method, the sum of the amounts allocated to individual members equals the consolidated amount. Commission B concludes in Enforcement Matter that Commission B requires the use of the "stand alone method" and expressly provides that the use of the "separate return method" will not be permitted for Commission B financial accounting and reporting (Commission B Form A and Form B.)

Commission B has issued several decisions rejecting the use of the "separate return method" for determining income tax expense when an entity files as part of a consolidated group. Instead, Commission B relies on the "stand alone method" of allocating income taxes between members of a consolidated group. Under the "stand alone method," the consolidated tax expense is allocated to individual members through recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under the "stand alone method," the sum of amounts allocated to individual members equal the consolidated amount.

Regarding Commission B Ratemaking, Opinion from Commission B describes the "stand alone method" as an income tax allowance "that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities ... " The "stand alone method" results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Based on this definition, for ratemaking purposes, the Commission B-approved tax allocation method for ratemaking purposes aligns with the Agency definition of "separate return method" despite using the term "stand alone method" in that the tax expense is only attributable to the cost of service and the activities involved in providing service to a utility's customers.

The receipt of cash from the Taxpayer's Parent Company for the consolidated utilization of the NOL results in the DTA being reduced to zero on Commission B Form A and Form B. Journal entries are not made to the financial statements of the subsidiary to re-establish the NOLC DTA for ratemaking purposes. The tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. This methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Because no journal entries are recorded to the financial statements to re-establish the DTA, Taxpayer represents that it is necessary to make adjustments for ratemaking purposes in order to comply with the normalization rules. Accordingly, these adjustments are incorporated into the filing package presented to the respective state regulatory bodies as part of the Taxpayer's rate requests. The filing packages include schedules that start with the financial information on Commission B's Form A and Form B and the financial information presented in Agency financial statements. Consistent with the separate return methodology, however, adjustments are made to align the rate request with the revenues and costs entering into the regulated cost of service. These adjustments are where the NOLC DTA is re-established as a component of accumulated deferred income taxes.

Taxpayer emphasizes the role that Commission B Form A and Form B play (and do not play) in the ratemaking context. Taxpayer asserts that Commission B Form A and Form B are simply the starting point for the financial data included in ratemaking. Adjustments are then made to arrive at the end result of a tax allowance for the test year associated with the provision of utility service to the regulatory jurisdiction's customers. The financial statement data in Commission B Form A and Form B are first adjusted to remove items of income and expense that are not associated with the provision of utility service. An example of one of these items is the expense in the financial statements for lobbying which is removed along with the income tax associated with that expense. In addition to the adjustments to remove non-utility activity, there are also adjustments that are made to the Commission B Form A and Form B financial statements for ratemaking purposes. An example of these ratemaking adjustments is changes to payroll expenses for known increases/decreases in the expense relative to the expense reported on the Commission B Form A and Form B. After these adjustments are made, a further adjustment is made to the income and expense to allocate it to the customers within the respective regulatory jurisdiction to which the filing is being made.

Per Commission B's guidance in Opinion, Taxpayer asserts that the income tax allowance in ratemaking should reflect the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Taxpayer asserts this ratemaking aligns with the consistency requirement set forth in § 168(i)(9) such that any projections of tax expense, depreciation expense, rate base and the deferred tax reserve remain in synch. Taxpayer believes that setting rates based on the unadjusted Commission B financial statements would violate the consistency requirement of the normalization rules.

Taxpayer and the intervenors in the case entered into a Joint Stipulation and Settlement Agreement (the "Settlement"). Pursuant to the terms of the Settlement, the stipulating parties agreed that the NOLC DTA will be excluded from ADFIT and treated as cost free capital for purposes of the base rate revenue requirement resulting from the rate case. Instead, the stipulating parties would request the Commission A allow that amount to be deferred as a regulatory asset until rates are effective in Taxpayer's next base rate case. If Taxpayer obtains a PLR concluding that excluding Taxpayer's stand-alone NOLC DTA from ADFIT treated as cost free capital would constitute a normalization violation, Taxpayer will initiate a limited proceeding to update Taxpayer's Tax Rider to reflect the NOLC adjustments, along with any Commission A-approved offsets, in rates on an ongoing basis and to recover the regulatory asset. Taxpayer is seeking this private letter ruling in accordance with the terms of the Settlement.

RULINGS REQUESTED

Taxpayer requests the following rulings:

1. Reducing Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments as an offset to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments would result in Taxpayer losing its right to claim accelerated depreciation on all of its State public utility property.

LAW & ANALYSIS

Section 168(f)(2) of the Code provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

Section 168(i)(10) defines, in part, public utility property as property used predominantly in the trade or business of the furnishing or sale of electrical energy if the rates for such furnishing or sale, as the case may be, have been established or approved by a State or political subdivision thereof.

Prior to The Revenue Reconciliation Act of 1990, the definition of public utility property was contained in § 167(l)(3)(A) and that definition is essentially unchanged in § 168(i)(10) and the regulations promulgated under former § 167(l) remain valid for application of the normalization rules.

In order to use a normalization method of accounting, § 168(i)(9)(A) of the Code requires that a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) provides that one way the requirements of § 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under § 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under § 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base (hereinafter referred to as the "Consistency Rule").

Former § 167(l) generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in § 168(i)(9)(A). Section 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under § 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under § 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under § 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under § 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under § 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under § 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under § 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Rev. Proc. 2020-39 provides guidance concerning the implementation of the EDIT normalization rules of TCJA § 13001 solely with respect to effects of tax rate reductions on timing differences related to accelerated depreciation. Sec. 4.01(6) of Rev. Proc. 2020-39 allows taxpayers that have amortized their EDIT in a manner not in accordance with the Revenue Procedure to prospectively correct the erroneous method at the next available opportunity. Taxpayers so correcting the erroneous method at such time and in such manner will not be treated as having violated the normalization rules of the TCJA.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. The deferred tax computation rules involve the method and life differences between book and tax depreciation and the statutory tax rate. In regard to request (1), Commission A's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would introduce a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate.

Section 168(i)(9)(B)(ii) provides that the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii) does not comply with the Consistency Rule unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base. Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its rate base by removing used and useful assets) without making similar adjustments to book and tax depreciation expense, tax expense, and the reserve for deferred taxes.

Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue. In regard to request (2), based on the response to request (1), Taxpayer's amortization of its EDIT must take into account the $f related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized.

In the setting of utility rates, a utility's rate base is offset by its EDIT and/or ADIT balance. Taxpayer maintains that the amortization of its EDIT must take into account the $f related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized. The EDIT should be reduced because these are the amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers.

In regard to request (3), Taxpayer sought to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39. Our understanding is that Commission A is in agreement to follow the outcome of the letter ruling request.

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By reducing Taxpayer's stand-alone DTA by reason of the TAA payments (or achieving a similar result through other methods), this improperly involves amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. Taxpayer's failure to comply with the Normalization Rules was inadvertent. Because Commission A, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency Rule or the deferred tax reserve computational rules constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

We are not providing a ruling on the overall merits of Commission A's policies towards separate return or consolidated return ratemaking. This ruling is solely with respect to the four normalization elements relevant to depreciation-related ratemaking. The treatment of non-ratemaking related payments as part of a TAA does not determine the normalization consequences of those arrangements. Ultimately, since depreciation normalization is based upon the construct of the extension of an interest free loan from the federal government to the utility in the form of deferred taxes, whether and how the group members allocate tax liabilities amongst themselves is irrelevant to the analysis. While under certain circumstances, the intercompany payments under a TAA might create an imputed loan between members, that is not a loan from the federal government, which is the *sine qua non* of depreciation normalization.

RULINGS

We rule as follows in response to Taxpayer's requested rulings:

1. Reducing Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments as an offset to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments would result in Taxpayer losing its right to claim accelerated depreciation on all of its State public utility property. However, as described this disallowance of Taxpayer's right to claim accelerated depreciation would only occur under facts not present in this case.

Except as specifically set forth above, no opinion is expressed or implied concerning the federal income tax consequences of the above-described facts under any other provision of the Code or regulations.

This ruling is directed only to the taxpayer requesting it. Section 6110(k)(3) of the Code provides that it may not be used or cited as precedent.

The rulings contained in this letter are based upon information and representations submitted by the taxpayer and accompanied by a penalty of perjury statement executed by an appropriate party. While this office has not verified any of the material submitted in support of the request for rulings, it is subject to verification on examination.

In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative.

This letter is being issued electronically in accordance with Rev. Proc. 2020-29, 2020-21 I.R.B. 859. A paper copy will not be mailed to Taxpayer.

Sincerely,

/S/

Patrick S. Kirwan
Chief, Branch 6
Office of the Associate Chief Counsel
(Passthroughs and Special Industries)

Enclosure: Copy for § 6110 purposes

cc:

ATTESTATION

I, KIMBERLY BELL, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Kimberly Bell
KIMBERLY BELL

07/25/2024
DATE

WITNESS MORROW
EXHIBIT WG (I)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

PUBLIC VERSION

DIRECT TESTIMONY OF FREDERICK J. MORROW
Exhibit WG (I)
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WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF FREDERICK J. MORROW

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Frederick John Morrow III. I serve as the Director of Construction for the District of Columbia for Washington Gas Light Company ("Washington Gas" or the "Company"). My business address is 6801 Industrial Road, Springfield, VA 22151.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY TO THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA ("COMMISSION") OR ANY OTHER PUBLIC UTILITY COMMISSION?

A. Yes. I have appeared before the Commission in Formal Case No. 1137, supporting the reasonableness of the costs incurred for certain accelerated replacement programs. In addition, I have appeared before the Maryland Public Service Commission ("Maryland Commission") regarding construction matters in Case Nos. 9481, 9605, and 9651. I have also appeared before the Maryland Commission in Administrative Meetings, related to Case Nos. 9335 and 9486, to explain the Company's management of its Commission-approved Strategic Infrastructure Development and Enhancement ("STRIDE") Plans and annual STRIDE Project Lists.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Business Management from Pennsylvania State University, The Behrend College, in Erie, Pennsylvania. I am also a Gas Technology Institute ("GTI") Certified Gas Distribution Professional and previously certified welding inspector. I have worked in underground utility construction, sales and marketing project management, contract management, and utility construction and operations in the natural gas industry for approximately 26 years. I was employed at an underground utility construction contractor from 1998 until 2004. During this time, I set up projects for the installation of natural gas facilities, scheduled the work for all crews, managed all back-office functions including Miss Utility management, payroll and accounts payable, performed the billing for work performed, and supervised the crews responsible for the installation of underground natural gas facilities.

I joined Washington Gas in May 2004 as the Fairfax County New Business Project Manager. I have subsequently been promoted within Washington Gas to positions of increasing scope and responsibilities, including Construction Manager for Virginia New Business, Construction Manager for the District of Columbia Replacement and New Business, Senior Construction Manager for Maryland and the District of Columbia and Director Construction for Maryland and the District of Columbia. I am currently the Director of Construction for the District of Columbia.

I have been an active member in various natural gas industry organizations. I was formerly Chairman and Vice Chairman of the Southern Gas Association's ("SGA") Distribution Construction, Operations and Maintenance Committee from 2012 to 2014. I have attended numerous Pipeline Safety and

Damage Prevention Conferences hosted by various public service commissions.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support certain costs that Washington Gas proposes to recover in base rates, as shown in the testimony and exhibits of Company Witness Tuoriniemi. I provide: 1) a high-level overview of the Utility Operations Capital Expenditure categories; 2) a summary and description of the PROJECT*pipes* ("PIPES") costs that are being transferred to base rates and support for the prudence of these costs; 3) a summary and description of the non-PIPES plant proposed to be collected in base rates in this proceeding and support for the prudence of these costs; and 4) a conclusion of my testimony.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I sponsor three (3) exhibits. 1) Exhibit WG (I)-1 is a copy of the May 13, 2024 letter sent by the U.S. Pipeline and Hazardous Materials Safety Administration ("PHMSA") to the Commission regarding PHMSA's evaluation of the safety plant replacement activities in the District of Columbia for 2023, 2) Exhibit WG (I)-2 provides the Formal Case No. 1154 PROJECT*pipes* Year 9 Annual Reconciliation Report (PUBLIC and CONFIDENTIAL versions), and Exhibit WG (I)-3 provides the Technical Conference report and presentation on increasing construction costs in the District of Columbia submitted in Formal Case No. 1154.

IV. ORGANIZATION OF TESTIMONY

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into four (4) additional sections. Section V provides an overview of the Company's gas piping system; Section VI provides an overview of the PIPES plant being transferred from the PIPES surcharge to base rates; Section VII provides an overview of the total plant being added to base rates in this proceeding. Section VIII is the conclusion of my testimony.

V. OVERVIEW OF THE COMPANY'S GAS SYSTEM

Q. PLEASE DESCRIBE THE WASHINGTON GAS SYSTEM.

A. Washington Gas serves approximately 1.2 million customers in the District of Columbia, Maryland and Virginia. Approximately 165,000 of those are District of Columbia customers. The Company delivers natural gas to its customers in the District of Columbia through approximately 1,200 miles of distribution main and 125,000 service lines within the District of Columbia.[1] All gas supplied to the District of Columbia is transported by the Company from interconnects with interstate pipeline operators in Maryland or Virginia via infrastructure owned and operated by Washington Gas. Additionally, the Company owns and operates gas storage and peak-shaving facilities in Maryland, Virginia and West Virginia which form part of the portfolio of gas supply assets required to provide service to customers in the District of Columbia. In other words, assets and pipe infrastructure throughout the Company's physical footprint are needed to ensure natural gas is available to

[1] Miles of main and number of services as of August 2021.

serve our customers in the District of Columbia. Currently, there is no other way to deliver natural gas to the District of Columbia.

Q. WHAT IS THE AGE OF THE COMPANY'S DISTRIBUTION SYSTEM?

A. Washington Gas was founded in 1848 through a Congressional charter to install gas lights in the Capitol Building. The average age of the distribution main pipe in the District of Columbia is 58 years old. The average age of service lines in the District of Columbia is 39 years.

Q. IS WASHINGTON GAS MEETING THE GAS OPERATOR RESPONSIBILITIES OUTLINED IN THE PHMSA AND DISTRICT OF COLUMBIA ("DCMR") REGULATIONS?

A. Yes. Washington Gas operates and maintains its system in full compliance with all federal, state and local regulations and provides gas service to customers on a safe and reliable basis, as a result.

Q. HAS PHMSA PROVIDED AN EVALUATION OF THE COMMISSION'S SAFETY ACTIVITIES FOR CALENDAR YEAR 2023 RELATED TO WASHINGTON GAS?

A. Yes. PHMSA provided a letter to the Commission on June 4, 2024, which assigned a 100% grade to the Commission for its evaluation of annual Progress Report documents and pipeline program procedures and records, as well as observations of an on-site pipeline operator inspection by Commission staff. A copy of PHMSA's letter to Commission Chairman Thompson is attached as Exhibit WG (I)-1.

Q. HOW RELIABLE IS WASHINGTON GAS' DISTRIBUTION SYSTEM IN THE DISTRICT OF COLUMBIA?

A. For the twelve-months ending March 31, 2024, the Company experienced 141 unplanned service interruptions resulting in outages affecting 507 out of 163,908 customers in the District of Columbia, resulting in a reliability percentage of 99.69%.

VI. TRANSFER OF PIPES COSTS TO BASE RATES

Q. PLEASE DESCRIBE THE LEVEL OF PIPES PLANT COSTS WASHINGTON GAS PROPOSES TO TRANSFER TO BASE RATES IN THIS PROCEEDING.

A. The Company is proposing to include approximately $138.7 million of PIPES-related plant into the development of base rates in this proceeding. Of that amount, $118.5 million of that plant balance was included in the Company's PIPES surcharge, and $20.2 million was not eligible for collection in the PIPES surcharge due to the necessary spend exceeding the Program 10 cap, Merger Commitment No. 72, and the gap between the end of the original approved PIPES 2 Program in 2023 and the start of the PIPES 2 Extension beginning March 1, 2024.

Q. DOES THIS MATCH THE PROJECT*PIPES* CHARGES IN COMPANY WITNESS TUORINIEMI'S DIRECT TESTIMONY.

A. No, this does not. The numbers provided above are actuals incurred through March 2024 and the differences are due to accruals during this timeframe. As stated in Company Witness Tuoriniemi's testimony, PROJECT*pipes* CWIP placed into service by the time of the hearings in rate base will be updated during the rebuttal phase of this case.

Q. PLEASE PROVIDE THE AMOUNT BEING TRANSFERRED FROM EACH PIPES PROGRAM THAT WAS APPROVED BY THE COMMISSION IN ITS PIPES 2 ORDER, ORDER NO. 20671.[2]

A. In accordance with Order No. 20671,[3] the Company's current PIPES Program consists of six (6) replacement programs: Program 1, which replaces bare and/or unprotected steel services; Program 2, which replaces bare and/or unprotected steel main; Program 3, which replaces vintage mechanically coupled main;[4] Program 4, which replaces cast iron main; Program 5, which replaces copper services; and Program 10, which replaces pipe based on work compelled by others.[5] The Company seeks to transfer $35.5 million of Program 1-related work, $18.4 million of Program 2-related work, $13.1 million of Program 3-related work, $18.5 million of Program 4-related work, $11.8 million of Program 5-related work, and $41.4 million of Program 10-related work into base rates. These costs total the $138.7 million referenced above.

Q. PLEASE PROVIDE SOME EXAMPLES OF HOW PROJECTS INCLUDED IN PIPES REPLACEMENTS THAT WASHINGTON GAS PROPOSES TO TRANSFER TO BASE RATES DEMONSTRATE CUSTOMER BENEFITS.

A. The purpose of the Company's PIPES program is to enhance the safety and reliability of the distribution system in the District of Columbia through accelerated pipe replacement. Proactively replacing the Company's aging infrastructure will increase the safety of the system by avoiding potential leaks

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[2] *In the Matter of Washington Gas Light Company's Application for Approval of PROJECTpipes 2 Plan*, Formal Case No. 1154, Order No. 20671, (December 11, 2020).
[3] *Id.*
[4] Wrapped steel pipe of 2" and less in diameter installed in 1952 – 1956 or 1962 – 1965.
[5] Main eligible for replacement in Programs 1 – 5, that is further accelerated for replacement in coordination with work compelled by others, i.e., District Department of Transportation ("DDOT") and DC PLUG.

on the pipes that are replaced. These replacements enhance safety with the installation of Excess Flow Valves (EFVs) on services lines and Thermal Safety Valves (TSVs) on meter sets. Furthermore, the Company installs new locating devices when installing new pipe and relocates inside meters outside, when feasible, to enhance the safety of the distribution system. The PIPES program also enhances reliability by upgrading low-pressure systems to medium-pressure systems, where possible. This is aimed at reducing water infiltration into the pipeline that causes outages and, thereby, increases reliability for customers.

Q. WERE THE PIPES-RELATED COSTS BEING TRANSFERRED INTO BASE RATES PRUDENTLY INCURRED?

A. Yes. The Company has implemented several measures to minimize costs while maintaining a safe and reliable system. The Company relies on qualified contractor crews to perform construction and replacement services and has multi-year contracts, with these contractors, through competitive bidding and negotiated unit pricing to obtain the most competitive unit prices in the market. Further, Company management personnel review and reject or approve all units necessary and appropriate for each project before payment. Through this multi-level process, Washington Gas's management personnel provide oversight of the pipeline contractors, for all work that is performed on the Company's system, to verify that the installation of the facilities are per required specifications, including contract pricing schedules and definitions. This oversight not only promotes safe, quality installations, but also provides thorough oversight of all proposed field design changes and any associated pay items required to complete the work on each project.

Washington Gas also implements a risk reduced per dollar spent methodology when selecting projects for replacement under the PIPES Plan and coordinates with DDOT and other utilities to minimize costs and reduce construction activity to reduce inconveniences to customers.

All of these efforts support the reasonableness and prudence of the costs of the PIPES Plan.

Q. WHAT DOCUMENTATION SUPPORTS THE PRUDENCE OF THESE COSTS?

A. The Company files bi-annual project reconciliation reports in Formal Case No. 1154, which, among other things, detail the work completed during the reporting period, estimated and actual expenditures and units replaced, variance analysis and project status. I have included the Company's CY 2023 Year 9 Project Reconciliation Report as Exhibit WG (I)-2. Neither the Commission, nor any intervening party has commented on the Company's individual project variances in Formal Case No. 1154.

Additionally, an independent management audit of PIPES 2, performed by Continuum Capital, found that "WGL has demonstrated prudence in implementing PROJECT*pipes* 2 projects regarding the reasonableness of actual costs."[6] Furthermore, the Commission acknowledged this finding in their attachment to Order No. 22003, stating "the Commission accepts the Audit findings that WGL completed the projects prudently, with sound engineering judgement, and constructional integrity. We also accept the Audit Report's

[6] Formal Case No. 1154, *Independent Management Audit of PROJECTpipes* 2, page 18 (December 12, 2023).

finding that the work WGL performed reduced the risk, leaks, and improved safety within the District."[7]

VII. CAPITAL TO BE INCLUDED IN BASE RATES IN THIS PROCEEDING

Q. PLEASE GIVE AN OVERVIEW OF THE LARGEST COMPONENTS OF THE COMPANY'S EXPENDITURES IN DEPRECIABLE GAS PLANT IN SERVICE THAT HAVE OCCURRED FROM THE COMPLETION OF FORMAL CASE NO. 1169 TO THE TEST YEAR IN THIS PROCEEDING.

A. The Company's filing reflects $1.34 billion of depreciable gas plant in service ("GPIS") rate base (on a 13-month average basis) in this proceeding. This amount includes investments directly incurred in the District of Columbia, as well as the total investments representing system assets allocated to the District which support service to the District of Columbia as part of the Company's integrated system.

Primarily, these investments are related to directly assigned capital for New Business (inclusive of new construction and conversion to natural gas) and other activities referred to as System Betterment. The majority of the System Betterment work is comprised of work compelled by others (replacements required to be performed in conjunction with third-party developers or other agencies), and emergency or expedited Washington Gas Field Operations originated work to maintain a safe and reliable system.

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[7] *In the Matter of Washington Gas Light Company's Application for Approval of PROJECTpipes 2 Plan,* Formal Case No. 1154; *In the Matter of Washington Gas Light Company's Application for Approval of PROJECTpipes 3 Plan,* Formal Case No. 1175; and, *In the Matter of the Investigation into Washington Gas Light Company's Strategically Targeted Pipe Replacement Plan,* Formal Case No. 1179 Order No. 22003 (June 12, 2024).

The largest component of the system assets, which are allocated across all jurisdictions, is transmission pipelines and associated pressure regulation for Washington Gas's integrated transmission system. Refer to Exhibits WG (F)-1 and (F)-2 sponsored by Company Witness Smith for a description of the factors used to allocate system assets to the District of Columbia and the detailed allocation methodologies.

As I detail later in my testimony, these capital expenditures are important and necessary for Washington Gas to operate its gas system in a safe and reliable manner and meet all federal and local requirements.

Q. PLEASE EXPLAIN THE AMOUNT OF CAPITAL BY MAJOR CATEGORY INCLUDED IN THE COMPANY'S RATE CASE FILING.

A. The largest cost categories in depreciable GPIS are costs related to transmission mains, distribution mains, and distribution services. These three categories also account for the largest growth in depreciable GPIS from the level of rate base approved in Formal Case No. 1169 and this case. The Company is requesting inclusion of approximately $108.6 million[8] in transmission mains, a $36.4 million increase, or a 17% increase from Formal Case No. 1169. The Company is also requesting approximately $561.6 million[9] in distribution mains and $416.3 million[10] in distribution services. This equates to a $93.1 million increase in distribution mains, or 43%, and an increase of $80.2 million, or 37% in distribution services from Formal Case No.1169.

Q. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW FOR THE WORK INCLUDED IN THE MAJOR CAPITAL COSTS LISTED ABOVE.

[8] 13-month average basis
[9] *Id.*
[10] *Id.*

A. The majority of capital costs included in the rate case are for transmission, distribution mains and distribution services. The Company's transmission and high-pressure distribution system is the backbone of the Washington Gas distribution system. Gas from suppliers feed into the transmission and high-pressure system which is then reduced in pressure and odorized. These lines then feed district regulator stations, which reduces the pressure that feed the distribution mains used to serve the customers. The Company's transmission and high-pressure system is designed to support the entire Washington Gas operating system, and therefore, the cost of designing, installing and maintaining these pipelines is allocated to customers in Maryland, Virginia, and the District of Columbia.

There are no supplier interstate pipelines that pass through the District of Columbia, nor are there any gate stations[11] located in the District of Columbia. The nearest interstate pipeline is the Transcontinental Gas Pipeline ("Transco") located approximately 16 miles away from the District's border in Maryland. As a result, the District of Columbia is supplied by transmission mains[12] fed from Virginia and Maryland through its distribution systems. The interstate pipelines pass through Virginia and Maryland, and the Company's transmission mains located in Virginia and Maryland supply the operating pressure needed to provide service in the District of Columbia. The majority of charges transferred into the rate base are allocable transmission dollars from work performed to maintain and enhance both the Maryland and Virginia transmission strips that are responsible for supplying the District of Columbia.

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[11] Washington Gas owned custody of transfer stations where the Company takes custody of gas from its interstate pipeline suppliers.
[12] In accordance with DOT PHMSA 49 CFR 192.

The Company's distribution mains and services are responsible for bringing natural gas locally to the customers. The distribution mains are usually located in the street or Public Right of Way and feed individual customer services. These service lines feed individual buildings, flowing through the customer's meter. Washington Gas performs a wide array of work in relation to its distribution mains and services. In addition to the accelerated replacement work discussed previously, the Company coordinates relocation work where existing gas facilities are in conflict with work to be completed by a third-party (*i.e.*, roadway redesign per DDOT or a building renovation from a private developer), replaces/abandons gas services in conjunction with customer requests, and performs main and service replacements based on direct observations of field operations personnel and the Company's risk model to prevent future leaks.

Q. HAS WASHINGTON GAS PREVIOUSLY PROVIDED INFORMATION DEMONSTRATING A HIGHER TREND IN CAPITAL PROJECT COSTS?

A. Yes, it has. The Company provided information in Formal Case Nos. 1137, 1115, 1154[13], and 1169 which summarized and described the factors that have driven the upward trend in the cost of performing construction work in the District of Columbia.

Q. WHAT CURRENT FACTORS ARE AFFECTING THE COST OF WORK IN THE DISTRICT OF COLUMBIA?

A. Washington Gas has experienced several escalating external (*i.e.*, outside the Company's control) cost drivers in recent years. The trend of

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[13] *See* Formal Case No. 1154, Technical Conference Report on Lowering PROJECT*pipes* Unit Costs (May 19, 2021), which is included as Exhibit WG (I)-3.

increasing costs from my Rebuttal Testimony in Formal Case No. 1137 continues to apply today. The Company is still experiencing the following cost drivers: 1) increased paving and restoration requirements; 2) increased traffic control requirements; 3) increased spoils, backfill and trucking use; 4) increased requirements for saw cutting and pavement breakage; 5) additional permitting expenses; 6) increased design drawing requirements; 7) restrictions on work hours; 8) the requirement to build chain link fences around all trees within the work zone,[14] and 9) increased labor costs, all of which have the effect of increased costs and/or reduced productivity.

Most recently, on April 22, 2021, the Company documented in the Formal Case No. 1154 Technical Conference[15] that the cost of construction in the District of Columbia has continued to increase due to these cost drivers. As noted at that conference, with respect to restrictions on work hours in particular, the Company has secured negligible increases in the amount of extended working hour permits for the Company's PIPES work through additional coordination with and the continued building of relationships within DDOT. However, these improvements have not been consistently applied across all work and are based upon case-by-case discussions as opposed to a more comprehensive policy or approach. Additionally, the Company continues to experience cost escalations associated with the growing regional demand for qualified underground construction contractor crews to perform work, as well as

[14] Urban Forestry Administration ("UFA") began requiring the Company to depict all trees on construction drawings, utilize more costly forms of excavation, such as hand digging or hydro excavation when in the vicinity of trees, etc. UFA also required the Company to install its facilities in the streets to avoid tree roots and/or future tree plantings.
[15] Exhibit WG (I)-3.

the overall effort to coordinate projects with external parties such as DDOT and the Potomac Electric Power Company ("PEPCO").

Furthermore, in Formal Case No. 1115, Order No. 17431, the Commission ordered an independent management audit to be performed on the Company's PROJECT*pipes* program.[16] Liberty Consulting Group, who performed the Management Audit, concluded the following in its report:

> As is common, particularly in dense urban areas, main and service replacement productivity experiences substantial impacts from government requirements and expectations. DDOT and Urban Forestry inspection have had such effects on WGL's replacement work. Early program permits allowed work from 7am and 7pm, conforming to the city utilities work schedule. A subsequent government change cut WGL's allowed time of occupancy of all streets in half. The current allowed six hours between 9:30am and 3:30pm comprises less than a normal day's work shift.
>
> Direct work is constrained even further. At the front end, traffic control crews can only begin setup activities at 9:30 am. Moreover, their required activities include temporary passageways for bicycles and pedestrians. Our observations showed this work typically to require at least 30 minutes in the morning for set-up. At the back end, all spoils, traffic signs, equipment, and all else must be off the street by 3:30 pm. These efforts require another 30 minutes or more. Any plating in place can add to unproductive time, if equipment to move it is not on-site. It cannot be removed until all traffic control is in place.
>
> Therefore, a day offers only five hours of productive work generally. Contractors have to build into their prices worker expectations for full-time work. They also cannot use overtime to wrap up a job, thereby allowing efficient re-mobilization at the next work site - - no work can take place after 3:30pm. Continuing work at the same site suffers as well. Consider, for example, a service replacement, which has to finish once begun. Contractors cannot continue for the short time it might take to finish a service replacement. They cannot take the chance that they might not be able to get the customer back in service before the 3:30 deadline (or 3:00 if a half hour of shut-down work remains).

[16] Formal Case Nos. 1093 and 1115, Order No. 17431 at 36 (March 31, 2014).

> Other changes not anticipated at program initiation followed. WGL began to have to provide temporary bike lanes and pedestrian walkways. Other changes include the requirement to use chain-link fencing in lieu of plastic construction fencing around all trees and tree-root preservation.[17]

Since the convening of the technical conference, DDOT has continued to impose additional restrictions on the Company. In 2021, traffic control plans ("TCP") were changed to expire within 6 months of their approval date. This has led to multiple renewals and additional permitting and design costs, plus added challenges during active construction when the originally approved TCP is denied during the renewal. Along with the short TCP expiration date, DDOT enforced a 1,200 total linear foot trench restriction. This requires the Company to complete final paving restoration prior to the completion of the project, breaking the work into multiple phases often causing underground crews to pull off the project until paving can be completed having a negative effect on overall project efficiencies.

In 2022, DDOT began restricting the Company's total allowable Traffic Control Plan work zone to 200' in length which included the required traffic control tapers, buffers and construction area, limiting the space for the Company to work into near infeasible conditions. The Company met with DDOT to explain this was not feasible and needed at least a minimum of 419' for main installations in order to follow their standards on a 25-mile-per-hour roadway. DDOT decided to only allow for a 300' work site instead. For example, a typical TCP may require 100' for the first taper, and 50' for the buffer zone which prohibits the Company from parking equipment in this area, and another 50' for

[17] Formal Case No. 1115, *Final Report Management Audit of PROJECTpipes*, prepared by the Liberty Consulting Group at 126-127 (April 19, 2019).

the end taper. That only allows the Company 100' in which to park their equipment/tool truck as well as perform the excavation which requires an excavator, dump truck, and sometimes a vacuum excavator. A single service replacement requires a minimum of 127' construction area and 209' when installing main not including the tapers and buffers. DDOT also created a limit for the number of pages that can be included in a TCP, increasing the number of TCPs the Company is required to design, and increasing costs.

Most recently, in 2023, DDOT ended the use of construction traffic control plans for paving. Washington Gas is now required to submit a separate TCP for paving and restoration of a project, requiring additional design hours, delays and further increasing costs.

Additionally, the Company continues to experience cost escalations associated with the growing demand for qualified underground contractor crews to perform work on accelerated infrastructure replacement programs as well as the overall effort to coordinate projects with external parties.

Q. PLEASE EXPLAIN HOW THE CAPITAL EXPENDITURES TO BE INCLUDED IN BASE RATES IN THIS PROCEEDING PROVIDE BENEFITS TO CUSTOMERS OF THE DISTRICT OF COLUMBIA.

A. The capital expenditures are imperative to the Company's ability to provide safe, compliant, reliable gas service at a reasonable cost to customers located in the District of Columbia. Some components of the System Betterment[18] category result in replacing aging and/or leaking infrastructure. By

[18] Inclusive of a variety of activities, such as replacements, pressure mains and facilities (related to the Company's integrated transmission system), storage and pumping facilities, general plant, and distribution equipment.

removing this infrastructure and installing modern pipe materials and components in its place, the Company is enhancing safety and improving reliability as well as receiving the added benefit of reducing related greenhouse gas emissions. Additionally, the Company's capital expenditures associated with transmission system improvements are necessary to maintain the reliable supply of gas to the District. Due to these investments, Washington Gas continues to provide our customers with a safe and reliable distribution system.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND PROVIDE YOUR RECOMMENDATION TO THE COMMISSION.

A. The Company continues to maintain a safe, compliant, reliable gas system in the District by expending capital during the rate effective period. These costs are necessary to remain in compliance with the District of Columbia laws and Federal Regulations, *i.e.*, DCMR and PHMSA, and to fulfill its obligation to provide customers with safe and reliable gas service. While these costs have increased due to external factors affecting construction in the District, they remain prudent and necessary. Furthermore, this work continues to provide additional safety benefits to customers such as the installation of EFVs and TSVs, increased gas supply pressures, and reduces risk and leaks on the system. Therefore, I recommend the Commission allow the Company to recover these expenditures in this rate case.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

U.S. Department
of Transportation
Pipeline and Hazardous
Materials Safety
Administration

1200 New Jersey Avenue, SE
Washington, DC 20590

May 13, 2024

Via Email

Mr. Emile C. Thompson
Chairman
Public Service Commission of the District of Columbia
1325 G Street NW, Suite 800
Washington, DC 20095

Dear Chairman Thompson:

On May 6-10, 2023, the Pipeline and Hazardous Materials Safety Administration (PHMSA) conducted an evaluation of the pipeline safety program activities carried out by the Public Service Commission of the District of Columbia (DCPSC) in Calendar Year (CY) 2023. This evaluation included a review of annual Progress Report documents and pipeline program procedures and records, as well as observations of an on-site pipeline operator inspection by DCPSC staff.

PHMSA conducted our evaluation pursuant to Sections 60105(e) and 60106(d) of Title 49 of the United States Code, which authorizes PHMSA to monitor state pipeline safety programs. This annual evaluation is designed to ensure compliance with the Pipeline Safety Act requirements and to provide information that will allow PHMSA to determine the state's total pipeline safety grant score for the upcoming year.

PHMSA assesses the overall performance of a state's pipeline safety program by scoring information contained in the pipeline safety program Progress Report and by conducting a Program Evaluation. Detailed results are below.

Progress Report Review

For CY 2023, the DCPSC Gas Pipeline Safety Program scored 50 out of a possible 50 points.

Program Evaluation Review

For CY 2023, the DCPSC Gas Pipeline Safety Program scored 100 out of a possible 100 points.

As you may be aware, PHMSA and the National Association of Pipeline Safety Representatives developed a set of performance metrics that are available to the public on PHMSA's stakeholder communication website, http://primis.phmsa.dot.gov/comm/states.htm. These metrics relate to the state's leak management, incident investigations, and damage prevention program, as well as its inspector qualification, inspection, and enforcement activities. PHMSA expects each state pipeline safety program to review these metrics and act, as necessary, to continuously improve performance trends, thereby supporting enhanced pipeline safety.

PHMSA encourages initiatives to remove and/or replace unprotected steel, cast iron, and other high-risk pipes within those gas distribution operators under the DCPSC authority. According to our data, there was a total of 392.56 miles of cast iron mains remaining in CY 2023 for the District of Columbia. The continued initiative to remove these types of pipes will enhance pipeline safety and should be monitored and accelerated as much as possible by the DCPSC until all high-risk pipe has been removed.

A reply to this letter is not necessary; however, your comments are always welcome, and my address is 3700 S. MacArthur Blvd., Suite B, Oklahoma City, Oklahoma 73179-7612. Thank you for your continued support of pipeline safety.

Sincerely,

Zach Barrett

Zach Barrett
Director, State Programs

cc: Mr. Udeozo Ogbue, Chief, Office and Compliance Enforcement, DCPSC
Mr. Robert Burrough, Director, PHMSA Eastern Region (PHP-100)
David Appelbaum, Senior Transportation Specialist, PHMSA State Programs (PHP-50)

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Washington Gas
A WGL Company

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April 1, 2024

VIA ELECTRONIC FILING

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 "G" Street, N.W., 8th Floor
Washington, D.C. 20005

Re: Formal Case No. 1154
[Washington Gas's Annual Project Reconciliation Report - PUBLIC]

Dear Ms. Westbrook-Sedgwick:

Pursuant to Public Service Commission of the District of Columbia Order No. 20773, transmitted for filing is Washington Gas Light Company's Year 9 Annual Project Reconciliation Report (public version). A confidential version will be filed under separate cover.

Please do not hesitate to contact me if you have questions regarding this matter.

Sincerely,

Cathy Thurston-Seignious
Supervisor, Administrative and
Associate General Counsel

cc: Per Certificate of Service

**BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA**

IN THE MATTER OF	)	
	)	
WASHINGTON GAS LIGHT COMPANY'S	)	
APPLICATION FOR APPROVAL OF	)	Formal Case No. 1154
PROJECTPIPES 2 PLAN	)	
	)	
	)	

WASHINGTON GAS LIGHT COMPANY'S
YEAR 9 ANNUAL PROJECT RECONCILIATION REPORT

Pursuant to Public Service Commission of the District of Columbia Order No. 20773, Washington Gas Light Company ("Washington Gas" or "Company") hereby submits its Year 9 Annual Project Reconciliation Report, covering the period January – December 2023, for all PROJECT*pipes* 2 programs. The report is organized into multiple attachments in compliance with the filing requirements.

Attachment A provides a project list summary of the Annual Project List. Attachment A includes an overview of the Year 9 Project List work completed during the reporting period, as well as total project scope as compared to the 2023 Project List, including estimated spend and units, actual spend and units, and project status as of the end of December 2023.

CONFIDENTIAL Attachment B provides variance remarks for those BCAs which have either closed in the reporting period or meet the cost variance requirements set forth in Order No. 20313. The Company is reporting a cost variance if the project status is "Closed" and has a cost variance of ±5%, or if the project status is "Authorized", "Active", "Paving", or "Pre-Close" and the cost variance is +5%.

Attachment C provides projects that result from Work Compelled by Others that do not qualify or were not included in the PROJECT*pipes* ("PIPES") 2 surcharge mechanism. Projects included in this attachment have units or dollars completed during the reporting period. Information regarding these projects is provided at the total project scope level, including the estimated units and costs, in a format similar to the PIPES 2 Project List. Projects not included in the PIPES 2 Program are estimated using a variety of methods, including the Company's enhanced estimating techniques.

Attachment D provides the Company's projects with existing low-pressure proposed to be installed with medium-pressure pipe, including their main installation and retirement footage by pressure, actual footage installed and retired, and total project cost in accordance with Order No. 19194 approved in Formal Case No. 1115 and Order No. 20671 approved in Formal Case No. 1154.

PROJECT*pipes* 2 Summary (1/1/2021 – 12/31/2023)

Commission Order No. 20671 set targets for miles of main retired, replaced services, and changeovers for PROJECT*pipes* 2. The Company achieved 117% of the retired main, exceeding the target by 2.5 miles of main, and 106% of the service replacements target by replacing an additional 219 services. In summary, the Company replaced more relatively risky pipe, main and service, than targeted in Order No. 20671.

CY 2023 Summary (1/1/2023 – 12/31/2023)

In the Company's Update for its PIPES 2 Year 9 PROJECT*pipes* Project List, the Company proposed a total estimated CY 2023 spend of $66.7 million, all of which will be eligible for recovery through the PROJECT*pipes* surcharge, estimated to replace 4.7 miles of main and 1,850 affected services.[1] Washington Gas had charges of $72.4 million from January 1, 2023, through December 31, 2023. The Company will recover $64.2 million as eligible spend through the surcharge, and $8.2 million is not recoverable through the surcharge. There remains approximately $1.3 million of eligible PIPES 2 expenditures for construction work completed through December 2023 that was paid in January 2024 and will be included in a future reconciliation.[2] The Company retired 5.0 miles of main and remediated 1,968 services (see the Table 1 below) exceeding the CY2023 targets.

Table 1 – 2023 Results as of 12/31/2023

Program	BCA Count	Services Remediated	Main Installed (miles)	Main Retired (miles)	2023 Charges ($M)
Program 1	78	770			$20M
Program 2	18	69	0.4	0.3	$5.6M
Program 3	21	275	0.6	0.6	$8.2M
Program 4	14	256	0.6	1.2	$8.0M
Program 5	12	324			$7.9M
Program 10	17	274	2.1	2.9	$22.7M

[1] Washington Gas Light Company's Annual Informational Update for its PIPES 2 Year 9 PROJECT*pipes* Project List.
[2] The approximate $1.3 million of eligible expenditures is calculated based on PIPES 2 expenditures included in the PIPES Surcharge of $148,716,751 which is approximately $1.3 million less than the PIPES 2 expenditure authorization.

TOTAL	**160**	**1,968**	**3.6**	**5.0**	**$72.4**
2023 Planned	*160*	*1850*	*3.6*	*4.7*	*$66.7*
2023 Surcharge Amt					$64.2M
2023 System Betterment					$8.2M
% of 2023 Planned	*100%*	*106%*	*100%*	*106%*	*108%*

As of December 2023, four (4) PROJECT*pipes* 2 BCAs are not authorized, six (6) BCAs are in an Authorized status, 70 BCAs are in Active status, 37 BCAs are in Paving status, five (5) BCAs are in Pre-Close status, and 38 BCAs are in Closed status.

<u>Program 10 Summary (1/1/2023 – 12/31/2023)</u>

Of the $72.4 million the Company has spent from January 1, 2023, through December 30, 2023, $22.7 million was spent on 17 Program 10 projects, installing 2.1 miles of main, retiring 2.9 miles of main, and remediating 274 affected services. Consistent with Order No. 20671, the Company will not recover any amount for the work performed under the Program 10 PIPES 2 Plan beyond $17.5 million for Calendar Year 2023 through the PROJECT*pipes* surcharge.

<u>Non-Program 10 Work Compelled by Others Summary (1/1/2023 – 12/31/2023)</u>

Washington Gas has spent $2.9 million from January 1, 2023, through December 31, 2023, on Non-Program 10 Work Compelled by Others. Within the reporting timeframe, the Company has worked and/or closed 21 BCAs, totaling the replacement of 0.6 miles of main and 69 services. To date, on the total project scopes, the Company has spent a total of $11.5 million on these BCAs, retired 1.1 miles of main, installed 1.1 miles of main, and remediated 71 services.

Reporting of Engineering and Permitting Costs

In Order No. 18503, the Commission directed the Company to include aggregated estimated and actual engineering and permitting costs contained in the overhead and project-level engineering, permitting and contingency costs.[3] As an alternative, the Company indicated that the allocated Design and Development Costs would most closely align with this requirement as all engineering and some permitting costs are contained in this allocation.[4] By Order No. 19153, the Commission found this information to be sufficient to track permitting and engineering costs.[5] Table 2 below provides the capital expenditures spent by Program Year with the Design and Development Costs broken out from other allocated costs.

Table 2: PROJECT*pipes* Reporting of Cost				
Program Year	**Direct**[6]	**Other Allocation**	**Design and Development**	**Grand Total**
Year 9	$56.5	$9.2M	$6.6M	$72.4M

The Company is working diligently with the District of Columbia Department of Transportation ("DDOT") to mitigate new rule changes that affect the Company's

[3] Order No. 18503 at 59-60 (August 23, 2016).
[4] Washington Gas Light Company's Response to Order No. 18815 at 9 (July 24, 2017).
[5] Order No. 19153 at 10 (October 23, 2017).
[6] Direct charges include Paving expenditures.

permitting process. These new changes affect both future and active permits, which reduce the Company work zones to 300 feet, limit placement of equipment staging areas, and sequence review during the permitting approval process. As a result, the Company anticipates an increase in Design and Development costs and Construction costs, as well as possible project delays.

Low-Pressure to Medium-Pressure Conversions

In Order No. 19194, the Commission directed the Company to provide the rationale for making all conversions from low-pressure mains to medium-pressure mains and from low-pressure service lines to medium-pressure service lines on projects included in the Annual Project List for each PROJECT*pipes* period and to identify and provide the cost and description of any such opportunity-driven conversions that are recoverable through the PROJECT*pipes* surcharge in each annual Completed Projects Reconciliation Report. In addition, the Company was to provide documentation for its low-to-medium pressure conversion program and plans, including the justification, benefits and costs, target locations and program schedule for projects in areas that are not on the current Project List and to include this documentation in future Reconciliation Reports.

The Company does not have a low- to medium-pressure conversion program. The PROJECT*pipes* program (Programs 1 through 5 and 10) targets assets that encompass many low-pressure systems. The Company has presented in the past and affirms herein that the associated costs of replacing low-pressure main with medium-pressure main are negligible, since Washington Gas is normally installing smaller diameter and/or replacing in-kind size Polyethylene ("PE") pipe that has a lower installation and material cost and has the same benefits described in enhanced safety.

In low-pressure systems, water infiltration is one of the top issues encountered that affects the reliable delivery of gas service. Water infiltration inside gas pipes can freeze in the service lines or at the meter buildup during the winter causing customer outages at times when gas use for heating is at its peak. Where feasible and efficiencies can be realized, the Company will upgrade low-pressure segments to medium pressure. This will provide the added benefit of mitigating customer outages due to water infiltration issues thereby improving reliability which is the other principle of PROJECT*pipes*.

The reduction and elimination of low-pressure systems will ultimately eliminate low-pressure regulator stations, reducing the related annual inspection and maintenance activity. This will also eliminate the required maintenance to pump out and properly dispose of water and other liquids collected in the piping system drips, as well as eliminate the quarterly lab testing of liquids collected, providing both cost savings and environmental benefits.

In addition, uprating low-pressure systems to medium-pressure will provide customers the opportunity to install high efficiency appliances such as tankless water heaters that cannot operate with low pressure deliveries. Besides the environmental benefits from the improved efficiencies, customers will realize cost savings due to the reduced gas consumption. Another advantage of medium pressure delivery is the opportunity to install gas-fired backup generators that also require the higher delivery pressure.

PROJECT*pipes* 2 has remediated approximately 14.3 miles of low-pressure main of which 9.1 miles was replaced with medium pressure. The Company is providing a list of 2023 PROJECT*pipes* main BCAs and information regarding whether the project includes converting customers from low-pressure to medium-pressure in Attachment D.

BCA	PROJECT_NAME_LOCATION	WARD	program	PROJECT STATUS	ESTIMATED TOTAL PROJECT SCOPE MAIN RETIREMENT (FT)	ACTUAL TOTAL PROJECT SCOPE MAIN RETIREMENT (FT)	ESTIMATED TOTAL PROJECT SCOPE MAIN INSTALLATION (FT)	ACTUAL TOTAL PROJECT SCOPE MAIN INSTALLATION (FT)	ESTIMATED TOTAL PROJECT SCOPE AFFECTED SERVICES	ACTUAL TOTAL PROJECT SCOPE AFFECTED SERVICES	ESTIMATED TOTAL PROJECT SCOPE COST (CLASS III)	ACTUAL TOTAL PROJECT SCOPE SPENT	TOTAL PROJECT SCOPE PERCENT SPENT (%)
102479	DC F.O. APRP 2 WATERSIDE DR NW WARD 2 OPT76468	2	Program 2	6. Closed	622	606	635	597	20	19	1,225,564	$1,330,640	109%
146223	DC APRP 1 L ST NW WARD 2 O003NW	2	Program 1	6. Closed	0	0	0	0	8	5	267,676	$250,999	94%
169482	DC APRP 1 14TH ST NW WARD 2 D002NW	2	Program 1	4. Paving	0	0	0	0	9	7	391,327	$483,798	123%
189546	DC APRP 1 17TH ST NW WARD 2 E004NW	2	Program 1	6. Closed	0	0	0	0	40	30	1,335,949	$774,983	58%
219260	DC APRP 1 CATHEDRAL AVE NW WARD 3 N006NW	3	Program 1	6. Closed	0	0	0	0	26	26	962,212	$1,016,523	106%
219400	DC APRP 1 50TH ST NE WARD 7 L002NE	7	Program 1	6. Closed	0	0	0	0	28	24	816,312	$523,714	64%
280065	DC APRP 4 17TH ST NE WARD 5 OPT58594	5	Program 4	6. Closed	945	966	1,215	988	18	18	8,618,000	$8,230,218	96%
281535	DC APRP 10 AOP Florida Ave NE 2nd H St FAP STP 2015(030) Wards 5 & 6	5&6	Program 10	3. Active	12,638	10,639	8,315	7,886	189	172	12,140,361	$12,102,135	100%
285137	DC APRP 10 AOP Rehabilitation C St NE Ward 6	6	Program 10	5. Pre-Close	3,896	3,666	3,500	2,642	95	88	5,484,783	$5,935,010	108%
286304	DC APRP 10 AOP MARYLAND AVE NE WARDS 5&6 Phase 1 WR 3341592	5&6	Program 10	5. Pre-Close	13,670	12,858	11,005	11,010	260	259	14,209,944	$15,767,342	111%
286503	DC APRP 10 AOP Massachusetts Ave NW Rehabilitation Ward2	2	Program 10	6. Closed	9,901	9,607	7,595	7,240	78	76	10,864,603	$9,543,896	88%
287031	DC APRP 10 AOP KENNEDY ST NW Ph 2 Ward 4 STP 2016(042)	4	Program 10	4. Paving	9,270	8,301	4,055	4,900	138	134	9,015,666	$7,615,535	84%
292257	DC APRP 4 F.O. 300 BLK 10th St NE C001NE1 Ward 6	6	Program 4	6. Closed	705	705	0	0	33	32	1,598,377	$2,597,360	163%
292561	DC APRP 2 F.O. Mass Ave NW L008NW Ward 3	3	Program 2	6. Closed	2,276	2,799	1,775	912	15	15	1,634,379	$1,708,107	104%
293819	DC APRP 10 AOP Cleveland Park Ward 3 G007NW	3	Program 10	4. Paving	2,046	1,373	1,480	1,377	22	17	3,606,803	$6,642,731	184%
294323	DC F.O. APRP 2 Massachusetts Ave NW Ward 3 I006NW	3	Program 2	6. Closed	1,891	1,608	1,740	1,930	9	5	6,806,798	$4,227,197	64%
294341	DC APRP 10 AOP PA Ave NW Streetscape (17th-22nd) FAP2017(043) Ward 2	2	Program 10	6. Closed	5,502	1,763	2,610	1,455	8	5	4,127,430	$3,178,995	77%
295350	DC F.O. APRP 2 49th ST NW M007NW WARD 3 OPT 77629	3	Program 2	6. Closed	408	432	420	418	3	3	764,546	$756,760	99%
295352	DC F.O. APRP 4 W Pl NW G005NW WARD 3 OPT 53277	3	Program 4	6. Closed	1,304	1,305	1,090	1,076	66	67	2,195,780	$2,372,099	108%
295624	DC F.O. APRP 4 Massachusetts Ave NW Ward 3 I006NW	3	Program 4	6. Closed	2,435	2,430	570	568	10	10	991,696	$360,447	36%
295999	DC APRP 10 215 G ST NE MCN BUILD A002NE WARD 6	6	Program 10	3. Active	444	420	0	0	1	0	63,724	$287,988	450%
297357	DC APRP 10 AOP S St NW Revitalization 4th to 7th B004NW1 Ward 1	1	Program 10	4. Paving	1,337	1,352	1,050	1,126	28	28	1,669,457	$1,449,592	87%
298472	DC APRP 10 PLUG FEEDER 15009 Ward 4	4	Program 10	3. Active	7,900	2,329	6,400	3,569	124	45	13,745,958	$5,672,638	41%
298518	DC APRP 10 AOP Connecticut Ave NW Streetscape F004NW,	2	Program 10	3. Active	673	758	245	260	0	0	1,713,847	$1,574,302	92%
299376	DC APRP 2 Sedgwick ST NW M008NW Ward 3 OPT 77625	3	Program 2	6. Closed	804	803	890	680	19	19	1,242,788	$980,557	79%
299378	DC APRP 4 Walter ST SE C003SE1 Ward 6 OPT 214983	6	Program 4	4. Paving	1,196	1,196	990	1,006	56	52	2,244,380	$1,626,974	72%
299388	DC APRP 2 34th St NW D006NW Ward 3 OPT111567	3	Program 2	6. Closed	355	458	375	418	5	5	608,970	$681,512	112%
299392	DC APRP 4 Lamont St NW C004NW1 Ward 1 OPT 55300	1	Program 4	6. Closed	602	666	615	627	32	34	1,058,889	$1,155,136	109%
299394	DC APRP 2 Verplanck Pl NW N008NW Ward 3 OPT 70022	3	Program 2	4. Paving	2,326	2,239	2,500	2,164	46	45	3,902,210	$3,313,307	85%
299396	DC APRP 2 45th St NW L010NW Ward 3 OPT 70244	3	Program 2	2. Authorized	982	0	750	0	20	0	1,392,746	$6,304	0%
299398	DC APRP 2 HOLBROOK ST NE WARD 5 E003NE1 OPT 80775	5	Program 2	4. Paving	395	395	410	446	23	23	793,891	$717,777	90%
299400	DC APRP 2 MACARTHUR BLVD NW WARD 3 N006NW OPT66454	3	Program 2	4. Paving	586	657	605	695	4	4	1,149,123	$1,306,458	114%
299401	DC APRP 2 MACARTHUR BLVD NW WARD 3 M004NW OPT77002	3	Program 2	2. Authorized	892	0	1,075	0	1	0	1,938,461	$0	0%
299402	DC APRP 2 INDEPENDENCE AVE SE Ward 6 G001SE1 OPT68297	6	Program 2	1. Not Authorized	2,800	0	2,810	0	132	0	6,150,101	$0	0%
299512	DC APRP 10 AOP MLK Ave SE Phase 2 Ward 8	8	Program 10	3. Active	7,938	0	5,850	2,068	163	52	9,088,603	$1,895,316	21%
299764	DC F.O. APRP 4 4th St NE B004NE Ward 5	5	Program 4	6. Closed	913	912	0	0	18	16	1,309,797	$1,064,866	81%
300025	DC F.O. APRP 4 40TH ST Ward 7 OPT 86285?	7	Program 4	6. Closed	482	465	595	633	16	15	1,068,398	$1,603,129	150%
300153	DC APRP 1 Wesley Pl SW B002SW Ward 6	6	Program 1	4. Paving	0	0	0	0	12	12	450,340	$426,825	95%
300159	DC APRP 3 Division Ave NE L001NE Ward 7	7	Program 3	6. Closed	0	0	0	0	16	16	565,941	$373,518	66%
300160	DC APRP 3 Beecher St NW H005NW Ward 3	3	Program 3	3. Active	0	0	0	0	9	6	332,331	$434,028	131%
300162	DC APRP 3 Kennedy St NE B010NE Ward 5	5	Program 3	6. Closed	0	0	0	0	17	17	716,146	$564,243	79%
300164	DC APRP 3 6TH St SE B030SE Ward 8	8	Program 3	3. Active	0	0	0	0	16	11	482,555	$366,576	76%
300176	DC APRP 3 Eastern Ave A012NE Ward 4	4	Program 3	6. Closed	0	0	0	0	14	14	472,565	$258,142	55%
300295	DC APRP 1 28th St SE F006SE Ward 8	8	Program 1	3. Active	0	0	0	0	7	3	237,655	$124,000	52%
300773	DC APRP 1 L St NE A003NE Ward 6	6	Program 1	6. Closed	0	0	0	0	14	13	600,135	$462,955	76%
300786	DC APRP 1 Acker Pl NE B002NE4 Ward 6	6	Program 1	4. Paving	0	0	0	0	13	10	408,469	$360,780	88%
300980	DC F.O. APRP 2 Rhode Island Ave NE B005NE3 Ward 5	5	Program 2	5. Pre-Close	571	586	395	420	10	9	894,275	$1,107,530	124%
300969	DC APRP 4 Emerald St NE QA1NE Ward 6 OPT 363402	6	Program 4	3. Active	1,817	1,817	1,150	1,216	76	79	2,800,223	$2,577,181	92%
300971	DC APRP 2 Randolph St NE F008NE Ward 5 OPT 62298	5	Program 2	2. Authorized	1,520	0	1,555	0	13	0	2,090,003	$52,908	3%
300975	DC APRP 4 Girard St NW C006NW3 Ward 1 OPT 111760	1	Program 4	2. Authorized	1,508	0	1,025	0	63	0	2,161,283	$344	0%
300976	DC APRP 3 Sedgwick St NW L008NW Ward 3 OPT 150415	3	Program 3	4. Paving	2,936	2,941	2,875	2,971	64	64	4,663,277	$3,074,128	66%
301129	DC APRP 1 17TH ST NW E014NW Ward 4	4	Program 1	4. Paving	0	0	0	0	9	6	370,064	$178,107	48%
301130	DC APRP 1 ANACOSTIA RD SE H001SE Ward 7	7	Program 1	4. Paving	0	0	0	0	7	6	251,502	$154,681	62%
301131	DC APRP 1 UNDERWOOD PL NE A012NE Ward 4	4	Program 1	6. Closed	0	0	0	0	8	4	430,189	$113,461	37%
301133	DC APRP 1 INGRAHAM ST NE B010NE Ward 5	5	Program 1	6. Closed	0	0	0	0	17	13	543,615	$256,806	47%
301134	DC APRP 1 MICHIGAN AVE NE B007NE Ward 5	5	Program 1	3. Active	0	0	0	0	22	15	774,044	$550,802	71%
301141	DC APRP 1 KIEFER PL NW B006NW1 Ward 1	1	Program 1	3. Active	0	0	0	0	20	14	721,116	$246,254	34%
301143	DC APRP 1 RHODE ISLAND AVE NW C003NW1 Ward	2	Program 1	3. Active	0	0	0	0	15	5	810,400	$367,933	45%
301144	DC APRP 1 G ST SE C002SE1 Ward 6	6	Program 1	3. Active	0	0	0	0	18	11	643,691	$549,763	85%
301145	DC APRP 1 42ND ST NE J003NE Ward 7	7	Program 1	3. Active	0	0	0	0	14	11	436,077	$207,892	48%
301146	DC APRP 1 GALLATIN ST NW A010NW3 Ward 4	4	Program 1	3. Active	0	0	0	0	26	20	866,836	$563,557	65%
301151	DC APRP 1 RHODE ISLAND AVE NW D003NW2 Ward	2	Program 1	6. Closed	0	0	0	0	16	10	563,475	$330,257	59%
301159	DC APRP 1 DOUGLAS ST NE F005NE Ward 5	5	Program 1	4. Paving	0	0	0	0	5	5	197,540	$250,000	127%
301160	DC APRP 1 E CAPITOL ST SE C001SE1 Ward 6	6	Program 1	3. Active	0	0	0	0	18	15	532,577	$441,471	83%
301162	DC APRP 1 8TH ST SE B001SE4 Ward 6	6	Program 1	3. Active	0	0	0	0	15	11	464,004	$301,554	65%
301163	DC APRP 1 MARINE PL NE I003NE Ward 7	7	Program 1	6. Closed	0	0	0	0	15	14	447,576	$272,354	50%
301164	DC APRP 1 HAMILTON ST NW A010NW3 Ward 4	4	Program 1	6. Closed	0	0	0	0	16	11	501,174	$366,599	73%
301165	DC APRP 1 8TH ST SE C001SE1 Ward 6	6	Program 1	4. Paving	0	0	0	0	16	16	406,204	$234,307	55%
301189	DC APRP 3 TEXAS AVE SE I001SE Ward 7	7	Program 3	5. Pre-Close	0	0	0	0	11	11	454,449	$246,614	54%
301190	DC APRP 3 A ST SE L001SE Ward 7	7	Program 3	6. Closed	0	0	0	0	12	10	413,725	$175,105	86%
301192	DC APRP 3 LEGATE RD NW D015NW Ward 4	4	Program 3	3. Active	0	0	0	0	21	20	730,073	$589,484	81%
301193	DC APRP 3 3RD ST SE A001SE Ward 6	6	Program 3	6. Closed	0	0	0	0	9	9	345,553	$389,363	163%
301194	DC APRP 3 3RD ST SW A002SW1 Ward 6	6	Program 3	6. Closed	0	0	0	0	2	2	55,996	$17,780	32%
301195	DC APRP 3 M ST SE H001SE Ward 7	7	Program 3	3. Active	0	0	0	0	17	15	400,191	$181,038	45%
301199	DC APRP 5 O ST SE O001SE4 Ward 6	6	Program 5	3. Active	0	0	0	0	8	3	258,670	$173,736	67%

BCA	PROJECT_NAME_LOCATION	WARD	program	PROJECT STATUS	ESTIMATED TOTAL PROJECT SCOPE MAIN RETIREMENT (FT)	ACTUAL TOTAL PROJECT SCOPE MAIN RETIREMENT (FT)	ESTIMATED TOTAL PROJECT SCOPE MAIN INSTALLATION (FT)	ACTUAL TOTAL PROJECT SCOPE MAIN INSTALLATION (FT)	ESTIMATED TOTAL PROJECT SCOPE AFFECTED SERVICES	ACTUAL TOTAL PROJECT SCOPE AFFECTED SERVICES	ESTIMATED TOTAL PROJECT SCOPE COST (CLASS III)	ACTUAL TOTAL PROJECT SCOPE SPENT	TOTAL PROJECT SCOPE PERCENT SPENT (%)
301202	DC APRP 5 5 ST NW F006NW2 Ward 2	2	Program 5	4. Paving	0	0	0	0	10	11	392,912	$548,964	140%
301204	DC APRP 5 8TH ST NW C012NW4 Ward 4	4	Program 5	6. Closed	0	0	0	0	19	17	630,132	$619,308	98%
301208	DC APRP 5 4TH ST NE B003NE2 Ward 5	5	Program 5	4. Paving	0	0	0	0	13	10	436,097	$521,958	120%
301215	DC APRP 3 G ST SW A002SW1 Ward 6	6	Program 3	4. Paving	0	0	0	0	20	20	398,350	$342,025	86%
301579	DC F.O. APRP 4 CUMBERLAND ST NW J009NW WARD 1	1	Program 4	4. Paving	1,075	1,075	810	805	19	19	1,185,805	$1,181,385	100%
302189	DC APRP 10 AOP Metro Branch Trail from Fort Totten to Takoma A011NE Ward 4	4	Program 10	2. Authorized	1,891	0	885	0	30	0	1,883,410	$7,622	0%
302672	DC APRP 10 PLUG FEEDER 15009 B11NW3 Ward 4	4	Program 10	1. Not Authorized	7,534	0	7,215	0	181	0	10,092,484	$0	0%
302783	DC APRP 10 PLUG FEEDER 15009 C012NW WARD 4	4	Program 10	2. Authorized	5,376	0	3,540	0	109	0	7,481,496	$180	0%
302784	DC APRP 10 PLUG FEEDER 15009 B012NW3 WARD 4	4	Program 10	1. Not Authorized	3,308	0	3,050	0	68	0	5,072,842	$0	0%
302785	DC APRP 10 PLUG FEEDER 15009 B011NW2 WARD 4	4	Program 10	1. Not Authorized	7,666	0	7,310	0	137	0	12,097,900	$0	0%
303116	DC APRP 2 Prospect St NW B003NW4 Ward 2 OPT 70853	2	Program 2	6. Closed	271	271	0	0	0	0	154,049	$70,277	46%
303117	DC APRP 4 Randolph St NW B008NW3 Ward 4 OPT 58011	4	Program 4	3. Active	1,382	1,309	655	683	44	43	2,127,449	$844,273	41%
303119	DC APRP 2 Montana Ave NE D006NE Ward 5 OPT 60627	5	Program 2	3. Active	748	0	615	492	8	7	1,233,608	$160,347	13%
303121	DC APRP 4 Longfellow St NW B050NW1 Ward 4 OPT 57347	4	Program 4	3. Active	715	607	670	658	38	36	1,752,297	$835,722	48%
303140	DC APRP 2 Q St SE E003SE Ward 8 OPT 387434	8	Program 2	3. Active	1,321	0	805	816	34	34	2,319,256	$838,712	36%
303250	DC APRP 4 SHEPHERD ST NW B008NW4 Ward 4 OPT 58013	4	Program 4	3. Active	490	505	475	466	16	16	1,448,264	$317,763	22%
303646	DC F.O. APRP 2 Luzon Ave NW D012NW Ward 4	4	Program 2	6. Closed	2,812	2,907	2,790	2,521	37	38	2,847,854	$2,606,913	92%
303868	DC APRP 1 RIVER RD NW K008NW Ward 3	3	Program 1	3. Active	0	0	0	0	10	4	463,497	$96,394	21%
303974	DC APRP 1 CHANNING ST NE B005NE1 Ward 5	5	Program 1	6. Closed	0	0	0	0	10	1	377,161	$4,791	1%
303976	DC APRP 1 NEBRASKA AVE NW G012NW Ward 4	4	Program 1	3. Active	0	0	0	0	12	1	492,845	$20,850	4%
303978	DC APRP 1 38TH ST SE E004SE Ward 7	7	Program 1	3. Active	0	0	0	0	7	3	314,050	$41,757	13%
303979	DC APRP 1 15TH ST NE D001NE4 Ward 6	6	Program 1	3. Active	0	0	0	0	12	11	591,125	$259,498	44%
303980	DC APRP 1 6TH ST NW B004NW1 Ward 1	1	Program 1	3. Active	0	0	0	0	12	2	495,563	$102,270	21%
303981	DC APRP 1 TILDEN ST NW K008NW Ward 3	3	Program 1	3. Active	0	0	0	0	11	6	630,231	$263,177	41%
303982	DC APRP 1 GREENVALE ST NW G014NW Ward 4	4	Program 1	3. Active	0	0	0	0	11	7	634,901	$342,439	22%
303990	DC APRP 1 NEWTON ST NW E007NW Ward 1	1	Program 1	3. Active	0	0	0	0	9	6	395,381	$110,976	28%
303991	DC APRP 1 S ST NW C004NW2 Ward 1	1	Program 1	4. Paving	0	0	0	0	13	6	434,048	$157,112	36%
303992	DC APRP 1 36TH ST NW D015NW Ward 4	4	Program 1	4. Paving	0	0	0	0	14	14	673,151	$395,718	59%
303993	DC APRP 1 18TH ST NE C005NE Ward 5	5	Program 1	3. Active	0	0	0	0	16	9	663,899	$188,925	28%
303994	DC APRP 1 HADFIELD LN NW K004NW Ward 3	3	Program 1	3. Active	0	0	0	0	16	11	995,898	$458,093	46%
303998	DC APRP 1 13TH ST NW C008NW Ward 4	4	Program 1	3. Active	0	0	0	0	11	9	534,334	$159,035	30%
303999	DC APRP 1 MILITARY RD NW I013NW Ward 3	3	Program 1	3. Active	0	0	0	0	12	8	584,612	$254,306	43%
304003	DC APRP 1 GROFF CT NE B007NE3 Ward 6	6	Program 1	4. Paving	0	0	0	0	15	12	579,349	$252,996	44%
304004	DC APRP 1 MASSACHUSETTS AVE NW L008NW Ward 3	3	Program 1	3. Active	0	0	0	0	10	5	634,766	$179,381	28%
304005	DC APRP 1 MINNESOTA AVE SE E003SE Ward 8	8	Program 1	3. Active	0	0	0	0	13	2	636,460	$43,117	7%
304007	DC APRP 1 TILDEN ST NW M008NW Ward 3	3	Program 1	4. Paving	0	0	0	0	11	9	645,442	$216,694	34%
304008	DC APRP 1 17TH PL NE E007NE Ward 5	5	Program 1	3. Active	0	0	0	0	18	14	898,441	$197,134	22%
304025	DC APRP 1 L ST NE C003NE Ward 6	6	Program 1	3. Active	0	0	0	0	11	7	580,217	$280,532	48%
304026	DC APRP 1 OWEN PL NE C003NE Ward 6	6	Program 1	3. Active	0	0	0	0	14	9	721,147	$188,632	26%
304028	DC APRP 1 13TH ST NE D006NE Ward 5	5	Program 1	4. Paving	0	0	0	0	9	9	532,708	$258,458	49%
304033	DC APRP 1 14TH ST NE D006NE Ward 5	5	Program 1	3. Active	0	0	0	0	10	1	429,419	$35,507	8%
304035	DC APRP 1 UNDERWOOD PL NW A012NW Ward 4	4	Program 1	4. Paving	0	0	0	0	6	4	201,551	$99,010	49%
304037	DC APRP 1 GARFIELD ST NW G006NW Ward 3	3	Program 1	3. Active	0	0	0	0	14	9	451,237	$220,858	49%
304038	DC APRP 1 CATHEDRAL AVE NW G006NW Ward 3	3	Program 1	3. Active	0	0	0	0	9	1	440,973	$380	0%
304039	DC APRP 1 17TH ST NW C014NW Ward 4	4	Program 1	3. Active	0	0	0	0	12	10	482,477	$218,946	45%
304040	DC APRP 1 GEORGIA AVE NW C014NW Ward 4	4	Program 1	3. Active	0	0	0	0	14	7	856,116	$153,717	18%
304041	DC APRP 1 GEORGIA AVE NW C011NW Ward 4	4	Program 1	3. Active	0	0	0	0	11	1	385,818	$12,608	3%
304042	DC APRP 1 18TH ST NW C011NW Ward 4	4	Program 1	3. Active	0	0	0	0	12	6	640,722	$145,831	23%
304043	DC APRP 1 CRITTENDEN ST NE C009NE3 Ward 5	5	Program 1	3. Active	0	0	0	0	11	10	481,676	$150,430	31%
304044	DC APRP 1 30TH ST NE C009NE3 Ward 5	5	Program 1	3. Active	0	0	0	0	12	11	546,197	$162,493	30%
304045	DC APRP 1 MINNESOTA AVE SE F003SE Ward 8	8	Program 1	3. Active	0	0	0	0	12	3	533,773	$46,653	9%
304046	DC APRP 1 PENNSYLVANIA AVE SE F003SE Ward 8	8	Program 1	3. Active	0	0	0	0	16	13	610,291	$300,384	49%
304053	DC APRP 1 FAIRMONT ST NW C006NW Ward 1	1	Program 1	4. Paving	0	0	0	0	23	21	1,097,912	$569,090	52%
304054	DC APRP 1 M ST NW H003NW Ward 2	2	Program 1	3. Active	0	0	0	0	16	4	404,957	$229,197	57%
304055	DC APRP 1 THOS JEFF ST NW H003NW Ward 2	2	Program 1	3. Active	0	0	0	0	11	6	559,511	$175,988	31%
304057	DC APRP 1 BARNABY ST NW H013NW Ward 4	4	Program 1	4. Paving	0	0	0	0	18	13	633,227	$230,150	36%
304058	DC APRP 1 TENNYSON ST NW H013NW Ward 4	4	Program 1	4. Paving	0	0	0	0	11	8	555,715	$125,636	23%
304059	DC APRP 1 W ST NW C005NW Ward 1	1	Program 1	3. Active	0	0	0	0	15	10	658,422	$168,352	26%
304060	DC APRP 1 47TH ST NW E009NW Ward 4	4	Program 1	3. Active	0	0	0	0	11	9	502,298	$201,806	40%
304061	DC APRP 1 13TH ST NW C005NW Ward 1	1	Program 1	3. Active	0	0	0	0	16	10	678,942	$166,902	25%
304062	DC APRP 1 RESERVOIR RD NW J004NW Ward 2	2	Program 1	3. Active	0	0	0	0	21	20	886,174	$611,781	69%
304063	DC APRP 1 37TH ST NW J004NW Ward 2	2	Program 1	4. Paving	0	0	0	0	19	19	926,061	$632,183	68%
304073	DC APRP 1 REMO RD NW I008NW Ward 3	3	Program 1	3. Active	0	0	0	0	11	9	568,963	$240,541	42%
304074	DC APRP 1 V ST NE A005NE3 Ward 5	5	Program 1	4. Paving	0	0	0	0	9	9	497,781	$202,679	41%
304077	DC APRP 1 15TH ST SE C001SE2 Ward 6	6	Program 1	3. Active	0	0	0	0	11	8	356,980	$179,126	50%
304078	DC APRP 1 2ND ST SW A009SW Ward 8	8	Program 1	3. Active	0	0	0	0	4	3	197,453	$53,857	27%
304081	DC APRP 1 SOUTH DAKOTA AVE NE C009NE Ward 5	5	Program 1	3. Active	0	0	0	0	24	6	560,542	$87,307	16%
304109	DC APRP 3 GALES ST NE E007NE4 Ward 6	6	Program 3	3. Active	0	0	0	0	11	9	404,007	$128,819	32%
304112	DC APRP 3 E CAPITOL ST SE C001SE2 Ward 6	6	Program 3	3. Active	0	0	0	0	16	11	492,375	$144,411	29%
304113	DC APRP 3 S CAPITOL TER SW A013SE Ward 8	8	Program 3	5. Pre-Close	0	0	0	0	8	8	355,369	$217,938	61%
304134	DC APRP 3 CONSTITUTION AVE NE B001NE4 Ward 6	6	Program 3	3. Active	0	0	0	0	22	18	1,022,196	$328,337	32%
304135	DC APRP 3 2ND ST NW A008NW Ward 4	4	Program 3	3. Active	0	0	0	0	21	6	1,025,063	$46,431	5%
304116	DC APRP 3 UPSHUR ST NW B008NW2 Ward 4	4	Program 3	3. Active	0	0	0	0	16	5	725,020	$101,083	14%
304117	DC APRP 3 TAYLOR ST NW C008NW Ward 4	4	Program 3	3. Active	0	0	0	0	16	8	747,158	$8,461	1%
304343	DC APRP 5 11TH ST NE C009NE2 Ward 5	5	Program 5	4. Paving	0	0	0	0	16	17	485,122	$323,693	67%
304344	DC APRP 5 DELAFIELD PL NE C009NE2 Ward 5	5	Program 5	4. Paving	0	0	0	0	13	13	550,125	$313,927	57%
304345	DC APRP 5 SAVANNAH PL SE E006SE Ward 8	8	Program 5	4. Paving	0	0	0	0	16	16	729,544	$469,856	64%
304347	DC APRP 5 20TH ST SE E006SE Ward 8	8	Program 5	4. Paving	0	0	0	0	11	12	452,706	$298,977	66%
304349	DC APRP 5 LEE ST NE K003NE Ward 7	7	Program 5	4. Paving	0	0	0	0	14	11	735,653	$273,030	37%
304351	DC APRP 5 49TH ST NE K003NE Ward 7	7	Program 5	4. Paving	0	0	0	0	18	15	938,150	$391,754	42%
304352	DC APRP 5 MEADE ST NE K003NE Ward 7	7	Program 5	4. Paving	0	0	0	0	12	11	585,701	$399,136	68%
305428	DC APRP 1 DAVIS PL NW K005NW Ward 3	3	Program 1	3. Active	0	0	0	0	30	33	1,048,260	$467,227	45%
9302301	Scattered	Various	Program 1	6. Closed	0	0	0	0	190	316	4,325,000	$7,570,216	175%
9302303	Scattered	Various	Program 3	6. Closed	0	0	0	0	33	106	580,000	$2,389,547	412%
9302305	Scattered	Various	Program 5	6. Closed	0	0	0	0	88	220	1,670,400	$4,302,114	258%

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102479	0	0	0	0	0	0	$0	$17,194	0%	Aug-21	Oct-21	May-22	Jun-22	Jun-22	Nov-22	Dec-22
146223	0	0	0	0	0	0	$0	$25,368	0%	Aug-21	Nov-15	Aug-22	Nov-21	Oct-22	Jun-23	Jul-23
160482	0	0	0	0	1	1	$20,000	$341,993	1710%	Sep-21	May-19	May-23	Mar-23	Jun-23		
169566	0	0	0	0	0	0	$0	$4,505	0%	Aug-21	Oct-19	Jun-22	Jun-22	Sep-22	Mar-23	Mar-23
219260	0	0	0	0	0	0	$0	$534	0%	Jun-21	Dec-17	Jan-22	Jun-22	Apr-22	Oct-22	Oct-22
219400	0	0	0	0	0	0	$0	$1,481	0%	Aug-21	Jul-21	Jul-22	Jun-22	Sep-22	Oct-22	Nov-22
280065	0	0	0	0	0	0	$0	$0	0%	Oct-18	Sep-17	Jan-22	Apr-22	Apr-22	Jun-22	Nov-22
281515	7,926	6,429	5,152	4,877	125	116	$5,299,053	$8,783,805	166%	Aug-21	Jun-21	Dec-23		Mar-24		
285137	0	0	0	0	0	0	$0	$9,005	0%	Sep-20	Nov-20	Jul-22	Jul-22	Jul-22	Oct-22	
286104	0	0	0	0	0	0	$0	-$4,444	0%	Oct-18	Aug-18	Oct-21	Oct-21	Nov-21	Dec-21	
286503	0	0	0	0	0	0	$0	$20,849	0%	Nov-19	Jan-20	Dec-21	Aug-22	Feb-22	Jan-23	Aug-23
287031	4,686	4,899	500	649	38	36	$2,572,998	$2,782,400	108%	Apr-21	May-21	Sep-23	Nov-23	Dec-23		
292257	0	0	0	0	0	0	$0	$105,374	0%	Mar-22	Jun-21	Sep-22	Oct-22	Mar-23	Jun-23	Jul-23
292561	0	0	0	0	0	0	$0	$9,950	0%	Nov-21	Oct-21	Jul-22	Jun-22	Jul-22	Oct-22	Dec-22
293819	0	0	0	0	0	0	$34,585	$700,121	2024%	Jul-20	Sep-20	Dec-23	Aug-23	Mar-24		
294323	0	0	0	0	0	0	$0	$11,551	0%	Jul-21	Jan-21	Dec-21	Dec-21	Apr-22	Aug-22	Dec-22
294841	0	0	0	0	0	0	$0	$280,583	0%	Nov-21	Jul-21	Jan-23	Oct-22	Mar-23	Jul-23	Jul-23
295350	0	0	0	0	0	0	$0	$47,067	0%	Apr-22	Jun-22	Jul-22	Jul-22	Mar-23	Sep-22	Dec-22
295352	0	0	0	0	0	0	$0	$85,888	0%	Dec-21	Dec-21	May-22	Jan-23	May-22	May-23	May-23
295824	0	0	0	0	0	0	$0	$10	0%	Sep-21	Jul-21	Jun-22	Dec-22	Jun-22	Apr-22	Jan-23
295999	0	420	0	0	1	0	$63,224	$263,623	417%	Oct-22	Sep-23	Dec-23		Mar-24		
297357	676	691	0	0	26	26	$788,810	$861,419	109%	Sep-22	Sep-22	May-23	Dec-23	Jun-23		
298072	0	2,329	2,845	3,233	53	45	$4,562,828	$5,570,265	122%	Feb-23	Dec-22	Sep-24		May-25		
298518	348	758	0	6	0	0	$818,492	$1,493,924	183%	Sep-22	Dec-22	May-23		Jun-23		
299376	0	0	0	0	0	0	$0	$101,627	0%	Aug-22	Jul-22	Nov-22	Nov-22	Dec-22	Mar-23	Apr-23
299378	1,196	1,196	0	0	29	37	$1,180,783	$1,480,890	125%	Aug-22	Aug-22	May-23	Jul-23	Jul-23		
299388	0	0	0	0	0	0	$0	$37,737	0%	Sep-22	Jun-22	Dec-22	Nov-22	Mar-23	Dec-22	Mar-23
299392	0	0	0	0	0	0	$216,050	$453,881	210%	Jul-22	Aug-22	Dec-22	Dec-22	Jun-23	Jul-23	Nov-23
299394	146	146	0	8	3	3	$1,900,000	$1,905,993	100%	Aug-22	Sep-22	Mar-23	Jan-23	Jun-23		
299396	0	0	0	0	0	0	$10,000	$6,204	62%	Dec-23		Oct-24		Mar-25		
299398	395	395	5	46	22	22	$611,980	$506,577	83%	Sep-22	Oct-22	May-23	Aug-23	Jul-23		
299400	0	657	0	695	0	4	$417,401	$1,240,574	297%	Nov-22	Jan-23	Apr-23	Apr-23	Jun-23		
299401	0	0	0	0	0	0	$10,000	$0	0%	Dec-23		Oct-24		Mar-25		
299402	0	0	0	0	0	0	$10,000	$0	0%	Dec-23		Oct-24		Dec-24		
299512	1,800	0	1,885	2,068	62	51	$2,801,331	$1,894,177	70%	Nov-22	Nov-22	Dec-24		Apr-25		
299764	0	0	0	0	9	8	$500,046	$272,970	55%	Aug-22	Jul-22	Nov-23	Jan-23	Jun-23	Mar-23	Mar-23
300025	0	0	0	0	0	0	$246,070	$183,212	74%	Jul-22	Feb-22	Nov-22	Nov-22	Apr-23	Aug-23	Aug-23
300153	0	0	0	0	1	1	$128,370	$90,865	71%	Apr-22	Mar-22	Apr-23	Mar-23	Jun-23		
300159	0	0	0	0	0	0	$0	$29,079	0%	Apr-22	Apr-22	Aug-22	Aug-22	Mar-23	Aug-23	Aug-23
300160	0	0	0	0	7	4	$260,435	$401,298	154%	May-22	May-22	Jun-23		Aug-23		
300162	0	0	0	0	1	1	$35,218	$88,195	250%	Jul-22	Jun-22	Apr-23	Jan-23	Apr-23	Mar-23	Apr-23
300164	0	0	0	0	1	1	$80,040	$68,544	85%	Apr-22	Mar-22	Jun-23		Sep-23		
300176	0	0	0	0	1	3	$10,000	$68,564	686%	Sep-22	Aug-22	Jun-23	Aug-23	Jun-23	May-23	Aug-23
300295	0	0	0	0	0	0	$0	$12,236	0%	Mar-22	May-22	Sep-22		Mar-23		
300773	0	0	0	0	1	1	$92,401	$47,580	51%	Apr-22	Apr-22	Feb-23	Jan-23	Apr-23	Apr-23	Apr-23
300786	0	0	0	0	2	3	$97,189	$113,231	117%	Sep-22	Jun-23	Jul-23	Aug-23	Sep-23		
300960	0	0	0	0	9	9	$629,579	$890,563	141%	Aug-22	Dec-22	Jun-23	Jul-23	Aug-23	Apr-23	
300969	1,817	1,817	1,150	1,216	76	79	$1,834,204	$2,577,181	141%	Jan-23	May-23	Dec-23		Apr-24		
300971	0	0	955	0	0	0	$440,000	$52,906	12%	Oct-23		May-24		Aug-24		
300975	1,508	0	1,025	0	63	0	$1,404,312	$244	0%	Jun-23		Jun-24		Apr-24		
300976	2,934	2,941	2,875	2,971	64	64	$2,434,462	$3,074,128	126%	Apr-23	Mar-23	Dec-23	Dec-23	Apr-24		
301129	0	0	0	0	1	1	$45,400	$92,771	204%	Apr-22	Apr-22	Dec-23	Sep-23	Mar-24		
301130	0	0	0	0	1	1	$49,515	$18,560	37%	Mar-22	Mar-22	Apr-23	Feb-23	Jun-23		
301131	0	0	0	0	0	0	$0	$1,077	0%	Jun-22	May-22	Nov-22	Nov-22	Mar-23	Sep-22	Dec-22
301132	0	0	0	0	0	0	$0	$1,765	0%	Apr-22	Mar-22	Mar-23	Feb-23	Mar-23	Aug-22	Mar-23
301134	0	0	0	0	1	1	$114,000	$87,076	76%	Jul-22	Jun-22	Apr-23		Jun-23		
301141	0	0	0	0	7	3	$266,743	$26,316	10%	May-22	May-22	Jul-23		Sep-23		
301143	0	0	0	0	5	2	$170,380	$78,311	46%	Jul-22	May-22	Apr-23		Jun-23		
301144	0	0	0	0	6	6	$338,763	$285,127	84%	May-22	Mar-22	Jun-23		Aug-23		
301145	0	0	0	0	6	5	$185,750	$101,305	54%	Jul-22	May-22	Jul-23		Sep-23		
301146	0	0	0	0	11	7	$307,091	$229,787	75%	Jul-22	Jun-22	Jul-23		Sep-23		
301151	0	0	0	0	0	0	$0	$10,146	0%	Aug-22	Jun-22	Nov-22	Nov-22	Mar-23	Mar-23	Mar-23
301159	0	0	0	0	0	0	$0	$130,266	0%	Aug-22	Jun-22	Nov-22	Nov-22	Mar-23		
301160	0	0	0	0	11	10	$315,027	$316,280	100%	Aug-23	Jun-23	Jun-23		Aug-23		
301162	0	0	0	0	2	2	$121,376	$77,348	64%	Sep-22	Jun-22	Apr-23		May-23		
301163	0	0	0	0	0	0	$0	$29,745	0%	Aug-22	May-23	Dec-22	Sep-22	Mar-23	May-23	May-23
301164	0	0	0	0	0	0	$0	$15,666	0%	Jul-22	Apr-22	Dec-22	Oct-22	Mar-23	May-23	May-23
301165	0	0	0	0	0	0	$14,761	$835	6%	Sep-22	Jun-22	Dec-22	Nov-22	Jun-23		
301189	0	0	0	0	6	6	$244,636	$196,651	80%	Sep-22	Apr-22	Jun-23	Oct-23	May-23	Apr-23	
301190	0	0	0	0	2	2	$117,275	$136,703	117%	May-22	May-22	Apr-23	Mar-23	Jun-23	May-23	May-23
301192	0	0	0	0	0	16	$217,255	$485,466	223%	Oct-22	Sep-22	Oct-23		Dec-23		
301193	0	0	0	0	2	2	$85,345	$163,258	192%	May-22	Apr-22	Apr-23	Mar-23	Jun-23	Jul-23	Aug-23
301194	0	0	0	0	0	1	$29,811	$2,130	7%	Sep-22	Sep-22	Feb-23	Jan-23	Apr-23	May-23	May-23
301195	0	0	0	0	0	4	$23,385	$85,315	365%	Aug-23	Jun-22	Aug-23		Oct-23		
301199	0	0	0	0	4	0	$86,502	$73,997	86%	Jul-22	Aug-22	Dec-23		Mar-24		

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301202	0	0	0	0	2	8	$114,917	$369,816	322%	Oct-22	Oct-22	Jun-23	Apr-23	Aug-23		
301204	0	0	0	0	3	2	$157,770	$287,796	182%	Aug-22	Jul-22	Jun-23	Apr-23	Aug-23	Aug-23	Aug-23
301208	0	0	0	0	5	4	$123,823	$375,341	303%	Aug-22	Aug-22	Oct-22	Jun-23	Dec-23		
301215	0	0	0	0	1	1	$32,003	$38,559	120%	Aug-22	Apr-22	Jun-23	Apr-23	Sep-23		
301579	1,036	1,075	0	0	16	16	$560,079	$664,819	119%	Sep-22	Oct-22	May-23	Apr-23	Jul-23		
302309	0	0	0	0	0	0	$50,000	$7,622	15%	Dec-23		Aug-24		Oct-24		
302672	0	0	0	0	0	0	$0	$0	0%							
302783	0	0	0	0	0	0	$10,000	$180	2%	Dec-23		Aug-25		Nov-25		
302784	0	0	0	0	0	0	$0	$0	0%							
302785	0	0	0	0	0	0	$0	$0	0%							
303116	271	271	0	0	0	0	$128,374	$70,277	55%	Jul-23	Jul-23	Nov-23	Aug-23	Mar-24	Sep-23	Oct-23
303117	0	1,309	300	663	0	43	$145,000	$944,273	651%	Dec-23	Sep-23	Jul-24		Oct-24		
303119	0	0	0	497	0	7	$10,000	$160,147	1601%	Dec-23	Oct-23	Oct-24		Dec-24		
303121	0	697	670	658	0	16	$410,000	$835,722	204%	Nov-23	Aug-23	Jun-24		Sep-24		
303140	0	0	805	816	0	34	$280,000	$330,712	118%	Oct-23	Sep-23	Mar-24		Jun-24		
303250	0	505	475	486	10	16	$630,000	$317,762	51%	Nov-23	Sep-23	May-24		Aug-24		
303646	0	0	0	0	0	0	$0	$178,044	0%	Jun-22	May-22	Jul-22	Jul-22	Sep-22	Aug-22	Apr-23
303868	0	0	0	0	10	4	$333,571	$96,294	29%	May-23	Apr-23	Nov-23		Apr-24		
303974	0	0	0	0	10	1	$244,443	$8,791	4%	Jul-23	Feb-23	Dec-23	Apr-23	Apr-24	Apr-23	Jun-23
303976	0	0	0	0	12	1	$310,166	$20,850	7%	Aug-23	Jun-23	Dec-23		Mar-24		
303978	0	0	0	0	7	1	$180,199	$41,757	23%	Aug-23	Jul-23	Jan-24		Apr-24		
303979	0	0	0	0	12	11	$365,410	$259,498	71%	Jul-23	Jan-23	Dec-23		Mar-24		
303980	0	0	0	0	12	2	$306,365	$102,270	33%	Aug-23	Jul-23	Jan-24		Apr-24		
303981	0	0	0	0	11	6	$532,892	$263,177	49%	Mar-23	Feb-23	Oct-23		Dec-23		
303982	0	0	0	0	11	7	$443,073	$142,438	32%	Jul-23	Mar-23	Dec-23		Apr-24		
303990	0	0	0	0	9	8	$278,660	$110,926	40%	Sep-23	Aug-23	Dec-23		Apr-24		
303991	0	0	0	0	13	6	$257,830	$157,192	61%	Aug-23	Jun-23	Jan-24	Nov-23	Apr-24		
303992	0	0	0	0	14	14	$560,959	$395,718	71%	Mar-23	Jan-23	Aug-23	Oct-23	Oct-23		
303993	0	0	0	0	16	9	$415,228	$188,925	45%	May-23	Jan-23	Nov-23		May-24		
303994	0	0	0	0	16	11	$606,230	$459,093	76%	Jun-23	May-23	Dec-23		Mar-24		
303998	0	0	0	0	11	9	$362,736	$159,035	44%	May-23	Feb-23	Nov-23		Mar-24		
303999	0	0	0	0	12	8	$408,830	$254,205	62%	Jun-23	Mar-23	Nov-23		Mar-24		
304003	0	0	0	0	13	12	$379,078	$252,996	67%	May-23	Feb-23	Nov-23	Dec-23	Mar-24		
304004	0	0	0	0	10	5	$454,399	$179,861	39%	Apr-23	Feb-23	Dec-23		Apr-24		
304005	0	0	0	0	13	2	$450,544	$43,137	10%	Aug-23	May-23	Feb-24		May-24		
304007	0	0	0	0	11	9	$470,987	$216,094	46%	Aug-23	Jun-23	Jan-24	Dec-23	Apr-24		
304008	0	0	0	0	18	14	$580,059	$197,124	34%	Jun-23	Apr-23	Dec-23		Apr-24		
304025	0	0	0	0	11	7	$390,935	$280,532	72%	Jul-23	May-23	Dec-23		Mar-24		
304026	0	0	0	0	14	9	$534,872	$188,632	36%	Jun-23	Sep-22	Nov-23		Mar-24		
304028	0	0	0	0	9	9	$345,479	$258,458	75%	Jul-23	May-23	Dec-23	Sep-23	Mar-24		
304033	0	0	0	0	10	1	$292,545	$35,507	12%	Aug-23	Nov-23	Jan-24		Apr-24		
304035	0	0	0	0	6	4	$123,796	$99,010	80%	Aug-23	Jul-23	Nov-23	Sep-23	Mar-24		
304037	0	0	0	0	14	9	$343,973	$220,858	64%	Jul-23	Mar-23	Dec-23		Mar-24		
304038	0	0	0	0	9	3	$331,455	$380	0%	Aug-23	Nov-23	Dec-23		Apr-24		
304039	0	0	0	0	12	10	$331,385	$218,946	66%	Aug-23	Aug-23	Jan-24		Apr-24		
304040	0	0	0	0	14	7	$526,169	$153,717	29%	Aug-23	May-23	Feb-24		May-24		
304041	0	0	0	0	11	1	$300,818	$12,898	4%	Aug-23	May-23	Jan-24		Apr-24		
304042	0	0	0	0	12	6	$432,850	$145,821	34%	Aug-23	May-23	Dec-23		Mar-24		
304043	0	0	0	0	11	10	$335,168	$150,430	45%	Aug-23	May-23	Dec-23		Mar-24		
304044	0	0	0	0	12	11	$361,548	$162,493	45%	Aug-23	Aug-23	Dec-23		Mar-24		
304045	0	0	0	0	12	3	$359,328	$48,853	14%	Aug-23	Jul-23	Dec-23		Mar-24		
304046	0	0	0	0	16	13	$441,253	$309,284	70%	Aug-23	May-23	Feb-24		May-24		
304053	0	0	0	0	23	21	$775,426	$568,080	73%	Aug-23	May-23	Mar-24	Dec-23	Jun-24		
304054	0	0	0	0	16	4	$316,365	$229,197	72%	Aug-23	May-23	Jan-24		Apr-24		
304055	0	0	0	0	0	6	$10,000	$175,988	1760%	Dec-23	May-23	Oct-24		Mar-25		
304057	0	0	0	0	18	13	$447,089	$230,150	51%	Jun-23	May-23	Dec-23	Dec-23	May-24		
304058	0	0	0	0	13	8	$362,577	$125,636	35%	Jul-23	Apr-23	Dec-23	Aug-23	Mar-24		
304059	0	0	0	0	0	10	$10,000	$168,852	1689%	Dec-23	Jul-23	Oct-24		Mar-25		
304060	0	0	0	0	11	9	$341,775	$201,606	59%	May-23	Jan-23	Nov-23		Mar-24		
304061	0	0	0	0	16	10	$451,224	$166,902	37%	Aug-23	Sep-23	Jan-24		Apr-24		
304062	0	0	0	0	21	20	$631,625	$611,781	97%	May-23	Mar-23	Dec-23		Apr-24		
304063	0	0	0	0	29	29	$623,159	$632,183	101%	May-23	Mar-23	Dec-23	Oct-23	Apr-24		
304073	0	0	0	0	11	9	$366,450	$280,541	64%	Jun-23	Feb-23	Nov-23		Mar-24		
304074	0	0	0	0	9	9	$338,549	$202,879	60%	Jun-23	Mar-23	Nov-23	Nov-23	Mar-24		
304077	0	0	0	0	11	8	$249,538	$179,126	72%	Aug-23	Jun-23	Jan-24		Mar-24		
304078	0	0	0	0	4	3	$123,633	$53,857	43%	Aug-23	Jul-23	Jan-24		Apr-24		
304081	0	0	0	0	24	6	$398,206	$87,107	22%	May-23	Apr-23	Dec-23		Apr-24		
304109	0	0	0	0	11	9	$351,310	$128,819	37%	Apr-23	Apr-23	Sep-23		Dec-23		
304112	0	0	0	0	16	11	$368,694	$144,411	39%	May-23	Feb-23	Nov-23		Mar-24		
304113	0	0	0	0	6	6	$256,263	$217,938	85%	Aug-23	Jun-23	Jan-24	Oct-23	Apr-24	Oct-23	
304114	0	0	0	0	22	18	$701,779	$328,337	47%	Aug-23	May-23	Mar-24		Jun-24		
304115	0	0	0	0	21	6	$642,070	$46,431	7%	Aug-23	May-23	Feb-24		May-24		
304116	0	0	0	0	16	5	$488,174	$101,083	21%	Aug-23	May-23	Feb-24		May-24		
304117	0	0	0	0	16	8	$492,354	$8,461	2%	Aug-23	Nov-23	Mar-24		Jun-24		
304143	0	0	0	0	16	17	$320,980	$323,083	101%	Aug-23	Jun-23	Feb-24	Dec-23	May-24		
304144	0	0	0	0	13	13	$365,900	$313,927	86%	May-23	Mar-23	Nov-23	Apr-23	Mar-24		
304145	0	0	0	0	11	16	$402,000	$469,856	117%	Oct-23	Aug-23	Mar-24	Oct-23	Jun-24		
304147	0	0	0	0	11	12	$301,485	$296,977	99%	Aug-23	Jun-23	Feb-24	Oct-23	May-24		
304149	0	0	0	0	14	11	$456,233	$273,030	60%	Jun-23	Mar-23	Dec-23	Jul-23	Apr-24		
304151	0	0	0	0	18	15	$10,000	$301,754	3018%	Jun-23	May-23	Dec-23	Sep-23	May-25		
304152	0	0	0	0	12	11	$388,461	$399,136	103%	Jul-23	May-23	Dec-23	Oct-23	Mar-24		
305429	0	0	0	0	30	13	$767,042	$467,227	61%	Jun-23	Mar-23	Dec-23		Apr-24		
9202301	0	0	0	0	190	316	$4,325,000	$7,570,216	175%	Jan-23	Jan-23	Dec-23	Dec-23	Dec-23	Dec-23	Dec-23
9202303	0	0	0	0	33	106	$680,000	$2,809,547	412%	Jan-23	Jan-23	Dec-23	Dec-23	Dec-23	Dec-23	Dec-23
9202305	0	0	0	0	86	220	$1,670,400	$4,302,134	258%	Jan-23	Jan-23	Dec-23	Dec-23	Dec-23	Dec-23	Dec-23

"Non-APRP PROJECT INFORMATION - Work Controlled by Others - January 1, 2022 - December 31, 2022"

Note: All project costing and timing data represent estimates based upon the best data available at the time. Many unknown factors outside the control of WG will impact both the cost and timing of each specific project, items such as projects by others in the area, permitting fees, and timing.

			TOTAL PROJECT SCOPE													
			ESTIMATED MAIN ABANDONMENT (FT)					MAIN INSTALLATION (FT)								
BCA	PROJECT NAME / LOCATION	WARD	CAST IRON	BARE/ UNPROTECTED WRAPPED STEEL	VINTAGE MECHANICALLY COUPLED (VMC) STEEL	NON-VMC PROTECTED WRAPPED STEEL	PLASTIC	2"	4"	6"	8"	12" OR LARGER	AFFECTED SERVICES	EST. EFVs		TOTAL ESTIMATED PROJECT COST
278878	DC BILLABLE @100% - PEPCO Takoma-Sligo Phase 1 - Ward 4 - B013NW	4	0	0	0	122	983	0	30	26	0	0	11	11	$	527,700
284186	DC AOP - Penn. Ave SE & Minn. Ave SE Intersection - Ward 7	7	0	0	0	116	746	460	15	285	35	25	22	21	$	1,245,871
285009	AOP - Cleveland Park Streetscape - G007NW - Ward 3	3	0	0	0	76	89	130	0	0	35	55	2	2	$	218,557
293772	AOP - BILLABLE @ 100% - K ST NW - H002NW - WARD 2 - DC WATER	2	0	0	0	23	215	0	305	25	0	0	1	0	$	354,159
295010	DC AOP - Connecticut Ave NW Streetscape - F004NW2 - Ward 2	2	0	57	0	546	340	0	880	0	0	0	11	10	$	1,089,045
295916	DC BILLABLE @100% - STATE DEPT - D ST NW - F001NW	2	0	0	0	0	440	0	475	0	0	0	1	1	$	414,627
296726	AOP - BILLABLE @100% - K ST NW - H002NW - WARD 2 - DC Water Structure 44	2	0	0	0	0	43	0	70	0	0	0	2	0	$	210,200
297999	AOP - BILLABLE @ 0% - VIKA - 3924 MINN AVE NE - I001NE - WARD 7	7	0	0	0	0	467	540	0	0	0	0	1	1	$	411,290
298171	AOP - BILLALBE @ 100% - 601 I ST SW - DAVIS UTILITY - A002SW4 - WARD 6	6	0	0	0	400	0	0	485	0	0	0	0	0	$	574,357
299196	DC AOP - BILLABLE @ 100% - CLARION GABLES - 1325 5TH ST NE - B003NE2 - WARD 5	5	0	0	0	251	0	0	305	0	0	0	2	2	$	372,029
299495	DC AOP - BILLABLE @100% - WMATA SQ 487 - 600 5TH ST NW - B002NW4 - WARD 4	4	0	0	0	284	0	0	0	270	0	0	1	1	$	683,419
300048	DC AOP - BILLABLE @ 100% - 111 N ST SE PARCEL H - A003SE - WARD 6	6	0	0	0	0	463	0	120	395	0	0	1	1	$	711,749
300385	DC AOP - BILLABLE @100% - HUNGARIAN EMBASSY - 1500 RHODE ISLAND AVE NW	2	0	0	0	81	0	70	0	0	0	0	1	1	$	286,557
300689	DC AOP - S St NW 4th to 7th - Wards 1 & 2 - B004NW2	1 & 2	0	14	0	815	3	515	0	0	0	0	20	20	$	601,308
300909	DC BILLABLE @100% - 500 Indiana Ave NW - B001NW - WARD 2 - AECOM	2	0	0	0	0	152	150	0	0	0	0	1	1	$	244,622
302467	DC AOP - DDOT - Lane Pl Ped. Bridge - J003NE - Ward 7	7	0	0	0	0	0	0	0	0	0	0	1	0	$	125,397
302657	DC AOP - BILL @ 0% - HOWARD RD SE - DFM DEVELOPMENT - B004SE - WARD 8	8	0	0	0	366	0	0	0	0	0	0	0	0	$	82,989
303142	DC AOP - BILL @ 0% - HOWARD RD SE - DFM DEVELOPMENT B004SE - WARD 8	8	0	0	0	257	0	0	0	0	0	0	0	0	$	71,492
304642	DC - AOP - BILLABLE AT 0% - EUCLID ST NW D005NW - WARD 1 - NOVEL 14TH ST	1	66	0	0	465	0	0	0	0	0	0	1	0	$	185,100
304931	DC AOP - BILLALBE @ 100% - 25 M ST SE - WILES MENSCH	6	0	0	0	188	16	175	0	0	0	0	1	1	$	214,283
306347	DC AOP - BILL @ 0% - BRENTWOOD RD NE - C005NE - WS	5	220	0	0	0	0	0	0	0	0	0	0	0	$	85,429
Totals			286	71	0	3,990	3,977	2,040	2,665	1,001	70	80	80	73	$	8,710,180

"Non-APRP PROJECT INFORMATION - Work Completed by Others - Janu

Note: All project costing and timing data represent estimates based upon the best data available both the cost and timing of each specific project, items such as projects by others in the area, per

			TOTAL PROJECT SCOPE ACTUALS AS OF 12/31/2023				REPORTING PERIOD ACTUALS FROM 01/01/2023 - 12/31/2023				
BCA	PROJECT NAME / LOCATION	WARD	ACTUAL MAIN ABANDONMENT	ACTUAL MAIN INSTALLATION	ACTUAL SERVICES REMEDIATED	ACTUAL PROJECT COST	ACTUAL MAIN ABANDONMENT	ACTUAL MAIN INSTALLATION	ACTUAL SERVICES REMEDIATED	ACTUAL PROJECT COST	APRP EXCLUSION REASON
278878	DC BILLABLE @100% - PEPCO Takoma-Sligo Phase 1 - Ward 4 - B013NW	4	1,120	42	9	$14,599	0	0	9	$955	Material not eligible for replacement under PIPES
284186	DC AOP - Penn. Ave SE & Minn. Ave SE Intersection - Ward 7	7	190	757	22	$4,067,603	190	67	22	$258,078	Material not eligible for replacement under PIPES
285009	AOP - Cleveland Park Streetscape - G007NW - Ward 3	3	201	0	2	$3,309,217	0	0	2	$172,023	Material not eligible for replacement under PIPES
293772	AOP - BILLABLE @ 100% - K ST NW - H002NW - WARD 2 - DC WATER	2	488	480	1	$6	0	0	1	$7	Material not eligible for replacement under PIPES
295030	DC AOP - Connecticut Ave NW Streetscape - F004NW2 - Ward 2	2	417	454	7	$811,076	417	454	6	$483,098	Material not eligible for replacement under PIPES
295916	DC BILLABLE @100% - STATE DEPT - D ST NW - F001NW	2	327	368	0	$21,834	327	368	0	-$408,307	Material not eligible for replacement under PIPES
296728	AOP - BILLABLE @100% - K ST NW - H002NW - WARD 2 - DC Water Structure 44	2	53	80	1	$41,079	0	0	1	$91	Material not eligible for replacement under PIPES
297999	AOP - BILLABLE @ 0% - VIKA - 3924 MINN AVE NE - I001NE - WARD 7	7	440	442	4	$221,504	70	26	4	$55,305	0% Reimbursable
298171	AOP - BILLALBE @ 100% - 60 I ST SW - DAVIS UTILITY - A002SW4 - WARD 6	6	0	910	0	$321,990	0	0	0	$179,760	100% Reimbursable
299196	DC AOP - BILLABLE @ 100% - CLARION GABLES - 1325 5TH ST NE - B003NE2 - WARD 5	5	317	385	1	$56,443	0	0	1	$764	100% Reimbursable
299495	DC AOP - BILLABLE @100% - WMATA SQ 487 - 600 5TH ST NW - B002NW4 - WARD 4	4	0	285	0	$351,300	0	285	0	$91,743	100% Reimbursable
300048	DC AOP - BILLABLE @ 100% - 111 N ST SE PARCEL H - A003SE - WARD 6	6	133	117	2	$24,197	133	117	0	$4,425	100% Reimbursable
300385	DC AOP - BILLABLE @100% - HUNGARIAN EMBASSY - 1500 RHODE ISLAND AVE NW	2	83	65	1	$0	0	0	1	-$17,245	100% Reimbursable
300699	DC AOP - S St NW 4th to 7th - Wards 1 & 2 - B004NW2	1 & 2	828	513	20	$1,209,305	828	513	21	$1,200,513	Material not eligible for replacement under PIPES/ Pipes Authorized Funding utilized, Work performed outside of PIPES
300909	DC BILLABLE @100% - 500 Indiana Ave NW - B001NW - WARD 2 - AECOM	2	138	146	0	$0	0	0	0	$0	Material not eligible for replacement under PIPES
302467	DC AOP - DDOT - Lane Pl Ped. Bridge - I003NE - Ward 7	7	0	0	1	$107,559	0	0	1	$2,025	PIPES authorized funding fully utilized, work performed outside of PIPES
302657	DC AOP - BILL @ 0% - HOWARD RD SE - DFM DEVELOPMENT - B004SE - WARD 8	8	0	586	0	$67,800	0	586	0	$67,800	Material not eligible for replacement under PIPES
303142	DC AOP - BILL @ 0% - HOWARD RD SE - DFM DEVELOPMENT B004SE - WARD 8	8	0	257	0	$29,973	0	257	0	$29,973	Material not eligible for replacement under PIPES
304642	DC - AOP - BILLABLE AT 0% - EUCLID ST NW D005NW - WARD 1 - NOVEL 14TH ST	1	531	0	0	$382,540	531	0	0	$382,540	Material not eligible for replacement under PIPES/ Pipes Authorized Funding utilized, Work performed outside of PIPES
304931	DC AOP - BILLALBE @ 100% - 25 M ST SE - WILES MENSCH	6	194	0	0	$186,741	194	0	0	$131,748	100% Reimbursable
306347	DC AOP - BILL @ 0% - BRENTWOOD RD NE - C005NE - WS	5	220	0	0	$290,458	220	0	0	$247,219	0% Reimbursable
Totals			5,888	5,888	71	$11,519,424	2,910	2,674	88	$2,881,615	

			Design Abandonment (Footage)			Design Installation (Footage)			Actual Units (Footage)[1]		
BCA #	BCA Name	Program	ABND LP	ABND MP	ABND Total	Install LP	Install MP	Install Total	Remediated	Installed	Replacement Type
292257	DC F.O. - APRP 4 - 300 BLK 10th St NE - C001NE1 - Ward 6	Program 4	705	0	705	0	0	0	705	0	Abandonment Only
295999	DC APRP 10 - 215 G ST NE - MCN BUILD - A002NE - WARD 6	Program 10	444	0	444	0	0	0	420	0	Abandonment Only
296948	DC APRP 10 - AOP - ASPEN ST NW - C013NW - Ward 4	Program 10	1,442	0	1,442	0	0	0	1,408	34	Abandonment Only
296965	DC APRP 10 - AOP - 1601 MASS AVE - AUSTRALIAN EMBASSY - D003NW1 - WARD 2	Program 10	746	0	746	0	0	0	741	0	Abandonment Only
299764	DC F.O. - APRP 4 - 4th St NE - B004NE - Ward 5	Program 4	913	0	913	0	0	0	912	0	Abandonment Only
303116	DC APRP 2 - Prospect St NW - I003NW4 - Ward 2 - OPT 70851	Program 2	271	0	271	0	0	0	271	0	Abandonment Only
290609	DC APRP 10 - AOP - Gallatin St & Kansas Ave NW - DCKA-2013-T0084 - Ward 4 - B010NW4	Program 10	22	0	22	25	0	25	42	88	LP-LP
294701	DC APRP 10 - AOP - 16th St NW Bus lanes - D002NW1 - Ward 2	Program 10	621	0	621	385	0	385	718	192	LP-LP
295350	DC F.O. - APRP 2 - 49th ST NW - M009NW - WARD 3 - OPT 77626	Program 2	408	0	408	420	0	420	432	438	LP-LP
295799	DC APRP 10 - AOP - Pennsylvania Ave & Minnesota Ave SE Intersection - F003SE	Program 10	168	0	168	185	0	185	172	208	LP-LP
301618	DC F.O. - APRP 4 - 16th St NW - D006NW - Ward 1	Program 4	205	0	205	5	0	5	74	8	LP-LP
298518	DC APRP 10 - AOP - Connecticut Ave NW Streetscape - F004NW2	Program 10	816	58	874	245	0	245	758	268	LP-LP
280811	DC APRP 2 - EASTERN AVE - WARD 4 - OPT 68257	Program 2	610	0	610	200	175	375	377	81	LP-LP & LP-MP
281515	DC APRP 10 - AOP - Florida Ave NE 2nd - H St - FAP STP 2015 (010) - Wards 5 & 6	Program 10	12,614	0	12,614	1,470	6,895	8,365	10,619	7,888	LP-LP & LP-MP
293819	DC APRP 10 - AOP - Cleveland Park - Ward 3 - G007NW - WARD 3	Program 10	2,046	0	2,046	175	1,305	1,480	1,291	371	LP-LP & LP-MP
298472	DC APRP 10 - PLUG - Feeder 15009 - Ward 4	Program 10	7,909	0	7,909	1,645	4,755	6,400	2,329	3,569	LP-LP & LP-MP
303119	DC APRP 2 - Montana Ave NE - D006NE - Ward 5 - OPT 60623	Program 2	748	0	748	140	608	748	0	492	LP-LP & LP-MP
102479	DC F.O. - APRP 2 - WATERSIDE DR NW - WARD 2 - OPT76865	Program 2	622	0	622	0	635	635	606	597	LP-MP
222221	DC APRP 2 - HAWTHORNE LA NW - WARD 3 - OPT78399	Program 2	1,180	0	1,180	0	1,270	1,270	575	0	LP-MP
280819	DC APRP 2 - HARRISON ST NW - WARD 3 - OPT78650	Program 2	1,289	105	1,394	0	1,350	1,350	1,107	210	LP-MP
287031	DC APRP 10 - AOP - KENNEDY ST NW Ph 2 - Ward 4 - STP-2016(042)	Program 10	9,270	0	9,270	0	4,855	4,855	8,301	4,900	LP-MP
293815	DC F.O. - APRP 4 - Seaton PL NE - B004NE - Ward 5	Program 4	255	0	255	0	245	245	252	0	LP-MP
293976	DC F.O. - APRP 4 - 2200 Block M ST NE - F003NE - Ward 5 - OPT 215133	Program 4	871	0	871	0	755	755	1,301	721	LP-MP
294341	DC APRP 10 - AOP - PA Ave NW Streetscape Ph 1 (17th-22nd) - FAP 2017043- Ward 2	Program 10	5,489	0	5,489	10	2,800	2,810	1,783	1,455	LP-MP
295352	DC F.O. - APRP 4 - W PL NW - I005NW - WARD 3 - OPT 53273	Program 4	1,304	0	1,304	0	1,090	1,090	1,305	1,076	LP-MP
295414	DC F.O. - APRP 4 - MORRIS RD SE - D005SE - WARD 8 - OPT 47141	Program 4	1,126	0	1,126	0	565	565	1,126	580	LP-MP
297357	DC APRP 10 - AOP - S St NW Revitalization 4th to 7th - B004NNW1 - Ward 1	Program 10	1,337	0	1,337	0	1,050	1,050	1,352	1,126	LP-MP
298874	DC F.O. - APRP 4 - Quackenbos St NE - A011NE	Program 4	309	0	309	0	315	315	316	320	LP-MP
299376	DC APRP 2 - Sedwick ST NW - M008NW - Ward 3 - OPT 77625	Program 2	804	0	804	0	690	690	801	690	LP-MP
299378	DC APRP 4 - Walter ST SE - C001SE2 - Ward 6 - OPT 214983	Program 4	1,196	0	1,196	0	990	990	1,196	1,005	LP-MP
299392	DC APRP 4 - Lamont St NW-C006NW1 - Ward 1 - OPT55301	Program 4	692	0	692	0	615	615	666	627	LP-MP
299394	DC APRP 2 - Verplanck PL NW - K008NW - Ward 3 - OPT 70022	Program 2	2,326	0	2,326	0	2,500	2,500	2,239	2,166	LP-MP
299512	DC APRP 10 - AOP - MLK Ave SE Phase 2 - Ward 8	Program 10	7,823	0	7,823	0	5,875	5,875	0	2,068	LP-MP

			Design Abandonment (Footage)			Design Installation (Footage)			Actual Units (Footage)[1]		
BCA #	BCA Name	Program	ABND LP	ABND MP	ABND Total	Install LP	Install MP	Install Total	Remediated	Installed	Replacement Type
300025	DC F.O. - APRP 4 - 40TH ST - Ward 7 - OPT 362857	Program 4	482	0	482	0	595	595	465	633	LP-MP
300960	DC F.O. - APRP 2 - Rhode Island Ave NE - B005NE3 - Ward 5	Program 2	571	0	571	0	395	395	584	420	LP-MP
300969	DC APRP 4 - Emerald St NE - QA1NE - Ward 6 - OPT 363402	Program 4	1,817	0	1,817	0	1,150	1,150	1,817	1,216	LP-MP
301579	DC F.O. - APRP 4 - CUMBERLAND ST NW - J009NW - WARD 3	Program 4	1,075	0	1,075	0	810	810	1,075	805	LP-MP
303117	DC APRP 4 - Randolph St NW - B008NW3 - Ward 4 - OPT 58916	Program 4	1,282	0	1,282	0	655	655	1,289	683	LP-MP
303121	DC APRP 4 - Longfellow St NW - B010NW1 - Ward 4 - OPT 57343	Program 4	710	5	715	0	670	670	697	658	LP-MP
303140	DC APRP 2 - OPT 3874144 - Q St SE - E003SE - Ward 8	Program 2	1,323	0	1,323	0	805	805	0	816	LP-MP
303250	DC APRP 4 - SHEPHERD ST NW - B008NW4 - Ward 4 - OPT 58913	Program 4	490	0	490	0	475	475	505	486	LP-MP
303646	DC F.O. - APRP 2 - Luzon Ave NW - D012NW - Ward 4	Program 2	2,723	89	2,812	0	2,290	2,290	2,907	2,521	LP-MP
285137	DC APRP 10 - AOP - Rehabilitation C St NE - Ward 6	Program 10	4,017	0	4,017	400	3,100	3,500	3,656	1,445	LP-MP & LP-LP
286104	DC APRP 10 - AOP - MARYLAND AVE NE	Program 10	13,663	0	13,663	480	10,430	10,910	10,802	1,615	LP-MP & LP-LP
286503	DC APRP 10 - AOP - Massachusetts Ave NW Rehabilitation - Ward 2	Program 10	9,756	144	9,900	705	6,890	7,595	4,119	1,810	LP-MP & LP-LP
295824	DC F.O. - APRP 4 - Massachusetts Ave NW - Ward 3 - I006NW	Program 4	2,445	0	2,445	190	380	570	2,438	566	LP-MP & MP-MP
280065	DC APRP 4 - 17TH ST NE - WARD 5 - OPT58594	Program 4	370	575	945	0	1,245	1,245	586	214	LP-MP & MP-MP
292561	DC F.O. - APRP 2 - MASS AVE NW - L008NW - WARD 3	Program 2	738	1,538	2,276	0	1,775	1,775	2,299	932	LP-MP & MP-MP

CERTIFICATE OF SERVICE

I, the undersigned counsel, hereby certify that on this 1st day of April 2024, I caused copies of the foregoing to be hand-delivered, mailed, postage-prepaid, or electronically delivered to the following:

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May 19, 2021

VIA ELECTRONIC FILING

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 "G" Street, N.W., 8th Floor
Washington, D.C. 20005

Re: Formal Case No. 1154
[Technical Conference Report on Lowering PROJECT*pipes* Unit Costs]

Dear Ms. Westbrook-Sedgwick:

Pursuant to Public Service Commission of the District of Columbia Order No. 20671, transmitted for filing is the Technical Conference Report on Lowering PROJECT*pipes* Unit Costs.

If you have any questions regarding this matter, please feel free to contact me.

Sincerely,

Cathy Thurston-Seignious

Cathy Thurston-Seignious
Supervisor, Administrative and
Associate General Counsel

cc: Per Certificate of Service

**BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA**

IN THE MATTER OF APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR APPROVAL OF PROJECTPIPES 2 PLAN	)))))))	Formal Case No. 1154

**TECHNICAL CONFERENCE REPORT ON
LOWERING PROJECT*PIPES* UNIT COSTS**

Pursuant to Public Service Commission of the District of Columbia ("Commission") Order No. 20671, issued on December 11, 2020 in the above-captioned proceeding, Washington Gas Light Company ("Washington Gas" or "Company") hereby submits the Technical Conference Report on Lowering PROJECT*pipes* Unit Costs. This report summarizes the topics discussed at the Technical Conference and identifies actionable items that are designed to help mitigate PROJECT*pipes* ("PIPES") costs.

On April 22, 2021, Commission Staff convened a Technical Conference to discuss actions Washington Gas could take to lower PIPES unit costs. Washington Gas, the Office of the People's Counsel for the District of Columbia, the Apartment and Office Building Association of Metropolitan Washington and Sierra Club were represented at the Technical Conference. Washington Gas gave a presentation on current cost drivers; changes in costs as compared to prior years; actions the Company has taken to reduce costs; and recommendations to further reduce program costs (see Attachment). The participants asked questions and engaged in constructive dialog.

The Company described a number of changes in policy and regulation at the District Department of Transportation ("DDOT") which have had a significant impact on the level of productivity and costs associated with the construction work under PIPES, including restrictions on work hours resulting from a typical 10-hour work day to a 6-hour work day. The imposition of DDOT's mandate to remove spoils at every job site requires a truck to haul the spoils, as well as additional dump fees. Prior to this change, the Company was able to keep the spoils at the work site and re-use suitable spoils to backfill the excavation. Other DDOT changes include a requirement for multiple occupancy permits, smaller scope per permit, and shorter permit durations, as well as the requirement to arrange for bicycle and pedestrian traffic flow on the same side of the roadway as the construction site. Washington Gas explained that all of these measures have resulted in increased costs to the Company, reduced productivity of work crews and longer time periods to complete required PIPES work.

Significant changes have also been imposed by DDOT to increase protection of trees in proximity to a construction work area. Chain link fences, rather than the previously used orange flexible fencing, are now required for all trees in a work zone, necessitating additional equipment for set up and removal which in many cases is performed by a separate crew. This requirement not only increases costs for the equipment but adds additional labor costs to the project. Crews are also compelled to hand-dig or vacuum excavate around tree roots near a drip line, and these more stringent rules have increased the amount of time it takes to complete the work and added costs for the specialized vacuum excavation equipment, thereby reducing productivity and increasing project costs.

Moreover, changing permit requirements to avoid installing facilities in the green space behind the curve have caused crews to perform pipe replacements in the roadway, which the Company explained has considerably raised costs associated with increased saw-cutting preparations, spoils, traffic control and restoration. DDOT also requires 100% select backfill in the roadway, which increases costs, compared to allowing facilities to be installed in the green space and utilizing suitable excavated material for backfilling.

In recent years, Washington Gas has changed some of its operating procedures due to pipeline safety concerns, such as suspending the use of trenchless technology, which eliminated the need for hard surface excavation and restoration and the associated costs. This change in procedure reduces the potential for cross-bores which inadvertently intersect gas lines with sewer lines that can lead to potential migration of natural gas into buildings, if these facilities are disturbed. This safety-related change, however, has increased the amount of hand-digging and vacuum excavation that are now required, which has increased both construction installation costs as well as restoration costs.

Also, a shift from small diameter main replacements being prioritized in prior years of the PIPES program to more large diameter main replacements has necessitated larger excavations that typically require additional shoring and have slower installation rates. As a result of this change in work mix, program costs have increased in recent years.

The Company detailed the measures it is taking to control costs, including its enhanced cost management, tracking and reporting methods, implementation of quality controls associated with paving and restoration, as well as aggressive construction contract negotiations and approaches, notwithstanding the District of Columbia minimum wage increase recently adopted. To address concerns regarding the impact of DDOT's policy and operational changes on the Company's construction activities, Washington Gas advised that its representatives have met with DDOT and its Urban Forestry Division ("Urban Forestry") on several occasions, with limited success in curbing DDOT's costly mandates. For example, Washington Gas has made consistent efforts to obtain authorization from DDOT to extend crew working hours in the District of Columbia. Washington Gas has had some success in receiving authorization for extended working hours, and discussions continue with DDOT in an effort to reach a reasonable resolution as DDOT has recently assigned dedicated staff to Washington Gas's work.

The Technical Conference participants discussed actions that may be taken to further mitigate PIPES costs. Washington Gas solicited stakeholder involvement to work with DDOT to effectuate changes in rules and regulations that would lead to lower costs, allow for longer crew work hours and improve productivity for the benefit of District of Columbia ratepayers. The Company's specific recommendations were as follows:

1. Develop a committee comprised of affected utilities and interested stakeholders to present a cost and impact analysis of DDOT's current requirements and propose changes to DDOT's regulations to the D.C. Council.
2. Enhance the Utility Coordination Committee, which includes utilities operating in the District of Columbia and DDOT, to allow for discussion on expanded issues affecting all participants, such as proposed DDOT regulation changes and impacts

on ratepayers; better coordination on projects; and comparison of permit approval requirements.

3. Conduct a study on permitting and D.C. Code and regulation requirements to find ways to streamline the permitting process.

Other topics and suggestions discussed during the Technical Conference included:

1. The importance of Commission involvement in discussions with DDOT, affected utilities and stakeholders.
2. Continued dialog with Urban Forestry regarding the chain link fence requirement, locating facilities in the roadway rather than behind the curb, and other requirements.
3. Enhanced customer communication and engagement regarding the cost impact of DDOT changes on PIPES construction work and how that impacts customers.
4. Examination of installation requirements in other jurisdictions to determine best practices.
5. Restoration timing and responsiveness.
6. Qualitative v. quantitative assessment of PIPES costs.

The recommended actions discussed herein to mitigate PIPES costs should be evaluated, prioritized and pursued through stakeholder collaboration and engagement in the interest of District of Columbia ratepayers.

WGL ENERGY ANSWERS. ASK US.

UNIT COST TECHNICAL CONFERENCE

FC1154 *PROJECTpipes*

WAYNE JACAS

APRIL 22, 2021

AGENDA

TIME	TOPIC	PRESENTER(S)
	Purpose	
	Cost Drivers	
	Main Replacement Mix of Work	
	Service Replacement	
	Spoils Removal: Select Backfill, Trucking & Dump Fees	
	Tree Protection	
	Design and Oversight	
	Labor Costs	
	Paving Limit Requirements	
	Permitting Restrictions	
	Permitting Design Requirements	
	Traffic Control	
	Current Cost Controls	
	Company Recommendations	
	Closing Remarks	

PURPOSE

In Order No. 20671 The District of Columbia Public Service Commission ordered:

(Paragraph 91)

The Commission also directs WGL to hold a technical conference with stakeholders and Commission Staff within 60 days of the date of this order to review actions the Company could take to lower unit costs. The Company shall file a report on its efforts to coordinate on the actionable items within 90 days of the date of this order.

COST DRIVERS

COST DRIVERS

CATEGORIZING COSTS

The company has previously testified in Formal Cases Nos. 1137, 1154 and 1162 as cost drivers being summarized as Controllable or Uncontrollable. In this context:

Controllable are the items directed or influenced by the Company's pipe installation regardless of jurisdictional requirements

Uncontrollable are items directed or influenced by external factors (i.e., jurisdictional requirements) that dictate the Company incur additional expenses

Price (P) x Quantity and type work (Q) = Total Cost

MAIN REPLACEMENT MIX OF WORK

BEGINNING OF PIPES

- Majority of work was small diameter main replacement and was estimated for WG to install approximately 60' - 70' per day of 2" diameter main
- Rental of steel plates and shoring were paid under negotiated payments

RECENT YEARS OF PIPES

- Due to the project prioritization in PIPES, more large diameter main replacements, necessitating larger excavations typically requiring additional shoring and slower installation rates
- WG only able to install approximately 30' – 35' per day of 2" diameter main

SERVICE REPLACEMENT

BEGINNING OF PIPES

- Crews were completing a typical service in a single day
- Service replacements were completed using trenchless technology (moling) that allowed the Company to trench under retaining walls, tree roots, landscaping, paved areas, etc. thus avoiding hard-surface restoration and some soft surface restoration

RECENT YEARS OF PIPES

- Suspended the use of moling due to industry issues related to cross bores – required additional labor for added hand digging and vacuum excavation
- Best alternative is insertion of new service in old. Impacted by 2014 PSC directive that requires 24" depth of cover on all facilities, including services, limiting the Company's ability to insert
- Service replacements now average 2 working days rather than 1 increasing support costs such as traffic control

RESTRICTIONS ON WORK HOURS (BY PERMIT)

10-HOUR WORKDAY

TIME	WORK TYPE
7:00 AM	Traffic Control Set Up
7:45 AM	Mobilize Crew Equipment
8:15 AM	Productive Time
9:00 AM	Productive Time
10:00 AM	Productive Time
11:00 AM	Productive Time
12:00 PM	Productive Time
1:00 PM	Productive Time
2:00 PM	Productive Time
3:00 PM	Productive Time
3:45 PM	Demobilize Crew Equipment
4:30 PM	Traffic Control Break Down

6-HOUR WORKDAY

TIME	WORK TYPE
7:00 AM	Non-Permit Hours
8:00 AM	Non-Permit Hours
9:30 AM	Traffic Control Set Up
10:15 AM	Mobilize Crew Equipment
10:45 AM	Productive Time
11:00 AM	Productive Time
12:00 PM	Productive Time
1:00 PM	Productive Time
2:00 PM	Demobilize Crew Equipment
3:00 PM	Traffic Control Break Down
3:30 PM	Non-Permit Hours
4:00 PM	Non-Permit Hours
5:00 PM	Non-Permit Hours

BEGINNING OF PIPES

- Shorter project durations due to longer working hours – up to 7am to 7pm on local roadways (approximately 8 crew productive hours per day)
- Crews able to complete more work in the same day

RECENT YEARS OF PIPES

- Longer project durations due to restricted working hours 9:30 am - 3:30 pm (approximately 4 crew productive hours per day)
- Service replacements now average 2 working days rather than 1 increasing support costs such as traffic control.

SPOILS REMOVAL: SELECT BACKFILL, TRUCKING & DUMP FEES

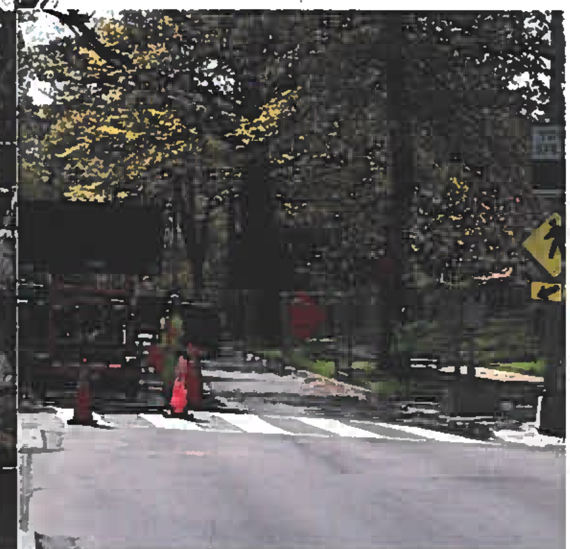
BEGINNING OF PIPES

- Spoils were able to remain onsite and could be used to backfill the excavation
- Main was able to be installed behind the curb, not requiring full select backfill
- Trenchless technology decreased the amount of excavation and spoils required to complete the installation

RECENT YEARS OF PIPES

- Spoils cannot remain on-site, requiring a truck to haul them as well as additional dump fees
  - increased the number of trucks required to maintain productive work
- DDOT requires 100% select backfill in the roadway

TREE PROTECTION



BEGINNING OF PIPES

- Able to use orange flexible fencing around the trees (15 – 30 min install per tree, easy removal – not charged by the contractor)
  - Included only trees within close proximity of excavation

RECENT YEARS OF PIPES

- Chain link fencing required around trees per Urban Forestry (30 mins to install per tree, additional separate crew and equipment for install and removal of chain link fencing)
  - Expanded to include all trees in the work zone, not just at excavation location

TREE PROTECTION (CONT.)

BEGINNING OF PIPES

- Able to use mechanized equipment within tree space as long as roots 2" or larger were not broken (15' of excavation in approx. 20 mins – 1 Operator and 1 Spotter)

RECENT YEARS OF PIPES

- Hand digging or vacuum excavation is required around tree roots within the drip line of the tree per Urban Forestry DDOT permit requirement (10' - 15' of hand excavation in approx. 1 – 2 hours – 2 Laborers)

TREE PROTECTION (CONT.)

BEGINNING OF PIPES

- Company was able install main behind the curb in the green space

RECENT YEARS OF PIPES

- Urban Forestry has driven replacements into the roadway increasing spoils, traffic control, and restoration

DESIGN AND OVERSIGHT

598' of 8" Steel Replacement on Residential Road TCP

BEGINNING OF PIPES

- The Company did not have a dedicated Project Management group
- The Company did not have a dedicated program management group (Construction Program and Strategy Management (CPSM))
- Permits required standard Traffic Control Plans (TCPs) Drawings
- Project estimates were created using a standard unit cost estimate

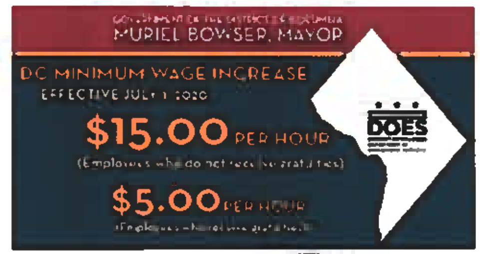
547' of 4" Cast Iron Replacement on Residential Road TCP

RECENT YEARS OF PIPES

- Company added Construction Management function and Project Management Staff, including a Project Manager position dedicated to PROJECT*pipes* and customer escalation line
- Established the CPSM group responsible for the program management of ARP Programs
- Site-specific TCPs required by DDOT
  - TCPs require significant number of detailed pages requiring 4 hours of design work per sheet
- Class III Estimates established as a requirement by the Commission in Order No. 18815

LABOR COSTS

Labor is a Substantial input to Construction Costs



BEGINNING OF PIPES

- Minimum Wage $9.50/hour
- Union presence primarily in skilled trades (operator, pipe fitting, welding, etc.)

RECENT YEARS OF PIPES

- Minimum Wage $15/hour
- DC Paid Family Leave
- Additional Unionized/prevailing wage roles
- Enhanced OQ training/testing requirements

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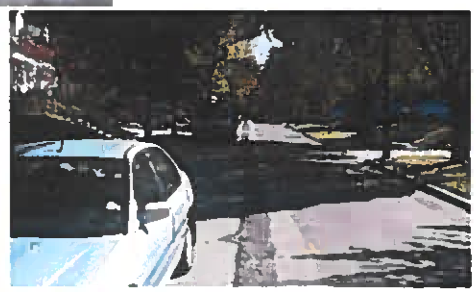
PAVING LIMITS



BEGINNING OF PIPES

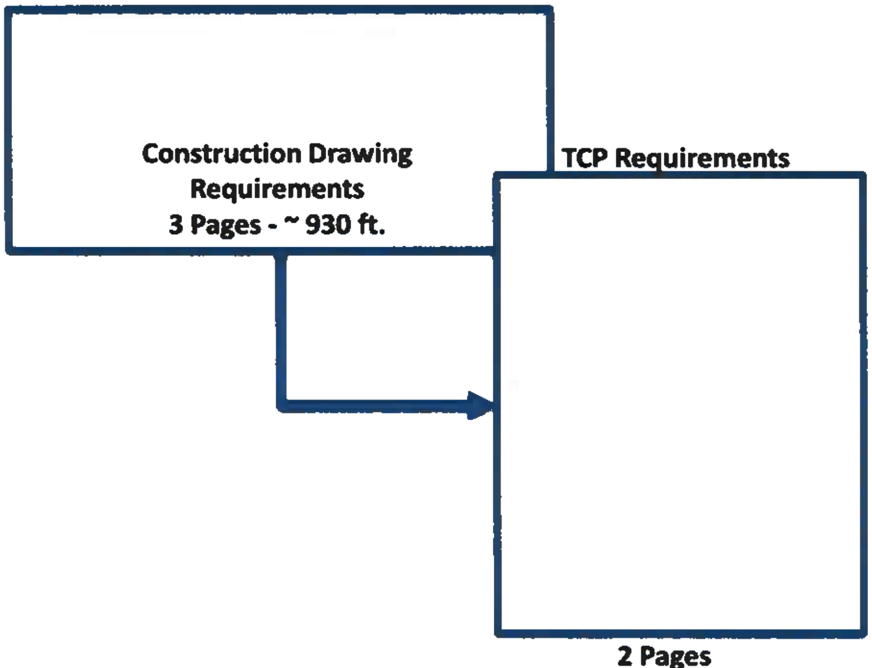
- Relaxed enforcement of restoration requirements from written requirements
- Mix of work was more geared to smaller diameter mains thus smaller excavations, less pavement disturbed
- Company utilized moling which reduced the need to open cut across yards and hard surfaces avoiding additional restoration costs

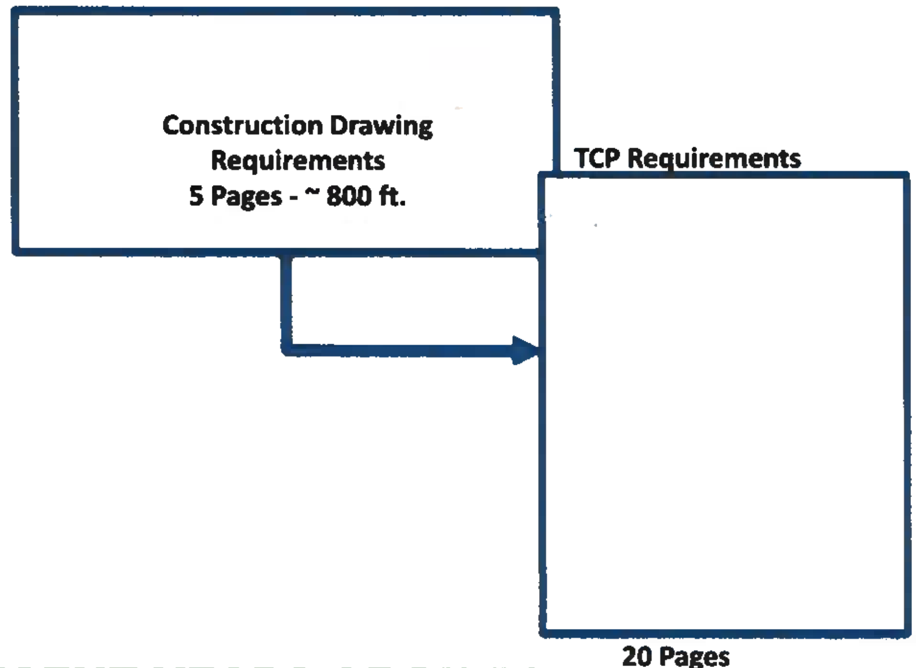
RECENT YEARS OF PIPES

- Urban Forestry has driven replacements into the roadway requiring more expensive hard surface restoration
- Increased DDOT enforcement of restoration requirements
- Due to the project prioritization in PIPES, more large diameter main replacements, necessitating larger excavations, shoring, and larger trenches to be repaired
- Suspending the use of moling resulting in the need to open trench across yards including landscaping and hard surfaces that needed to be replaced

WGL ENERGY ANSWERS. ASK US.

PERMITTING DESIGN REQUIREMENTS





BEGINNING OF PIPES

- Standard TCPs
- Basic designs required as attachment to application
- Longer permit durations, less permit renewals
- Fewer types of permits required

RECENT YEARS OF PIPES

- Site-specific TCPs
- Enhanced design requirements (cover page updates, pressure warnings, regulator awareness zone, sequence of operations, DTOPs review, tree identification)
- DDOT policy changes – multiple occupancy permits, smaller scope per permit, shorter permit duration

TRAFFIC CONTROL

BEGINNING OF PIPES

- Shorter project durations due to longer working hours (7am to 7pm on local roadways (8 crew productive hours per day)
- Use of just cones and arrow boards was an accepted means of traffic control

RECENT YEARS OF PIPES

- Longer project durations due to restricted working hours 9:30 am - 3:30 pm (approximately 4 crew productive hours per day)
- Bicycle and pedestrian traffic cannot be deferred across the roadway
- Additional use of Flaggers are now required as a typical requirement of the TCPs

CURRENT COST CONTROLS

CURRENT COST TRACKING METHODS

- Cost Management Procedure
- Monthly Variance Meetings
- Bi-Monthly ARP Governance Meetings
- Monthly Executive Governance Meetings
- Dedicated resource for PROJECT*pipes* Project Management
- Construction Pay Item Approval Log
- Merger Commitment No. 72 in FC 1142
- Annual Lessons Learned Meetings

REPORTING TOOLS

WR Aging Report

Pipe Complete Report

EAC Graph

Spend and Units Report

Monthly Dashboard (Page 1)

Monthly Dashboards (Page 2)

COMPANY MITIGATION EFFORTS

The Company continues to maintain and enhance its:

1. Cost management and oversight functions
2. Employing the most efficient construction methodology
3. Contracting Approaches
4. Contract unit rate alignment with current requirements

EXTERNAL PARTY ASSISTANCE

1. Coordinate with other utilities and vested partners who are similarly impacted by DDOT regulations and assemble a blue-ribbon committee to provide impact and constituent costs analysis to the D.C. Council directly on any proposed DDOT regulations as well as to suggest improvements to existing regulations.
   - Complete study of Permitting and District Code language
   - Ways to streamline permitting process
2. Enhance the Utility Coordination Committee with utilities operating in the District of Columbia and the District Department of Transportation ("DDOT")
   - Discuss pending regulation changes and impacts with feedback to DDOT and City Counsel
   - Allow for better coordination on projects
   - Engage with other utilities to compare permit approval requirements

RECOMMENDATION IMPACTS ON THE 15% REDUCTION GOAL

1. Obtaining extended working hours on all projects
2. Removal of the chain link fence tree protection requirement, allowing the previously used orange flexible fence
3. Allow the Company to install facilities behind the curb
4. Reasonable traffic control requirements in line with the federal manual on uniform traffic control devices (MUTCD)
5. Allow the Company to stock pile materials.

WE ARE

Washington Gas
A WGL Company

WGL Energy
A WGL Entity

WGL Midstream
A WGL Company

Hampshire Gas
A WGL Company

CERTIFICATE OF SERVICE

I, the undersigned counsel, hereby certify that on this 19th day of May 2021, I caused copies of the foregoing to be hand-delivered, mailed, postage-prepaid, or electronically delivered to the following:

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Cathy Thurston-Seignious

CATHY THURSTON-SEIGNIOUS

ATTESTATION

I, FREDERICK JOHN MORROW III, whose Testimony accompanies this Attestation,

state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Frederick J. Morrow III
FREDERICK J MORROW III

7/24/24
DATE

WITNESS QUENUM
EXHIBIT WG (J)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

PUBLIC VERSION

DIRECT TESTIMONY OF GHISLAINE (CELINE) QUENUM
Exhibit WG (J)
(Page 1 of 1)

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Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF GHISLAINE QUENUM

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Ghislaine (Celine) Quenum. I am Manager, Corporate Accounting at Washington Gas Light Company ("Washington Gas" or "Company"). In my role, I manage and supervise the General Ledger Accounting Team, and oversee the day-to-day activities and period-end close activities performed by the team for Washington Gas. My business address is 1000 Maine Avenue, SW, Washington, D.C. 20024.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have over 20 years of combined experience as an accounting professional, in the United States and my native country, Benin. I hold a Master of Science degree in Finance from The Kogod School of Business at American University, in Washington, D.C., and a Bachelor of Science degree in Accounting from The Smith School of Business at the University of Maryland, College Park. I also hold a Certified Public Accounting certification, currently inactive, in the State of Maryland.

Upon graduating from the University of Maryland, I worked as an intern and then as a staff auditor at Reznick Group (currently CohnReznick) from 2007 to March 2009, where I performed audits of residential and commercial real estate and of affordable housing sponsored by the U.S. Department of Housing and Urban Development ("HUD"). In April 2009, I joined the accounting team of Inova Health System as a staff accountant and maintained the books of the company's flagship hospital – Fairfax Hospital. From December 2010 to August 2017, I was employed by Discovery Communications, Inc., 3net, a subsidiary of Discovery Communications, Inc. ("Discovery"), The National Geographic Society, and The National Academies of Sciences, Engineering, and Medicine. During my tenure at Discovery, I managed the day-to-day accounting of the company's multi-billion dollar advertisement revenue across all the U.S. television networks owned or managed by the company and liaised with my peers in Latin America, Europe, and Asia to consolidate and report global advertisement revenue to management. At the National Geographic Society and the National Academies of Sciences, Engineering, and Medicine, I performed and managed film production and distribution accounting, and project funds' accounting, respectively.

In August 2017, I was hired by Washington Gas as Manager, Corporate Accounting, General Ledger, and I have served in that role since then.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE ANY REGULATORY COMMISSION?

A. No, I have not previously filed testimony before any public utility commissions, but I have assisted various witnesses in rate cases by developing and providing financial information and schedules for their testimonies.

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to describe the transactions between Washington Gas and its affiliates during the test year, the preparation and compilation of the Affiliate Cost of Service Study ("ACOSS")[1] and the Cost Allocation and Inter-Company Pricing Manual for the District of Columbia ("CAM") that Washington Gas filed on April 30, 2024, in Docket No. WGCAM2024-01-G (2023 CAM). My testimony also describes the approach that Washington Gas takes to ensure that the Company is made whole for all services that it renders to its affiliates and that the costs of those services provided to affiliates are not passed through to customers.

Q. WHICH OTHER WASHINGTON GAS WITNESSES ADDRESS AFFILIATE TRANSACTIONS?

A. Company Witness Eric Block describes the nature of the corporate services provided by AltaGas to Washington Gas and demonstrates how these services are necessary, benefit Washington Gas, and are reasonable. Company Witness Patrick Baryenbruch presents the results of his study of AltaGas' charges to Washington Gas, specifically demonstrating the necessity and reasonableness of the charges over the test year. Company Witness Robert Tuoriniemi demonstrates how affiliate costs are reflected in the development of the revenue requirement in this case.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

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[1] *Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Natural Gas Service*, Formal Case No. 1169, Order No. 21939 at 134 (December 22, 2023).

A. Yes, I am sponsoring the following five (5) exhibits in support of my testimony:

- Exhibit WG (J)-1 - the Washington Gas Cost Allocation and Inter-Company Pricing Manual for the District of Columbia for the 12 months ended December 31, 2023, including CONFIDENTIAL Appendix F —Amounts the Utility Allocated or Assigned (Net Costs Billed To/From) for the Twelve Months Ending December 31, 2023, By Type of Cost (PUBLIC version).
- Exhibit WG (J)-2 - the Washington Gas Cost Allocation and Inter-Company Pricing Manual for the District of Columbia for the 12 months ended December 31, 2023, including CONFIDENTIAL Appendix F —Amounts the Utility Allocated or Assigned (Net Costs Billed To/From) for the Twelve Months Ending December 31, 2023, By Type of Cost (CONFIDENTIAL version).
- Exhibit WG (J)-3 - CONFIDENTIAL Appendix F — Amounts the Utility Allocated or assigned (Net Costs Billed To/From) for the Test Year, the Twelve Months Ending March 31, 2024.
- Exhibit WG (J)-4 - Washington Gas's ACOSS for the 12 months ended March 31, 2024, the test year in this case (PUBLIC version).
- Exhibit WG (J)-5 - Washington Gas's ACOSS for the 12 months ended March 31, 2024, the test year in this case. (CONFIDENTIAL version).

IV. OVERVIEW OF THE COMPANY'S INTERNAL AFFILIATE COSTS

i. THE CAM

Q. PLEASE PROVIDE A SUMMARY OF THE CAM.

A. Washington Gas provides to, and receives services from, its affiliates as described in the 2023 CAM, and in accordance with affiliate service agreements approved by the Virginia State Corporation Commission on December 11, 2023, in Case No. PUR-2023-00164. Washington Gas's policy is to directly assign costs to the appropriate affiliate and to allocate costs whenever direct assignment is not reasonably possible. For example, when tracking direct costs is not reasonable because one or more affiliates benefit from the expenditures, costs are allocated either based on the underlying cost drivers for the related costs, or by using a general allocation methodology based on the Modified Massachusetts Formula ("MMF"), as described in the CAM.

Washington Gas maintains a large, centralized database of outside suppliers with whom the Company maintains on-going business activities. Whenever it makes economic sense for the Company to leverage its long-standing business relationships to negotiate contracts that primarily would result in cost savings for the Company and its customers, Washington Gas procures such services for itself and its affiliates, and directly assigns or allocates a portion of the cost to the affiliate that benefited from the service(s). The costs of services provided by Washington Gas to its affiliates are largely equivalent to market prices, and such costs are excluded from Washington Gas's cost of service and are not included in the per book test year in a rate case filing.

Washington Gas also charges its affiliates for all labor, labor-related, and overhead costs on actual time spent by Company employees in providing services to its affiliates. Common and shared costs are allocated to the affiliates that benefited from the common services or assets of Washington Gas.

Q. PLEASE DESCRIBE HOW WASHINGTON GAS HANDLES THE COST OF PROVIDING SERVICE TO AFFILIATES.

A. As stated in the Company's CAM, Washington Gas's policy is to directly assign costs to the appropriate affiliate whenever reasonably possible, and if not reasonably possible, to allocate such costs based on the allocation procedures and methodologies discussed in the CAM.

To accomplish this, Washington Gas developed a transactions coding structure that ensures all charges paid by the Company on behalf of its affiliates are appropriately captured in its Peoplesoft Financial System as intercompany transactions. The Financial system creates intercompany receivables/payables, which are cash-settled by the Company's Treasury Department every month. Additional controls, such as monthly budget to actual variance reviews and analysis, account reconciliations, and allocations' pool reviews, aid in detecting and identifying any charge that may have been mis-coded to Washington Gas.

In addition, in my role as Manager, Corporate Accounting, during the preparation and compilation of CONFIDENTIAL Appendix F "Washington Gas Amounts the Utility Allocated or Assigned by Type of Cost" of the CAM, I review all charges recorded on Washington Gas and the affiliates' books to ensure: 1) that the charges reflected on the affiliates' records are properly excluded from Washington Gas's records, and 2) that the costs of services by Washington Gas are cash-settled. I also review cash paid by Washington Gas to affiliates for services received from the affiliates for accuracy and completeness.

As part of my responsibilities, I also monitor and review allocations pools for adequacy and completeness and perform routine reviews of allocations' design. Whenever necessary, an allocation design may be revised, such as when significant changes are made to the Company's organizational or business structure, to ensure that the results of such allocations capture the change and continue to meet the Company's compliance requirements.

The Company's transactional accounting, direct costs assignment, billing, and allocation are performed through automated processes, thus limiting the risks of errors.

Q. WHAT ARE THE COMPONENTS OF THE WASHINGTON GAS AFFILIATE COST DISTRIBUTIONS?

A. Washington Gas's affiliate costs are categorized as direct labor, labor overheads, direct expenses, and allocations.

Q. PLEASE DESCRIBE THE LEVEL OF THE COMPANY'S AFFILIATE COSTS OVER TIME.

A. CONFIDENTIAL Appendix F "Washington Gas Amounts the Utility Allocated or Assigned by Type of Cost" included in the CAM presents the costs by category (rows) and the amounts allocated or assigned by each affiliate (columns). The costs are separated between services provided by Washington Gas to affiliates and the services provided by affiliates to Washington Gas. The costs are further broken down into categories: Direct Labor, Direct Expenses, Allocation of Common Services, Overheads, and Other Services. Traditionally, CONFIDENTIAL Appendix F of the CAM includes inter-company transactions that do not represent actual services provided. Such transactions are pass-thru transactions and include, but are not limited to, reimbursements, parent company's affiliate share of costs, and remittances received by Washington Gas for the benefit of affiliates. When those transactions are removed from "Total Services Provided to Affiliates by WG" of CONFIDENTIAL Appendix F, the remaining balance represents the true costs of service by Washington Gas to affiliates.

ii. THE ACOSS

Q. PLEASE DESCRIBE WHY THE COMPANY HAS SUBMITTED THE ACOSS, WHICH IS PROVIDED AS EXHIBIT WG (J)-3.

A. Consistent with Commission requirements, Washington Gas submitted an ACOSS filing on May 15, 2024, related to the requirements from Formal Case No. 1169. To support the Commission in this proceeding, Washington Gas has prepared an ACOSS that summarizes affiliate transactions for the 12-months ended March 31, 2024, which is the test year in this case.

Q. HOW DOES THE ACOSS PROVIDE ADDITIONAL TRANSPARENCY?

A. While the actual amounts of shared services are provided in CONFIDENTIAL Appendix F of the CAM, the ACOSS is designed to increase the transparency and granularity of the data provided in the CAM and its appendices. The ACOSS recharacterizes the data presented in CONFIDENTIAL Appendix F of the CAM to "Direct Assigned" and "Allocated" costs to affiliates, and from affiliates, to demonstrate whether the charges had an impact on Washington Gas' operating expenses or were simply pass-thru. "Pass-thru" in this context means that the amounts did not hit the Company's income statement and therefore have no impact on rates.

The ACOSS also provides the FERC accounts and subaccounts impacted by affiliates' transactions on Washington Gas books, the pool and allocation factors used in the computation for each allocation.

Additionally, to provide further clarity on affiliate transactions, Washington Gas provides in the ACOSS, documentation of data and computations used to compute each allocation factor employed in the determination of costs allocated to each affiliate. Such documentation added as appendixes to Exhibit WG (J)-3, include:

- Detailed support calculations for the Benefit Overhead rate for each of the benefit allocations. (Appendix WG(J)-3.1)
- Detailed support calculations of the quarterly MMF factors for WG and all the affiliates (Average Invested Capital, Adjusted Net Revenue, Direct and assigned Labor). (Appendix WG(J)-3.2)
- PeopleSoft System data that presents the amounts billed to each affiliate, and amounts collected. (Appendix WG(J)-3.3)
- PeopleSoft System data for “Pool Total” amounts for Time & Labor Charged to Affiliates. (Appendix WG(J)-3.4)
- PeopleSoft System data showing the calculation for Building Services and Telephone allocations. (Appendix WG(J)-3.5)

Q. HOW IS THE ACOSS PRESENTED IN YOUR DIRECT TESTIMONY?

A. The ACOSS is presented in three parts as described below.

1. Part A - Description of methodologies for cost assignments and allocations.
2. Part B - Summary of charges allocated to and from affiliates, which ties to the March 31, 2024 CONFIDENTIAL Appendix F:
    a. Description of whether the charges had an impact on Washington Gas’s operating expenses or were simply pass-thru;

b. A reconciliation of total operating expenses per the Jurisdictional Cost Allocation Study included in Exhibit WG (F)-2, sponsored by Company Witness Tracey Smith, in this case to what those operating expenses would have been had none of the appropriate charges been allocated out;

c. Whether the charges are direct or associated with an allocation calculation; and

d. The affiliate to which costs are allocated or assigned.

3. Part C - Detailed calculation for each overhead allocation, including affiliate charged, FERC account, description of cost pool and burden rate/allocation factor used.

Q. PLEASE SUMMARIZE THE ACOSS.

TABLE 1

A. Table 1 summarizes the ACOSS for the TME March 31, 2024, which is prepared on a system basis:

	Income Statement	Balance Sheet	Total
O&M Expenses Before Affiliate Activity	$ 853,403,253		
Pass Through Amounts/Cash Payments			
To Affiliates	$ (1,233,076)	$ (51,058,246)	$ (52,291,322)
From Affiliates	-	5,616,850	$ 5,616,850
Total Pass Through Amounts/Cash Payments	(1,233,076)	(45,441,396)	(46,674,472)
Services			
Total Direct Assignments To Affiliates	-	(4,505,469)	(4,505,469)
Total Allocations out to Affiliates	(1,528,400)	(3,340,618)	(4,869,018)
Direct Assignment From Affiliates			
Altagas, Ltd.	1,845,186		1,845,186
SEMCO	748,675		748,675
Hampshire	12,006,572		12,006,572
Total Direct Assignment From Affiliates	14,600,433	-	14,600,433
Total Allocations From ALA	26,051,443	2,207,172	28,258,615
Net Services (Provided To) Received From Affiliates	39,123,476	(5,638,915)	33,484,561
Total Affiliate Transactions	37,890,400	$ (51,080,311)	$ (13,189,911)
Per Book Operation and Maintenance Expense (Formal Case No. 1169, Exhibit WG (F)-3, Schedule EX, page1 of 10, line 2 and 3, column d.)	$ 891,293,653		

Q. PLEASE PROVIDE A BRIEF DISCUSSION OF EACH OF THE COMPONENTS SHOWN IN THIS SUMMARY.

A. The following is a discussion of the individual components reflected in the table above.

Pass-thru Amounts and Cash Payments To/From Affiliates: Consists primarily of payments made by Washington Gas or its affiliates to outside service providers for the benefits of affiliates and cash receipts on behalf of the affiliates; these transactions are recorded by Washington Gas as intercompany receivables/payables and have no impact on its operating expenses.

Services-Direct Assignment To Affiliates: Consists primarily of time and labor charged by Washington Gas employees to affiliates for work performed for the benefits of the affiliates.

Services-Allocations To Affiliates: Consists primarily of payroll overheads, building maintenance costs, shared costs, and other internal costs allocated to affiliates.

Services-Direct Assignment From Affiliates: Consists primarily of internal costs of affiliates charged to Washington Gas for services performed by the affiliates' personnel for Washington Gas.

Q. HAS THE COMPANY MET WITH INTERESTED PARTIES PRIOR TO FILING THIS RATE CASE AND THIS INFORMATION TO EXPLAIN THE ACOSS FRAMEWORK AND COMPUTATIONS?

A. Yes, representatives of the Company met with the Apartment and Office Building Association of Metropolitan Washington (AOBA), District of Columbia Government, U.S. General Services Administration and District of Columbia Water and Sewer Authority to discuss the topics identified in Order No. 22011, as well as to answer any questions they had regarding the CAM and the submitted ACOSS. A Joint Report has been submitted to the Commission which reflects the agreed upon format and content of an ACOSS. The ACOSS appended to my testimony is consistent with the agreed upon format and content referenced in the Joint Report. Additional supporting documentation for the ACOSS is included in the Workpapers filed with the Company's Supplemental Information Filing, which is being filed concurrent with this testimony.

Q. PLEASE SUMMARIZE YOUR TESTIMONY?

A. Washington Gas' interactions with its affiliates have been subject to comprehensive oversight and regulation for decades, as the record in Formal Case No. 1169 confirms. The Company is in compliance with the Commission's Standard of Conduct regulations, annually submits the required CAM, completes the limited engagement review required by Chapter 39, "Affiliate Transactions Code of Conduct," of Title 15, District of Columbia Municipal Regulations and, provides reasonably requested material and explanations during formal rate cases.

In this case, Company Witness Tuoriniemi demonstrates that the Company's books and records accurately account for the reasonable shared services.

Company Witness Baryenbruch details how the shared services provided are traditionally provided by corporate entities, both regulated and unregulated. He further demonstrates the reasonableness of those charges. Company Witness Block describes the nature of the corporate services provided by AltaGas to Washington Gas and demonstrates how these services are necessary, benefit Washington Gas, and are reasonable. Finally, my testimony provides background on the Company preparation and submission of the annual CAM, as well as the Commission-required ACOSS.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Exhibit WG (J)-1

WASHINGTON GAS LIGHT COMPANY

December 31, 2023

Cost Allocation And Inter-company Pricing Manual

Annual Report of Transactions Between Washington Gas Light Company and its Affiliates

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Filed with the Public Service Commission of the District of Columbia

Exhibit WG (J)-1

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SECTION I

Purpose of Manual

Accurately recording operating costs and properly assigning or allocating those costs among Washington Gas Light Company (the Company, the Utility or Washington Gas), its various pre-merger affiliates, including WGL Holdings, Inc. (WGL Holdings, WGLH), Hampshire Gas Company (Hampshire) and other WGLH subsidiaries, and post-merger affiliates (Altagas, Ltd., Petrogas, Inc., Wrangler SPE[1], AltaGas Services (U.S.), Inc. (ASUS), [2]and ASUS' Subsidiaries[3]) are important for accurate financial reporting and accounting for the on-going business activities of each affiliate and the consolidated entity. Note that Sections I-V of this Manual reflect the descriptions and services in-effect for the majority of 2023 and do not reflect the updated services agreements filed in December 2023.

This Cost Allocation Manual (CAM) describes how the cost of shared services are assigned, allocated and billed. Shared services may be provided by Washington Gas to its affiliates, or it may receive certain shared services from its corporate parent or other affiliates. The purpose of the CAM is to document the methodologies and procedures for allocating the costs of shared assets, shared employees and common services between the Utility and its affiliates. The CAM also serves as an aid in identifying the transactions that are taking place between the Utility and its affiliates and assists the various regulators in verifying that appropriate cost allocations are being made. The following appendices are incorporated for reference:

- A Listing of Affiliate Agreements with Washington Gas, affiliate's statement of business, and organizational chart (Appendix A);
- The Officers for Washington Gas and each Affiliate (Appendix B);
- Washington Gas Time and Labor Reporting Procedures (Appendix C);
- Washington Gas General Allocation Methodology (Appendix D);
- Washington Gas Methodology for Overhead Calculations (Appendix E);
- A listing of the transactions allocated or charged directly between the Utility and corporate affiliates (Appendix F).

The CAM summarizes the procedures in place to assign or allocate shared costs. The Vice President and Controller of the Company is responsible for implementing and maintaining processes and procedures designed to achieve the fair and equitable assignment and allocation of costs including: i) designing and maintaining an effective account coding structure, ii) establishing procedures to properly code transactions such as time sheets and invoices, iii) designing and maintaining cost allocation processes and procedures, and iv) monitoring the results of coding and allocation processes for consistency with management intent and for compliance with the laws, rules and regulations of the various jurisdictions within which the Company operates. Business

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[1] Wrangler SPE is a bankruptcy remote special purpose entity ("SPE") established to hold the common equity of Washington Gas as a ring-fencing protection measure (See PUR-2018-00103 filed on July 9, 2018 with the Virginia SCC for purpose and detail of activities of the SPE).

[2] ASUS is the U.S. Holding company for AltaGas's investments in the United States. ASUS indirectly owns 100% of the stock of WGL Holdings and Wrangler SPE, LLC.

[3] On July 6, 2018, Washington Gas's parent, WGL Holdings, merged with AltaGas, Ltd (AltaGas). Post-merger, Washinton Gas began receiving shared corporate services from ASUS, as allocated from AltaGas. As of December 31, 2023, Washington Gas provides certain existing shared services to AltaGas subsidiaries: (1) ASUS; (2) AltaGas Power Holdings (U.S.) Inc. (APHUS); (3) AltaGas Utility Holdings (U.S.) Inc. (AUHUS); (4) AltaGas Marketing (U.S.) Inc. (AMUS); (5) AltaGas Blythe Operations Inc.; (6) Blythe Energy, Inc.; (7) AltaGas Sonoran Energy Inc.; (8) SEMCO Energy, Inc. (SEMCO), and (9) Petrogas, Inc. (Petrogas).

unit managers are charged with the responsibility for compliance with these procedures and for accurate coding of transactions and time by their respective personnel.

SECTION II

Cost Assignment and Allocation Objectives

General Approach

The primary objective of Washington Gas' cost accounting methodology is to create a framework where all costs (labor, overheads, and other expenses) are properly attributed to the entity responsible for generating the expense or receiving the benefit of a service. Washington Gas utilizes a fully distributed cost accounting process that accumulates costs and bills amounts to affiliates. The fully distributed cost approach assigns costs either as direct labor charges (with appropriate overheads) and direct expenses, or as allocations of labor and expenses based on factors that are both relevant and measurable for the individual type of cost. This framework results in an assignment or allocation of costs that places all expenses with the appropriate business entity.

It is the policy of Washington Gas and all its affiliates that costs will be directly assigned to the appropriate affiliate whenever reasonably possible, and that such costs will be allocated whenever direct assignment is not reasonably possible. Direct costs that benefit an affiliate are "assigned and billed" directly to the appropriate affiliate. For common services, tracking direct costs is not reasonable because one or more affiliates benefit from the expenditures. In such cases, these direct costs are allocated based on appropriate allocation factors described herein. Where appropriate, indirect costs are allocated based on the assignment or allocation of the related direct costs. It is the general intent to allocate operational costs to operational affiliates rather than holding companies.

Assignment of Direct Labor and Direct Expense Charges

As described above, Washington Gas's policy and practice is to assign costs directly to the appropriate business entity whenever possible and practicable. All Washington Gas employees' direct labor hours are recorded and captured in WorkDay, Washington Gas's time and expense reporting system, following the Company's Time and Labor Reporting Procedure (see Appendix C for a summary of this procedure). Washington Gas employees code to time sheets in WorkDay, which interfaces directly into the Company's general ledger accounting system, and charge labor costs to the appropriate affiliate company based on actual time spent serving each affiliate. The procedures for calculating and charging overheads are described in Appendix E.

Payroll-related overhead expenses associated with direct labor assigned to the appropriate affiliate are allocated each accounting period based upon the current period's labor costs multiplied by a specific benefit overhead rate. The specific benefit overhead rate is calculated as a percentage of the specific budgeted benefit costs compared to the total budgeted labor costs. Management will compare the actual costs vs. budgeted costs on a periodic basis and adjust the cost to actual cost if the variance exceeds the established threshold.

Direct non-labor expenses are charged directly to the business entity receiving the benefit.

In some cases, Washington Gas will pay an invoice on behalf of an affiliate and will subsequently be reimbursed by that affiliate (Direct reimbursements). Direct reimbursements_are not for actual services provided by Washington Gas. Any payments made by Washington Gas on behalf of an affiliate are cash-settled by the Affiliate in the period immediately following the transactions.

Allocation of Internal Common Services Benefiting Multiple Affiliates

There may be occasions when more than one entity should bear certain costs and under these circumstances, the cost is allocated among the appropriate business entities based on defined factors.

Washington Gas has identified certain departments that perform centralized shared services that clearly benefit Washington Gas and one or more affiliates, including AltaGas' affiliates. Examples of such departments include Accounting and Tax, Corporate Communications, and Finance. By definition, shared services within these functions support multiple affiliates within the corporate function. For these types of services, there is no specific measure, and it is not practical to directly assign departmental costs (or benefits) to individual affiliates. Therefore, an allocation will be utilized. The Company's primary methodology to apply such allocations is described in Appendix D and is referred to as the "General Allocation Method" throughout Section IV of this CAM. The General Allocation Method is based on the Modified Massachusetts Formula (MMF), which fairly apportions the expenses to the benefiting operating affiliates. The calculation is reviewed by Washington Gas management and the methodology is approved by the Company's Vice President and Controller.

For other common services not allocated using the General Allocation Method, a specific allocation measure may be used approved by the Company's Vice President and Controller. In addition, there are other departments within Washington Gas (e.g. Field Operations, Construction, etc.) that may not be specifically addressed in this CAM, whose primary function is to perform utility-based activities. For these departments, their costs are charged directly to the Utility. If one of these departments performed activities benefitting an affiliate, the related costs associated with those activities would be directly assigned or allocated to the affiliate(s) as prescribed in this manual.

Following the merger with Altagas, Washington Gas (and its legacy WGL Holdings affiliates) are allocated certain corporate shared services from AltaGas[4]. These services include costs for internal Board of Directors fees, Executive Committee services, Finance, Accounting and Tax services, Legal and Compliance services, Information Technology and ERP services, Procurement, and Investor Relations activities. The consolidated corporate shared costs are allocated by AltaGas to ASUS, which then allocates those costs to all AltaGas US affiliates, including Washington Gas. Washington Gas is allocated the corporate shared costs for services provided to both Washington Gas and its legacy affiliates. Washington Gas in turn allocates these costs to its legacy affiliates using the General Allocation Methodology, similar to its practice prior

[4] Costs for corporate services are allocated to AltaGas' business units and subsidiaries using a Modified Massachusetts Formula (MMF). AltaGas's MMF uses three factors: (i) EBITDA, (ii) payroll, and (iii) property (net plant, property and equipment, including construction work in progress, materials and inventories).

to the merger close. The allocation of costs from ASUS is done utilizing the same MMF allocation methodology/formula that Washington Gas has historically utilized.

Allocation of Outside Services Provided Benefiting Multiple Affiliates

In certain instances, either WGLH, Washington Gas, ASUS, or AltaGas will engage for services or purchase certain goods and services that benefit one or more of its direct and indirect affiliates (e.g. financial audit fees) – these are typically described as external corporate services. In these cases, the cost of these goods and services is allocated to the affiliate consistent with the benefit(s) received. When possible, specific costs associated with a certain affiliate are charged directly. In other cases, these charges may be allocated across the affiliates using an allocation factor approved by the Vice President and Controller (e.g. MMF). A few specific examples include the following:

Financial Services Costs

Washington Gas, WGL Energy Services, Inc. (WGL Energy Services or WGES), and Hampshire Gas Company (Hampshire Gas, Hampshire) have individual standalone audits or agreed-upon reviews and each entity is charged directly for the costs of its standalone audits/reviews, when billed.

The fees for the audit of WGLH is split 50/50, of which 50% amount is directly charged to WGLH and the other half is allocated to the legacy WGLH affiliates based on their respective MMF rates; it is assumed that the audit of the consolidated entity and its controls (WGLH) benefits all entities. When practical, the charges are allocated to Washington Gas, WGES and other affiliates based on an estimate of the time spent evaluating the controls for each affiliate. Otherwise, they are allocated based using the MMF. Post-merger, the corporate shared service allocation to WGLH will include fees related to the corporate audit of AltaGas which will be allocated to Washington Gas and its legacy affiliates using the MMF.

Other Services

Other departments that provide common services may allocate costs based on the specific nature of the service performed. Examples include Payroll and Benefits, IT Services and Accounts Payable. In these examples, expenses are allocated using a formula based on the measured activity level of the service provided (e.g. number of employees paid; number of payments processed, etc.) as described throughout Section IV of this CAM which addresses the types of services allocated to Washington Gas affiliates.

Board of Directors Fees and Directors Expenses

Washington Gas has its own separate and distinct Board of Directors, with its own separate meetings. The Washington Gas Board of Directors has external Directors. The fees paid to the external Directors or expenses paid on behalf of the external Directors for attending board-related meetings are charged directly to Washington Gas.

Wrangler SPE is wholly owned by WGL Holdings for the single purpose of owning all of Washington Gas' common equity. Wrangler SPE does not have a separate Board of Directors, but has an independent director, "a Golden Share Member", who is an employee of an administration company in the business of protecting SPEs. The golden shareholder is the sole individual to determine whether Washington Gas can file for bankruptcy. WGL Holdings funds all SPE activities through equity infusions.

Corporate governance cost performed by AltaGas' Board of Directors on behalf of all its business units and affiliates are included in the corporate shared service allocation from ALA and are allocated as previously described.

Group Insurance Costs and Other Employee Benefits

Washington Gas uses a 3rd party service provider to administer certain of its group insurance plans, including medical, dental, vision, life, disability, and accidental death and dismemberment insurance. The plans are offered to employees of Washington Gas and certain affiliates. The benefit providers charge either the negotiated monthly premium or the actual cost of claims incurred depending on the structure of the plan. The total cost charged by the benefit providers is either directly assigned to the appropriate affiliate or for those items which are administratively impractical to directly assign, allocated to affiliates based on headcount.

Overheads

Washington Gas has determined that there are a variety of indirect expenses associated with providing common services to affiliated companies that cannot be directly charged to the appropriate entity. These indirect expenses (sometimes referred to as "overheads") include, but are not limited to: fringe benefits; rent, building space maintenance and utilities expenses; communications expenses; transportation costs; and similar expenses. Washington Gas has implemented procedures to accumulate these overheads, and to allocate them to the appropriate affiliate. A full description and methodologies for allocating various overhead pools is included in Appendix E.

Exhibit WG (J)-1

SECTION III
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Exhibit WG (J)-1

CONFIDENTIAL PAGES REDACTED

SECTION IV

Description of Services Provided by Washington Gas Light Company to Affiliates

Introduction

Section IV describes the different types of services provided by various functional areas of Washington Gas to its affiliates, including ASUS, and ASUS' Subsidiaries. For each area, information is provided about the types of services performed and the affiliates receiving these services.

The cost allocation methodology for all labor costs associated with each functional area's services are captured in Washington Gas' Time and Labor Reporting System (see Appendix C) and billed directly to the appropriate affiliate based on actual time spent. Labor that cannot be directly assigned, but benefits the affiliates (e.g. consolidation of financial statements and tax returns) is allocated according to the General Allocation Method described in Appendix D. All fringe benefit overheads follow the labor charges, as described in Appendix E of this Manual. Materials, supplies, consulting fees, and other out-of-pocket expenses are recorded and billed directly to the appropriate affiliate, or allocated according to the General Allocation Method when such expenses cannot be directly assigned. Please refer to Section II for specific types of cost assignments and allocation methodologies. In all cases, detailed information describing the allocation methodology is maintained by the Accounting Department. The allocations are updated on an as-needed basis as determined by the Vice President and Controller, in order to keep the allocation of costs timely, fair, and equitable.

1. Accounting and Tax

The Accounting and Tax departments provide a variety of services for affiliates. These services include performing monthly, quarterly, and annual accounting and reporting close activities. Examples of these activities include:

- Recording original transactions and accruals, depreciation and amortization, and fair value calculations.
- Producing the monthly inter-company bills between Washington Gas and its affiliates.
- Recording overhead allocations, subsidiary earnings, elimination, and consolidation entries.
- Executing control activities (including reconciliations of general ledger and bank accounts). This activity is also supplemented by the Internal Controls and the Internal Audit departments.
- Preparing financial reports for internal use.
- Preparing regulatory reports for external agencies and debtholders, including FERC and state regulatory agencies.
- Providing accounting services for benefit and incentive plans.

Other services include:

- Providing tax planning and tax return preparation services (on a consolidated and stand-alone basis) for both income and general tax requirements.
- Researching and documenting the impact of new accounting standards on existing accounting policies, processes, and procedures.
- Researching and applying the appropriate accounting guidance to new or proposed business transactions and establishing the related accounting and disclosure policies and procedures.
- Engaging an independent accountant to audit the financial statements and review tax returns.

Washington Gas employees who provide accounting services exclusively for affiliates directly charge all of their time to the appropriate affiliates.

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Energy Systems, Inc. (WGL Energy Systems), WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, Washington Gas Resources Corp. (WGR), WGSW, Inc. (WGSW), ASUS, AltaGas, Ltd., APHUS, AUHUS, Wrangler SPE, AMUS, AltaGas Blythe Operations Inc., AltaGas Blythe Energy, Petrogas, and SEMCO.

2. Office of the General Counsel

The Office of the General Counsel (OGC) provides legal representation, advice and paralegal support services for Washington Gas and its affiliates.

Attorneys in the Regulatory Matters group principally provide legal services for Washington Gas and its affiliates, as permitted by law, in relation to federal and local regulatory matters, utility upstream and downstream gas purchase activities, and gas transportation contract activities. For efficiency of assignments, these attorneys may also provide general corporate support services from time to time and the cost of these services is billed to the appropriate affiliate.

Affiliates benefiting[5] from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Energy Systems, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGR, WGSW, ASUS, AltaGas, Ltd., APHUS, AUHUS, Wrangler SPE, AMUS, AltaGas Blythe Operations Inc., AltaGas Blythe Energy, Petrogas, and SEMCO.

3. Strategy, Corporate Development

Individuals in Strategy and Corporate Development provide long-term planning and analysis services to Washington Gas and to affiliates. These groups also pursue new business opportunities as well as strategies for continued company growth and value creation and help develop related business plans for both regulated and non-regulated affiliates. These activities may include investment portfolio planning and tracking, identification, assessment and tracking of general

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[5] Washington Gas will advise and assist the ASUS/APHUS family entities in connection with corporate and legal matters, and with administrative and judicial proceedings involving regulatory, tax, contract, tort, property, insurance, and other matters.

business opportunities, strategic planning (including vision, mission, performance, branding and other outreach activities), and tracking and reporting consolidated results to internal and external stakeholders.

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGL Energy Systems, WGR, WGSW, and SEMCO.

4. Sustainability

Individuals in the Sustainability Department work with others throughout the Utility to promote and track resource stewardship and carbon reduction activities. They are also the principal sponsors of utility customer energy efficiency programs and activities and serve on multiple regional policy groups and task forces that focus on efficient energy utilization and greenhouse gas emissions reductions.

The department's activities primarily serve Washington Gas but, in limited instances, may also benefit the following affiliates: WGL Holdings, WGL Energy Services, WGL Energy Systems, and SEMCO.

5. Internal Audit

The Internal Audit department regularly performs various types of audits, appraisals and examinations of company operations and records related to all Washington Gas affiliates. These reviews are completed to determine the adequacy of internal controls and the integrity of reports, records, procedures, programs, and compliance activities. The department assists management in their CSOX compliance activities for compliance with Canadian Bill 198, including internal control assessments.

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGR, WGSW, ASUS, AltaGas, Ltd., APHUS, AUHUS, Wrangler SPE, AMUS, AltaGas Blythe Operations Inc., Blythe Energy, and SEMCO.

6. Finance

In addition to accounting and tax, the Finance unit provides a variety of additional services to Washington Gas and all the affiliates. These additional services are broadly grouped into the following functional areas: risk management; asset optimization; and treasury/cash management.

The Treasury function oversees the investment portfolio of the defined benefit pension plan, post-retirement medical and insurance benefit plans and the 401(k) plan. The treasury function regularly performs cash planning and cash management activities for all affiliates. Services can include various cash management functions. Specifically, individuals in this department perform cash application, and daily cash planning, prepare rating agency presentations, establish credit facilities, and evaluate alternative forms of financing.

The Risk Management group evaluates internal and external market, credit, enterprise, insurance, and certain operational risk factors for all affiliates. The function performs trade/transaction valuation and independent analysis of new initiatives, investment opportunities and non-standard transactions, assesses current and potential counterparty credit risk, negotiates various types of insurance coverage and processes insurance claims information, performs trade confirmation, facilitates and negotiates trading contract language, and has responsibility for developing various corporate risk management policies to govern the risks identified above. The group also prepares presentations for the Risk Management Committee and reviews policy violations, market-to-market movements, new transaction assessments, counterparty exposure, as well as other items, as appropriate. On occasion, insurance coverage premiums are obtained on a consolidated basis for price advantages, but arrangements are made for premiums to be billed directly to the participating companies of Washington Gas and its affiliates.

The Financial Planning function oversees all activities related to budgeting, forecasting, and allocations of the company financial resources for different business purposes. The group assists with the planning of the company's financial resources to meet both short-term and long-term strategic goals and objectives. Specific individuals in that group collaborate with individuals in functional areas across the organization to gather valuable information used in the planning, budgeting, and forecasting process.

All the costs of these functions can be charged specifically to an individual affiliate or allocated to all affiliates.

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Energy Systems, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGR, WGSW, ASUS, AltaGas, Ltd., APHUS, AUHUS, Wrangler SPE, AMUS, AltaGas Blythe Operations Inc., AltaGas Blythe Energy, Petrogas, and SEMCO.

7. Gas Supply Operations

Gas Supply Operations provides a variety of services for Washington Gas and for Hampshire, a federally regulated utility. Some specific items of work related to Hampshire include (1) the calibration, certification and repair of various instruments and equipment on Hampshire facilities; and (2) the operation and maintenance of the supervisory control and data acquisition (SCADA)[6] and microwave systems. Procurement of certain supplies for operations and maintenance may be necessary for each of these areas.

The affiliate benefiting from these services is Hampshire.

[6] SCADA is a system for remote monitoring and control that operates Washington Gas facilities with coded signals over communication channels.

8. Corporate Public Policy

Corporate Public Policy directs Washington Gas and its affiliates' public policy activities that include information regarding various aspects of the business operations and financial results. Corporate Public Policy also handles philanthropic activities and government affairs. The costs of executing these business activities may be charged directly to a specific affiliate or the costs can be allocated, depending on the specific circumstances.

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGL Energy Systems, WGR, and WGSW.

9. Corporate Communications

Corporate Communications directs Washington Gas and its affiliates' internal and external communications, media relations, and activities that include information regarding various aspects of the business operations and financial results. Corporate Communications also manages community relations. The costs of executing these business activities may be charged directly to a specific affiliate or the costs can be allocated, depending on the specific circumstances.

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Energy Systems, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGR, WGSW, ASUS, AltaGas, Ltd., APHUS, AUHUS, Wrangler SPE, AMUS, AltaGas Blythe Operations Inc., AltaGas Blythe Energy, and SEMCO.

10. Utility Operations, Engineering, Construction and Safety

Individuals in this department provide support for capital improvements, replacement projects, as well as operations and maintenance projects. Services provided also include compliance support, storage inventory projects, well down-hole analysis support, pipeline pigging support and analysis, design and engineering services, material specifications and procurement support, project management and construction support, and preparing comprehensive operating/facility drawings and equipment books. This function primarily charges Washington Gas.

Affiliates benefiting from these services are Hampshire, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, and SEMCO.

11. Executive Officers

In their capacity as officers of WGL Holdings, Inc., and in the capacity of an officer providing common services (such as the Controller, the SVP of Finance, and the General Counsel), certain officers of Washington Gas act on behalf of or as officers and/or directors of one or more of the affiliated companies (including WGL Holdings). Generally, the roles of these individuals are principally limited to providing specialized expertise (e.g., treasury or accounting management) and are not involved in the day-to-day operations of the affiliates. In some circumstances, officers only work related to Washington Gas and these officers charge their costs directly to Washington Gas. If circumstances warrant, all officers will direct charge any individual affiliate or the officers will directly allocate their costs to all affiliates.

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGL Energy Systems, WGR, WGSW, ASUS, AUHUS, Wrangler SPE, and SEMCO.

12. Payroll and Benefits

A 3rd party service provider engaged by the Utility provides payroll-related services for Washington Gas and its affiliates, and services for the administration of benefits for all Washington Gas employees and employees of the non-utility subsidiaries who are covered by Washington Gas benefit plans. Payroll-related services include all functions related to producing a biweekly payroll, including withholding voluntary and mandatory deductions and remittance to third parties, preparation of employee year-end wage and tax statements, and preparing and remitting tax deposits for federal withholding, state withholding and federal and state unemployment taxes.

Management has retained employees to oversee outsourced payroll and benefits administration activities and support payroll and benefit administration activities not performed by the 3rd party service provider (e.g., time entry, time off and time approval processes, garnishment documentation, processing death claims, Tuition Reimbursement program). In certain instances, the individuals in the retained organization may work on issues related to the common services provided to affiliates of Washington Gas, or such effort may relate directly to one of the affiliates. The charges from the Retained Management and outsourced service provider are charged to the appropriate subsidiary either directly or through an allocation of charges as described herein, depending on the nature of the outsourced activity.

Affiliates benefiting from these direct services are Hampshire, WGL Energy Services, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGL Energy Systems, AltaGas Blythe Operations Inc., ASUS, Petrogas, and SEMCO.

13. Information Technology Services

Third party services are engaged by the utility to perform a variety of Information Technology services for Washington Gas and its affiliates. Specifically, these services include the procurement and installation of computer hardware and software systems, as well as implementation, administration and maintenance of network security systems (i.e., firewall processes), troubleshooting and diagnostics of computer hardware and software applications, database administration and database support. Additionally, 3rd party servicers provide some aspects of software application support, and hardware support, including technical enhancements and configuration management (i.e., Help Desk). 3rd party servicers also support the acquisition, installation, and operation of telecommunications equipment.

Third party servicers provide ongoing management support and technical enhancements to the human resources, financial, and supply chain modules of the PeopleSoft systems for Washington Gas. Specifically, this support includes developing application programs and system enhancements to existing programs. On occasion, the 3rd party servicers will also provide application program support in the development of new business transactions where such would be economically feasible.

Third party servicers provided relationship management troubleshooting and diagnostics services as appropriate. Third party servicers also provide network system support. Specifically, this support includes the installation and support of network servers and related infrastructure.

Management has retained employees to oversee outsourced activities, including IT, in certain instances, the individuals in the Retained Management Organization may work on issues related to the common services provided to affiliates of Washington Gas, or such effort may relate directly to one of the affiliates. The charges from the Retained Management and outsourced provider are charged to the appropriate subsidiary either directly or through an allocation of charges as described herein, depending on the nature of the outsourced activity.

When appropriate, Washington Gas may obtain funding from an affiliate to pay for the acquisition and capital costs of certain computer systems that benefit Washington Gas and the affiliate, resulting in the co-ownership of certain IT systems. In other instances, for systems used in common services, costs are allocated as described in Appendix E of this Manual.

Affiliates benefiting[7] from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Energy Systems, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGR, WGSW, ASUS, AltaGas, Ltd., APHUS, AUHUS, Wrangler SPE, AMUS, AltaGas Blythe Operations Inc., AltaGas Blythe Energy, and SEMCO.

14. Cash Receipts / Cash Disbursements

Washington Gas employees provide disbursement services to affiliates. Disbursement services include processing of vouchers and executing vendor payments, remittance processing, and Purchasing Card processing & administration and resolving payment posting issues (i.e., providing copies of canceled checks) and procurement administration. Washington Gas employees process automated clearing house (ACH) and wire transfers for affiliates, and charge their time, accordingly, as described above. Costs associated with vouchers processing are allocated based on time spent on each affiliate's activities. Likewise, costs associated with cash management are allocated on a formula based on the average amount of time spent on Washington Gas activities vs. affiliate activities.

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[7] Washington Gas will provide the ASUS/APHUS family entities program management and administration of services to the Affiliates for their individual IT systems, as well as assist the Affiliates in the development and execution of strategic improvements to the infrastructure and application portfolio Washington Gas will also provide limited application maintenance and development.

A 3rd party service provider performs cash collection activities for affiliates. Cash receipts related services provided by the 3rd party provider include lockbox administration and processing, and cash application.

Management has retained employees to oversee activities performed by the outsourced provider or affiliates for cash receipts, and in certain instances, the individuals in the retained organization may work on issues related to the common services provided to affiliates of Washington Gas, or such effort may relate directly to one of the affiliates. The charges from the Retained Management, affiliate provider and outsourced provider are charged to the appropriate subsidiary either directly or through an allocation of charges as described herein, depending on the nature of the outsourced activity.

All the costs of these functions can be charged specifically to an individual affiliate or allocated to all affiliates. Affiliates also perform these services for themselves whenever customers send payments directly to the affiliate.

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Energy Systems, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGR, WGSW, ASUS, AltaGas, Ltd., APHUS, AUHUS, Wrangler SPE, AMUS, AltaGas Blythe Operations Inc., and AltaGas Blythe Energy, Inc.

15. Human Resources

A 3rd party service provider engaged by the Utility provides Human Resources services including, employee data management and performance management administration services for Washington Gas employees and employees of the non-utility subsidiaries.

Management has retained employees to oversee outsourced human resources activities. In certain instances, the individuals in the retained organization may work on issues related to the common services provided to affiliates of Washington Gas, or such effort may relate directly to one of the affiliates.

Other Human Resource-related services, including Talent Management, candidate sourcing, background screening, relocation, training, compensation administration, HRIS reporting, and data analytics, advice, counsel, and labor contract administration are provided to the affiliates by the retained Human Resources.

Costs incurred by Washington Gas or by the 3rd party service provider are billed directly to the appropriate affiliate based on actual time spent or based on an allocation when more than one affiliate is the beneficiary of the services. In some cases, the costs associated with this activity are billed to affiliates based on the number of affiliate employees in the service bucket as a percentage of the total.

Affiliates benefiting from these direct services are Hampshire, WGL Energy Services, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGL Energy Systems, ASUS, AltaGas, Ltd., APHUS, AltaGas Blythe Operations Inc., AltaGas Blythe Energy, Inc., Petrogas, and SEMCO.

16. Supply Chain

The Supply Chain group works with Washington Gas and the affiliates to procure and establish contracts for the purchase of goods, such as but not limited to office supplies and when applicable purchase of services from third party providers.

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Energy Systems, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGR, WGSW, ASUS, AltaGas, Ltd., APHUS, AUHUS, Wrangler SPE, AMUS, AltaGas Blythe Operations Inc., AltaGas Blythe Energy, Inc., and SEMCO.

17. Regulatory Affairs

The Regulatory Affairs group works with Washington Gas and the affiliates to ensure compliance with tariff requirements applicable to their operations. Specific services include regulatory review of tariffs and service agreements, compliance with federal and jurisdictional regulatory requirements and regulatory strategy development.

Affiliates benefiting from these services are WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, Hampshire, and SEMCO.

18. Facilities and Transportation

Washington Gas advise and assist the Affiliates in matters relating to Facilities and Transportation, including: Real Estate Services (identifying and negotiating property leases and property management contracts, Design/Build, Interior designing, procurement of furniture), Facilities Operation & Maintenance Services (overseeing property maintenance and charges for tenants), and Fleet Management Services (negotiating sales, purchases and lease of transportation equipment and coordinating maintenance services).

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGL Energy Systems, WGR, WGSW, and ASUS.

19. Security

Washington Gas advise and assist the Affiliates in security matters, including security risk assessments for physical locations, employee awareness and training, as well as services and support necessary to ensure the proper installation and maintenance of such systems.

Affiliates benefiting from these services are WGL Holdings, Hampshire, WGL Energy Services, WGL Sustainable Energy, LLC, WGL Midstream MVP, LLC, WGL Energy Systems, WGR, WGSW, ASUS, and SEMCO.

SECTION V

Description of Services Provided To Washington Gas Light Company by Affiliates

Storage services

Hampshire Gas operates an underground natural gas storage facility that provides gas storage services to Washington Gas that solely benefits the utility customers of Washington Gas. Hampshire is regulated by the Federal Energy Regulatory Commission (FERC) and the pricing of its services are subject to the FERC approved tariff and charged 100 percent to Washington Gas.

AltaGas Corporate Shared Services[8]

AltaGas Ltd. (AltaGas) provides general corporate services to Washington Gas. The consolidated corporate shared costs are allocated by AltaGas to ASUS. The CAD: USD exchange rates[9] used to determine the allocation from AltaGas to ASUS is provided monthly and ASUS translates the allocated costs (in Canadian dollars) to US dollars. Those exchange rates are the monthly average exchange rates for each particular month and are obtained from Bank of Canada. ASUS then uses Washington Gas' MMF allocation methodology to further allocate the costs to its affiliates WGL Holdings, APHUS, and SEMCO. The portion of shared costs allocated to WGL Holdings is further allocated to Washington Gas, and the pre-merger affiliates of WGL Holdings.

The services provided by AltaGas include:

Accounting and Tax

Services include general accounting and tax matters required to maintain the publicly listed company status, including preparation of consolidated financial statements, management discussion and analysis and other financial analysis required for securities filings and coordination of external audits. Other services include implementing internal controls framework and procedures; assisting and advising business units with annual planning and budget cycle to ensure forecasts are incorporated in strategic planning; and coordinating corporate tax audits, advising on overall tax compliance, tax planning and cross-border transfer tax planning and advice.

Finance

Services include treasury matters such as managing capital structure and financial management, consolidated cash flow forecasts and liquidity management; implementing corporate risk management such as insurance services; and investor relations and stakeholder communications.

Legal and Compliance

Services include general legal service and advice to all business units, including regulatory, general corporate matters, governance, compliance, disclosure and registration requirements, management of external counsel and corporate secretarial services. Compliance

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[8] At times, AltaGas enters into contract arrangements with third-party service providers to leverage the cost advantage associated with the negotiation of larger scale contracts for the benefits of its affiliates. The charges associated with such contracts are paid for by AltaGas, which then seek reimbursements from the affiliates, on a dollar-for-dollar basis, for the services received by the affiliates. These charges are separate and distinct from costs incurred by AltaGas in performing corporate services and are considered direct reimbursements.

[9] CAD:USD rates from January through December 2023: $1.3422, $1.3450, $1.3682, $1.3485, $1.3520, $1.3288, $1.3215, $1.3485, $1.3535, $1.3717, $1.3709, and $1.3431, respectively.

services include developing an annual internal audit plan to examine, evaluate and report on the adequacy, effectiveness, and efficiency of the systems of internal controls across operations.

Information Technology Services

Services include developing and maintaining organization-wide IT strategy, standardization, policies, and practices, to ensure access to information assets is safeguarded; establishing strategic IT procurement procedures and practices and leveraging economies of scale for favorable purchasing terms and conditions; and providing information system application training and day-to-day support to employees.

Board of Directors

Services include overall supervision and stewardship; strategic business and corporate advice; governance; succession planning; and oversight of principal business risks.

Executive Committee

Services include strategic management oversight of all business units; setting strategic direction on financial planning, capital access, business and capital risk management and organizational structure; and leadership and guidance to optimize business.

Office Services and Corporate Resources

Services include providing a safe and secure workplace environment with the necessary facilities for employees to perform corporate services; managing savings initiatives to enable employees to benefit from the resulting economies of scale; facilitating organization- wide employee outreach communication; supporting executives' and employees' compensation plan design; pension (including retirement savings) and benefits management; union relationship management; environmental and occupational health and safety compliance; and administration of organization-wide policies, including the code of business and ethics ("COBE") annual certification process.

SEMCO Corporate Services

Washington Gas receives certain corporate services from SEMCO Energy, Inc., (SEMCO), a subsidiary of ASUS. The charges represent employees' time and labor, and related overhead costs, for work performed for Washington Gas, or allocations to Washington Gas for work performed for the US Utilities, and some reimbursable travel expenses. SEMCO also provides accounts payable services that are charged to Washington Gas based on time spent by SEMCO's employees on Washington Gas-related activities.

Accounts Payable services provided by SEMCO to Washington Gas and its affiliates include procurement card administration and expense processing, vendor management, invoice, and payment processing, as well as customer refunds. The Company expects this change will optimize and streamline the overall cash disbursements process.

APPENDIX A

A. Washington Gas Affiliate Agreements, Affiliate's Statement of Business, and Organization Chart

Exhibit WG (J)-1

Listing of Affiliate Agreements with Washington Gas
(As of March 31, 2024)

Name of Affiliate	Contract Type	Virginia State Corporation Commission SCC Case #/Date of Final Order	**Expiration Date**
WGL Holdings, Inc.; Washington Gas Resources Corp.; Hampshire Gas Company; WGL Energy Services, Inc.; WGL Energy Systems, Inc.; WGL Sustainable Energy LLC; WGL Midstream MVP, LLC; WGSW, Inc. AltaGas Services U.S.; AltaGas Power Holdings (U.S.) Inc.; AltaGas Utility Holdings (U.S.) Inc.; Wrangler SPE, LLC; Wrangler 1 LLC; SEMCO Energy, Inc.; AltaGas Marketing (U.S.) Inc.; AltaGas Blythe Operations, Inc.; AltaGas Blythe Energy Inc.; AltaGas Sonoran Energy Inc.; AltaGas Ltd.; Petrogas, Inc.; Petrogas Energy Corp.;* IXL Propane, Inc.;* Petrogas West, LLC;* Mountain View Property Management;* Seaside Management, Inc.;*	Service Agreement	No. PUR-2023-00164/December 11, 2023**	December 10, 2028
Affiliates (Tax Sharing Agreement)	Tax Sharing Agreement	No. PUR-2023-00164/December 11, 2023**	December 10, 2028
AltaGas Ltd./ASUS	Service Agreement (for centralized corporate services)	No. PUR-2023-00164/December 11, 2023**	December 10, 2028
WGL Energy Systems, Inc.	Project Management Services	No. PUE-2015-00130/March 3, 2016	March 19, 2026
Washington Gas Energy Services, Inc.	Gas Supplier Agreement	No. PUA980005/July 15, 1998	

* New affiliate additions in Service Agreement No. PUR-2023-00164.
** Shared Service Agreement No. PUR-2023-00164 replaced PUR-2018-00130, PUR-2020-00058, PUR-2020-00224, PUR-2019-00055, PUR-2017-00177, and PUR-2022-00060.

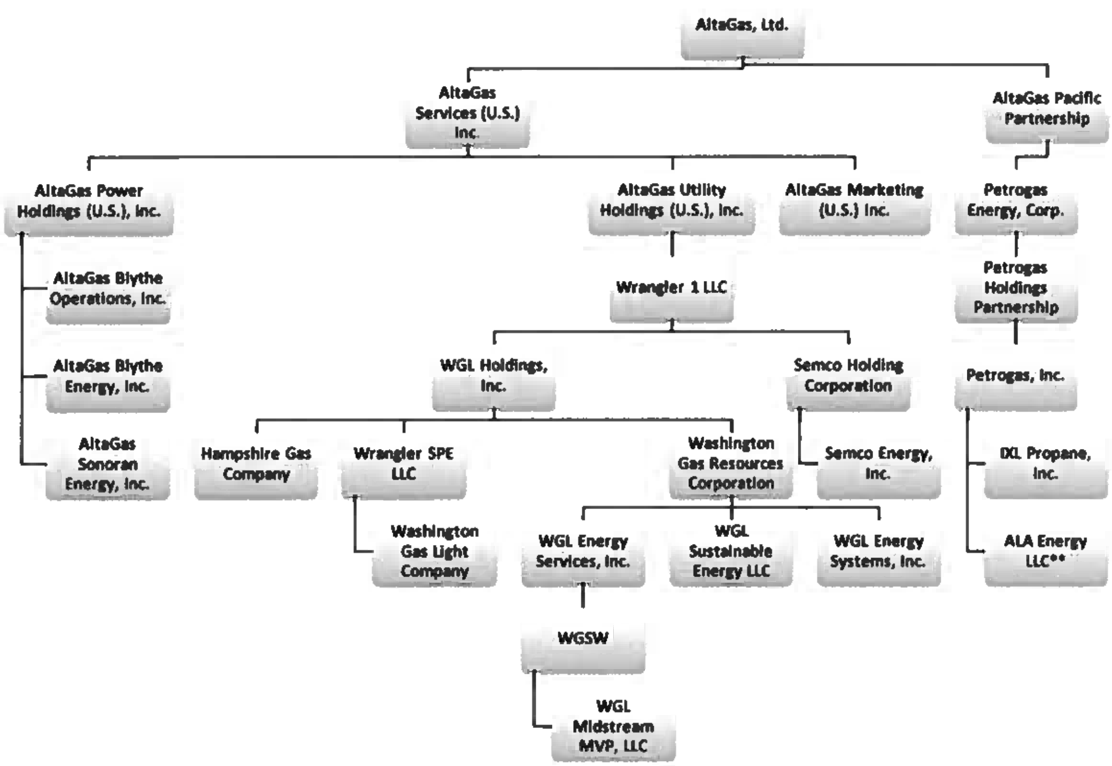
Exhibit WG (J)-1

APPENDIX A (con't)

Washingon Gas Affiliates' Statement of Business	
Affiliate Name	**Statement of Business**
WGL Holdings, Inc.	Holding Company - Direct Subsidiaries are: Wrangler SPE, LLC, Hampshire Gas Company, and Washington Gas Resources Corporation.
Wrangler SPE, LLC	Holding Company of Washington Gas Light Company; A bankruptcy remote special purpose entity which owns all the shares of the common stock of Washington Gas.
Wrangler 1, LLC	A subsidiary of AltaGas Utility Holdings (U.S.) Inc. At the completion of the Merger, Wrangler 1 assumed ownership of 100% of the stock of WGL Holdings, Inc.
Hampshire Gas Company	Underground gas storage operator that provides storage services to Washington Gas Light Company under a FERC approved interstate storage service tariff.
Washington Gas Resources Corporation	Holding Company for certain Non-Utility Operations.
WGL Energy Services, Inc.	Retail energy marketer supplying natural gas and electricity to residential, commercial, and industrial customers.
WGL Energy Systems, Inc.	Historically provided commercial energy efficient and sustainable solutions to government and commercial clients. The majority of the affiliate's assets have been sold.
WGL Sustainable Energy LLC	Formed to hold assets not transferred in connection with the sale of WGL Midstream, Inc. on April 23, 2021.
WGL Midstream MVP, LLC	A holding entity for certain interstate pipeline investments.
WGSW, Inc.	Holding Company of WGL Midstream MVP, LLC.
AltaGas, Ltd.	A Canadian corporation and parent company of AltaGas Services (U.S.) Inc.
AltaGas Services (U.S.) Inc.	U.S. Holding Company for AltaGas's investments in the United States.
AltaGas Power Holdings (U.S.) Inc.	Holding company of AltaGas' U.S. power generation facilities.
AltaGas Utility Holdings (U.S.) Inc.	Holding Company of Wrangler 1, LLC.
AltaGas Marketing (U.S.) Inc.	Owns transportation and marketing contract of natural gas in the U.S. for the non-utility business.
AltaGas Blythe Operations Inc.	Operating company of Blythe Energy Inc.
AltaGas Blythe Energy, Inc.	Owns and operates a 507 MW combined cycle gas fired power plant in Blythe, California and a 67 mile transmission line.
AltaGas Sonoran Energy Inc.	Owns approximately 75 acres of land adjacent to the plant owned by AltaGas Blythe Energy, Inc.
SEMCO Energy Inc.	Regulated Public Utility with primary business in the transmission, distribution, and storage and sale of natural gas.
Petrogas, Energy Corp.	Indirect wholly owned subsidiary of AltaGas, Ltd. which owns and operates midstream facilities and logistic networks in North America.
Petrogas, Inc.	Indirect subsidiary of Petrogas Energy Corp. which provides marketing services to the Petrogas Energy Corp. group entities which provide crude oil and natural gas liquids marketing and supply services to propane retailers, refiners, and petrochemical producers across North America. Holding Company of IXL Propane, Mountain View Property Management, Petrogas West, LLC, and Seaside Management, Inc.
IXL Propane, Inc.	Propane trucking company that transports propane in the Pacific Northwest.
Petrogas West, LLC	Owns LPG export and storage facilities and infrasstructures in Washington State.
Mountain View Property Management	Management company for certain landholdings in Washington State.
Seaside Management, Inc.	Oversees the dock and aquatic lease in Washington State.

APPENDIX A (con't)

CONDENSED COMPANY STRUCTURE *
As of March 31, 2024



** Primarily reflects only Affiliates that have Service Agreements with Washington Gas Light Company. Note that Mountain View Property Management and Seaside Management, Inc. have both merged with Petrogas, Inc., effective December 18, 2023.*
*** Formerly Petrogas, West LLC; name changed to ALA Energy LLC, effective March 19, 2024.*

APPENDIX B

B. Washington Gas & Affiliates Officers

Exhibit WG (J)-1

WASHINGTON GAS LIGHT COMPANY
1000 Maine Avenue, SW
Washington, DC 20024

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	President
Mallik Angalakudati	Senior Vice President, Strategy and Innovation
JP Arcuri	Senior Vice President, Chief Digital Officer
Laura Boisvert	Senior Vice President, Operations
Karen M. Hardwick	Senior Vice President and General Counsel
Peter Ledig	Senior Vice President, Commercial, Utilities
M. Colleen Starring	Strategic Advisor
James Steffes	Senior Vice President, Regulatory
Wendy Zelond	Senior Vice President, Finance and Treasurer
Michelle Musgrove	Vice President, Customer Experience
Krista Nufrio	Vice President, Business Excellence
Tracy L. Townsend	Vice President-Construction, Compliance and Safety
Colin Bond	Interim Vice President and Controller
Debbi Jarvis	Vice President and Chief Communication Officer
David Lewis	Vice President, Business Development
Kevin Murphy	Vice President of Asset Management, Engineering and Supply
Mark Shaver	Vice President, Strategy Execution
Paul Zohorsky	Vice President, Operations
Jimmi Duce	Corporate Secretary

APPENDIX B (con't)

AltaGas Services (U.S.) Inc.
1000 Maine Avenue, SW
Washington, DC 20024

OFFICERS
As of March 31, 2024

Vernon Yu	President and Chief Executive Officer
Donald M. "Blue" Jenkins	President Utilities
James Harbilas	Executive Vice President and Chief Financial Officer
Peter Ledig	Senior Vice President Power
Marc Simone	Senior Vice President Utilities
Ann L. Forster	Vice President Administrative Services
Wendy Zelond	Treasurer
Jimmi Duce	Corporate Secretary

AltaGas Marketing (U.S.) Inc.
1000 Maine Avenue, SW
Washington, DC 20024

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	President
Peter Ledig	Senior Vice President Power
Peter Karl	Vice President
Wendy Zelond	Treasurer
Jimmi Duce	Corporate Secretary

AltaGas Power Holdings (U.S.) Inc.
1000 Maine Avenue, SW
Washington, DC 20024

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	President
Peter Ledig	Senior Vice President Power
Wendy Zelond	Treasurer
Jimmi Duce	Corporate Secretary

Exhibit WG (J)-1

AltaGas Utility Holdings (U.S.) Inc.
1000 Maine Avenue, SW
Washington, DC 20024

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	President
Marc Simone	Senior Vice President
Wendy Zelond	Senior Vice President and Treasurer
Ann L. Forster	Vice President Administrative Services
Mark A. Moses	Vice President Finance
Jimmi Duce	Corporate Secretary

WGL Holdings, Inc.
1000 Maine Avenue, SW
Washington, DC 20024

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	President
Wendy Zelond	Senior Vice President, Finance, and Treasurer
Karen M. Hardwick	Senior Vice President and General Counsel
Peter Ledig	Senior Vice President, Commercial, Utilities
Krista Nufrio	Vice President
Colin Bond	Vice President and Controller
Jimmi Duce	Corporate Secretary

Wrangler SPE LLC
1000 Maine Avenue, SW
Washington, DC 20024

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	President
D. James Harbilas	Executive Vice President
Wendy Zelond	Vice President and Treasurer
Jimmi Duce	Corporate Secretary

APPENDIX B (con't)

Hampshire Gas Company
8614 Westwood Center Drive, Suite 1200

Vienna, VA 22182

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	President
Wendy Zelond	Senior Vice President, Finance and Treasurer
Krista Nufrio	Vice President
Colin Bond	Vice President and Controller
Kevin Murphy	Vice President Asset Management, Engineering and Supply
Jimmi Duce	Corporate Secretary

Washington Gas Resources Corp.
8614 Westwood Center Drive, Suite 1200
Vienna, VA 22182

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	President
Peter Ledig	Senior Vice President, Commercial
Wendy Zelond	Senior Vice President, Finance and Treasurer
Krista Nufrio	Vice President
Colin Bond	Vice President and Controller
Jimmi Duce	Corporate Secretary

WGL Energy Services, Inc.
8614 Westwood Center Drive, Suite 1200
Vienna, VA 22182

OFFICERS
As of March 31, 2024

Peter Ledig	President
Wendy Zelond	Senior Vice President, Finance and Treasurer
Kevin Anderson	Vice President, Operations
Mike McGinn	Vice President, Sales
Clinton S. Zediak, Jr.	Vice President, Growth & Innovation
Krista Nufrio	Vice President
Colin Bond	Vice President and Controller
Jimmi Duce	Corporate Secretary

APPENDIX B (con't)

WGL Energy Systems, Inc.
8614 Westwood Center Drive, Suite 1200

Vienna, VA 22182

OFFICERS
As of March 31, 2024

Peter Ledig	President
Wendy Zelond	Senior Vice President, Finance and Treasurer
Krista Nufrio	Vice President
Colin Bond	Vice President and Controller
Jimmi Duce	Corporate Secretary

WGSW, INC.
8614 Westwood Center Drive, Suite 1200
Vienna, VA 22182

OFFICERS
As of March 31, 2024

Peter Ledig	President
Wendy Zelond	Senior Vice President, Finance and Treasurer
Krista Nufrio	Vice President
Colin Bond	Vice President and Controller
Jimmi Duce	Corporate Secretary

AltaGas Blythe Operations Inc.
1000 Maine Avenue, SW
Washington, DC 20024

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	President
Peter Ledig	Senior Vice President Power
Wendy Zelond	Treasurer
Jimmi Duce	Corporate Secretary

APPENDIX B (con't)

Blythe Energy Inc.
1000 Maine Avenue, SW
Washington, DC 20024

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	President
Peter Ledig	Senior Vice President Power
Wendy Zelond	Treasurer
Jimmi Duce	Corporate Secretary

SEMCO Energy, Inc.
1411 Third Street, Suite A,
Port Huron, MI 48060

OFFICERS
As of March 31, 2024

Donald M. "Blue" Jenkins	Chair
Marc Simone	President
Ann L. Forster	Vice President Administrative Services
Mark A. Moses	Vice President, Chief Financial Officer and Treasurer
Jimmi Duce	Corporate Secretary

Petrogas, Inc.
1000 Maine Avenue, SW
Washington, DC 20024

OFFICERS
As of March 31, 2024

Randy Toone	President
James Harbilas	Chief Financial Officer
Bradley Grant	Chief Legal Officer
Peter Ledig	Senior Vice President
Ken Wentworth	Senior Vice President
Wendy Zelond	Senior Vice President and Treasurer
Krista Nufrio	Vice President
Colin Bond	Vice President and Controller
Jimmi Duce	Corporate Secretary

APPENDIX C

C. Washington Gas Time and Labor Reporting Procedures

Exhibit WG (J)-1

Washington Gas
Time and Labor Reporting Procedures

Washington Gas maintains systems and procedures to capture employee time and labor costs and to accurately assign those costs to the proper accounts and entities. The Time and Labor Reporting Procedure (TLRP) requires that every employee report his labor hours with detailed information that permits the accounting process to properly charge the labor cost (and associated overheads) to the appropriate entity which benefits from the activity. The TLRP format also includes information related to department project identification numbers (where appropriate) and sub-account descriptions (where appropriate), necessary to record the item to the financial statements.

Washington Gas utilizes Workday's Time and Expense Management System. The System enables employees to electronically submit their timesheets by entering their time and expenses directly into Workday System. The ability to submit electronic timesheets is not currently available to all employees. Those who do not submit their timesheets electronically submit paper timesheets to dedicated employees (timekeepers) who enter the timesheet data into the Workday System.

As described in other sections of this Manual, the primary method for accurately capturing and assigning labor costs is to instruct employees to charge their time directly to the appropriate entity in conjunction with actual time spent on each activity. However, because a significant number of employees either work exclusively on utility activities or spend a very small and limited amount of time on affiliate activities, the Company utilizes procedures which permit such employees to have their time default to a pre-determined fixed account distribution which would include coding to bill the affiliates being served. Such employees are required to submit time sheets (paper or electronic as appropriate) when the hours worked differ from the pre-determined fixed labor distribution.

APPENDIX D

D. Washington Gas General Allocation Methodology

Exhibit WG (J)-1

Washington Gas
General Allocation Methodology

As noted in the departmental descriptions, there are several shared service functions which, by their nature, benefit Washington Gas and its US affiliates. Such common shared services include, but are not limited to, the consolidation of the financial results, preparation of consolidated tax returns, corporate communications, and other related functions.

Washington Gas allocates most of these costs to its affiliates using the Massachusetts Modified Mass (MMF); the MMF is calculated using three factors - adjusted net revenue, direct & assigned labor and average invested capital.

Washington Gas believes that allocations based on broad measures of business activity are appropriate for allocating expenses resulting from common shared services. Specific factors used to allocate common shared services include the MMF, direct labor charges, or other appropriate indicators of activity approved by the Vice President and Controller. Each affiliate is allocated a portion of Washington Gas's common shared services based on a formula which reflects this philosophy. These costs are allocated to operating affiliates that have underlying cost drivers.

The General Allocation Method is utilized in allocating the costs related to common shared services described above <u>after</u> all costs (and related overheads) that can be directly charged are so charged. This approach is applied to fairly apportion the costs of the identified functions to those affiliates receiving the benefits.

APPENDIX E

E. Methodology for Overhead Calculations

Exhibit WG (J)-1

Methodology for Overhead Calculations

Payroll Overheads

Payroll overheads consist of the following employee related expenses: OPEB (Other Post-employment Benefits), pensions, group insurance, 401(k) plans (Savings Plan for management employees, Capital Appreciation Plan for union employees), worker's compensation, FICA tax (company liability), federal unemployment tax and state unemployment tax.

The payroll-related overhead expenses are allocated each accounting period based upon the current period's Labor costs multiplied by a specific benefit overhead rate. The specific benefit overhead rate is calculated as a percentage of the specific budgeted benefit costs compared to the total budgeted Labor costs (ex: Budgeted FICA Costs / Total Budgeted Labor Costs = FICA Benefit Overhead Rate. Management will compare the actual costs vs. budgeted costs on a periodic basis and adjust the cost to actual cost if the variance exceeds an established threshold.

Other Supplemental Benefit Costs

Other supplemental benefit costs consist of the expense associated with the non-executive short and long-term incentive compensation plans.

Other Supplemental Benefit Costs are allocated each accounting period based upon the current period's Labor costs multiplied by a specific benefit overhead rate. The specific benefit overhead rate is calculated as a percentage of the specific budgeted benefit costs compared to the total budgeted Labor costs. Management will compare the actual costs vs. budgeted costs on a periodic basis and adjust the cost to actual cost if the variance exceeds established threshold.

Building Service Costs

Building costs represent the cost to operate and maintain the company-owned or leased facilities, including the Springfield Center and the 1000 Maine Avenue office building. These costs include rent, utilities, maintenance, janitorial service, supplies, insurance, taxes and security costs. Each accounting period, building service costs are pooled by facility and allocated to each affiliate based on the labor cost for departments assigned to the facilities. Every month, a calculation is made to determine what each department's labor cost is as a percentage of the total labor charges for the facility. The percentages are then used to allocate each pool of building costs.

Telephone Expense

Telephone expenses include the cost of operating and maintaining Washington Gas' telephone system at all locations. The cost of this service (actual calls, equipment lease costs and overheads) is charged to the appropriate affiliate based on labor charges for the prior 12 months.

Software Expense

Software expenses consist of the cost to operate and maintain certain software systems used by Washington Gas and its affiliates. The cost of this service (depreciation expense, maintenance fees and return on Investment) is allocated to the appropriate affiliate based on the General Allocation Methodology discussed in Appendix D; however, the methodology may vary depending on the nature of the software system.

Below is the summary for the overhead and related allocation factors

Allocation	**Basic Calculation**
Common Services (General Allocation Method, Appendix D)	Pool costs x **Modified Massachusetts Formula**
ASUS Corporate Shared Services	Costs x **Modified Massachusetts Formula**
Payroll Overheads	Pool costs x **Benefit Overhead Rate**
Executive Supplemental Benefit Costs	Pool costs x **Benefit Overhead Rate**
Other Supplemental Benefits Costs	Pool costs x **Benefit Overhead Rate**
Building Services Costs	Pool costs x **Direct Labor Costs Ratio**
Telephone Expenses	Pool costs x **Direct Labor Costs Ratio**
Software Expense	Pool costs x **Modified Massachusetts Formula** or direct assignment

Modified Massachusetts Formula

The Massachusetts Formula is a method used to allocate costs incurred by a parent company on behalf of its affiliates to those affiliates using three allocation factors. WGL determined that adjusted net revenue, direct & assigned labor and average invested capital were the appropriate factors to reflect the cost drivers for each business unit. The total of each affiliate's respective three factors is used as the numerator for that affiliate for the respective factors. The denominator of respective three factors is the total for all affiliates combined. Average of the three factors is calculated for each of the affiliates to arrive at the Modified Massachusetts ratio. ASUS will be allocating corporate shared services from ALA to Washington Gas using this MMF calculation.

Executive Labor Costs Ratio

The total of each affiliate's current month Executive labor charges for the eligible officers is used as the numerator for that affiliate. The denominator of this ratio is the grand total sum of labor charges for all affiliates combined. This calculation is system automated.

Executive Labor Study Ratio – Director and above Workforce

A study is conducted to determine the distribution among affiliates of the director's and above labor charges for the prior fiscal year as a percentage of total director's and above labor cost basis. The twelve-month executive labor charges of each affiliate labor charges are used as the numerator for that affiliate. The denominator of this ratio is the grand total sum of executive labor charges for all affiliates combined.

Direct Labor Costs Ratio

The total of each affiliate's current month labor charges is used as the numerator for that affiliate. The denominator of this ratio is the grand total sum of labor charges for all affiliates combined. This calculation is system automated.

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APPENDIX F

F. Washington Gas Amounts the Utility Allocated or Assigned by Type of Cost for Twelve Months Ended December 31, 2023

CONFIDENTIAL SECTION TO BE FILED SEPARATELY

EXHIBIT (J) -2

CONFIDENTIAL

EXHIBIT (J)-3

CONFIDENTIAL

WASHINGTON GAS LIGHT COMPANY

Affiliate Cost of Service Study
2024 DC Rate Case
Twelve Months Ended March 31, 2024

Filed with the Public Service Commission of the District of Columbia

Part A - Description of methodologies for cost assignments and allocations

Direct Costs

Washington Gas and its affiliates' policy is that costs will be directly assigned to the appropriate affiliate whenever reasonably possible. As such, direct costs that benefit an affiliate are "assigned and billed" directly to the appropriate affiliate. These costs have no impact to WGL's revenue or expense.

Common/shared Costs

Where tracking costs is not reasonable because one or more affiliates benefit from the expenditures, such costs will be allocated based on appropriate allocation methodology and factors described herein.

Allocation Factors

- *Benefits Overhead Rates*
  The benefit overhead rate is calculated as a percentage of the specific budgeted benefit costs compared to the total budgeted Labor costs (ex: Budgeted FICA Costs / Total Budgeted Labor Costs = FICA Benefit Overhead Rate). The detailed benefit overhead rates are presented in Part C.

- *Direct Labor Costs Ratio*

  This calculation is system automated and described below:

  Direct labor assigned to the affiliate / Total labor
  For the building service allocations, the labor costs used in the calculations are specific to the WGL departments occupying each building/facility.

- *Modified Massachusetts Formula*
  The Modified Massachusetts Formula ("MMF") is a method used to allocate costs incurred by a parent company on behalf of its affiliates to those affiliates using a simple average of three allocation factors. Washington Gas uses: 1) Adjusted net revenue, 2) Direct & assigned labor and 3) Average invested capital.

  The calculation is shown below:

(Adjusted Net Revenue of the affiliate / Total Adjusted Net Revenue
+
Direct & assigned labor of the affiliate / Total Direct & assigned labor
+
Average invested capital of the affiliate / Total Average invested capital) / 3

Methodology for Overhead Calculations

Table 1

Allocation	Basic Calculation	Pool Description
Payroll Overheads	Pool x **Benefit Overhead Rate**	Direct Time & Labor Charged to each Affiliate (All levels)
Other Supplemental Benefits Costs	Pool x **Benefit Overhead Rate**	Direct Time & Labor Charged to each Affiliate (Directors, AVP's, Executives)
Executive Supplemental Benefit Costs (SERP)	Pool x **Benefit Overhead Rate**	Direct Time & Labor Charged to Affiliates (Executives)
Building Services Costs	Pool costs x **Direct Labor Costs Ratio**	Cost of leases for facilities, facility staff, maintenance, and other facility costs.
Telephone Expenses	Pool costs x **Direct Labor Costs Ratio**	Telephone - land & wireless related costs.
Software Expenses	Pool costs x **Modified Massachusetts Formula**	Capitalized Software Amortization & Return on the asset.
WGL Common Services	Pool costs x **Modified Massachusetts Formula**	Labor and non-labor costs for corporate support services that benefit WGL Holdings and subsidiaries.
ASUS Corporate Shared Services	Costs x **Modified Massachusetts Formula**	Labor and non-labor costs for corporate support services that benefit ASUS and all affiliates.
Altagas Ltd. Corporate Shared Services	Costs x **Modified Massachusetts Formula**	Altagas Ltd corporate allocation of shared services.

PART B
CONFIDENTIAL

PART C
CONFIDENTIAL

EXHIBIT (J) -5

CONFIDENTIAL

ATTESTATION

I, GHISLAINE CELINE QUENUM, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Celine Quenum

GHISLAINE C. QUENUM

7/29/2024

DATE

WITNESS BLOCK
EXHIBIT WG (K)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

PUBLIC VERSION

DIRECT TESTIMONY OF ERIC BLOCK
Exhibit WG (K)
(Page 1 of 2)

Table of Contents

Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF ERIC BLOCK

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Eric Block. I am the Vice President and Controller for AltaGas Ltd. ("AltaGas"), the parent company of Washington Gas Light Company ("Washington Gas" or "Company"). My business address is 1700 355 4th Avenue S.W. Calgary, Alberta T2P 0J1, Canada.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am a Canadian Chartered Professional Accountant ("CPA"). I qualified for my CPA designation in 2011. I worked at Ernst & Young ("EY") in their Calgary Office in the Assurance (Audit) practice from 2008 to 2013, leaving EY as a Manager in Audit to join AltaGas. At EY, I worked on the audits of multinational companies. I started in AltaGas in the Midstream Division, progressing to Manager Planning and Reporting before transferring to Corporate as the Director of Enterprise Reporting in 2018. I transferred to the position of Corporate Controller in 2022, and was promoted to my current position, Vice President and Controller, in April 2024. As Vice President and Controller, I lead a cross-functional team delivering External Reporting, Corporate Controllership (Consolidations, Technical Accounting, Accounts Payable, Payroll), and Financial Planning and Analysis ("FP&A").

I graduated from the University of Calgary in 2008 with a Bachelor of Commerce with Distinction.

Q. HAVE YOU PREVIOUSLY SUPPORTED TESTIMONY REGARDING UTILITY BASE RATE PROCEEDINGS?

A. No, I have not.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to describe the nature of the corporate services provided by AltaGas to Washington Gas; explain how these services are necessary and benefit Washington Gas; describe how the costs incurred for these services are managed and how the costs are charged by AltaGas to AltaGas Services U.S. Inc. ("ASUS"); and demonstrate that the costs are reasonable. Company Witness Quenum discusses the Cost Allocation Manual in her direct testimony, which directs how these AltaGas costs are charged by ASUS to Washington Gas. Company Witness Tuoriniemi demonstrates how these costs are reflected in the test year and revenue requirement for the District of Columbia. Witness Baryenbruch presents the results of his study demonstrating the necessity and reasonableness of the charges over the test year.

III. EXHIBITS

Q. DOES YOUR TESTIMONY INCLUDE EXHIBITS?

A. Yes, I am sponsoring one (1) exhibit. Exhibit WG (K)-1 is a diagram showing how corporate services costs incurred by AltaGas are allocated to its businesses.

IV. CORPORATE SERVICES PROVIDED BY ALTAGAS TO WASHINGTON GAS

Q. WHAT ARE THE CORPORATE SERVICES ALTAGAS PROVIDES TO WASHINGTON GAS?

A. The corporate services AltaGas provides to Washington Gas are generally strategic in nature; focus on business oversight, development and exercise of corporate governance; and ensure Washington Gas has appropriate access to capital. These are common services AltaGas performs as a parent company and a publicly traded organization for, and on behalf of, all its businesses, which includes Washington Gas. Specifically, AltaGas engages in activities in the following categories:

- Board of Directors;
- Executive Management;
- Finance;
- Accounting and Tax;
- Legal;
- Compliance;
- Digital / Information Technology;
- Office Services and Human Resources; and
- Supply Chain.

The costs associated with these corporate services and allocated to Washington Gas on a system basis by service category are included in the following table, in $000s:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. PLEASE DESCRIBE THE CORPORATE SERVICES PROVIDED BY ALTAGAS TO WASHINGTON GAS.

A. Section V of the Washington Gas Light Company Cost Allocation and Inter-company Pricing Manual - Annual Report of Transactions Between Washington Gas Light Company and its Affiliates (the "CAM") includes a description of the Corporate Services provided by AltaGas to Washington Gas.[1] Those service descriptions are reproduced as follows:

Board of Directors

1. Fulfills the regulatory requirements outlined in the Canada Business Corporations Act (CBCA) for publicly listed companies
2. Provides enterprise-wide supervision and stewardship
3. Provides enterprise-wide strategic business and corporate advice
4. Supports effective governance enterprise-wide (e.g., approves AltaGas' Delegation of Authority and succession planning)

[1] Washington Gas filed its most recent Cost Allocation and Inter-Company Pricing Manual for the District of Columbia, for the 12 months ended December 31, 2023 on April 30, 2024. (*Docket WGCAM2024*)

5. Provides oversight of principal business risks enterprise-wide
6. Approves AltaGas audited consolidated financial statements, consolidated budgets

Executive Management

1. Provides strategic management oversight to all businesses
2. Provides strategic direction on enterprise-wide financial planning, capital access, business & capital risk management, and organization structure
3. Establishes effective company-wide governance models
4. Establishes internal control standards and procedures
5. Formulates strategy and provides guidance to operational leadership
6. Provides general oversight of corporate matters supporting the businesses and the delegation of authority related to such matters

Finance

1. Consolidates cash flow forecasts and manages liquidity needs for the entire AltaGas organization
2. Manages capital structure and financials of the entire AltaGas organization
3. Manages credit rating agency relationships and presentations
4. Manages capital market transactions and credit facilities for the enterprise
5. Manages investor relations
6. Develops funding plans with the businesses to address their operational and capital needs
7. Provides strategic oversight and assists with strategic planning during negotiations with large underwriters, allowing Washington Gas to leverage the buying power of AltaGas

8. Implements enterprise-wide risk management such as cyber insurance programs and Director and Officers liabilities programs

Accounting and Tax

1. Manages general accounting matters which is required to maintain status as a publicly listed company
2. Prepares consolidated financial statements, financial analysis and discussion required for securities filings for the entire AltaGas organization
3. Engages an independent accountant to perform the audit of the consolidated financial statements for the entire AltaGas organization
4. Prepares a consolidated enterprise budget and ensures the organization has adequate capital to fund operations and meet enterprise goals
5. Assists and advises business units with annual planning and budget cycle to ensure forecasts are incorporated in strategic planning
6. Develops enterprise-wide risk management and internal controls framework & procedures; coordinates Enterprise Risk Management (ERM) for the consolidated enterprise
7. Develops annual internal audit plan addressing entity level controls, and examining governance, risk management, and compliance procedures.
8. Advises on overall tax compliance, tax planning and cross-border transfer tax planning for the entire AltaGas organization
9. Coordinates international corporate tax audits and ESG tax disclosures.
10. Executes control activities and documentation including those required to certify compliance with applicable regulatory standards

Legal

1. Provide general legal services on corporate matters including regulatory, governance, compliance, disclosure, registration requirements; corporate development, banking and finance; employment and tax legal matters
2. Support general management of legal team at the businesses including assistance with strategy and resource development
3. Management of external counsel
4. Provides corporate secretarial services for AltaGas and subsidiaries
5. Develops enterprise-wide environmental and occupational health and safety and security compliance policies and practices

Compliance

1. Develops enterprise-wide polices, including the annual certification process for the Code of Business and Ethics, anti-bribery policies, privacy policies
2. Reviews the GHG emissions data from the businesses and consolidates into organization wide GHG emissions reporting
3. Consolidate information across the businesses and develop all ESG external reporting for the entire enterprise.
4. Develops enterprise-wide communication strategy; oversees the implementation of corporate communications plan in the businesses to ensure consistent and effective messaging to internal and external audience

Digital / Information Technology ("IT") Services

1. Develops and maintains organization-wide IT strategy, architecture, policies and practices, to ensure access to information assets is safeguarded
2. Develops and provides organization-wide enterprise technologies / solutions platforms

3. Establishes strategic IT procurement procedures and practices and leveraging economies of scale for favorable purchasing terms and conditions
4. Manages vendor relations and operations for enterprise-wide application, information / cybersecurity, and infrastructure services
5. Selects and implements best practices for system security across all of AltaGas, to limit risk to data and broader IT systems from external threats
6. Ensures IT systems are up-to-date and information assets remain protected against cyber threats to maintain system integrity

<u>Office Services and Human Resources</u>

1. Oversees, prioritizes and provides feedback on organization-wide employee outreach and communication
2. Maintain AltaGas corporate office with necessary facilities to perform activities
3. Support design of executive and employee compensation plans; manage employee pensions, retirement savings and benefits; manage employee savings initiatives
4. Develop and implement enterprise-wide learning & development and talent management programs
5. Promote employee engagement, enable the development and retention of business knowledge and experience within the organization
6. Design and develop enterprise-wide HR data models, reports, and dashboards
7. Oversee enterprise-wide human capital management systems, maintenance of employee Master Data, and response to HR-related employee inquiries

Supply Chain

1. Establishes company-wide strategic procurement procedures and practices to effectively secure supply of goods and services with quality vendors, mitigate commercial risks, and utilize procurement strategies to drive competitive tension and reduce price
2. Facilitates active collaboration among procurement leaders from across the organization on procurement activities where possible to leverage enterprise spend opportunities to realize more favorable terms and conditions

Q. ARE THE CORPORATE SERVICES PROVIDED BY ALTAGAS NECESSARY?

A. Yes. The services are common activities that are required as part of the ongoing management of a diversified, publicly traded company. Many of these services are focused directly on corporate governance, legal mandates, regulatory compliance, and reducing financial, operational, and other types of risk. The remaining services are focused on management control, strategic planning, and operational execution. As previously stated, these services are necessary for AltaGas to maintain its public issuer status to satisfy the capital needs of its business units, including Washington Gas, in a timely and efficient manner.

It is worth noting that in Order No. 21939 regarding the Company's most recent rate case, Formal Case No. 1169, the Commission, after reviewing evidence in the record, determined that the services and costs of the services provided to Washington Gas by AltaGas encompass traditional corporate parent company support activities and costs.[2] The scope of corporate services provided by AltaGas has not changed since the Company's last rate case.

Q. IN ADDITION TO THE CORPORATE SERVICES BEING NECESSARY, HOW DO THE CORPORATE SERVICES PROVIDED BY ALTAGAS BENEFIT CUSTOMERS?

A. The corporate services provided by AltaGas benefit customers in several ways. First, by consolidating the performance of corporate services at AltaGas, Washington Gas is able to enjoy the benefits of cost efficiencies and economies of scale. Having AltaGas perform the corporate services that are commonly required across its businesses, including Washington Gas, avoids overlap and optimizes utilization of employees and resources to providing these services. Consolidation of corporate services at AltaGas enables sharing of costs so that each business unit bears only a portion of these costs.

Second, the activities undertaken by AltaGas are required to maintain its public issuer status such that it can raise capital in the debt and equity markets to fund the operational and capital needs of its businesses, including Washington Gas. While Washington Gas maintains its own debt securities, it relies on AltaGas for equity capital.

To illustrate this point, from 2019 (the first full calendar year after the completion of the merger transaction) to 2023, the Company's capital expenditure requirement was approximately $2.4 billion but it only generated approximately $1.9 billion free cash flow during the same time period. The funding gap was principally financed with AltaGas's incremental equity

[2] *Formal Case No. 1169*, Order No. 21939 at 459.

investment into Washington Gas, which approximated $0.5 billion from 2019-2023.

AltaGas has a well-established track record in capital market issuances, access to bank credit facilities and the equity capital market. For example, its investor relations function, which is part of the Finance group discussed earlier, manages AltaGas's communications with the shareholders, investors and other capital market participants. Such outreach efforts facilitate capital issuance activities undertaken by AltaGas's Finance group to provide capital access to its businesses, including Washington Gas. In other words, Washington Gas can rely on AltaGas as, and when, it requires capital to deliver safe and reliable gas utility services.

Third, the corporate services provided by AltaGas which focus on corporate governance, legal mandates and regulatory compliance, mitigates financial, operational, and other types of risk for Washington Gas.

To summarize, the activities undertaken by AltaGas enhance effective management and efficiency of AltaGas and Washington Gas, ensures proper governance and mitigates potential liability and risk exposure for Washington Gas; and enable AltaGas's ability to access the capital markets to meet the capital requirements of Washington Gas and other businesses. All these attributes provide benefits to Washington Gas and its customers.

Q. IS THERE ANY DUPLICATION OF THE CORPORATE SERVICES PROVIDED BY ALTAGAS AND THE SERVICES PROVIDED BY WASHINGTON GAS EMPLOYEES?

A. No. There is not. AltaGas and Washington Gas are responsible for distinct roles in the delivery of affiliated services within the enterprise. While certain corporate services AltaGas performs have similar names and descriptions as the shared services performed by Washington Gas employees, the purpose, focus or content of the activity performed by AltaGas and Washington Gas is different. AltaGas provides corporate and administrative oversight and governance to its portfolio of businesses, including Washington Gas and its affiliates. Many of these activities focus on business oversight, corporate governance, and access to capital. These activities are either fiduciarily required (*e.g.*, Board of Director oversight) or enable Washington Gas to operate (*e.g.*, access to capital). On the other hand, Washington Gas provides its own local management and shared services to its affiliates utilizing a model that has been in place for several decades, as discussed by Company Witness Quenum.

As an example, Washington Gas prepares separate financial statements for itself and the U.S. affiliates, excluding SEMCO Energy, Inc. (a utility affiliate) which prepares its financial statements independently. These financial statements are then provided to AltaGas, which prepares the consolidated financial statements and engages an external auditor to audit the consolidated financial statements. Both entities also prepare regulatory external reports for their respective stakeholders in Canada (*e.g.*, AltaGas prepares securities filings to satisfy its public issuer status for access to capital in the debt and equity markets) and the United States (*e.g.*, Washington Gas prepares Federal Energy Regulatory Commission reports).

Therefore, the activities performed by AltaGas and Washington Gas are complementary and not duplicative.

Q. HOW DOES ALTAGAS MANAGE THE COSTS INCURRED IN PROVIDING CORPORATE SERVICES?

A. The actual costs incurred in providing corporate services are tracked against budget. AltaGas, Washington Gas, and other affiliate executives and finance leaders review monthly performance (both financial and operational) across the portfolio of businesses and collaborate with each other to review variances and discuss potential mitigation strategies for any identified cost overruns. These regular reviews and discussions allow management to engage meaningfully in cost control as business conditions evolve.

Q. HAS ALTAGAS INCURRED ANY COSTS FOR CORPORATE SERVICES THAT ARE NOT ALLOCATED TO WASHINGTON GAS?

A. Yes. Certain types of corporate costs, based on the nature of the expenses (such as stock-based incentive expenses, supplemental retirement plan expenses, and corporate donation and promotion expenses) and functions (such as the corporate credit function that primarily supports the midstream business), are not allocated to Washington Gas. As an illustration, for the twelve-month period ending March 31, 2024, $75 million of corporate costs were not allocated to its businesses which include Washington Gas.

Q. HOW DOES ALTAGAS CHARGE THE CORPORATE SERVICES COSTS INCURRED TO WASHINGTON GAS?

A. AltaGas allocates costs for Corporate Services to Washington Gas using the Modified Massachusetts Formula ("MMF"). Exhibit WG (K)-1 shows how corporate services costs incurred by AltaGas are allocated. First, after applying the exclusion of certain corporate costs as previously discussed, costs for corporate services are combined into one common cost pool at AltaGas for allocation. This cost pool is then allocated to AltaGas Services (U.S.) Inc. ("ASUS"), the holding company of AltaGas's U.S. business, and AltaGas's Canadian businesses, using the AltaGas MMF. The AltaGas MMF uses a simple average of three different cost allocator-bases (the "AltaGas MMF Allocator") of each business of the AltaGas consolidated group. The three cost allocator-basis in the AltaGas MMF Allocator are the (1) relative earnings before interest, tax and depreciation ("EBITDA"), (2) relative payroll costs, and (3) relative property (Plant, Property and Equipment, including construction work-in-progress, plus Materials and Supplies Inventories and Gas Inventories) of each business unit. In the second step, when ASUS receives the allocation from AltaGas, ASUS allocates the costs to its U.S. businesses. Company Witness Quenum described the Cost Allocation Manual in her direct testimony, which directs how the costs were allocated from ASUS to Washington Gas. As shown in the table on page 3 of my direct testimony, the amount of corporate costs allocated to Washington Gas by AltaGas, for the twelve-month period ending March 31, 2024, was $26 million.

Q. HOW DOES ALTAGAS ENSURE THE COSTS IT INCURRED IN PROVIDING CORPORATE SERVICES ARE COMPETITIVE TO WHAT WASHINGTON GAS CAN OBTAIN FROM THE MARKET?

A. I will explain this from several perspectives. First, about 51% of the corporate services costs allocated from AltaGas to Washington Gas in the twelve-month period ending March 31, 2024 were labor costs. AltaGas's labor services follow the same compensation philosophy as Washington Gas, paying its employees targeting the market median and resulting in labor costs that represent market. Furthermore, as I previously mentioned, the labor costs allocated by AltaGas exclude stock-based compensation and supplemental retirement plan costs.

Second, the remaining 49% of corporate services costs allocated from AltaGas to Washington Gas during the twelve-month period ending March 31, 2024 were non-labor costs. AltaGas's non-labor services are procured using standard procurement practices common to all businesses and functions across the AltaGas enterprise. Non-labor costs, as they represent arms-length transactions conducted by unrelated parties, represent the market price for these costs.

Third, the labor and non-labor costs incurred by AltaGas to perform corporate services are allocated to Washington Gas with no mark-up or profit margins of any kind.

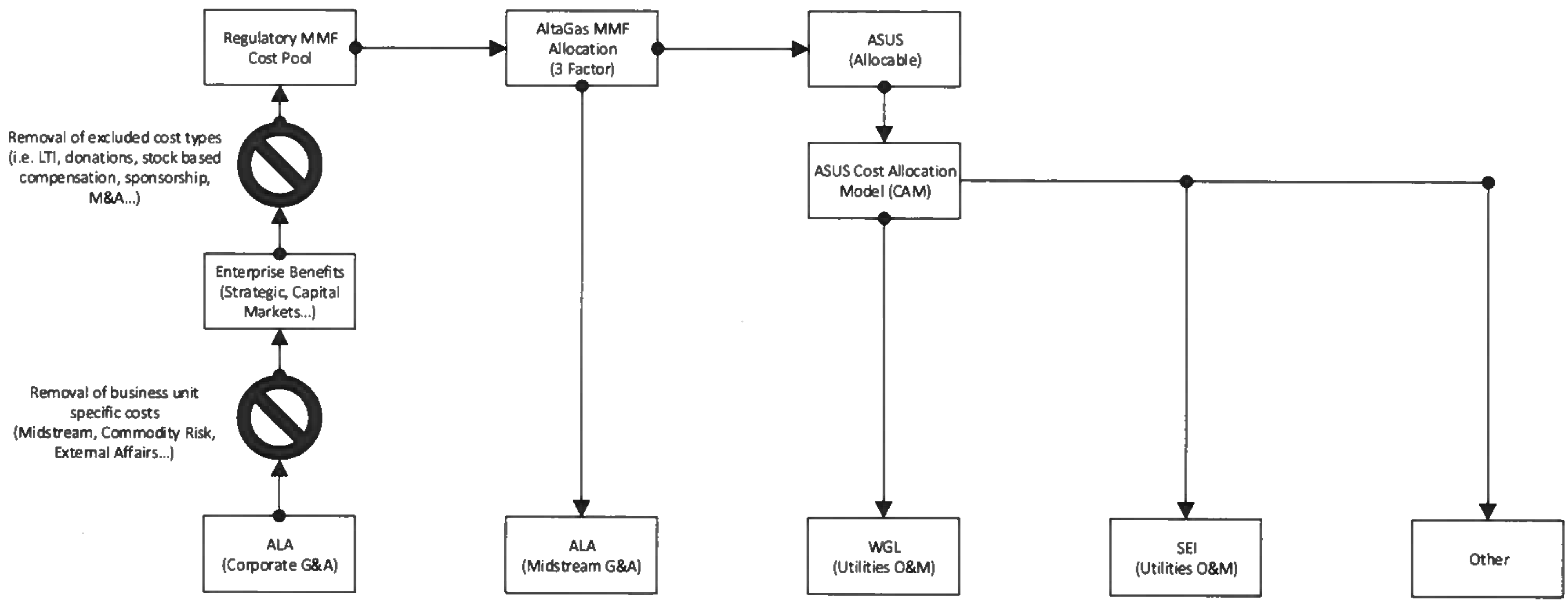
Fourth, as part of Company Witness Baryenbruch testimony, he conducted an objective assessment of the necessity of services provided and the reasonableness of the associated charges. The resulting assessment concluded that the costs incurred by AltaGas in providing corporate services were lower than those that could be obtained from outside service providers. See Company Witness Baryenbruch direct testimony for additional detail.

Q. WHAT ARE YOUR OVERALL CONCLUSIONS RELATING TO THE CORPORATE SERVICES PROVIDED BY ALTAGAS TO WASHINGTON GAS AND THE COSTS ASSOCIATED WITH THOSE CORPORATE SERVICES?

A. The corporate services provided by AltaGas to Washington Gas are necessary, non-duplicative, and benefit the customers. The allocation method AltaGas uses to allocate corporate services costs to Washington Gas is widely accepted/used, and the established process to develop and manage corporate services costs is effectively implemented. Furthermore, the costs AltaGas incurs in providing corporate services are competitive to market, as confirmed by the independent assessment conducted by Company Witness Baryenbruch. For these reasons, the costs are reasonable for the corporate services provided by AltaGas to Washington Gas.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.


Regulatory MMF Cost Pool
AltaGas MMF Allocation (3 Factor)
ASUS (Allocable)
ASUS Cost Allocation Model (CAM)
Removal of excluded cost types (i.e. LTI, donations, stock based compensation, sponsorship, M&A...)
Enterprise Benefits (Strategic, Capital Markets...)
Removal of business unit specific costs (Midstream, Commodity Risk, External Affairs...)
ALA (Corporate G&A)
ALA (Midstream G&A)
WGL (Utilities O&M)
SEI (Utilities O&M)
Other

ATTESTATION

I, ERIC BLOCK, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Eric Block
ERIC BLOCK

July 25, 2024
DATE

WITNESS BARYENBRUCH
EXHIBIT WG (L)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF PATRICK L. BARYENBRUCH
Exhibit WG (L)
(Page 1 of 1)

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Exhibits

WASHINGTON GAS LIGHT COMPANY

District of Columbia

DIRECT TESTIMONY OF PATRICK L. BARYENBRUCH

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Patrick L. Baryenbruch. My business address is 2832 Claremont Road, Raleigh, North Carolina 27608.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the President of my own consulting practice, Baryenbruch & Company, LLC, which was established in 1985. In that capacity, I provide consulting services to utilities and their regulators.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor's degree in Accounting from the University of Wisconsin-Oshkosh and a Master's in Business Administration degree from the University of Michigan. I am a member of the American Institute of Certified Public Accountants and the North Carolina Association of Certified Public Accountants.

I began my career with Arthur Andersen & Company, where I performed financial audits. I left to pursue an M.B.A. degree, and upon graduation from business school, I worked with the management consulting firms of Theodore Barry & Associates and Scott Consulting Group (now ScottMadden) before establishing my own firm.

Q. DO YOU HOLD ANY PROFESSIONAL CERTIFICATIONS?

A. Yes. I am a Certified Public Accountant (CPA) with an active license from the states of Wisconsin and North Carolina. I am a Certified Information Technology Professional (CITP), an accreditation awarded by the American Institute of Certified Public Accountants to CPA professionals who can demonstrate expertise in cybersecurity and information technology management.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE OTHER REGULATORS?

A. Yes. During my career, I have performed more than 150 evaluations of affiliate charges to 46 utility companies. I have acted as an expert witness on utility/affiliate charges in over 100 rate case proceedings. Exhibit WG (L)-1 presents my previous affiliate transaction-related assignments.

Q. WHAT OTHER WORK EXPERIENCE DO YOU HAVE WITHIN THE UTILITY INDUSTRY?

A. In addition to my work supporting rate cases, much of my career has been spent as a management consultant for projects related to the utility industry. I have performed consulting assignments for more than 70 utilities and 10 public service commissions. I have participated as project manager, lead consultant or staff consultant for 24 commission-ordered management and prudence audits of public utilities. Of these, I was responsible for evaluating the area of affiliate charges and allocation of corporate expenses in the commission-ordered audits of Connecticut Light and Power (now Eversource), Connecticut Natural Gas, General Water Corporation (now Veolia), Philadelphia Suburban Water Company (now Essential Utilities), and Pacific Gas & Electric Company.

For 20 years, I was heavily involved in providing consulting services related to information technology ("IT") infrastructure within the utility industry. These projects involved improvements in business management practices of utility IT organizations, covering processes such as business planning, risk management, performance measurement and reporting, cost recovery, budgeting, cost management, and personnel development.

I acted as the project manager and a member of the project management team for twenty large-scale IT implementation projects for a large electric utility.

II – OVERVIEW

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS CASE?

A. I am presenting the results of my study that evaluated the necessity of services provided by affiliates to WGL and the reasonableness of the associated charges during the 12 months ending March 31, 2024, Test Year (TY 2024).

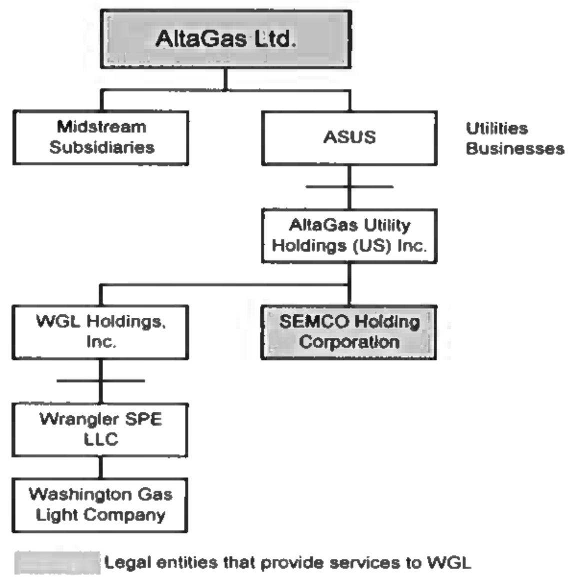
Q. ARE YOU SPONSORING ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibit WG (L)-1, which presents my previous affiliate transaction-related assignments, and Exhibit WG (L)-2, which is the Market-to-Cost-Comparison of Affiliate Charges to WGL during TY 2024. This study was undertaken in conjunction with WGL's rate case and the results are true to the best of my knowledge and belief.

Q. WHICH AFFILIATES PROVIDED SERVICES TO WGL DURING TY 2024?

A. Affiliates AltaGas Ltd. (AltaGas) and SEMCO ENERGY Gas Company (SEMCO) provided certain services to WGL during TY 2024. Table 1 below shows where these entities fit in the corporate structure.

Table 1



Source: Company information

Q. WHAT IS THE NATURE OF THESE SERVICES?

A. The two affiliates provided services in the functional areas shown in the table below.

Table 2

AltaGas

Accounting	Human Resources
Board of Directors	Information Technology
Compliance	Legal
Executive Management	Procurement
Finance	Taxes

SEMCO

Executive Management	Human Resources
Accounts Payable	(Recruiting)

Source: Company Information

Q. IN GENERAL, WHAT ARE THE BENEFITS OF AFFILIATES PROVIDING SERVICES WITHIN A UTILITY HOLDING COMPANY?

A. In my professional experience working as an auditor or management consultant for more than 70 utility companies, I have found shared services among affiliates provide the following benefits:

- Purchasing Economies – Common expenses (e.g., insurance, benefits administration, outside audit services) can be procured on a larger scale, thereby providing greater bargaining power for the combined entity compared to individual utility operating companies.
- Operating Economies of Scale – Shared services facilitate efficiencies because workloads can be balanced across more persons and facilities.
- Continuity of Service – Shared services staff who perform similar services facilitate job cross-training and sharing of knowledge and expertise. This makes it easier to manage staff turnover and absences and to sustain high levels of service among operating utilities.
- Maintenance of Enterprise-Wide Standards – Shared service among affiliates makes it easier to establish standards for business processes, operating procedures and maintenance practices. It is easier to align operating utility operations because the shared services groups support their implementation.
- Improved Support and Guidance – Shared services among affiliates provide another dimension of management and financial support and guidance that supplements local operating utility management.

Q. WHAT WERE THE OBJECTIVES OF YOUR EVALUATION?

A. This study was undertaken to determine the reasonableness of affiliate charges for services provided to WGL during TY 2024. Reasonableness was determined by answering four questions. First, are the services affiliates provided to WGL necessary? Second, did affiliates provide services to WGL at the lower of cost or market value during TY 2024? Third, are WGL's total TY 2024 administrative and general ("A&G") expenses reasonable compared to those of other utilities? Fourth, are the governance practices applied to affiliates' charges appropriate?

Q. HOW MUCH DID AFFILIATES CHARGE WGL DURING TY 2024?

A. As shown below, AltaGas and SEMCO charged WGL approximately $27.6 million for services provided during TY 2024.

Table 3

Affiliates	TY 2024
AltaGas	$ 26,051,443
SEMCO	$ 1,562,389
Total	$ 27,613,832

Source: Company information

QUESTION 1 – NECESSITY OF AFFILIATE SERVICES

Q. WHAT BENEFITS DOES WGL RECEIVED FROM AFFILIATE SERVICES?

A. I assessed the value of affiliate services to WGL according to the following criteria:

- Governance – The service facilitates oversight and management control over functional or operating areas and processes. Governance activities include, among other things, planning and reporting of actual performance.

- Compliance – The service helps ensure enterprise-wide compliance with regulatory, legal, financial, and other obligations of individual operating companies and the combined company.
- Capital Availability – The service enables affiliates to secure debt and equity financing required to provide service to customers.
- Economies – The service facilitates cost savings from purchasing and operating economies of scale. The services enable greater bargaining power to realize better prices for common goods and services and pass those savings on to affiliates. They can also more efficiently utilize staff through workload balancing and specialization, which allows operating companies to avoid the need to staff for less than a full-time workload.
- Continuity of Service – The service helps ensure on-going provision of service through the centralization of staff performing similar activities. Larger concentrations of these resources mean there is coverage of work during potential disruptions such as absences and departures.
- Enterprise Standards – The service plays a role in ensuring that standard policies, procedures, and practices are established and followed across the enterprise.

The matrix below designates which of these benefits pertain to services provided by AltaGas and SEMCO.

Table 4

		Benefits to WGL from TY 2024 Affiliate Services					
Affiliate	Service Category	Governance	Compliance	Capital Availability	Economies	Continuity of Service	Enterprise Standards
AltaGas	Accounting and Taxes		X	X			X
	Board of Directors	X	X	X		X	X
	Compliance		X			X	X
	Executive Management	X	X	X		X	X
	Finance	X	X	X			X
	Human Resources		X		X	X	X
	Information Technology	X	X		X	X	X
	Legal	X	X	X	X	X	X
	Supply Chain				X		
SEMCO	Accounting and Taxes	X					
	Accounts Payable				X		
	Executive Management	X	X			X	X
	Human Resources				X		

Source: Company information; Baryenbruch & Company, LLC, analysis

Q. ARE AFFILIATE SERVICES REDUNDANT WITH WORK PERFORMED BY WGL ITSELF?

A. No. I determined this by developing a responsibility matrix (Exh. WG L-2, pg. 7) that shows which entity (WGL, AltaGas, or SEMCO) is primarily responsible or provides support for all of the A&G activities that WGL requires to ultimately provide service to customers. This analysis showed that affiliate services are not duplicative with WGL's own business processes.

<u>QUESTION 2 – LOWER-OF-COST-OR-MARKET COMPARISON</u>

Q. WHAT IS THE PURPOSE OF THIS TEST?

A. The reason for performing this test is to determine if affiliate services are less expensive than the cost of outside providers during TY 2024.

Q. HOW DID YOU PERFORM THIS TEST?

I determined that the following outside service providers could assume affiliates' services:

- Attorneys

- Certified Public Accountants
- Management Consultants
- Information Technology (IT) Professionals

I assigned affiliates' departments to one of these provider categories. I then developed cost and hour pools and calculated affiliates' hourly rates for each provider categories. Next, hourly billing rates for outside service providers were determined using information from pertinent surveys. Finally, affiliates' average cost per hour was compared to the average cost per hour for outside providers.

Q. WHAT WAS THE RESULT OF YOUR COMPARISON OF AFFILIATES' HOURLY RATES AND THOSE OF OUTSIDE PROVIDERS?

A. I was able to draw the following conclusions:

1. Affiliates' services were provided to WGL during TY 2024 at the lower of cost or market value.
2. On average, the hourly rates for outside service providers are 203% higher than comparable hourly rates of affiliates, as calculated below.

Table 5

Service Provider	TY 2024 Hourly Rates WGL Affiliates	Outside Providers	Difference-- WGL Affiliates Greater(Less) Than Outside
Attorney	$ 101	$ 358	$ (257)
CPA - Accounts Payable	$ 56	$ 124	$ (68)
CPA - Other Finance	$ 62	$ 192	$ (130)
IT Professional	$ 91	$ 254	$ (163)
Management Consultant	$ 116	$ 355	$ (239)

Service Provider	TY 2024 Dollar Difference Hourly Rate Difference-- WGL Affiliates Greater(Less) Than Outside	WGL Affiliates Hours Charged	Dollar Difference
Attorney	$ (257)	8,577	$ (2,204,382)
CPA - Accounts Payable	$ (68)	13,056	$ (887,796)
CPA - Other Finance	$ (130)	101,642	$ (13,213,451)
IT Professional	$ (163)	31,450	$ (5,126,402)
Management Consultant	$ (239)	77,547	$ (18,533,823)
Total WGL Affiliates Less Than Outside Providers			$ (39,965,854)

Total Difference	$ (39,965,854)
Total Testable WGL Affiliate Charges	$ 19,710,924
Percent Outside Providers Are Greater	203%

3. If all of the managerial and professional services now provided by affiliates had been outsourced in TY 2024, WGL and its customers would have incurred approximately $40.0 million in additional expenses, as calculated in the table above.
4. Affiliates charge their actual costs of service.

QUESTION 3 – COMPARISON OF WGL'S TOTAL A&G EXPENSES

Q. PLEASE DESCRIBE YOUR COST COMPARISON FOR WGL'S TOTAL A&G EXPENSES.

A. Affiliate charges represent a sizable portion of WGL's A&G expenses. As shown in the table below, for 2023 they made up 13% of WGL's total A&G expenses:

Table 6

	2023
Affiliate Charges	
AltaGas	$ 26,781,103
SEMCO	$ 1,556,406
Total Affiliate Charges	$ 28,337,509
Total WGL A&G	$ 218,749,642
Affiliate Charges as Percent	13%

Source: Company information

Thus, a comparison of WGL's total A&G expenses to those of other utilities also involves a comparison of the affiliate charges component. The comparison metric I used is total A&G expenses per retail customer. The comparison group consists of twenty-nine combination electric/gas utilities. The source of comparative data is the FERC Form 1, which is filed by these utilities. FERC Form 2 is a report filed by gas companies regulated by FERC. Unfortunately, most gas distribution companies are not regulated by FERC so it is not possible to select an all-gas distribution comparison group.

Q. WHAT WAS WGL'S TOTAL A&G EXPENSES PER CUSTOMER FOR 2023?

A. WGL's 2023 total A&G expenses per customer were $178, as calculated below.

Table 7

FERC A&G Account	Total 2023 A&G Expenses
920 Administrative and General Salaries	$ 96,520,307
921 Office Supplies and Expenses	$ 35,374,963
923 Outside Services Employed	$ 38,603,257
925 Injuries and Damages	$ 18,261,111
928 Regulatory Commission Expenses	$ 2,488,795
930.1 General Advertising Expenses	$ 881,558
930.2 Miscellaneous General Expenses	$ 24,850,631
931 Rents	$ 249,387
935 Maintenance of General Plant	$ 1,519,633
Total WGL A&G Expenses	$ 218,749,642
Total WGL Customers at 12/31/2023	1,226,879
Total WGL A&G Charges per Customer	$ 178

Source: FERC Form 2; Baryenbruch & Company, LLC, analysis

Charges to 926 – Pensions and Benefits expenses are excluded because they are related to all utility functions (i.e., transmission, distribution, customer service and A&G), not just A&G. Also, these expenses can fluctuate from year to year due to changes in the market value of retirement plan assets.

Q. HOW DOES WGL'S COST COMPARE TO THE UTILITY GROUP?

A. WGL is in the middle of the third quartile, somewhat above the group median, as shown below. Twelve comparison group utilities have higher costs and eighteen lower. I consider WGL's relative cost position to be reasonable.

Table 8

Comparison Group Utilities	2023 Total A&G Expenses per Customer		Quartile
San Diego Gas & Electric Company	$918		
Pacific Gas & Electric Company	$541		
Black Hills Power, Inc.	$432		
Northern Indiana Public Service Company	$379		
Empire District Electric Company	$292		4th
Central Hudson Gas & Electric Corporation	$258		
Southern Indiana Gas and Electric Company	$245		
Niagra Mohawk Power Company	$218		
Madison Gas and Electric Company	$204		
Dominion Energy South Carolina, Inc	$185		
Northern States Power Company (Minnesota)	$184		
Wisconsin Power and Light Company	$182		3rd
Washington Gas Light Company	**$178**		
Northern States Power Company (Wisconsin)	$168		
Montana Dakota Utilities, Inc.	$166		
Union Electric Company	$160	< median	
Fitchburg Gas & Electric Light Company	$159		
Consolidated Edison Company	$148		
Duke Energy Progress, LLC	$140		
New York State Gas & Electric Company	$134		2nd
Baltimore Gas and Electric Company	$131		
Louisville Gas and Electric Company	$129		
Public Service Company of Colorado	$122		
Ameren Illinois Company	$119		
Rochester Gas & Electric Company	$119		
Duke Energy Indiana, LLC	$116		
Oklahoma Gas & Electric Company	$115		
PECO Energy Company	$99		1st
Wisconsin Public Service Corporation	$86		
Consumers Energy Company	$66		
Duke Energy Ohio, Inc.	$58		

Source: Company information, FERC Form 1 (2023), Baryenbruch & Company, LLC analysis

Q. HOW MUCH DID WGL'S TOTAL A&G EXPENSES CHANGE FROM 2023 TO TY 2024?

A. WGL's total A&G expenses increased from $218.8 million in 2023 to $226.9 million, an increase of 4%.

Q. HOW MUCH DID CHARGES FROM AFFILIATES CHANGE FROM 2023 TO TY 2024?

A. As shown in the table below, total charges from affiliates decreased by 2.6% from 2023 to TY 2024.

Table 9

Affiliate Charges to WGL

			Change	
Affiliate	2023	TY 2024	Amount	Percent
AltaGas	$26,781,103	$26,051,443	$ (729,660)	(2.7%)
SEMCo	$ 1,556,406	$ 1,562,389	$ 5,983	0.4%
Total	$28,337,509	$27,613,832	$ (723,677)	(2.6%)

Source: Company information

QUESTION 4, GOVERNANCE PRACTICES APPLIED TO AFFILIATE CHARGES

Q. WHAT ARE GOVERNANCE PRACTICES?

A. Governance practices are internal controls designed to provide assurance that objectives are being achieved relating to operations, reporting and compliance. Among other things, this is achieved through control activities, which are defined as follows:

> *Control activities are the actions established through policies and procedures that help ensure that management's directives to mitigate risks to the achievement of objectives are carried out. Control activities are performed at all levels of the entity,*

at various stages within business processes, and over the technology environment.

Source: "Internal Control – Integrated Framework, Executive Summary," Committee of Sponsoring Organizations of the Treadway Commission.

Control activities include authorizations, approvals, verifications and business performance reviews.

Q. WHAT GOVERNANCE PRACTICES ARE APPLIED TO AFFILIATE SERVICES AND CHARGES?

A. Control activities that are applied by WGL to affiliate charges include the following:

A. Review and approval of the budgets, including affiliate charges to WGL, for WGL, AltaGas, and SEMCO

- Analysis and reporting of budget versus actual spending, including charges from affiliates to WGL
- Review of transactions between WGL and affiliates by WGL's independent auditors

These are the type of control activities that I expected to be in place when I helped manage the implementation of Sarbanes-Oxley 404 for Duke Energy. In my opinion, they are effective practices that help ensure that affiliate charges to WGL are necessary and reasonable.

Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING THE SERVICES PROVIDED BY AFFILIATES TO WGL AND THE COST OF THOSE SERVICES?

A. Affiliate services are essential to WGL's ability to deliver gas service to its customers. For each cost comparison I performed, affiliates' TY 2024 charges were shown to be reasonable.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

Patrick Baryenbruch's Previous Affiliate Transactions and Rate Case Engagements

Client	State	Year	Purpose	Rate Case Witness?
1 Connecticut American Water	Connecticut	1999	Rate Case	Yes
2 Illinois American Water	Illinois	2007	Rate Case	No
	Illinois	2021	Rate Case	Yes
	Illinois	2023	Rate Case	Yes
3 Indiana American Water	Indiana	2017	Rate Case	Yes
	Indiana	2022	Rate Case	Yes
4 Iowa American Water	Iowa	2020	Rate Case	Yes
5 Kentucky American Water	Kentucky	2003	Rate Case	Yes
	Kentucky	2006	Rate Case	Yes
	Kentucky	2008	Rate Case	Yes
	Kentucky	2009	Rate Case	Yes
	Kentucky	2018	Rate Case	Yes
	Kentucky	2022	Rate Case	Yes
6 Massachusetts American Water	Massachusetts	2000	Rate Case	Yes
7 Missouri American Water	Missouri	2002	Rate Case	Yes
	Missouri	2008	Rate Case	Yes
	Missouri	2014	Rate Case	Yes
	Missouri	2016	Rate Case	Yes
	Missouri	2019	Rate Case	Yes
	Missouri	2019	Rate Case	Yes
8 New Jersey American Water	New Jersey	2005	Rate Case	Yes
	New Jersey	2007	Rate Case	Yes
	New Jersey	2009	Rate Case	Yes
	New Jersey	2010	Rate Case	Yes
	New Jersey	2014	Rate Case	Yes
	New Jersey	2017	Rate Case	Yes
	New Jersey	2019	Rate Case	Yes
	New Jersey	2021	Rate Case	Yes
	New Jersey	2023	Rate Case	Yes
9 New Mexico American Water	New Mexico	2007	Rate Case	Yes
10 New York American Water	New York	2006	Rate Case	Yes
	New York	2010	Rate Case	Yes
	New York	2013	Rate Case	Yes
	New York	2015	Rate Case	Yes
11 Ohio American Water	Ohio	2006	Rate Case	Yes
	Ohio	2010	Rate Case	Yes
12 Pennsylvania American Water	Pennsylvania	2008	Compliance	No
	Pennsylvania	2011	Compliance	No
	Pennsylvania	2014	Compliance	No
	Pennsylvania	2017	Compliance	No
	Pennsylvania	2020	Compliance	No
13 Tennessee American Water	Tennessee	2006	Rate Case	Yes
	Tennessee	2010	Rate Case	Yes
14 Virginia-American Water	Virginia	1996	Rate Case	Yes
	Virginia	1999	Rate Case	Yes
	Virginia	2000	Rate Case	Yes
	Virginia	2001	Rate Case	Yes
	Virginia	2003	Rate Case	Yes
	Virginia	2007	Rate Case	Yes
	Virginia	2009	Rate Case	Yes
	Virginia	2011	Rate Case	Yes
	Virginia	2015	Rate Case	Yes
	Virginia	2018	Rate Case	Yes
	Virginia	2021	Rate Case	Yes
	Virginia	2023	Rate Case	Yes
15 West Virginia American Water	West Virginia	2002	Rate Case	Yes
	West Virginia	2006	Rate Case	Yes
	West Virginia	2007	Rate Case	Yes
	West Virginia	2009	Rate Case	Yes
	West Virginia	2012	Rate Case	Yes
	West Virginia	2014	Rate Case	Yes
	West Virginia	2017	Rate Case	Yes
	West Virginia	2020	Rate Case	Yes
	West Virginia	2022	Rate Case	Yes
16 Atlanta Gas Light (Southern Co)	Georgia	2009	Rate Case	Yes
17 Atmos Energy Corporation	Virginia	2004	Compliance	No
18 Columbia Gas of Kentucky	Kentucky	2015	Rate Case	Yes
19 Columbia Gas of Maryland	Maryland	2015	Rate Case	Yes
20 Columbia Gas of Massachusetts	Massachusetts	2004	Rate Case	Yes
	Massachusetts	2006	Internal Info	No
	Massachusetts	2011	Internal Info	No
	Massachusetts	2012	Internal Info	No
	Massachusetts	2014	Internal Info	No
	Massachusetts	2017	Internal Info	No
21 Northern Indiana Public Service	Indiana	2015	Internal Info	No
	Indiana	2016	Rate Case	Yes
	Indiana	2020	Rate Case	Yes
	Indiana	2021	Rate Case	Yes
	Indiana	2022	Rate Case	Yes
	Indiana	2023	Rate Case	Yes
22 Liberty Utilities New York Water	New York	2022	Rate Case	Yes
23 Columbia Gas of Virginia	Virginia	2003	Compliance	No
	Virginia	2004	Compliance	No
	Virginia	2005	Rate Case	Yes
	Virginia	2006	Compliance	No
	Virginia	2007	Compliance	No
	Virginia	2008	Compliance	No
	Virginia	2009	Rate Case	Yes
	Virginia	2010	Compliance	No
	Virginia	2011	Compliance	No
	Virginia	2012	Compliance	No
	Virginia	2013	Rate Case	Yes
	Virginia	2014	Compliance	No
	Virginia	2015	Rate Case	Yes
	Virginia	2016	Compliance	No
	Virginia	2017	Rate Case	Yes
	Virginia	2018	Compliance	No
	Virginia	2019	Compliance	No
	Virginia	2020	Compliance	No
	Virginia	2021	Rate Case	Yes
	Virginia	2022	Compliance	No
	Virginia	2023	Rate Case	Yes
24 Columbia Gas of Pennsylvania	Pennsylvania	2015	Internal Info	No
	Pennsylvania	2020	Rate Case	Yes
25 Dominion Energy, Inc.	Virginia	2008	Rate Case	Yes
	Virginia	2009	Compliance	No
	Virginia	2010	Compliance	No
	Virginia	2011	Compliance	No
	Virginia	2012	Compliance	No
	Virginia	2014	Compliance	No
	Virginia	2017	Compliance	No
	Virginia	2019	Compliance	No
	Virginia	2022	Compliance	No
26 Duke Energy	North Carolina	2006	Compliance	No
27 Elizabethtown Gas (Southern Co)	New Jersey	2008	Rate Case	Yes
28 Electric Transmission Texas	Texas	2016	Rate Case	Yes
	Texas	2020	Rate Case	Yes
	Texas	2022	Rate Case	Yes
29 General Water Works of Rio Rancho	New Mexico	1993	Rate Case	Yes
30 General Water Works of Virginia	Virginia	1992	Rate Case	Yes
31 Po River Water and Sewer	Virginia	1993	Rate Case	Yes
	Virginia	2007	Rate Case	Yes
	Virginia	2008	Rate Case	Yes
32 Progress Energy	North Carolina	2001	Internal Info	No
33 Roanoke Gas	Virginia	2006	Compliance	No
34 Southern California Edison	California	2002	Compliance	No
	California	2003	Compliance	No
	California	2004	Compliance	No
	California	2005	Compliance	No
35 AEP Texas	Texas	2018	Rate Case	Yes
	Texas	2023	Rate Case	Yes
36 Appalachian Power	Virginia	2021	Rate Case	Yes
	Virginia	2023	Rate Case	Yes
37 Southwestern Electric Power	Texas	2016	Rate Case	Yes
	Texas	2020	Rate Case	Yes
38 Kentucky Utilities	Virginia	2020	Rate Case	Yes
	Virginia	2023	Rate Case	Yes
39 Virginia Natural Gas (Southern Co)	Virginia	2004	Compliance	No
	Virginia	2005	Rate Case	Yes
	Virginia	2010	Rate Case	Yes
40 United Water of Pennsylvania	Pennsylvania	2004	Rate Case	Yes
41 Corix Infrastructure/Water Services Corp.	Enterprise	2018	Internal Info	No
	Enterprise	2019	Internal Info	No
	Enterprise	2021	Internal Info	No
42 Community Utilities of Indiana	Indiana	2020	Rate Case	No
43 Massanutten Public Service Company	Virginia	2006	Rate Case	Yes
	Virginia	2008	Rate Case	Yes
	Virginia	2013	Rate Case	Yes
	Virginia	2019	Rate Case	Yes
44 Water Service Corporation Kentucky	Kentucky	2010	Rate Case	Yes
	Kentucky	2012	Rate Case	Yes
	Kentucky	2019	Rate Case	Yes
	Kentucky	2021	Rate Case	Yes
45 Corix Utilities Oklahoma	Oklahoma	2019	Compliance	Yes
46 Great Basin Water Company	Nevada	2019	Rate Case	Yes
	Nevada	2021	Rate Case	Yes
			Total Studies	156
			Number of Rate Cases	112
			Number of Utility Clients	46
			Number of States	21

Washington Gas Light Company

Market Cost Comparison for Affiliate Company Charges
12 Months Ended March 31, 2024

July 2024

Baryenbruch & Company, LLC

Washington Gas Light Company
Market Cost Comparison for Affiliate Company Charges
12 Months Ended March 31, 2024

Table of Contents

I – Summary of Results

Purpose of This Study

This study was undertaken to evaluate the necessity of services provided to Washington Gas Light Company (WGL) by affiliates AltaGas Ltd. (AltaGas) and SEMCO Energy Gas Company (SEMCO) and the reasonableness of the associated charges. The period of evaluation is the 12 months ending March 31, 2024 (TY 2024), during which time affiliates charged WGL $27.6 million for services rendered. Necessity and reasonableness will be determined by answering the following questions:

1. Are the services WGL receives from AltaGas and SEMCO necessary?

2. Was WGL charged the lower of cost or market for services provided by AltaGas and SEMCO during TY 2024?

3. Are WGL's total Administrative and General (A&G) expenses for TY 2024 reasonable?

4. Are governance practices applied to affiliate charges to WGL appropriate?

Study Results

Conclusions concerning question 1:

- AltaGas and SEMCO services are of value to WGL and are necessary to ultimately provide service to WGL's customers

Conclusions concerning question 2:

- Affiliates' services were provided to WGL during TY 2024 at the lower of cost or market.

- On average, the hourly rates for outside service providers are 203% higher than comparable hourly rates charged by affiliates.

- If all of the managerial and professional services now provided by affiliates had been outsourced in TY 2024, WGL and its customers would have incurred approximately $40.0 million in additional expenses.

- Affiliates charge their actual costs of service.

Conclusions concerning question 3:

- Charges from AltaGas and SEMCO are recorded by WGL as A&G expenses. Thus, WGL's total A&G expenses include affiliate charges and expenses WGL incurred directly. For 2023, affiliate charges make up 13% of WGL's total A&G expenses (excluding charges to FERC Account 926 – Employee Pensions and Benefits).

- WGL's total 2023 A&G expenses per customer were $178, which is in the middle of the third quartile, somewhat above the utility comparison group median of $160 per customer. Twelve comparison group utilities have higher costs and eighteen lower. This relative position makes WGL's A&G expenses reasonable. Information for the comparison group came from the FERC Form 1.

I – Summary of Results

- WGL's TY 2024 total A&G expenses increased by 4% compared from 2023. Its charges from AltaGas and SEMCO decreased from $28.3 million to $27.6 million from 2023 to TY 2024.

Conclusions concerning question 4:

- The control activities applied to affiliate charges to WGL are the type that help ensure both services and charges are necessary and reasonable.

This study's results show that the services provided by AltaGas and SEMCO during TY 2024 are necessary and the associated charges during TY 2024 are reasonable. The following pages elaborate on the research and findings supporting these results.

II – Background

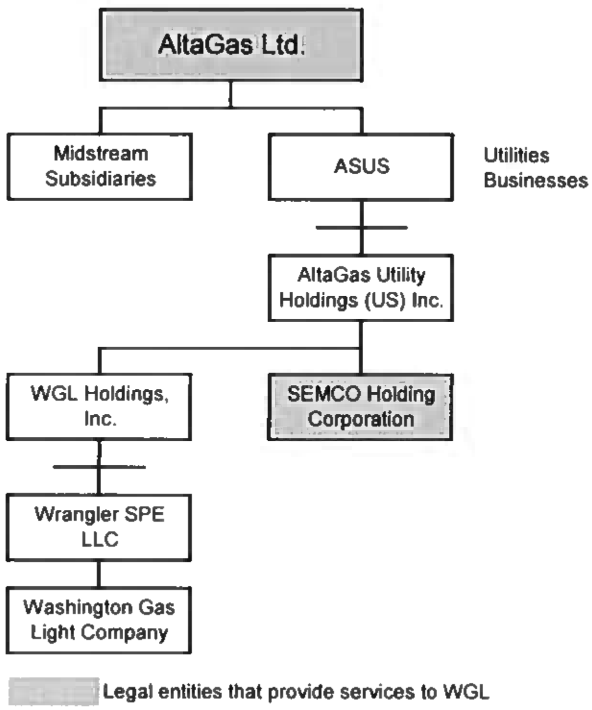
Affiliates Providing Services to WGL

The business of affiliates that provide services to WGL is described below:

- AltaGas Ltd. – Parent company, which owns and operates utility assets in Canada and the US, is headquartered in Calgary, Alberta, Canada.

- SEMCO Energy, Inc. - Regulated utility with primary business in the transmission, distribution, and storage and sale of natural gas. SEMCO is headquartered in Port Huron, Michigan.

The graphic below shows where these affiliates fall within the corporate structure.



Source: Company information

Description of Affiliate Services

Services provided by affiliates to WGL fall into the following categories:

AltaGas		SEMCO	
Accounting	Human Resources	Accounting	Human Resources
Board of Directors	Information Technology	Accounts Payable	(Recruiting)
Compliance	Legal	Executive Management	Information Technology
Executive Management	Procurement		
Finance	Taxes		

Source: Company Information

II – Background

The specific services provided to WGL by AltaGas and SEMCO are described in Exhibit 1 (page 5). In its order 1169, dated December 22, 2023, the Public Service Commission of the District of Columbia ruled the following regarding the services AltaGas provides to WGL:

> The Supplemental Testimony, discovery documents and WGL's annual CAM filings demonstrate that these costs encompass traditional corporate parent company support costs, including finance, corporate governance, corporate accounting, compliance, certain corporate legal costs, tax services and corporate IT systems costs. (Opinion and Order in Case No. 1169, page 133)

Services provided to WGL by SEMCO during 2023 are more focused on economic benefits. WGL has sourced its accounts payable function to SEMCO because it is far less expensive to perform the associated work in Port Huron, Michigan than in the Washington, DC area.

Service Agreements with Affiliates

Transactions between WGL and affiliates are covered by the service agreements shown in the table below. Both agreements were reviewed and approved by the Virginia State Corporation Commission in its order PUR-2023-00164.

Type of Services	Affiliate	Agreement Date
Corporate Services	SEMCO Energy, Inc.	Dec. 11, 2023
Corporate Services	AltaGas Ltd./ASUS	Dec. 11, 2023

Source: Company information

The service agreements specify the following services that can be provided by affiliates to WGL.

Services Provided by Affiliates per Service Agreements

AltaGas	SEMCO
Accounting and Taxes	Accounting and Taxes
Board of Directors	Accounts Payable
Compliance	Cash Receipts
Executive Management	Compliance
Finance	Executive Management
Human Resources	Human Resources
Information Technology	Information Technology
Legal	Payroll
Supply Chain	Supply Chain

Source:
AltaGas - Service Agreement dated December 11, 2023
SEMCO - Service Agreement dated December 23, 2023

Exhibit 1

Washington Gas Light Company
Description of Services Provided to WGL
by AltaGas Ltd. And SEMCO Energy, Inc.

AltaGas Ltd.

Board of Directors Services include overall supervision and stewardship; strategic business and corporate advice; governance; succession planning; and oversight of principal business risks.

Executive Management Services include strategic management oversight of all business units; setting strategic direction on financial planning, capital access, business and capital risk management and organizational structure; and leadership and guidance to optimize business.

Legal and Compliance Services include general legal service and advice to all business units, including regulatory, general corporate matters, governance, compliance, disclosure and registration requirements, management of external counsel and corporate secretarial services. Compliance services include developing an annual internal audit plan to examine, evaluate and report on the adequacy, effectiveness, and efficiency of the systems of internal controls across operations.

Finance Services include treasury matters such as managing capital structure and financial management, consolidated cash flow forecasts and liquidity management; implementing corporate risk management such as insurance services; and investor relations and stakeholder communications.

Accounting and Tax Services include general accounting and tax matters required to maintain the publicly listed company status, including preparation of consolidated financial statements, management discussion and analysis and other financial analysis required for securities filings and coordination of external audits. Other services include implementing internal controls framework and procedures; assisting and advising business units with annual planning and budget cycle to ensure forecasts are incorporated in strategic planning; and coordinating corporate tax audits, advising on overall tax compliance, tax planning and cross-border transfer tax planning and advice.

Information Technology Services include developing and maintaining organization-wide IT strategy, standardization, policies, and practices, to ensure access to information assets is safeguarded; establishing strategic IT procurement procedures and practices and leveraging economies of scale for favorable purchasing terms and conditions; and providing information system application training and day-to-day support to employees.

Office Services and Corporate Resources Services include providing a safe and secure workplace environment with the necessary facilities for employees to perform corporate services; managing savings initiatives to enable employees to benefit from the resulting economies of scale; facilitating organization-wide employee outreach communication; supporting executives' and employees' compensation plan design; pension (including retirement savings) and benefits management; union relationship management; environmental and occupational health and safety compliance; procurement support and administration of organization wide policies, including the code of business and ethics ("COBE") annual certification process.

SEMCO Energy, Inc.

Accounts Payable Services provided by SEMCO to Washington Gas and its affiliates include procurement card administration and expense processing, vendor management, invoice, and payment processing, as well as customer refunds. This service optimizes and streamlines the overall cash disbursements process.

Human Resources Services include assistance with recruiting, as needed by WGL.

Source: WGL Cost Allocation Manual; Company information

III – Question 1 – Necessity of Affiliate Services

Designation of Affiliate Services

The need for Corporate Support Services was evaluated by determining if they would be required if WGL were stand-alone gas distribution utility. This evaluation began by determining in detail what specifically AltaGas and SEMCO do for WGL. Based on discussions with Company personnel, the matrix in Exhibit 2 (page 7) was created showing which entity—WGL, AltaGas or SEMCO—is responsible for each function that must be performed for WGL to ultimately provide service to their customers. This matrix was reviewed to determine if there was redundancy or overlap in the services being provided to WGL by AltaGas and SEMCO.

Benefits of Affiliate Services

Affiliates are evaluated according to the following benefits are realized for CRU US and their customers:

- Corporate Governance – The service provides oversight and management control over functional or operating areas and processes. These governance activities include, among other things, planning and reporting of actual performance.
- Compliance – The service helps ensure enterprise-wide compliance with regulatory, legal, financial and other obligations of individual operating companies and the combined company.
- Capital Availability – The service enables affiliates to secure debt and equity financing required to provide service to customers.
- Economies – The service facilitates cost savings from purchasing and operating economies of scale. Corporate support services are able to employ greater bargaining power to realize better prices for common goods and services and pass those savings on to affiliates. It can also more efficiently utilize staff through workload balancing and specialization, which allows operating companies to avoid the need to staff for less than a full-time workload.
- Continuity of Service – The service helps ensure on-going provision of service through the centralization of staff performing similar activities. Larger concentrations of these resources mean there is coverage of work during potential disruptions such as absences and departures.
- Enterprise Standards – The service plays a role in ensuring that standard policies, procedures and practices are established and followed across the enterprise.

Exhibit 3 (page 8) shows which of these benefits are provided by each category of service provided by AltaGas and SEMCO.

Based upon these analyses, it can be concluded that:

- There is no redundancy or overlap in the services provided by affiliates and the work performed by WGL
- The services that affiliates provide are necessary and beneficial to WGL

Exhibit 2

Washington Gas Light Company
Responsibility Matrix for A&G Functions

Primarily Responsible P
Provides Support S

	Performed by		
Gas Company Function	WGL	AltaGas	SEMCO
Executive/Management	P	S	S
Corporate Planning			
Strategic Planning	S	P	
Business Planning	P	S	
Financial Services			
Financial Planning Analysis	P	S	S
Accounting	P	S	
SOX Compliance	S	P	
Investor Relations		P	
Taxes	P	S	
Risk Management	S	P	
Treasury	S	P	
Accounts Payable			P
Asset Accounting	P		
Insurance	P	S	
Internal Audit	S	P	
Rates and Regulatory			
Rates and Regulatory Finance	P		
Regulatory Legal	P		
Government Affairs	P		
Regulatory Policy	P		
Federal	P		
State	P		
Corporate Secretary		P	
Legal			
Legal Services	P	S	
Compliance	S	P	

Primarily Responsible P
Provides Support S

	Performed by		
Gas Company Function	WGL	AltaGas	SEMCO
Human Resources			
HR Programs Administration	P	S	
HR Services Delivery	S	P	
Recruiting	P	S	S
Organizational Development	S	P	
Information Technology Services			
IT Security	S	P	
IT Service Delivery	P	S	
IT Operations and Maintenance	P	S	
Service Performance	S	P	
Communications			
Corporate Communications	S	P	
Utilities Communications	P	S	
Facilities	P		
Energy Supply & Optimization	P		
Environmental Health and Safety			
Safety Services	P	S	
Compliance Services	S	P	
Training	P	S	
Remediation	P	S	
Permitting	P		
Fleet Services	P		
Supply Chain			
Specification Development	P	S	
Bid Solicitation	P	S	
Contract Administration	P	S	
Ordering	P	S	
Inventory Management	P		

Source: Company information, Baryenbruch & Company, LLC, analysis

Exhibit 3

Washington Gas Light Company
Benefits of Affiliate Services Matrix

		Benefits to WGL from TY 2024 Affiliate Services					
Affiliate	Service Category	Governance	Compliance	Capital Availability	Economies	Continuity of Service	Enterprise Standards
AltaGas	Accounting and Taxes		X	X			X
	Board of Directors	X	X	X		X	X
	Compliance		X			X	X
	Executive Management	X	X	X		X	X
	Finance	X	X	X			X
	Human Resources		X		X	X	X
	Information Technology	X	X		X	X	X
	Legal	X	X	X	X	X	X
	Supply Chain				X		
SEMCO	Accounting and Taxes	X					
	Accounts Payable				X		
	Executive Management	X	X			X	X
	Human Resources				X		

Source: Company information; Baryenbruch & Company, LLC, analysis

IV – Question 2 – Provision of Services at the Lower of Cost or Market

Purpose of Lower-of-Cost-or-Market Comparison

There are several ways by which to evaluate the pricing of affiliate transactions involving services provided by a nonregulated affiliate to a regulated utility. I utilize the method recommended by National Association of Regulatory Utility Commissions (NARUC), which recommends pricing at the lower of cost or market, as described below:

> *Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.*
>
> "Guidelines for Cost Allocations," National Association of Regulatory Utility Commissioners.

Methodology

Affiliates' TY 2024 billings to WGL are market tested by comparing affiliates' cost per hour to those of outside service providers to whom these duties could be outsourced.

The first step was to determine which types of outside providers could assume the services provided to WGL by AltaGas and SEMCO's. Based on the nature of these services, it was determined that the following outside service providers could perform the categories of services indicated:

- Attorneys – legal and compliance services
- Certified Public Accountants - accounting, finance, taxes and accounts payable services
- Management Consultants – board of directors, executive management, human resources and communications services
- Information Technology (IT) Professionals – information technology services

The next step was to calculate affiliates' hourly rate for each of the four outside service-provider categories, based on the dollars and hours charged to WGL during TY 2024. Next, hourly billing rates for outside service providers were determined using information from pertinent surveys. Finally, affiliates' average cost per hour was compared to the average cost per hour for outside providers.

Affiliates' Hourly Rates

The first step in determining affiliates' hourly rates is to designate the appropriate expenses to be included in the calculation. The following affiliate charges are excluded from the hourly rate calculations:

- Contract Services – Test Year 2023 affiliate charges to WGL include expenses associated with the use of outside service providers to perform certain enterprise-wide services (e.g., legal, financial audit fees). These fees are excluded from the affiliates' hourly rate calculation because the related services have effectively been out-sourced already.
- Enterprise IT Expenses – Included in Test Year 2023 affiliate charges to WGL are leases, maintenance fees and depreciation related to enterprise computing and network infrastructure and business applications. An outside provider that takes over operation of

IV – Question 2 – Provision of Services at the Lower of Cost or Market

this infrastructure would recover these expenses over and above the cost of their personnel.

- Travel Expenses – In general, client-related travel expenses incurred by outside service providers are not recovered through their hourly billing rates. Rather, actual out-of-pocket travel expenses are billed to clients in addition to fees for professional services. Thus, it is appropriate to remove these affiliate charges from the hourly rate calculation.
- Ancillary Expenses – These include corporate expenses such board of directors' fees. They are not related to the provision of services by affiliate personnel and have been excluded.

The next step was to assign affiliates' service-related charges to cost pools for the five outside service providers—attorney, certified public accountant – accounts payable, certified public accountant – other finance, management consultant and IT professional. This is based on the service category (e.g., human resources, accounting) to which charges are assigned. Exhibit 4 (page 11) shows the tabulation of cost pools by outside provider. Exhibit 5 (page 12) shows the assignment of affiliate staff hours to the four outside service providers. Exhibit 6 (page 13) shows the charges that are excluded from the hourly rate calculation for the reasons stated above. Based on the assignment of charges and hours to outside provider categories, affiliates' TY 2024 equivalent cost per hour is calculated below.

	12 Months Ended March 31, 2024					
		Certified Public Accountant		IT	Management	
	Attorney	Accts Payable	Other Finance	Professional	Consultant	Total
Total management, professional & technical services charges	$ 1,195,122	$ 757,094	$ 7,735,912	$ 7,034,873	$ 10,890,831	$ 27,613,832
Less: Exclusions						
Contract services	$ 310,128	$ 28,080	$ 1,354,865	$ 1,796,849	$ 1,070,727	$ 4,560,649
Enterprise IT expenses	$ -	$ -	$ 8,193	$ 2,334,278	$ -	$ 2,342,471
Travel expenses	$ 16,084	$ -	$ 23,033	$ 43,183	$ 298,421	$ 380,721
Ancillary expenses	$ -	$ -	$ 58,472	$ -	$ 560,595	$ 619,066
Total Exclusions	$ 326,212	$ 28,080	$ 1,444,562	$ 4,174,310	$ 1,929,743	$ 7,902,907
Net Service-Related Charges (A)	$ 868,909	$ 729,014	$ 6,291,350	$ 2,860,563	$ 8,961,088	$ 19,710,924
Total Hours (B)	8,577	13,056	101,642	31,450	77,547	232,273
Average Hourly Rate (A / B)	$ 101	$ 56	$ 62	$ 91	$ 116	

Source: Company information; Baryenbruch & Company, LLC, analysis

Exhibit 4

Washington Gas Light Company
Test Year 2023 Affiliate Charges by Service Category

	TY 2024 Charges by Outside Provider Category					
		Certified Public Accountant		IT	Management	
Service Category	Attorney	Accts Payable	Other Finance	Professional	Consultant	Total
Accounting	$ -	$ -	$ 4,496,904	$ -	$ -	$ 4,496,904
Accounts Payable	$ -	$ 757,094	$ -	$ -	$ -	$ 757,094
Board of Directors	$ -	$ -	$ -	$ -	$ 928,144	$ 928,144
Compliance	$ -	$ -	$ -	$ -	$ 2,927,621	$ 2,927,621
Executive Management	$ -	$ -	$ -	$ -	$ 4,131,115	$ 4,131,115
Finance	$ -	$ -	$ 2,018,838	$ -	$ -	$ 2,018,838
Human Resources	$ -	$ -	$ -	$ -	$ 2,903,951	$ 2,903,951
Information Technology	$ -	$ -	$ -	$ 7,034,873	$ -	$ 7,034,873
Legal	$ 1,195,122	$ -	$ -	$ -	$ -	$ 1,195,122
Procurement	$ -	$ -	$ 133,069	$ -	$ -	$ 133,069
Taxes	$ -	$ -	$ 1,087,101	$ -	$ -	$ 1,087,101
Total	$ 1,195,122	$ 757,094	$ 7,735,912	$ 7,034,873	$10,890,831	$27,613,832

Source: Company information, Baryenbruch & Company, LLC, analysis

Exhibit 5

Washington Gas Light Company
Test Year 2023 Service Company Hours by Service Category

	TY 2024 Hours by Outside Provider Category					
		Certified Public Accountant		IT	Management	
Service Category	Attorney	Accts Payable	Other Finance	Professional	Consultant	Total
Accounting	-	-	68,085	-	-	68,085
Accounts Payable	-	13,056	-	-	-	13,056
Board of Directors	-	-	-	-	-	-
Communications & Compliance	-	-	-	-	39,802	39,802
Executive Management	-	-	-	-	19,565	19,565
Finance	-	-	17,155	-	-	17,155
Human Resources	-	-	-	-	18,181	18,181
Digital	-	-	-	31,450	-	31,450
Legal	8,577	-	-	-	-	8,577
Procurement	-	-	4,289	-	-	4,289
Taxes	-	-	12,114	-	-	12,114
Total	8,577	13,056	101,642	31,450	77,547	232,273

Source: Company information, Baryenbruch & Company, LLC, analysis

Exhibit 6

Washington Gas Light Company
Test Year 2023 Service Company Charges Excludable from the Hourly Rate Calculation

Service Category	Exclusions From Hourly Rate Calculation					Service Provider Category
	Contract Services	Enterprise IT Expenses	Travel Expenses	Ancillary Expenses	Total	
Accounting	$ 1,044,182	$ 8,193	$ (6,718)	$ -	$ 1,045,657	CPA - Other Finance
Accounts Payable	$ 28,080	$ -	$ -	$ -	$ 28,080	CPA - Accounts Payable
Board of Directors	$ (148,107)	$ -	$ 133,559	$ 436,112	$ 421,564	Management Consultant
Compliance	$ 705,968	$ -	$ 40,122	$ -	$ 746,090	Management Consultant
Executive Management	$ (62,919)	$ -	$ 99,769	$ 124,483	$ 161,333	Management Consultant
Finance	$ 147,505	$ -	$ 11,764	$ 58,472	$ 217,741	CPA - Other Finance
Human Resources	$ 575,785	$ -	$ 24,972	$ -	$ 600,757	Management Consultant
Information Technology	$ 1,796,849	$ 2,334,278	$ 43,183	$ -	$ 4,174,310	IT Professional
Legal	$ 310,128	$ -	$ 16,084	$ -	$ 326,212	Attorney
Procurement	$ (93,553)	$ -	$ 6,952	$ -	$ (86,601)	CPA - Other Finance
Taxes	$ 256,731	$ -	$ 11,035	$ -	$ 267,766	CPA - Other Finance
Total	$ 4,560,649	$ 2,342,471	$ 380,721	$ 619,066	$ 7,902,907	

Recap By Outside Provider	Exclusions From Hourly Rate Calculation				
	Contract Services	Enterprise IT Expenses	Travel Expenses	Ancillary Expenses	Total
Attorney	$ 310,128	$ -	$ 16,084	$ -	$ 326,212
CPA - Accounts Payable	$ 28,080	$ -	$ -	$ -	$ 28,080
CPA - Other Finance	$ 1,354,865	$ 8,193	$ 23,033	$ 58,472	$ 1,444,562
IT Professional	$ 1,796,849	$ 2,334,278	$ 43,183	$ -	$ 4,174,310
Management Consultant	$ 1,070,727	$ -	$ 298,421	$ 560,595	$ 1,929,743
Total	$ 4,560,649	$ 2,342,471	$ 380,721	$ 619,066	$ 7,902,907

Source: Company information, Baryenbruch & Company, LLC, analysis

IV – Question 2 – Provision of Services at the Lower of Cost or Market

Outside Service Provider Hourly Rates

The next step in the lower-of-cost-or-market comparison was to calculate the average billing rates for outside service providers. The source of this information and the determination of the average rates are described in the paragraphs that follow.

It should be noted that professionals working for three of the five outside provider categories may be licensed to practice by state regulatory bodies. However, not every professional working for these firms is licensed. For instance, among Virginia certified public accounting firms, only the more experienced staff members are predominantly licensed CPAs, as shown in the table below. Some affiliates employees also have professional licenses. Thus, it is valid to compare affiliates' hourly rates to those of the outside professional service providers included in this study.

Position	% In VA Who Are CPAs
Partners/Owners	98%
Directors (over 10 years experience)	90%
Managers (6-10 years experience)	72%
Sr Associates (4-5 years experience)	61%
Associates (1-3 years experience)	17%
New Professionals	8%

Source: AICPA's National PCPS/TSCPA Management of an Accounting Practice Survey (2010)

Attorneys

An estimate of Virginia attorney billing rates is developed from actual rates compiled by Clio, a practice management service provider to law firms. The TY 2024 average rate of relevant practice areas is calculated in Exhibit 7 (page 16).

Certified Public Accountants

Two hourly rates are developed for Certified Public Accountants (CPA). One is for accounts payable services for comparison to the cost of services provided by SEMCO to WGL. The second is for comparison to the cost of AltaGas' other financial services, which are more complex and generally performed by higher-level accounting staff. In both cases, source data for comes from a bi-annual survey performed by the American Institute of Certified Public Accounts (AICPA). The survey contains rates for 2022 so they must be escalated by inflation to the midpoint of TY 2024 (September 30, 2023) to arrive at average 2023 rates.

Exhibit 8 (page 17) shows the average hourly billing rate for accounts payable services. The weighting for each accountant position is based on SEMCO's Accounts Payable staffing during TY 2024. Exhibit 9 (page 18) shows the average hourly rate for the type of financial services provided by AltaGas. Here, a more typical staffing mix for accountant positions is used to develop the average rate.

Information Technology Professionals

The TY 2024 average hourly rate for information technology consultants and contractors was developed from two sources: WGL for IT contractor rates and a survey performed by Rodenhauser & Company, LLC, for IT consultants. As shown in Exhibit 10 (page 19), that data was compiled

IV – Question 2 – Provision of Services at the Lower of Cost or Market

and a weighted average was calculated based on a percent of time that is typically applied to an IT consulting assignment, based on Baryenbruch & Company's experience.

Management Consultants

The cost per hour for management consultants was developed from a survey performed by Rodenhauser & Company, LLC, a research company that monitors the consulting industry. The survey includes rates that were in effect during 2023 for firms throughout the United States. As shown in Exhibit 11 (page 20) an average hourly rate is calculated by applying a percentage weighting to the average rates by consultant position. The weighting is based upon the percent of time that is typically applied to a consulting assignment, based on Baryenbruch & Company, LLC's, experience.

Exhibit 7

Washington Gas Light Company
Billing Rates for Attorneys

Average Billing Rates - Virginia (2023)

Practice Area	Hourly Rate (A)
Administrative	$ 289
Appellate	$ 299
Bankruptcy	$ 424
Business	$ 366
Civil Litigation	$ 362
Collections	$ 328
Commercial/Sale of Goods	$ 468
Construction	$ 328
Contracts	$ 371
Corporate	$ 363
Employment/Labor	$ 397
Insurance	$ 290
Intellectual Property	$ 436
Mediation/Arbitration	$ 373
Real Estate	$ 360
Tax	$ 424
Worker's Compensation	$ 203
2023 Average Hourly Rate	$ 358

Note A: Source is Themis Solutions Inc. (Clio)

Exhibit 8

Washington Gas Light Company
Billing Rates for Certified Public Accountants – Accounts Payable Services

Calculation of Average Hourly Billing Rate by Public Accounting Position
Survey billing rates were those in effect in 2022

	Average Hourly Billing Rate (Note A)			
	Para-Professional	Associate	Manager	
Average Hourly Billing Rate by CPA Firm Position	$ 109	$ 119	$ 233	
				Weighted Average
Percent of Accounting Assignment (C)	87.5%	3.0%	9.5%	
	$ 95	$ 4	$ 22	$ 121

Escalation to Test Year 2024 Midpoint (September 30, 2023)	
CPI at December 31, 2022	296.8
CPI at September 30, 2023	305.1
Inflation/Escalation (Note B)	2.8%
Average Hourly Billing Rate For CPAs At September 30, 2023	$ 124

Note A: Source is AICPA's 2023 National PCPS/TSCPA Management of an Accounting Practice Survey
Note B: Source is U.S. Bureau of Labor Statistics (https://data.bls.gov/cgi-bin/surveymost)
Note C: Based on SEMCO's actual staffing levels for accounts payable personnel.

Exhibit 9

Washington Gas Light Company
Billing Rates for Certified Public Accountants – Other Finance Services

Calculation of Average Hourly Billing Rate by Public Accounting Position
Survey billing rates were those in effect in 2022

	Average Hourly Billing Rate (Note A)				
	Staff Accountant	Senior Accountant	Manager	Partner	
Average Hourly Billing Rate by CPA Firm Position	$ 119	$ 158	$ 233	$ 331	
Percent of Accounting Assignment	30%	30%	30%	10%	Weighted Average
	$ 36	$ 47	$ 70	$ 33	$ 186

Escalation to Test Year 2024 Midpoint (September 30, 2023)	
CPI at December 31, 2022 (B)	296.8
CPI at September 30, 2023 (B)	305.1
Inflation/Escalation	2.8%
Average Hourly Billing Rate For CPAs At September 30, 2023	$ 192

Note A: Source is AICPA's 2023 National PCPS/TSCPA Management of an Accounting Practice Survey
Note B: Source is U.S. Bureau of Labor Statistics (https://data.bls.gov/cgi-bin/surveymost)

Exhibit 10

Washington Gas Light Company
Billing Rates for Information Technology Professionals

Calculation of Average Hourly Billing Rate by Information Technology Position

Survey billing rates were those in effect during TY 2024

	Average Hourly Billing Rate (Note A)					
	Contractor Positions		Consultant Positions			
	Contractor	Senior Contractor	Associate	Manager	Partner	
Average Hourly Billing Rate by IT Position Category	$ 109	$ 163	$ 289	$ 401	$ 531	
Percent of IT Assignment	25%	25%	25%	15%	10%	Weighted Average
	$ 27	$ 41	$ 72	$ 60	$ 53	$ 254

Note A: Source is WGL and Rodenhauser & Company

Exhibit 11

Washington Gas Light Company
Billing Rates for Management Consultants

Survey billing rates in effect in 2023

A. Calculation of Average Hourly Billing Rate by Consultant Position

	Average Hourly Rates (Note A)				
	Analyst Consultant	Associate	Sr. Assoc/ Manager	Principal	Partner
Average	$ 255	$ 308	$ 377	$ 569	$ 707

B. Calculation of Overall Average Hourly Billing Rate Based on a Typical Distribution of Time on an Engagement

	Entry-Level Consultant	Associate Consultant	Senior Consultant	Junior Partner	Senior Partner	Weighted Average
Average Hourly Billing Rate (from above)	$ 255	$ 308	$ 377	$ 569	$ 707	
Percent of Consulting Assignment	30%	30%	25%	10%	5%	
	$ 76	$ 92	$ 94	$ 57	$ 35	$ 355

2023 Average Hourly Billing Rate For Management Consultants $ 355

Note A: Source is Rodenhauser & Company, LLC

IV – Question 2 – Provision of Services at the Lower of Cost or Market

Affiliates Versus Outside Provider Cost Comparison

As shown in the table below, affiliates' costs per hour are considerably lower than those of outside providers.

	TY 2024 Hourly Rates		
Service Provider	WGL Affiliates	Outside Providers	Difference--WGL Affiliates Greater(Less) Than Outside
Attorney	$ 101	$ 358	$ (257)
CPA - Accounts Payable	$ 56	$ 124	$ (68)
CPA - Other Finance	$ 62	$ 192	$ (130)
IT Professional	$ 91	$ 254	$ (163)
Management Consultant	$ 116	$ 355	$ (239)

As calculated below, based on these cost-per-hour differentials and the number of hours that affiliates billed WGL during TY 2024, the services would cost approximately $40.0 million more from outside providers. This is 198% more ($39,965,854 / $19,710,924 = 203%) than affiliates' total TY 2024 testable service billings to WGL.

	TY 2024 Dollar Difference		
Service Provider	Hourly Rate Difference--WGL Affiliates Greater(Less) Than Outside	WGL Affiliates Hours Charged	Dollar Difference
Attorney	$ (257)	8,577	$ (2,204,382)
CPA - Accounts Payable	$ (68)	13,056	$ (887,796)
CPA - Other Finance	$ (130)	101,642	$ (13,213,451)
IT Professional	$ (163)	31,450	$ (5,126,402)
Management Consultant	$ (239)	77,547	$ (18,533,823)
Total WGL Affiliates Less Than Outside Providers			$ (39,965,854)

V – Question 3 – Reasonableness of WGL's Total A&G Expenses

WGL's Total A&G Expenses per Customer

The cost of AltaGas and SEMCO services are recorded by WGL as Administrative and General expenses.

All of the services provided to WGL by AltaGas and SEMCO are A&G related and their charges are recorded as such in the books of WGL. Charges from affiliates are a sizable component of WGL's total A&G expenses. For 2023, these charges represent 13% of WGL's total A&G expenses, as calculated below.

Affiliate	2023
AltaGas	$ 26,781,103
SEMCO	$ 1,556,406
Total Affil. Charges	$ 28,337,509
Total WGL A&G	$218,749,642
Percent of WGL A&G	13%

Source: Company information

I compare WGL's total 2023 A&G expenses per customer to those of other combination gas/electric utilities whose data is available in the FERC Form 1. Data is not readily available for gas-only retail distribution utilities since there is no requirement that they file the Form 2 because most are not regulated by FERC.

It should be noted that account 926 – Employee Pensions and Benefits is excluded from the cost calculation for WGL and the comparison group. Expenses in this account pertain to all functional areas of a regulated utility, not just A&G.

FERC A&G Account	Total 2023 A&G Expenses
920 Administrative and General Salaries	$ 96,520,307
921 Office Supplies and Expenses	$ 35,374,963
923 Outside Services Employed	$ 38,603,257
925 Injuries and Damages	$ 18,261,111
928 Regulatory Commission Expenses	$ 2,488,795
930.1 General Advertising Expenses	$ 881,558
930.2 Miscellaneous General Expenses	$ 24,850,631
931 Rents	$ 249,387
935 Maintenance of General Plant	$ 1,519,633
Total WGL A&G Expenses	$ 218,749,642
Total WGL Customers at 12/31/2023	1,226,879
Total WGL A&G Charges per Customer	$ 178

Source: FERC Form 2; Baryenbruch & Company, LLC, analysis

V – Question 3 – Reasonableness of WGL's Total A&G Expenses

Comparison Group Total A&G Expenses per Customer

The following combination gas and electric utilities make up the comparison group:

Combination Gas and Electric Utility Comparison Group

Ameren Illinois Company	New York State Gas & Electric Company
Baltimore Gas and Electric Company	Niagra Mohawk Power Company
Black Hills Power, Inc.	Northern Indiana Public Service Company
Central Hudson Gas & Electric Corporation	Northern States Power Company (Minnesota)
Consolidated Edison Company	Northern States Power Company (Wisconsin)
Consumers Energy Company	Oklahoma Gas & Electric Company
Dominion Energy South Carolina, Inc	Pacific Gas & Electric Company
Duke Energy Indiana, LLC	PECO Energy Company
Duke Energy Ohio, Inc.	Public Service Company of Colorado
Duke Energy Progress, LLC	Rochester Gas & Electric Company
Empire District Electric Company	San Diego Gas & Electric Company
Fitchburg Gas & Electric Light Company	Southern Indiana Gas and Electric Company
Louisville Gas and Electric Company	Union Electric Company
Madison Gas and Electric Company	Wisconsin Power and Light Company
Montana Dakota Utilities, Inc.	Wisconsin Public Service Corporation

Source: FERC Form 1

The comparison group's expense pool includes the balances in the same FERC accounts as WGL. They are shown in the table below.

Accounts in Total

Operation
(920) Administrative and General Salaries
(921) Office Supplies and Expenses
(923) Outside Services Employed
(925) Injuries and Damages
(928) Regulatory Commission Expenses
(930.1) General Advertising Expenses
(930.2) Miscellaneous General Expenses
(931) Rents
Maintenance
(935) Maintenance of General Plant

Exhibit 12 (page 24) shows the calculation of total A&G expenses per customer for the comparison group.

WGL's 2023 total A&G expenses per customer are compared to the comparison group in Exhibit 13 (page 25). WGL's 2023 $178 per customer is in the middle of the third quartile, slightly higher than the group median. The cost for twelve comparison group utilities are higher than WGL and eighteen are lower.

WGL's total A&G expenses increased by 4% from 2023 to TY 2024. During that period, total charges from affiliates to WGL decreased by 2.6%, as shown in the table below.

Table 9

Affiliate Charges to WGL

Affiliate	2023	TY 2024	Change Amount	Change Percent
AltaGas	$26,781,103	$26,051,443	$ (729,660)	(2.7%)
SEMCo	$ 1,556,406	$ 1,562,389	$ 5,983	0.4%
Total	$28,337,509	$27,613,832	$ (723,677)	(2.6%)

Source: Company information

Exhibit 12

Washington Gas Light Company
Calculation of Comparison Group Total 2023 A&G Expenses Per Customer

Comparison Group Utilities	Total 2023 A&G Expenses	Total Customers	A&G Expenses per Customer
Ameren Illinois Company	$ 146,421,661	1,226,027	$ 119
Baltimore Gas and Electric Company	$ 175,469,625	1,336,794	$ 131
Black Hills Power, Inc.	$ 32,867,802	76,036	$ 432
Central Hudson Gas & Electric Corporation	$ 72,724,956	282,115	$ 258
Consolidated Edison Company	$ 540,895,075	3,645,153	$ 148
Consumers Energy Company	$ 125,151,723	1,884,290	$ 66
Dominion Energy South Carolina, Inc	$ 146,171,630	790,221	$ 185
Duke Energy Indiana, LLC	$ 103,555,044	894,160	$ 116
Duke Energy Ohio, Inc.	$ 43,752,059	752,909	$ 58
Duke Energy Progress, LLC	$ 240,404,072	1,718,128	$ 140
Empire District Electric Company	$ 53,659,920	183,990	$ 292
Fitchburg Gas & Electric Light Company	$ 4,894,571	30,736	$ 159
Louisville Gas and Electric Company	$ 56,099,896	434,120	$ 129
Madison Gas and Electric Company	$ 33,295,327	163,278	$ 204
Montana Dakota Utilities, Inc.	$ 24,108,239	144,895	$ 166
New York State Gas & Electric Company	$ 123,309,038	919,140	$ 134
Niagra Mohawk Power Company	$ 335,866,723	1,542,713	$ 218
Northern Indiana Public Service Company	$ 184,623,144	487,079	$ 379
Northern States Power Company (Minnesota)	$ 286,765,540	1,556,301	$ 184
Northern States Power Company (Wisconsin)	$ 45,252,268	268,830	$ 168
Oklahoma Gas & Electric Company	$ 102,713,878	892,274	$ 115
Pacific Gas & Electric Company	$ 3,056,766,478	5,649,612	$ 541
PECO Energy Company	$ 167,693,066	1,700,223	$ 99
Public Service Company of Colorado	$ 191,248,294	1,569,461	$ 122
Rochester Gas & Electric Company	$ 46,433,786	391,614	$ 119
San Diego Gas & Electric Company	$ 470,829,200	512,632	$ 918
Southern Indiana Gas and Electric Company	$ 38,057,399	155,182	$ 245
Union Electric Company	$ 200,994,657	1,254,162	$ 160
Wisconsin Power and Light Company	$ 90,162,390	495,097	$ 182
Wisconsin Public Service Corporation	$ 39,872,310	463,129	$ 86

Source: Company information, FERC Form 1 (2023), Baryenbruch & Company, LLC analysis

Exhibit 13

Washington Gas Light Company
Comparison of Service Company 2023 A&G Charges Per Customer

Comparison Group Utilities	2023 Total A&G Expenses per Customer		Quartile
San Diego Gas & Electric Company	$918		4th
Pacific Gas & Electric Company	$541		
Black Hills Power, Inc.	$432		
Northern Indiana Public Service Company	$379		
Empire District Electric Company	$292		
Central Hudson Gas & Electric Corporation	$258		
Southern Indiana Gas and Electric Company	$245		
Niagra Mohawk Power Company	$218		
Madison Gas and Electric Company	$204		3rd
Dominion Energy South Carolina, Inc	$185		
Northern States Power Company (Minnesota)	$184		
Wisconsin Power and Light Company	$182		
Washington Gas Light Company	**$178**		
Northern States Power Company (Wisconsin)	$168		
Montana Dakota Utilities, Inc.	$166		
Union Electric Company	$160	< median	
Fitchburg Gas & Electric Light Company	$159		2nd
Consolidated Edison Company	$148		
Duke Energy Progress, LLC	$140		
New York State Gas & Electric Company	$134		
Baltimore Gas and Electric Company	$131		
Louisville Gas and Electric Company	$129		
Public Service Company of Colorado	$122		
Ameren Illinois Company	$119		
Rochester Gas & Electric Company	$119		1st
Duke Energy Indiana, LLC	$116		
Oklahoma Gas & Electric Company	$115		
PECO Energy Company	$99		
Wisconsin Public Service Corporation	$86		
Consumers Energy Company	$66		
Duke Energy Ohio, Inc.	$58		

Source: Company information, FERC Form 1 (2023), Baryenbruch & Company, LLC analysis

V – Question 3 – Reasonableness of Total A&G Expenses

WGL's total A&G expenses increased by 4% from 2023 to TY 2024. During the same period, total charges from affiliates to WGL decreased by 2.6%, as shown in the table below.

Affiliate Charges to WGL

Affiliate	2023	TY 2024	Change Amount	Change Percent
AltaGas	$26,781,103	$26,051,443	$ (729,660)	(2.7%)
SEMCo	$ 1,556,406	$ 1,562,389	$ 5,983	0.4%
Total	$28,337,509	$27,613,832	$ (723,677)	(2.6%)

Source: Company information

V – Question 4 – Effectiveness of Governance Practices

Accounting for Affiliate Transactions

WGL's Cost Allocation Manual (CAM) describes WGL's cost accounting methodology as follows:

> The primary objective of Washington Gas' cost accounting methodology is to create a framework where all costs (labor, overheads, and other expenses) are properly attributed to the entity responsible for generating the expense or receiving the benefit of a service. Washington Gas utilizes a fully distributed cost accounting process that accumulates costs and bills amounts to affiliates. The fully distributed cost approach assigns costs either as direct labor charges (with appropriate overheads) and direct expenses, or as allocations of labor and expenses based on factors that are both relevant and measurable for the individual type of cost. This framework results in an assignment or allocation of costs that places all expenses with the appropriate business entity.
>
> It is the policy of Washington Gas and all its affiliates that costs will be directly assigned to the appropriate affiliate whenever reasonably possible, and that such costs will be allocated whenever direct assignment is not reasonably possible. Direct costs that benefit an affiliate are "assigned and billed" directly to the appropriate affiliate. For common services, tracking direct costs is not reasonable because one or more affiliates benefit from the expenditures. In such cases, these direct costs are allocated based on appropriate allocation factors described herein. Where appropriate, indirect costs are allocated based on the assignment or allocation of the related direct costs. It is the general intent to allocate operational costs to operational affiliates rather than holding companies.
>
> As described above, Washington Gas's policy and practice is to assign costs directly to the appropriate business entity whenever possible and practicable. All Washington Gas employees' direct labor hours are recorded and captured in WorkDay, Washington Gas's time and expense reporting system, following the Company's Time and Labor Reporting Procedure. Washington Gas employees code to time sheets in WorkDay, which interfaces directly into the Company's general ledger accounting system, and charge labor costs to the appropriate affiliate company based on actual time spent serving each affiliate.
>
> Direct non-labor expenses are charged directly to the business entity receiving the benefit. In some cases, Washington Gas will pay an invoice on behalf of an affiliate and will subsequently be reimbursed by that affiliate (Direct reimbursements). Direct reimbursements are not for actual services provided by Washington Gas. Any payments made by Washington Gas on behalf of an affiliate are cash-settled by the Affiliate in the period immediately following the transactions.
>
> Payroll-related overhead expenses associated with direct labor assigned to the appropriate affiliate are allocated each accounting period based upon the current period's labor costs multiplied by a specific benefit overhead rate. The specific benefit overhead rate is calculated as a percentage of the specific budgeted benefit costs compared to the total budgeted labor costs. Management will compare the actual costs vs. budgeted costs on a periodic basis and adjust the cost to actual cost if the variance exceeds the established threshold. Direct non-labor expenses are charged directly to the business entity receiving the benefit. In some cases, Washington Gas will pay an invoice on behalf of an affiliate and will subsequently be reimbursed by that affiliate (Direct reimbursements). Direct reimbursements are not for actual services provided by Washington Gas. Any payments made by

V – Question 4 – Effectiveness of Governance Practices

> Washington Gas on behalf of an affiliate are cash-settled by the Affiliate in the period immediately following the transactions.
>
> Cost Allocation Manual (pages 6-7)

Definition of Governance Practices

Governance practices are internal controls designed to provide assurance that objectives are being achieved relating to operations, reporting and compliance. Among other things, this is achieved through control activities, which are defined as follows:

> Control activities are the actions established through policies and procedures that help ensure that management's directives to mitigate risks to the achievement of objectives are carried out. Control activities are performed at all levels of the entity, at various stages within business processes, and over the technology environment.
>
> Source: "Internal Control – Integrated Framework, Executive Summary," Committee of Sponsoring Organizations of the Treadway Commission.

Governance Practices Applied to Affiliate Services/Charges

There are several ways by which WGL exercises control over affiliate services and charges. The most important of these are described below:

- Accounting and Financial Reporting – WGL's accounting and financial reporting policies and practices conform to Generally Accepted Accounting Principles (GAAP). GAAP refers to the common set of accounting conventions, rules and procedures recognized as authoritative by the accounting profession and used by all non-governmental entities as a basis for their external financial statements and reporting. In addition, WGL's accounting records are kept in accordance with the Uniform System of Accounts (USofA) for major gas utilities, as prescribed by the Federal Energy Regulatory commission (FERC). Affiliates also follows the directives of Sarbanes-Oxley regulations.

- Affiliate and WGL Internal Controls – Affiliates and WGL follow the directives of various internally established control procedures. Examples of these control procedures: (1) authority limits and approvals required for requisition and disbursements, (2) time and labor reporting; expense reporting and general ledger transactions; reasonableness review of actual to budget costs, (3) bank and general ledger account reconciliations, (4) access limitations to the accounts payable and general ledger accounting system and (5) internal audit testing procedures.

- AltaGas Budget Review – AltaGas' Financial Planning and Analysis (FP&A) group formally reviews AltaGas' budget for reasonableness and develops an understanding of material changes for both the whole of the budgets and allocation to affiliates, including WGL.

- SEMCO Budget Review – SEMCO's FP&A team reviews with senior management SEMCO's budget for reasonableness and develops an understanding of material changes for both the whole of the budgets and allocation to affiliates, including WGL.

- WGL Budget Review - WGL's FP&A team formally reviews with senior management WGL's budget for reasonableness and develops an understanding of material changes for both the whole of the budgets and allocation from affiliates, including WGL.

V – Question 4 – Effectiveness of Governance Practices

- Management Budget Review – After budgets have been reviewed by FP&A teams, they are reviewed by the management teams of AltaGas, SEMCO and WGL. Included in these reviews are affiliates' budgeted charges to WGL.

- Affiliate Bill Reviews – Invoices for both direct and assigned charges from affiliates are reviewed by the appropriate functional areas before reimbursements to AltaGas and SEMCO.

- WGL Budget Variance Analysis – WGL's FP&A team reviews the monthly spending report showing budget versus actual charges from AltaGas and SEMCO to determine drivers of variances, including charges from affiliates.

- Budget Variance Reporting – Each month, the FP&A teams from WGL, AltaGas, SEMCO prepare a series of reports included in a Monthly Results Package that are reviewed by various levels of management to document variances and provide explanations, as needed.

- External Audit Reviews – Washington Gas Light's independent auditors perform a Review of transactions between Washington Gas Light and its Affiliates in accordance with Chapter 39, "Affiliate Transactions Code of Conduct," of Title 15, District of Columbia Municipal Regulation, and an Examination of the affiliates transactions as required by the Code of Maryland, Section 4-208(b) and with the Code of Maryland Regulations 20.40.02, Affiliate Regulations Public Service Commission of Maryland. The review and examination consist principally of applying analytical procedures, making inquiries of persons responsible for the operations of the Company, obtaining an understanding of the data management systems and processes used to record, generate, aggregate, and report information, and a random sampling of transactions between the Utility and its affiliates.

ATTESTATION

I, PATRICK BARYENBRUCH, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Patrick Baryenbruch

PATRICK BARYENBRUCH

July 19, 2024

DATE

WITNESS BURGUM
EXHIBIT WG (M)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF THOMAS BURGUM
Exhibit WG (M)

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WASHINGTON GAS LIGHT COMPANY

District of Columbia

DIRECT TESTIMONY OF THOMAS BURGUM

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. Thomas Burgum. I am the Senior Director of Total Rewards and HR Operations for Washington Gas Light Company ("Washington Gas" or "Company"). My expertise is in Total Rewards optimization aligning program value with company goals. My business address is 6801 Industrial Road, Springfield, Virginia 22151.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a degree in mathematics from the University of Richmond in Richmond, VA.

I hold professional certifications in compensation (Certified Compensation Professional), benefits (Certified Employee Benefits Specialist) and human resources (Senior Professional in Human Resources).

I have over twenty-five (25) years of experience in Compensation, Benefits, and Human Resources Information Systems in program design, cost management, and professional development.

Prior to my role at Washington Gas, I held total rewards leadership positions at various energy companies and companies in other industries including Senior Director of Total Rewards at Ferguson Enterprises from 2018 to

2022, Vice President Compensation & Benefits at Interstate Hotels & Resorts from 2016 to 2018, and Global Total Rewards Director at AES Corporation from 2013 to 2016.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE ANY REGULATORY COMMISSION?

A. Yes, I previously filed rebuttal and rejoinder testimony before the District of Columbia Public Service Commission ("Commission") in Formal Case No. 1169. I also filed rebuttal testimony in Case No. 9704 before the Maryland Public Service Commission.

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to discuss the Company's Short-Term Incentive ("STI") program. My testimony describes the approach Washington Gas takes to ensure the Company pays competitive and reasonable compensation that will ensure value for customers. I also describe the changes to the STI program since my testimony in Formal Case No. 1169.

Please note that in my testimony I refer to the Company's 2023 Value Driver results sponsored by Company Witness Steffes, which are labeled as Exhibit WG (A)-1. Please also note that Company Witness Smith addresses why the Company is not proposing to eliminate any portion of STI related to the scorecard in her testimony.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. No.

IV. DISCUSSION

Q. PLEASE DESCRIBE THE COMPANY'S APPROACH TO COMPENSATION.

A. Washington Gas' compensation program is market-based and ties pay to performance. The Company's compensation philosophy for all management employees—including executives—is to target compensation at the market median of other similarly-sized energy and utility companies. The Company holds some pay "at risk" in the form of incentive that is not paid unless corporate and individual goals are met. The Company has designed compensation programs to attract, motivate, and retain qualified employees with the skills and experience required to operate the Company effectively, and to achieve the organization's short and long-term goals. Without appropriate, competitive compensation, the Company would lack critical means with which to attract and retain qualified employees and incent employee behavior towards meeting the Company's overarching goal to provide long-term value to its stakeholders, customers being primary among them.

Q. WHAT ARE THE COMPONENTS OF THE WASHINGTON GAS MANAGEMENT COMPENSATION PROGRAM?

A. The management compensation program consists of base salary and "at risk" pay which includes both an annual short-term incentive plan and a long-term incentive plan. All Company employees, including those covered by collective bargaining agreements, are eligible to receive an STI payment. Employees at the level of director and above, as well as those employees identified as having high potential, are included in the long-term incentive plan. Incentive programs are developed to link pay directly with performance. If the

Company does not meet its goals, incentive compensation awards may be reduced or not paid at all.

The Company's total rewards program includes both competitive pay and competitive benefits including retirement benefits for all employees. A limited number of executives also participate in the Defined Benefit ("DB") Supplemental Executive Retirement Plan ("SERP") or the Defined Contribution ("DC") SERP. The SERPs and associated restoration plans address federal limits placed on standard employee retirement plans ("qualified plans") that would otherwise result in executives receiving lesser income replacement in retirement than other employees. Like all Company-provided employee benefits, these plans were designed to enable the Company to compete for talent.

Q. PLEASE DESCRIBE THE COMPANY'S STI PLAN.

A. The Washington Gas annual STI plan was established to focus employees, including executives, on annual goals that help the Company achieve its strategy. All employees of the Company—including non-supervisory personnel, administrative personnel and union employees—are eligible to receive payments, depending on Company and individual performance. Under the terms of the plan, supervisory employees are assigned a target payout level expressed as a percentage of their base salary. Actual payout depends on the attainment of corporate goals included in the Company's Value Drivers.

Value Drivers include individual goals established early in the performance period, as well as a description of the customer benefits they provide as shown in Exhibit WG (A)-1 sponsored by Company Witness Steffes. The weighting of divisional versus individual goals varies by organizational level. Incentive payments to employees at the executive level are more dependent on

Company performance than individual performance because at higher levels in the organization individuals have increased opportunity to impact corporate performance. The Company's performance against established operational and financial measures determines whether incentive is paid, and if so, how much. Goals are set annually and vary year-to-year. The actual payment of incentive depends on the Company's performance against its balanced set of scorecard goals.

Q. HOW HAS THE COMMISSION TREATED STI PAY IN THE PAST?

A. My understanding is that since at least Formal Case No. 1093 in 2013, the Commission has found that STI is an accepted element of the Company's cost of service based on its benefits to customers.

Q. DOES THE COMPANY'S STI PROGRAM CONTINUE TO BENEFIT CUSTOMERS?

A. Yes. The STI program reinforces the link between employee performance and achievement of the Company's Value Drivers by rewarding individuals for their contributions towards such goals. Value Drivers reflect the utility's core obligations to customers and focus employees on providing safer, more reliable service at a reasonable cost. The Company's Value Drivers include, but are not limited to other goals, cost efficiency, safety, customer satisfaction, and system reliability, all of which benefit customers. Thus, by motivating employees to achieve these goals, incentive plans also benefit customers. As employees continuously strive to improve Washington Gas's operations, service provided to customers is improved.

Q. HAVE THERE BEEN ANY CHANGES TO THE STI PROGRAM SINCE YOUR PRIOR TESTIMONY IN FORMAL CASE NO. 1169?

A. Yes. Effective January 1, 2024, the Company increased the threshold of actual Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) performance versus budgeted EBITDA to allow for funding of the annual STI pool. The EBITDA funding threshold for the STI plan was increased from 80% to 90% beginning in 2024. In addition, Value Drivers have been stated more clearly with quantifiable metrics for defining a "success" or "exceeds" rating. Lastly, a scorecard specific to Washington Gas was introduced. Previously, Washington Gas followed a division-wide STI scorecard which included performance from SEMCO.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

ATTESTATION

I, THOMAS BURGUM, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

THOMAS BURGUM

7/19/24

DATE

WITNESS RAAB
EXHIBIT WG (N)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF PAUL H. RAAB
Exhibit WG (N)
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DIRECT TESTIMONY OF PAUL H. RAAB
Exhibit WG (N)
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Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF PAUL H. RAAB

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Paul H. Raab, and my business address is 5313 Portsmouth Road, Bethesda, MD 20816. I am an independent economic consultant.

Q. ON WHOSE BEHALF ARE YOU APPEARING TODAY?

A. I am appearing on behalf of Washington Gas Light Company ("Washington Gas" or "Company").

I. QUALIFICATIONS

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a B.A. in Economics from Rutgers University and an M.A. from the State University of New York at Binghamton with a concentration in Econometrics. While attending Rutgers, I studied as a Henry Rutgers Scholar.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I have been providing consulting services to the utility industry for my entire career, having assisted electric, gas, telephone, and water utilities; commissions; and intervenor clients in a variety of areas. I am trained as a quantitative economist so that most of this assistance has been in the form of mathematical and economic analysis and information systems development. My areas of focus are planning issues, costing and rate design analysis, and depreciation and life analysis. I began my career with the professional services firm that is now known as Ernst & Young, where I was employed for ten years.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE COMMISSIONS IN REGULATORY PROCEEDINGS?

A. Yes. I have provided expert testimony before the Public Service Commission of the District of Columbia ("Commission") in many cases since 1990, as well as numerous state regulatory authorities. I have also provided expert testimony before the Federal Energy Regulatory Commission, the Pennsylvania House Consumer Affairs Committee, the Michigan House Economic Development and Energy Committee, the Province of Saskatchewan, and the United States Tax Court. Details on the subject matter of the testimony presented are provided in Exhibit WG (N)-1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony serves two main purposes. First, I provide an estimate of "normal" weather that is consistent with the Commission's decision in Order No. 21939.[1] Consistent with that same order, I then use these estimates of normal weather to weather normalize test year volumes which are used by Company Witness Tracey Smith as an input to her class cost of service studies and as the basis for the Company's rate design.

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[1] *In the Matter of the Application of Washington Gas Light Co. for Auth. to Increase Existing Rates & Charges for Gas Serv.,* Formal Case No. 1169, Order No. 21939, Paragraph 178, page 55., December 22, 2023.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I sponsor four exhibits. Exhibit WG (N)-1 is a summary of my qualifications and experience. Exhibit WG (N)-2 presents normal weather heating degree days ("HDDs") for the District of Columbia on a calendar basis. Exhibit WG (N)-3 provides the meter reading schedule for the test period and presents the conversion of the calendar normal weather HDDs to a billing basis. The revised normal weather HDDs are used to develop weather-normalized billing determinants for the test year, as summarized in Exhibit WG (N)-4. The above-designated exhibits were prepared by me or under my direction and supervision.

IV. ORGANIZATION OF TESTIMONY

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into three additional sections, labeled V through VII. Section V presents my calculation of "normal" weather that is consistent with the Commission's decision in the Company's prior rate proceeding, Formal Case No. 1169. I recommend that these estimates of normal weather HDDs be used to weather normalize volumes in the test year in this case. Section VI presents the method by which billing determinants are weather normalized and the resulting weather normalized billing determinants used by Company Witness Tracey Smith in the development of a fully allocated class cost of service study and the rates that are intended to collect the necessary revenues in the rate effective period. Finally, Section VII contains conclusions and recommendations.

V. NORMAL WEATHER

Q. PLEASE DISCUSS HOW WEATHER AFFECTS NATURAL GAS USAGE IN THE TEST YEAR.

A. Weather affects natural gas usage in the test year in two ways. First, natural gas is primarily used in the District of Columbia for heating and usage is therefore inherently weather-sensitive. Second, because rates are based on an estimate of "normal" weather usage in the rate-effective period, if the estimate of normal weather does not reflect what is likely to occur in that period, usage will be over- or under-stated.

Q. HAS THE COMMISSION PREVIOUSLY CONSIDERED THE ISSUE OF NORMAL WEATHER FOR WASHINGTON GAS?

A. Yes, how normal weather was to be determined was a part of Designated Issue (e) in Formal Case No. 1093. In its final order in that case, Order No. 17132, the Commission rejected the Company's long-standing approach to determine normal weather because it relied on data that was not publicly available, instead finding that "using 30 years of weather data independently generated by NOAA and third parties provides a better assessment of what the weather is likely to be during the rate effective period than WGL's use of weather data dating back to 1871."[2] The Commission further found that, "[i]n future cases, WGL shall use the most

[2] *In the Matter of the Investigation into the Reasonableness of Washington Gas Light Companys Existing Rates & Charges for Gas Serv.*, Formal Case No. 1093, Order No. 17132, ¶ 121 (May 13, 2013). The fact that this discussion was related to the data source from which the normal weather estimate was to be derived and not the normal weather estimate itself was subsequently clarified in Formal Case No. 1169, Order No. 21939, ¶ 174 (December 22, 2023).

recent 30 years to determine normal weather"[3] and that "[t]o ensure that the Company's weatherization adjustment is fully transparent, WGL is directed to file in all future rate cases all of its work papers related to weather normalization, identify the sources of data it relies upon, explain any statistical models, and provide clearer step-by-step descriptions of how it calculates its weather normalization adjustment."[4]

Q. DID THE COMMISSION ALSO CONSIDER THE ISSUE OF NORMAL WEATHER FOR WASHINGTON GAS IN SUBSEQUENT CASES?

A. Yes, the Commission considered the issue of normal weather and how it was to be calculated in Formal Case No. 1162 and Formal Case No.1169. In Formal Case No. 1162, the Commission approved the Non-Unanimous Agreement of Stipulation and Full Settlement filed by Washington Gas, finding that it was in the public interest. With respect to weather normalization, Section 2 of the Agreement states that:

> The Settling Parties agree that rates will be based upon billing determinants recommended by Washington Gas in this proceeding, without any attribution to a weather normalization method or normal weather study for calculating the billing determinants. No element of settlement shall be construed as support for: Washington Gas's proposed weather normalization methodology; Washington Gas's recommended heating degree day measures or methodology for estimating normal heating degree days; or the details of its normal weather study. All parties retain their rights to propose a particular weather normalization method, heating degree day measures or methodology for estimating normal heating degree days, and normal weather study in future cases.

In Formal Case No. 1169, the Commission directly addressed the Company's weather normalization adjustment methodology.

[3] Ibid., ¶ 121.
[4] Ibid., ¶ 121.

As I explain more fully in this section of my testimony, the Company's estimate of normal weather HDDs fully adheres to these requirements.

Q. GIVEN THE COMMISSION'S PRIOR DECISIONS, HOW DID YOU CALCULATE NORMAL WEATHER HDDS FOR THIS CASE?

A. I calculated normal weather HDDs in the following steps:

1. Download daily maximum and minimum temperature data for Washington Reagan National Airport, Station ID No. USW00013743 from the NOAA website (https://www.ncdc.noaa.gov/cdo-web/search) for the prior 30-year period (1994 to 2023), and determine daily HDDs for this same period.

2. Develop a 30-year average HDD value for each day of the sample.

3. Sum the appropriate daily observations by month and year to develop corresponding estimates of normal weather HDDs on a calendar basis. This calculation is summarized in Exhibit WG (N)-2.

4. Convert the calendar year estimates to billing cycle estimates using test year meter read schedules. This calculation is summarized in Exhibit WG (N)-3.

Q. HOW DO YOU CONVERT NORMAL WEATHER HDDS FROM A CALENDAR BASIS TO A BILLING BASIS?

A. The Company uses the actual read dates, for each cycle day in each month, and sums the calendar HDDs that occurred between the two meter read dates (current month read date and prior month read date). Washington Gas sums the calendar HDDs starting on the day prior to the read dates based on a simplified assumption that all meters are read in the morning. The average of the cycle day HDDs in a month becomes the monthly billing basis Normal Weather HDDs used in the Normal Weather Study's calculation of Normal Weather Throughput. Exhibit WG (N)-3 provides the meter reading schedule for the test period and presents the conversion of the calendar normal weather HDDs to a billing basis as described above.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE NORMAL WEATHER ESTIMATE THAT SHOULD BE USED TO DEVELOP TEST YEAR BILLING DETERMINANTS?

A. I recommend that a normal weather estimate of 3729 HDDs be used for this purpose, as provided in more detail in Exhibit WG (N)-2 and associated workpapers.

VI. NORMAL WEATHER THROUGHPUT STUDY

Q. PLEASE DESCRIBE THE CALCULATION OF NORMAL WEATHER THROUGHPUT.

A. The process begins by first calculating Normal Weather HDDs, as described in the prior section of my testimony. After Normal Weather HDDs are calculated, they are converted from a calendar month basis to a billing month basis using the Company's most recent meter reading schedule. Next, the Company gathers 60 months of usage and actual HDD data from the Company's billing system. The usage information is extracted by customer class. Using these data, and on a class-by-class basis, the Company performs a linear regression calculation where usage per customer is the dependent variable and HDDs, a trend variable and a binary variable representing the impact of COVID-19 are the explanatory variables. This formula yields the variation per HDD (weather sensitivity coefficient) and the base use factor.

The weather sensitivity coefficient, multiplied both by the Normal Weather HDDs and by the number of customers,[5] results in normal weather gas usage. This step is performed by month and by customer class. The base use factor multiplied by the number of customers results in the base gas usage. This calculation is also performed by month and customer class. Total Normal Weather Gas plus Base Gas Usage yields total Normal Weather Throughput.

Q. HAS THE COMPANY MADE ANY CHANGES TO THIS CALCULATION FOR THIS CASE RELATIVE TO FORMAL CASE NO. 1169?

A. No.

Q. HOW IS THE NORMAL WEATHER STUDY ORGANIZED?

A. The Normal Weather Study, Exhibit WG (N)-4, consists of three schedules:

- Schedule 1 is the summary of the results of the study. It presents total normal weather therm throughput by customer class.
- Schedule 2 calculates the weather gas and base gas usage based on the billing basis Normal Weather HDDs, customers, variation per HDD, and the base gas factor. This schedule is presented in two formats: a summarized version showing the total of the amounts calculated by customer class as well as a detailed version showing the detail by customer class per month over the 12-month period.
- Schedule 3 calculates the variation per HDD and base gas factors based on 60 months of usage and actual HDD data.

[5] The Company uses active meters in the test year as an estimate for the normal number of bills that will be rendered.

The process of preparing the study begins with Schedule 3 and builds up to Schedule 1. Schedule 3 is the first calculation step followed by Schedule 2 and then Schedule 1. Each of the calculations performed in the Normal Weather Study is more fully described below.

Q. HOW ARE THE VARIATION PER HDD (OR WEATHER SENSITIVITY COEFFICIENT) AND BASE USE FACTORS CALCULATED?

A. In order to calculate the variation per HDD and base gas factors, the Company uses a simple linear regression calculation based on the relationship between HDDs, a COVID dummy variable[6], and any trend in usage per customer, and usage per bill. The process begins by extracting 60 months of usage and Months Billed data from the Company's billing system by customer class. Aggregate usage for the month is divided by the number of Months Billed to arrive at an average usage per bill. Actual HDDs are based on temperature observations recorded at Ronald Reagan Washington National Airport. Using the same process as described for the Normal Weather HDD calculation, the Company converts the temperature readings into HDDs, and then converts the calendar HDDs to a billing basis. The relationship between usage per bill and actual HDDs and other relevant variables forms the basis for the regression calculation. Actual HDDs, the COVID dummy variable, and any trend in usage per customer are the independent variables, and usage per bill is the dependent variable. The coefficient associated with the HDD variable is the weather sensitivity

[6] While Covid last directly affected usage in 2021, a variable reflecting its impact is included to ensure that the effects of the pandemic and associated quarantine are isolated from the impact of temperature on usage and that the estimated heat sensitive factors measure the impact of temperature on usage, and nothing else.

coefficient and the point at which the regression line intercepts the y-axis (*i.e.*, zero HDDs) is the base gas factor. These regression coefficients are calculated using the commercially available regression package EViews, the output of which is summarized on Schedule 3 of the Normal Weather Study by customer class.

Q. WHY IS IT APPROPRIATE TO USE A LINEAR REGRESSION CALCULATION FOR CALCULATING WEATHER SENSITIVITY?

A. The Company knows that because most customers are using natural gas for space heating, outdoor air temperature will impact their usage. Even for customers in non-heating classes, there is a strong relationship between heating degree days and usage. This is likely driven by using natural gas for water heating and gas fireplaces. That all classes are sensitive to weather is further demonstrated in test period actual throughput. For all classes, usage spikes in the winter such that almost 50% of throughput occurs in just three months: the January through March billing periods.

As the purpose of this adjustment is weather normalization, the Company is attempting to explain the effect of weather on usage, not other variables that may have an impact on usage. Thus, it is appropriate to use heating degree days as the explanatory variable. However, it is also important that all relevant variables be included that may have an impact on usage and affect the weather sensitivity coefficient and the resulting calculation of weather normal usage. Thus, inclusion of the COVID dummy variable and the trend variable in this case is appropriate to ensure that an accurate estimate of weather normal usage has been obtained. The Company's current model does this, while also providing for simplicity in execution and allowing for all parties to clearly understand the inputs, the calculation, and outputs while still achieving the goal of a reasonably accurate prediction of normal weather usage.

Q. PLEASE EXPLAIN MONTHS BILLED AND WHY THIS IS USED IN THE CALCULATION.

A. Months Billed is a calculated field, which in turn relies on the days served per bill, in the Company's billing system. This calculated field represents a normal bill based on the typical number of days served derived from the meter reading schedule. For example, if 60 days served were billed on one bill, the calculation would count that as two Months Billed. The reason for using this calculation is so that Washington Gas can arrive at an accurate usage per customer calculation. If the Company used just the number of bills or the number of customers, that would misstate usage per customer on bills that cover more than one period.

Q. ONCE THE VARIATION PER HDD AND BASE GAS FACTORS ARE CALCULATED IN SCHEDULE 3, WHAT IS THE NEXT CALCULATION STEP?

A. The factors calculated in Schedule 3 are used next in Schedule 2. Schedule 2 incorporates number of customers, usage, actual HDDs, the COVID dummy variable, the trend variable, and Normal Weather HDDs (Normal Weather HDDs are converted to a bill month basis using the same process as is used for actual HDDs) for the 12-month test period. Test period weather-related throughput is then calculated by multiplying the number of customers, Normal Weather HDDs, and the variation per HDD factor. Test period base gas usage is calculated by multiplying Months

Billed and the base gas factor (including COVID effects and any trend in usage). Test period weather-related usage plus test period base gas usage results in Total Test Period Normal Weather Throughput. All calculations on Schedule 2 are performed by customer class.

Q. HOW HAS THE COMPANY INCORPORATED THE SPECIAL CONTRACT CUSTOMERS INTO ITS NORMAL WEATHER STUDY?

A. The Company has created separate categories to address normal weather calculations for the special contract customers. The therms calculated here support the calculation of revenues for these customers used elsewhere in this case.

Q. WHAT ARE THE FINAL RESULTS OF THESE CALCULATIONS AND HOW ARE THEY USED?

A. The final, adjusted, test period, normal weather throughput is summarized by customer class on Schedule 1 of the Normal Weather Study. The firm customer throughput summarized on Schedule 1 is then used by Company Witness Banks in her Revenue Study to calculate test period, normal weather distribution charge (also referred to as volumetric rate) revenues. Company Witness Tuoriniemi also uses normal weather throughput in his demonstration of the operation of the Company's proposed Weather Normalization Adjustments ("WNA")

The normal weather throughput is further used by Company Witness Smith in the Per Book Jurisdictional Cost of Service Study, Exhibit WG (F)-2, to allocate costs among the jurisdictions. Equally, throughput information from the Normal Weather Study is used in the Class Cost of Service Study to allocate costs among customer classes. Within both cost-of-service studies, normal weather throughput (either in total, for firm only, for sales or delivery customers only, peak usage, or a composite of peak and total usage) is used to allocate several items in rate base[7] and expense (this is detailed in Company Witness Smith's Exhibit WG (F)-2 and the Class Cost of Service Study in her Exhibit WG (F)-4.

Finally, normal weather throughput is also used as the basis for determining volumetric rates in the rate design calculation, as discussed by Company Witness Lawson.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Customer usage and outdoor air temperature are directly, positively, and linearly correlated with one another. As such, using the Company's method arrives at a reasonable estimate of usage under normal weather conditions. Therefore, I recommend that the Commission adopt the Company's calculation of normal weather throughput as presented in the Normal Weather Study that I sponsor as Exhibit WG (N)-4.

VII. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE APPROPRIATE ESTIMATE OF NORMAL WEATHER HDDS TO BE USED IN THE CURRENT CASE.

A. I have developed estimates of normal weather HDDs using prior Commission decisions as a guide. This guidance requires that such estimates rely on the most recent 30 years of weather data independently generated by NOAA. This guidance also requires that this estimate be

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[7] As approved by the Commission in Order No. 18827.

supported by all work papers related to weather normalization, an identification of the sources of data upon which the estimate relies, an explanation of any statistical models, and clear step-by-step descriptions of how it calculates its weather normalization adjustment. The results of applying these guidelines are estimates of normal weather HDDs on a calendar basis summarized in Exhibit WG (N)-2, estimates of normal weather HDDs on a billing cycle basis summarized in Exhibit WG (N)-3, and estimates of normal weather throughput summarized in Exhibit WG (N)-4.

Q. WHAT DO YOU RECOMMEND?

A. I make two recommendations:

1. I recommend that 3729 HDDs be used as the estimate of normal weather HDDs in this case, as developed in more detail in Exhibit WG (N)-2 and associated workpapers.
2. I recommend that the Commission adopt the Company's calculation of normal weather throughput as presented in the Normal Weather Study that I sponsor as Exhibit WG (N)-4.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

PAUL H. RAAB

Mr. Raab's consulting focus is on the regulated public utility industry. His experience includes mathematical and economic analyses and system development and his areas of expertise include regulatory change management, load forecasting, supply-side and demand-side planning, management audits, mergers and acquisitions, costing and rate design, and depreciation and life analysis.

PROFESSIONAL EXPERIENCE

Mr. Raab has directed or has had a key role in numerous engagements in the areas listed above. Representative clients are provided for each of these areas in the subsections below.

Regulatory Change Management. Mr. Raab has recently been assisting both electric and natural gas utilities as they prepare to operate in an environment that is significantly different from the one they operate in today. This work has involved the development of unbundled cost of service studies; the development of strategies that will allow companies to prosper in a restructured industry; retail access program development, implementation, and evaluation; and the development of innovative ratemaking approaches to accompany changes in the regulatory structure. Representative clients for whom he has performed such work include:

- Texas Gas Service
- Virginia Natural Gas
- UGI Utilities, Inc. – Gas Division, UGI Penn Natural Gas, Inc., and UGI Central Penn Gas, Inc.
- The Peoples Natural Gas Company d/b/a Dominion Peoples
- National Fuel Gas Distribution Corporation
- Columbia Gas of Pennsylvania, Inc.
- Aquila
- Kansas Corporation Commission
- Atmos Energy Corporation
- Electric Cooperatives' Association
- Cleco
- Washington Gas
- Western Resources
- Kansas Gas Service
- Mid Continent Market Center.

Load Forecasting. Mr. Raab has broad experience in the review and development of forecasts of sales forecasts for electric and natural gas utilities. This work has also included the development of elasticity of demand measures that have been used for attrition adjustments and revenue requirement reconciliations. Representative clients for whom he has performed such work include:

- Washington Gas Energy Services
- Central Louisiana Electric Company
- Washington Gas
- Saskatchewan Public Utilities Review Commission
- Union Gas Limited
- Nova Scotia Power Corporation
- Cajun Electric Power Cooperative
- Cincinnati Gas & Electric
- Commonwealth Edison Company
- Cleveland Electric Illuminating
- Public Service of Indiana
- Atlantic City Electric Company
- Detroit Edison Company
- Sierra Pacific Power
- Connecticut Natural Gas Corporation
- Appalachian Power Company
- Missouri Public Service Company
- Empire District Electric Company
- Public Service Company of Oklahoma
- Wisconsin Electric Power Company
- Northern States Power Company
- Iowa State Commerce Commission
- Missouri Public Service Commission.

Supply Side Planning. Mr. Raab has assisted clients to determine the most appropriate supply-side resources to meet future demands. This assistance has included the determination of optimal sizes and types of capacity to install, determination of production costs including and excluding the resource, and an assessment of system reliability changes because of different resource additions. Much of this work for the following clients has been done in conjunction with litigation:

- Enstar Natural Gas
- AGL Resources
- Washington Gas
- Soyland Electric Cooperative
- Houston Lighting and Power
- City of Farmington, New Mexico
- Big Rivers Electric Cooperative
- City of Redding, California
- Brown & Root
- Kentucky Joint Committee on Electric Power Planning Coordination
- Sierra Pacific Power.

Demand Side Planning. Demand Side Planning involves the forecasting of future demands; the design, development, implementation, and evaluation of demand side management programs; the determination of future supply side costs; and the integration of cost-effective demand side management programs into an Integrated Least Cost Resource Plan. Mr. Raab has performed such work for the following clients:

- UGI Utilities
- Dominion Peoples Gas
- National Fuel Gas Distribution Corporation
- Columbia Gas of Pennsylvania
- Kansas Gas Service
- Atmos Energy Corporation
- Black Hills Gas Company
- Oklahoma Natural Gas Company
- Washington Gas Light Company
- Piedmont Natural Gas Company
- Chesapeake Utilities
- Pennsylvania & Southern Gas
- Montana-Dakota Utilities.

Management Audits. Mr. Raab has been involved in several management audits. Consistent with his other experience, the focus of his efforts has been in the areas of load forecasting, demand- and supply-side planning, integrated resource planning, sales and marketing, and rates. Representative commission/utility clients are as follows:

- Arizona Corporation Commission/Arizona Public Service Company
- Public Utilities Commission of Ohio/East Ohio Gas
- Kentucky Public Service Commission/Louisville Gas & Electric
- New Hampshire Public Service Commission/Public Service Company of New Hampshire
- New Mexico Public Service Commission/Public Service of New Mexico
- New York Public Service Commission/New York State Electric & Gas
- Missouri Public Service Commission/Laclede Gas Company
- New Jersey Board of Public Utilities/Jersey Central Power & Light
- New Jersey Board of Public Utilities/New Jersey Natural Gas
- Pennsylvania Public Utilities Commission/ Pennsylvania Power & Light
- California Public Utilities Commission/San Diego Gas & Electric Company.

Mergers and Acquisitions. Mr. Raab has been involved in several merger and acquisition studies throughout his career. Many of these were conducted as confidential studies and cannot be listed. Those in which his involvement was publicly known are:

- ONEOK, Inc./Southwest Gas Corporation
- Western Resources
- Constellation.

Costing and Rate Design Analysis. Mr. Raab has prepared generic rate design studies for the National Governor's Conference, the Electricity Consumer's Resource Council, the Tennessee Valley Industrial Committee, the State Electricity Commission of

Western Australia, and the State Electricity Commission of Victoria. These generic studies addressed advantages and disadvantages of alternative costing approaches in the electric utility industry; the strengths and weaknesses of commonly encountered costing methodologies; future tariff policies to promote equity, efficiency, and fairness criteria; and the advisability of changing tariff policies. Mr. Raab has performed specific costing and rate design studies for the following companies:

- New Mexico Gas
- SEMCO Gas
- Enstar Natural Gas
- Atmos Energy Corporation
- Southern Maryland Electric Cooperative, Inc.
- Comcast Cable Communications, Inc.
- Cable Television Association of Georgia
- Devon Energy
- Aquila
- Oklahoma Natural Gas
- Semco Energy Gas Company
- Laclede Gas
- Western Resources
- Kansas Gas Service Company
- Central Louisiana Electric Company
- Washington Gas Light Company
- Piedmont Natural Gas Company
- Chesapeake Utilities
- Pennsylvania & Southern Gas
- KPL Gas Service Company
- Allegheny Power Systems
- Northern States Power
- Interstate Power Company
- Iowa-Illinois Gas & Electric Company
- Arkansas Power and Light
- Iowa Power & Light
- Iowa Public Service Company
- Southern California Edison
- Pacific Gas & Electric
- New York State Electric & Gas
- Middle South Utilities
- Missouri Public Service Company
- Empire District Electric Company
- Sierra Pacific Power
- Commonwealth Edison Company
- South Carolina Electric & Gas
- State Electricity Commission of Western Australia
- State Electricity Commission of Victoria, Australia
- Public Service Company of New Mexico

- Tennessee Valley Authority.

Depreciation and Life Analysis. Mr. Raab has extensive experience in depreciation and life analysis studies for the electric, gas, rail, and telephone industries and has taught a course on depreciation at George Washington University, Washington, DC. Representative clients in this area include:

- Champaign Telephone Company
- Plains Generation & Transmission Cooperative
- CSX Corporation (Includes work for Seaboard Coast Line, Louisville & Nashville, Baltimore & Ohio, Chesapeake & Ohio, and Western Maryland Railroads)
- Lea County Electric Cooperative, Inc.
- North Carolina Electric Membership Cooperative
- Alberta Gas Trunk Lines (NOVA)
- Federal Communications Commission.

TESTIMONY

The following table summarizes Mr. Raab's testimony experience.

Jurisdiction	Docket Number	Subject
Alaska	U-09-069, U-09-070	Rate Design
	U-14-010	Rate Design
Colorado	14AL-0300G	Costing/Rate Design
	17AL-0363G	Costing/Rate Design
	19AL-0309G	Costing/Rate Design
	22AL-0046G	Costing/Rate Design
District of Columbia	834	Demand Side Planning
	905	Costing/Rate Design
	917	Costing/Rate Design
	921	Demand Side Planning
	922	Rate Design
	934	Rate Design
	989	Rate Design
	1016	Rate Design
	1053	Costing/Rate Design
	1054	Costing/Rate Design
	1079	Rate Design
	1093	Costing/Rate Design
	1137	Costing/Rate Design
	1162	Costing/Rate Design
	1169	Costing/Rate Design

Jurisdiction	Docket Number	Subject
Georgia	18300-U	Costing/Rate Design
Indiana	36818	Capacity Planning
Iowa	RPU-05-2	Costing/Rate Design
Kansas	174,155-U	Retail Competition
	176,716-U	Costing/Rate Design
	98-KGSG-822-TAR	Rate Design
	99-KGSG-705-GIG	Restructuring
	01-KGSG-229-TAR	Rate Design
	02-KGSG-018-TAR	Rate Design
	02-WSRE-301-RTS	Cost of Service
	03-KGSG-602-RTS	Cost of Service/Rate Design
	03-AQLG-1076-TAR	Rate Design
	05-AQLG-367-RTS	Cost of Service/Rate Design
	06-KGSG-1209-RTS	Cost of Service/Rate Design
	07-AQLG-431-RTS	Rate Design
	08-WSEE-1041-RTS	Cost of Service
	10-KCPE-415-RTS	Cost of Service/Rate Design
	10-KGSG-421-TAR	Demand Side Planning
	10-KCPE-795-TAR	Demand Side Planning
	12-WSEE-112-RTS	Cost of Service/Rate Design
	12-KGSG-835-RTS	Cost of Service/Rate Design
	12-GIMX-337-GIV	Demand Side Planning
	12-KG&E-718-CON	Cost of Service
	13-KG&E-451-CON	Cost of Service
	13-WSEE-629-RTS	Cost of Service/Rate Design
	14-ATMG-320-RTS	Cost of Service/Rate Design
	15-WSEE-181-TAR	Demand Side Planning
	15-KCPE-116-RTS	Cost of Service/Rate Design
	16-ATMG-079-RTS	Cost of Service/Rate Design
	16-KGSG-491-RTS	Cost of Service/Rate Design
	16-KCPE-446-TAR	Demand Side Planning
	18-KCPE-480-RTS	Cost of Service/Rate Design
	18-KGSG-560-RTS	Cost of Service/Rate Design
	19-ATMG-525-RTS	Cost of Service/Rate Design
	22-EKME-254-TAR	Demand Side Planning
	23-ATMG-359-RTS	Cost of Service/Rate Design
	23-EKCE-775-RTS	Cost of Service/Rate Design
	24-KGSG-610-RTS	Cost of Service/Rate Design

Jurisdiction	Docket Number	Subject
Kentucky	9613	Capacity Planning
	97-083	Management Audit
	2009-00354	Cost of Service
	2013-00148	Cost of Service
	2015-00343	Cost of Service
	2017-00349	Cost of Service
	2018-00281	Cost of Service
	2021-00214	Cost of Service
Louisiana	U-21453	Restructuring/Market Power
Maryland	8251	Costing/Rate Design
	8259	Demand Side Planning
	8315	Costing/Rate Design
	8720	Demand Side Planning
	8791	Costing/Rate Design
	8920	Costing/Rate Design
	8959	Costing/Rate Design
	9092	Costing/Rate Design
	9104	Costing/Rate Design
	9106	Costing/Rate Design
	9180	Capacity Planning
	9267	Costing/Rate Design
	9433	Capacity Planning
	9481	Costing
	9651	Costing/Rate Design
	9704	Costing/Rate Design
Michigan	U-6949	Load Forecasting
	U-13575	Costing/Rate Design
	U-16169	Costing/Rate Design
	U-20479	Costing/Rate Design
Missouri	GR-2002-356	Rate Design
Montana	D2005.4.48	Costing/Rate Design
Nebraska	NG-0001, NG-0002, NG-0003	Rate Design
	NG-0041	Rate Design
Nevada	81-660	Load Forecasting
New Jersey	OAL# PUC 1876-82	Load Forecasting

Jurisdiction	BPU# 822-0116 **Docket Number**	**Subject**
New Mexico	2087	Capacity Planning
	11-00042-UT	Rate Design
New York	27546	Costing/Rate Design
Ohio	81-1378-EL-AIR	Load Forecasting
Oklahoma	27068	Load Forecasting
	PUD 200400610	Costing/Rate Design
	PUD 200700449	Demand Side Planning
	PUD 200800348	Costing/Rate Design
	PUD 200900110	Costing/Rate Design
	PUD 201000143	Demand Side Planning
	PUD 201100170	Demand Side Planning
	PUD 201200029	Demand Side Planning
	PUD 201300007	Demand Side Planning
	PUD 201300032	Demand Side Planning
	PUD 201400069	Demand Side Planning
	PUD 201500138	Demand Side Planning
	PUD 201500213	Costing/Rate Design
	PUD 201600132	Demand Side Planning
	PUD 201700079	Demand Side Planning
	PUD 201800028	Demand Side Planning
	PUD 201900018	Demand Side Planning
	PUD 201900021	Demand Side Planning
	PUD 202000022	Demand Side Planning
	PUD 202100062	Demand Side Planning
	PUD 202100063	Costing/Rate Design
	PUD 202200023	Demand Side Planning
	PUD 202200036	Demand Side Planning
	PUD 202300012	Demand Side Planning
	PUD 202400010	Demand Side Planning

Jurisdiction	Docket Number	Subject
Pennsylvania	R-0061346	Costing/Rate Design
	M-2009-2092222, M-2009-2112952, M-2009-2112956	Demand Side Planning
	M-2009-2093216	Demand Side Planning
	M-2009-2093217	Demand Side Planning
	M-2009-2093218	Demand Side Planning
	M-2010-2210316	Demand Side Planning
	R-2010-2214415	Demand Side Planning
	M-2012-2334387, M-2012-2334392, M-2012-2334398	Demand Side Planning
	M-2012-2334388	Demand Side Planning
	M-2015-2177174	Demand Side Planning
Tennessee	PURPA Hearings	Costing/Rate Design
US Tax Court	4870	Life Analysis
	4875	Life Analysis
Texas	GUD No. 9762	Costing/Rate Design
	GUD No. 10170	Costing/Rate Design
	GUD No. 10174	Costing/Rate Design
	GUD No. 10506	Demand Side Planning
	GUD No. 10526	Demand Side Planning
	GUD No. 10779	Costing/Rate Design
	GUD No. 10928	Costing/Rate Design
	OS-22-00009896	Costing/Rate Design
	Case No.00014399	Costing/Rate Design

Jurisdiction	Docket Number	Subject
Virginia	PUE900013	Demand Side Planning
	PUE920041	Costing/Rate Design
	PUE940030	Costing/Rate Design
	PUE940031	Costing/Rate Design
	PUE950131	Capacity Planning
	PUE980813	Costing/Rate Design
	PUE-2002-00364	Costing/Rate Design
	PUE-2003-00603	Costing/Rate Design
	PUE-2006-00059	Costing/Rate Design
	PUE-2008-00060	Demand Side Planning
	PUE-2009-00064	Demand Side Planning
	PUE-2012-00118	Demand Side Planning
	PUE-2015-00132	Demand Side Planning
	PUE-2015-00138	Demand Side Planning
	PUE-2016-00001	Capacity Planning
	PUR-2018-00080	Capacity Planning
	PUR-2018-00193	Demand Side Planning
	PUR-2021-00288	Demand Side Planning
	PUR-2022-00054	Costing/Rate Design
West Virginia	79-140-E-42T	Capacity Planning
	90-046-E-PC	Demand Side Planning
Wisconsin	05-EP-2	Capacity Planning

In addition, Mr. Raab has presented expert testimony before the Federal Energy Regulatory Commission, the Pennsylvania House Consumer Affairs Committee, the Michigan House Economic Development and Energy Committee and the Province of Saskatchewan. He has also served on the Advisory Board of the Expert Evidence Report, published by The Bureau of National Affairs, Inc.

EDUCATION

Mr. Raab holds a B.A. (with high distinction) in Economics from Rutgers University and an M.A. from SUNY at Binghamton with a concentration in Econometrics. While attending Rutgers, he studied as a Henry Rutgers Scholar.

PUBLICATIONS AND PRESENTATIONS

Mr. Raab has published in several professional journals and spoken at several industry conferences. His publications/ presentations include:

- "Natural Gas as an Electric DSM Tool," American Gas Association Membership Services Committee Meeting, Williamsburg, VA, September 15, 2009.

- "Electric-to-Gas Fuel Switching," NARUC Summer Meeting, Seattle, WA, July 20, 2009.
- "The Future of Fuel in Virginia: Natural Gas," The Twenty-Seventh National Regulatory Conference, Williamsburg, VA, May 19, 2009.
- "Revenue Decoupling for Natural Gas Utilities," Energy Bar Association Midwest Energy Conference, Chicago, IL, March 6, 2008.
- "Responses to Arrearage Problems from High Natural Gas Bills," American Gas Association Rate and Regulatory Issues Seminar, Phoenix, AZ, April 8, 2004.
- "Factors Influencing Cooperative Power Supply," National Rural Utilities Cooperative Finance Corporation Independent Borrower's Conference, Boston, MA, July 3, 1997.
- "Current Status of LDC Unbundling," American Gas Association Unbundling Conference: Regulatory and Competitive Issues, Arlington, VA, June 19, 1997.
- "Balancing, Capacity Assignment, and Stranded Costs," American Gas Association Rate and Strategic Planning Committee Spring Meeting, Phoenix, AZ, March 26, 1997.
- "Gas Industry Restructuring and Changes: The Relationship of Economics and Marketing" (with Jed Smith), National Association of Business Economists, 38th Annual Meeting, Boston, MA September 10, 1996.
- "Improving Corporate Performance By Better Forecasting," 1996 Peak Day Demand and Supply Planning Seminar, San Francisco, CA, April 11, 1996.
- "Natural Gas Price Elasticity Estimation," AGA Forecasting Review, Vol. 6, No. 1, November 1995.
- "Assessing Price Competitiveness," Competitive Analysis & Benchmarking for Power Companies, Washington, DC, November 13, 1995.
- "Avoided Cost Concepts and Management Considerations," Workshop on Avoided Costs in a Post 636 Gas Industry: Is It Time to Unbundle Avoided Cost? Sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, Milwaukee, WI, June 29, 1994.
- "Estimating Implied Long- and Short-Run Price Elasticities of Natural Gas Consumption," Atlantic Economic Conference, Philadelphia, PA, October 10, 1993.

- "Program Evaluation and Marginal Cost," The Natural Gas Least Cost Planning Conference, Washington, DC, April 7, 1992.
- "The New Environmentalism & Least Cost Planning," Institute for Environmental Negotiation, University of Virginia, May 15, 1991.
- "Development of Conditional Demand Estimates of Gas Appliances," AGA Forecasting Review, Vol. 1, No. 1, October 1988.
- "The Feasibility Study: Forecasting and Sensitivities," Municipal Wastewater Treatment Facilities, The Energy Bureau, Inc., November 18, 1985.
- "The Development of a Gas Sales End-Use Forecasting Model," Third International Forecasting Symposium, The International Institute of Forecasting, July 1984.
- "New Forecasting Guidelines for REC's - A Seminar," (Chairman), Kansas City, Missouri, June 1984.
- "A Method and Application of Estimating Long Run Marginal Cost for an Electric Utility," Advances in Microeconomics, Volume II, 1983.
- "Forecasting Under Public Scrutiny," Forecasting Energy and Demand Requirements, University of Wisconsin - Extension, October 25, 1982.
- "Forecasting Public Utilities," The Journal of Business Forecasting, Vol. 1, No. 4, Summer, 1982.
- "Are Utilities Underforecasting," Electric Ratemaking, Vol. 1. No. 1, February 1982.
- "A Polynomial Spline Function Technique for Defining and Forecasting Electric Utility Load Duration Curves," First International Forecasting Symposium, Montreal, Canada, May 1981.
- "Time-of-Use Rates and Marginal Costs," ELCON Legal Seminar, March 20, l980.
- "The Ernst & Whinney Forecasting Model," Forecasting Energy & Demand Requirements, University of Wisconsin - Extension, October 8, l979.
- "Marginal Cost in Electric Utilities - A Multi-Technology Multi-Period Analysis" (with Frederick McCoy), ORSA/Tims Joint National Meeting, Los Angeles, California, November 13-15, 1978.

Calculation of 30-Year Average HDDS

Year	1	2	3	4	5	6	7	8	9	10	11	12	TME March Total
						Monthly HDDs							
1994	-	-	-	135	132	0	0	0	5	190	348	639	
1995	782	853	485	274	59	0	0	0	30	144	651	901	3569
1996	993	798	675	268	131	0	0	0	9	182	617	677	4525
1997	861	564	499	322	110	30	0	0	14	232	557	737	3808
1998	675	596	581	229	50	11	0	0	4	153	433	638	3854
1999	824	667	630	251	34	3	0	0	22	240	348	707	3639
2000	896	649	408	280	46	2	0	0	60	171	544	1022	3558
2001	908	670	654	246	54	4	0	0	44	207	302	598	4357
2002	717	621	532	225	101	0	0	0	1	257	531	855	3325
2003	1043	871	549	303	128	15	0	0	13	231	366	791	4433
2004	1062	771	494	267	34	4	0	0	7	209	414	766	4174
2005	887	702	675	240	121	4	0	0	5	179	439	881	3965
2006	672	733	529	174	81	0	0	0	22	250	419	639	3803
2007	746	950	535	353	53	0	0	0	10	74	451	713	3816
2008	769	688	487	204	67	0	0	0	2	225	543	759	3598
2009	1028	698	607	270	73	5	0	0	8	208	376	835	4133
2010	914	856	419	159	58	0	0	0	0	144	428	933	3964
2011	965	648	594	225	48	0	0	0	14	212	369	613	3929
2012	746	595	272	220	4	0	0	0	5	163	543	603	3094
2013	759	741	651	217	83	0	0	0	9	156	543	696	3689
2014	1008	754	678	245	32	0	0	0	0	102	505	649	4144
2015	904	964	603	181	16	6	0	0	0	197	338	421	4004
2016	923	722	351	269	119	0	0	0	1	116	370	710	3155
2017	701	478	548	123	74	1	0	0	6	87	456	792	3312
2018	900	549	657	312	2	1	0	0	1	191	548	659	3645
2019	855	632	561	128	29	0	0	0	0	88	561	698	3762
2020	691	608	367	288	127	0	0	0	30	124	311	723	3170
2021	810	756	430	231	83	0	0	0	0	51	507	532	3599
2022	936	619	447	259	56	0	0	0	17	208	388	766	3406
2023	608	505	487	146	59	0	0	0	9	124	456	597	3294
2024	775	591	399										3156

HDD Summary for DCA

30-Year HDD's based on weather data through 3/31/24													
Month:	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Std.Dev	120.6	119.4	105.5	57.8	37.6	6.1	0.0	0.0	13.8	54.6	92.3	123.1	384.3
Min	608.0	478.0	272.0	123.0	2.0	0.0	0.0	0.0	0.0	51.0	302.0	421.0	3094.0
avg-2std (95% lb)	604.1	456.1	315.8	119.3	0.0	0.0	0.0	0.0	0.0	61.3	270.8	472.1	2960.8
Average	**845.3**	**695.0**	**526.8**	**234.8**	**68.8**	**2.9**	**0.0**	**0.0**	**11.6**	**170.5**	**455.4**	**718.3**	**3729.3**
avg+2std (95% ub)	1086.4	933.9	737.8	350.3	144.0	15.1	0.0	0.0	39.2	279.7	640.0	964.5	4497.8
Max	1062.0	964.0	678.0	353.0	132.0	30.0	0.0	0.0	60.0	257.0	651.0	1022.0	4525.0

METER READING SCHEDULE - CY 2024

CYCLE	Dec-2023	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024
1	11/27/23	12/28/23	01/30/24	02/28/24	03/28/24	04/29/24	05/30/24	06/27/24	07/30/24	08/29/24	09/27/24	10/30/24	11/27/24
2	12/02/23	12/29/23	01/31/24	02/29/24	03/29/24	04/30/24	05/31/24	06/28/24	07/31/24	08/30/24	09/30/24	10/31/24	12/02/24
3	12/03/23	01/02/24	02/01/24	03/01/24	04/01/24	05/01/24	06/03/24	07/01/24	08/01/24	09/03/24	10/01/24	11/01/24	12/03/24
4	12/04/23	01/03/24	02/02/24	03/04/24	04/02/24	05/02/24	06/04/24	07/02/24	08/02/24	09/04/24	10/02/24	11/04/24	12/04/24
5	12/05/23	01/04/24	02/05/24	03/05/24	04/03/24	05/03/24	06/05/24	07/03/24	08/05/24	09/05/24	10/03/24	11/05/24	12/05/24
6	12/06/23	01/05/24	02/06/24	03/06/24	04/04/24	05/06/24	06/06/24	07/05/24	08/06/24	09/06/24	10/04/24	11/06/24	12/06/24
7	12/09/23	01/08/24	02/07/24	03/07/24	04/05/24	05/07/24	06/07/24	07/08/24	08/07/24	09/09/24	10/07/24	11/07/24	12/09/24
8	12/10/23	01/09/24	02/08/24	03/08/24	04/08/24	05/08/24	06/10/24	07/09/24	08/08/24	09/10/24	10/08/24	11/08/24	12/10/24
9	12/11/23	01/10/24	02/09/24	03/11/24	04/09/24	05/09/24	06/11/24	07/10/24	08/09/24	09/11/24	10/09/24	11/12/24	12/11/24
10	12/12/23	01/11/24	02/12/24	03/12/24	04/10/24	05/10/24	06/12/24	07/11/24	08/12/24	09/12/24	10/10/24	11/13/24	12/12/24
11	12/13/23	01/12/24	02/13/24	03/13/24	04/11/24	05/13/24	06/13/24	07/12/24	08/13/24	09/13/24	10/11/24	11/14/24	12/13/24
12	12/16/23	01/16/24	02/14/24	03/14/24	04/12/24	05/14/24	06/14/24	07/15/24	08/14/24	09/16/24	10/14/24	11/15/24	12/16/24
13	12/17/23	01/17/24	02/15/24	03/15/24	04/15/24	05/15/24	06/17/24	07/16/24	08/15/24	09/17/24	10/15/24	11/18/24	12/17/24
14	12/18/23	01/18/24	02/16/24	03/18/24	04/16/24	05/16/24	06/18/24	07/17/24	08/16/24	09/18/24	10/16/24	11/19/24	12/18/24
15	12/19/23	01/19/24	02/20/24	03/19/24	04/17/24	05/17/24	06/20/24	07/18/24	08/19/24	09/19/24	10/17/24	11/20/24	12/19/24
16	12/20/23	01/22/24	02/21/24	03/20/24	04/18/24	05/20/24	06/21/24	07/19/24	08/20/24	09/20/24	10/18/24	11/21/24	12/20/24
17	12/23/23	01/23/24	02/22/24	03/21/24	04/19/24	05/21/24	06/24/24	07/22/24	08/21/24	09/23/24	10/21/24	11/22/24	12/23/24
18	12/24/23	01/24/24	02/23/24	03/22/24	04/22/24	05/22/24	06/25/24	07/23/24	08/22/24	09/24/24	10/22/24	11/25/24	12/24/24
19	12/26/23	01/25/24	02/26/24	03/25/24	04/23/24	05/23/24	06/26/24	07/24/24	08/23/24	09/25/24	10/23/24	11/25/24	12/26/24
20													
21													

HDD ALLOCATION CALCULATION - CY 2024

		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	3728	691	894	703	517	280	78	1	0	0	6	159	399
2	3728	623	895	700	508	271	73	1	0	0	10	164	483
3	3728	705	818	695	527	235	70	0	0	0	12	171	495
4	3728	711	816	730	479	228	65	0	0	0	14	203	482
5	3728	717	864	675	470	222	60	0	0	0	16	213	491
6	3728	723	862	669	462	226	45	0	0	0	19	222	500
7	3728	740	806	663	454	219	41	0	0	0	28	225	552
8	3728	745	804	657	466	191	38	0	0	0	31	235	561
9	3728	750	802	689	419	184	35	0	0	0	35	285	529
10	3728	755	850	633	409	179	31	0	0	0	39	295	537
11	3728	759	848	626	400	178	23	0	0	0	43	306	545
12	3728	801	761	620	391	171	21	0	0	0	57	307	599
13	3728	806	757	614	398	147	20	0	0	0	62	348	576
14	3728	810	753	642	354	141	18	0	0	0	67	359	584
15	3728	814	820	564	345	135	16	0	0	0	72	370	592
16	3728	874	759	557	336	134	10	0	0	0	78	381	599
17	3728	830	754	550	327	129	8	0	0	2	94	380	654
18	3728	832	750	543	331	111	6	0	0	3	100	425	627
19	3728	809	792	520	291	106	5	0	0	4	106	418	677
20													
21													
		14495	15405	12050	7884	3487	663	2	0	9	889	5466	10482
HDD's	3,729	763	811	634	415	184	35	-	-	-	47	288	552

Washington Gas Light Company
District of Columbia Jurisdiction

Summary of Therm Sales Statistics Total

Based on 12 Months Ending Mar 2024

Line No.	Class Of Service	Actual Therms a/	<-----Weather Gas----- Actual b/	Normal c/ ----->	Weather Adjustment	<-----Base Gas----- Actual	Normal d/ ----->	Total Normal Weather Therm Sales	<-----Peak Day----- Weather Gas e/	Base Gas f/ ----->	Total
	A	B	C	D	E=D-C	F=B-C	G	H=D+G	I	J	K=I+J
1	Residential										
2	Heating and Cooling	74,124,105	60,453,429	70,729,615	10,276,186	13,670,676	14,063,551	84,793,166	1,138,887	36,521	1,175,408
3	Non Heating and Non Cooling - IMA's	624,411	264,394	309,352	44,958	360,017	368,268	677,620	4,978	987	5,965
4	Non Heating and Non Cooling	1,480,156	1,100,079	1,287,100	187,021	380,077	416,434	1,703,534	20,770	1,126	21,896
5	Total - Residential	76,228,671	61,817,902	72,326,067	10,508,165	14,410,769	14,848,253	87,174,320	1,164,635	38,634	1,203,269
6											
7	Commercial and Industrial										
8	Heating and Cooling										
9	Less than 3075	4,671,124	3,467,503	4,057,018	589,515	1,203,621	1,279,120	5,336,138	65,270	3,468	68,738
10	More than 3075	61,303,846	33,508,268	39,197,035	5,688,767	27,795,578	29,657,369	68,854,404	633,771	81,489	715,260
11	Non Heating and Non Cooling	8,145,664	2,346,071	2,745,262	399,191	5,799,593	5,267,470	8,012,732	44,047	13,896	57,943
12	CHP	1,814,088	963,870	1,127,791	163,921	850,218	973,241	2,101,032	18,146	2,616	20,762
13	Total - Commercial and Industrial	75,934,721	40,285,712	47,127,106	6,841,394	35,649,009	37,177,200	84,304,306	761,234	101,469	862,703
14											
15	Group Metered Apartments										
16	Heating and Cooling										
17	Less than 3075	1,092,958	484,154	566,702	82,548	608,804	432,477	999,179	9,042	1,160	10,202
18	More than 3075	26,578,961	17,517,359	20,493,631	2,976,272	9,061,602	9,180,472	29,674,103	330,407	24,735	355,142
19	Non Heating and Non Cooling	3,756,632	1,326,063	1,551,590	225,527	2,430,569	2,378,258	3,929,848	24,953	6,347	31,300
20	Total - Group Metered Apartments	31,428,552	19,327,576	22,611,923	3,284,347	12,100,976	11,991,207	34,603,130	364,402	32,242	396,644
21											
22	Total Firm	183,591,944	121,431,190	142,065,096	20,633,906	62,160,754	64,016,660	206,081,756	2,290,271	172,345	2,462,616
23	Interruptible	37,706,690	13,597,776	15,911,005	2,313,229	24,108,914	23,916,786	39,827,791	254,561	63,953	318,514
24	Special Contracts	36,175,445	9,297,721	10,878,939	1,581,218	26,877,724	27,341,796	38,220,735	175,043	73,499	248,542
25	Total Throughput	257,474,080	144,326,687	168,855,040	24,528,353	113,147,393	115,275,242	284,130,282	2,719,875	309,797	3,029,672

a/ Schedule 1B, Column B
b/ Schedule 2A, Column F
c/ Schedule 2A, Column G
d/ Schedule 2A, Column I
e/ Schedule 2B, Column K - For Allocation Purposes Only
f/ Schedule 2B, Column L - For Allocation Purposes Only

Washington Gas Light Company
District of Columbia Jurisdiction

Therm Sales Statistics Monthly Totals

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Actual Therms a/	Normal Weather Gas b/	Normal Base Gas c/	Total Normal Weather Therm Sales
	A	B	C	D	E=C+D
1	*Residential Heating and Cooling*				
2	Mar-2024	9,929,458	12,000,476	1,105,356	13,105,832
3	Feb-2024	14,520,541	15,382,166	1,119,452	16,501,618
4	Jan-2024	13,323,881	14,482,846	1,132,153	15,614,999
5	Dec-2023	10,890,742	10,491,416	1,145,488	11,636,904
6	Nov-2023	5,413,194	5,473,702	1,157,330	6,631,032
7	Oct-2023	1,968,056	891,806	1,167,262	2,059,068
8	Sep-2023	1,622,364	-	1,178,441	1,178,441
9	Aug-2023	1,316,376	-	1,188,853	1,188,853
10	Jul-2023	1,655,214	-	1,198,802	1,198,802
11	Jun-2023	2,296,757	662,056	1,210,861	1,872,917
12	May-2023	3,331,233	3,481,245	1,222,917	4,704,162
13	Apr-2023	7,856,288	7,863,902	1,236,637	9,100,539
14	Total	74,124,105	70,729,615	14,063,551	84,793,166
15					
16	*Residential Non Heating and Non Cooling - IMA's*				
17	Mar-2024	70,148	52,265	30,398	82,663
18	Feb-2024	103,348	67,086	30,502	97,588
19	Jan-2024	81,335	63,307	30,594	93,901
20	Dec-2023	60,138	45,884	30,651	76,535
21	Nov-2023	51,713	24,054	30,797	54,851
22	Oct-2023	30,619	3,924	30,788	34,712
23	Sep-2023	21,735	-	30,802	30,802
24	Aug-2023	27,299	-	30,783	30,783
25	Jul-2023	37,608	-	30,805	30,805
26	Jun-2023	37,552	2,916	30,721	33,637
27	May-2023	37,754	15,309	30,679	45,988
28	Apr-2023	65,163	34,607	30,749	65,356
29	Total	624,411	309,352	368,268	677,620

a/ Schedule 3, Column C
b/ Schedule 2B, Column G
c/ Schedule 2B, Column I

Washington Gas Light Company
District of Columbia Jurisdiction

Therm Sales Statistics Monthly Totals

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Actual Therms a/	Normal Weather Gas b/	Normal Base Gas c/	Total Normal Weather Therm Sales
	A	B	C	D	E=C+D
1	*Residential Non Heating and Non Cooling*				
2	Mar-2024	190,410	219,470	34,896	254,366
3	Feb-2024	279,296	280,350	34,847	315,197
4	Jan-2024	259,455	264,126	34,896	299,022
5	Dec-2023	215,376	191,244	34,925	226,169
6	Nov-2023	118,734	99,780	34,925	134,705
7	Oct-2023	43,928	16,293	34,945	51,238
8	Sep-2023	35,484	-	34,740	34,740
9	Aug-2023	27,960	-	34,526	34,526
10	Jul-2023	33,963	-	34,516	34,516
11	Jun-2023	54,630	11,967	34,468	46,435
12	May-2023	69,522	63,055	34,546	97,601
13	Apr-2023	151,399	140,815	34,205	175,020
14	Total	1,480,156	1,287,100	416,434	1,703,534
15					
16	*Commercial and Industrial Heating and Cooling < 3075*				
17	Mar-2024	638,500	696,833	108,619	805,452
18	Feb-2024	922,229	892,347	108,738	1,001,085
19	Jan-2024	794,129	830,019	107,506	937,525
20	Dec-2023	616,887	599,295	107,292	706,587
21	Nov-2023	286,815	311,363	106,842	418,205
22	Oct-2023	111,430	50,486	106,155	156,641
23	Sep-2023	89,196	-	105,373	105,373
24	Aug-2023	133,302	-	105,942	105,942
25	Jul-2023	109,193	-	105,847	105,847
26	Jun-2023	207,835	37,436	105,705	143,141
27	May-2023	248,719	196,941	105,776	302,717
28	Apr-2023	512,891	442,298	105,326	547,624
29	Total	4,671,124	4,057,018	1,279,120	5,336,138

a/ Schedule 3, Column C
b/ Schedule 2B, Column G
c/ Schedule 2B, Column I

Washington Gas Light Company
District of Columbia Jurisdiction

Therm Sales Statistics Monthly Totals

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Actual Therms a/	Normal Weather Gas b/	Normal Base Gas c/	Total Normal Weather Therm Sales
	A	B	C	D	E=C+D
1	*Commercial and Industrial Heating and Cooling > 3075*				
2	Mar-2024	7,048,511	6,679,269	2,534,980	9,214,249
3	Feb-2024	9,579,483	8,538,989	2,525,778	11,064,767
4	Jan-2024	9,179,131	8,059,460	2,526,164	10,585,624
5	Dec-2023	8,246,712	5,823,894	2,515,482	8,339,376
6	Nov-2023	4,892,685	3,005,718	2,480,647	5,486,365
7	Oct-2023	2,796,234	488,489	2,462,774	2,951,263
8	Sep-2023	2,280,981	-	2,463,161	2,463,161
9	Aug-2023	2,122,296	-	2,440,278	2,440,278
10	Jul-2023	2,143,434	-	2,432,680	2,432,680
11	Jun-2023	2,921,839	363,768	2,432,294	2,796,062
12	May-2023	3,753,702	1,905,012	2,415,329	4,320,341
13	Apr-2023	6,338,839	4,332,436	2,427,803	6,760,239
14	Total	61,303,846	39,197,035	29,657,369	68,854,404
15					
16	*Commercial and Industrial Non Heating and Non Cooling*				
17	Mar-2024	812,825	465,937	427,724	893,661
18	Feb-2024	1,029,848	595,693	429,244	1,024,937
19	Jan-2024	1,011,587	560,131	430,762	990,893
20	Dec-2023	879,320	405,895	433,221	839,116
21	Nov-2023	669,594	212,347	436,158	648,505
22	Oct-2023	484,132	34,691	438,393	473,084
23	Sep-2023	488,031	-	439,916	439,916
24	Aug-2023	396,431	-	441,437	441,437
25	Jul-2023	447,120	-	443,196	443,196
26	Jun-2023	532,430	25,876	446,162	472,038
27	May-2023	559,059	136,549	449,622	586,171
28	Apr-2023	835,287	308,143	451,637	759,780
29	Total	8,145,664	2,745,262	5,267,470	8,012,732

a/ Schedule 3, Column C
b/ Schedule 2B, Column G
c/ Schedule 2B, Column I

Washington Gas Light Company
District of Columbia Jurisdiction

Therm Sales Statistics Monthly Totals

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Actual Therms a/	Normal Weather Gas b/	Normal Base Gas c/	Total Normal Weather Therm Sales
	A	B	C	D	E=C+D
1	*CI - Delivery CHP*				
2	Mar-2024	213,273	191,745	81,103	272,848
3	Feb-2024	223,168	245,277	81,103	326,380
4	Jan-2024	201,194	230,760	81,103	311,863
5	Dec-2023	180,659	166,946	81,103	248,049
6	Nov-2023	155,198	87,102	81,103	168,205
7	Oct-2023	110,880	14,215	81,103	95,318
8	Sep-2023	116,440	-	81,103	81,103
9	Aug-2023	54,051	-	81,103	81,103
10	Jul-2023	95,233	-	81,103	81,103
11	Jun-2023	133,811	10,585	81,103	91,688
12	May-2023	132,553	55,649	81,103	136,752
13	Apr-2023	197,628	125,512	81,103	206,615
14	Total	1,814,088	1,127,791	973,241	2,101,032
15					
16	*Group Metered Apartments Heating and Cooling < 3075*				
17	Mar-2024	209,140	96,825	36,457	133,282
18	Feb-2024	112,455	125,290	36,878	162,168
19	Jan-2024	173,573	114,986	35,974	150,960
20	Dec-2023	141,291	82,909	35,854	118,763
21	Nov-2023	75,765	43,766	36,276	80,042
22	Oct-2023	30,459	7,071	35,914	42,985
23	Sep-2023	7,329	-	35,131	35,131
24	Aug-2023	37,048	-	35,553	35,553
25	Jul-2023	46,309	-	35,914	35,914
26	Jun-2023	57,656	5,283	36,035	41,318
27	May-2023	118,956	28,240	36,637	64,877
28	Apr-2023	82,980	62,332	35,854	98,186
29	Total	1,092,958	566,702	432,477	999,179

a/ Schedule 3, Column C
b/ Schedule 2B, Column G
c/ Schedule 2B, Column I

Washington Gas Light Company
District of Columbia Jurisdiction

Therm Sales Statistics Monthly Totals

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Actual Therms a/	Normal Weather Gas b/	Normal Base Gas c/	Total Normal Weather Therm Sales
	A	B	C	D	E=C+D
1	*Group Metered Apartments Heating and Cooling > 3075*				
2	Mar-2024	3,450,456	3,487,217	765,898	4,253,115
3	Feb-2024	4,537,194	4,445,117	763,209	5,208,326
4	Jan-2024	4,146,785	4,201,673	766,795	4,968,468
5	Dec-2023	4,022,262	3,043,296	767,691	3,810,987
6	Nov-2023	2,098,072	1,574,830	761,417	2,336,247
7	Oct-2023	806,722	257,306	762,313	1,019,619
8	Sep-2023	680,292	-	768,139	768,139
9	Aug-2023	610,304	-	765,898	765,898
10	Jul-2023	674,182	-	764,106	764,106
11	Jun-2023	1,003,827	192,737	766,795	959,532
12	May-2023	1,419,540	1,006,141	761,417	1,767,558
13	Apr-2023	3,129,326	2,285,314	766,795	3,052,109
14	Total	26,578,961	20,493,631	9,180,472	29,674,103
15					
16	*Group Metered Apartments Non Heating and Non Cooling*				
17	Mar-2024	387,341	263,973	196,062	460,035
18	Feb-2024	485,332	339,219	197,428	536,647
19	Jan-2024	470,308	317,318	196,762	514,080
20	Dec-2023	404,577	229,303	196,998	426,301
21	Nov-2023	332,250	119,499	197,233	316,732
22	Oct-2023	212,092	19,524	197,922	217,446
23	Sep-2023	205,020	-	198,156	198,156
24	Aug-2023	164,739	-	198,846	198,846
25	Jul-2023	198,058	-	199,079	199,079
26	Jun-2023	250,083	14,522	199,540	214,062
27	May-2023	257,798	76,434	200,232	276,666
28	Apr-2023	389,032	171,798	200,001	371,799
29	Total	3,756,632	1,551,590	2,378,258	3,929,848

a/ Schedule 3, Column C
b/ Schedule 2B, Column G
c/ Schedule 2B, Column I

Washington Gas Light Company
District of Columbia Jurisdiction

Therm Sales Statistics Monthly Totals

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Actual Therms a/	Normal Weather Gas b/	Normal Base Gas c/	Total Normal Weather Therm Sales
	A	B	C	D	E=C+D
1	*Interruptible*				
2	Mar-2024	4,256,287	2,689,864	1,982,552	4,672,416
3	Feb-2024	5,212,470	3,409,540	1,964,529	5,374,069
4	Jan-2024	4,517,811	3,237,171	1,982,552	5,219,723
5	Dec-2023	4,052,004	2,363,254	2,000,575	4,363,829
6	Nov-2023	2,692,403	1,266,327	2,054,645	3,320,972
7	Oct-2023	1,896,869	201,219	2,000,575	2,201,794
8	Sep-2023	1,907,483	-	2,000,575	2,000,575
9	Aug-2023	1,589,971	-	1,964,529	1,964,529
10	Jul-2023	1,824,210	-	1,964,529	1,964,529
11	Jun-2023	2,377,769	147,144	1,964,529	2,111,673
12	May-2023	2,930,695	787,751	2,000,575	2,788,326
13	Apr-2023	4,448,719	1,808,735	2,036,622	3,845,357
14	Total	37,706,690	15,911,005	23,916,786	39,827,791
15					
16	*Special Contracts*				
17	Mar-2024	3,893,553	1,849,624	2,278,483	4,128,107
18	Feb-2024	4,633,011	2,366,002	2,278,483	4,644,485
19	Jan-2024	3,457,246	2,225,967	2,278,483	4,504,450
20	Dec-2023	3,057,456	1,610,398	2,278,483	3,888,881
21	Nov-2023	2,186,944	840,207	2,278,483	3,118,690
22	Oct-2023	2,486,177	137,117	2,278,483	2,415,600
23	Sep-2023	2,531,559	-	2,278,483	2,278,483
24	Aug-2023	2,484,438	-	2,278,483	2,278,483
25	Jul-2023	2,320,367	-	2,278,483	2,278,483
26	Jun-2023	2,500,318	102,109	2,278,483	2,380,592
27	May-2023	2,711,630	536,799	2,278,483	2,815,282
28	Apr-2023	3,912,747	1,210,716	2,278,483	3,489,199
29	Total	36,175,445	10,878,939	27,341,796	38,220,735

a/ Schedule 3, Column C
b/ Schedule 2B, Column G
c/ Schedule 2B, Column I

Washington Gas Light Company
District of Columbia Jurisdiction

Summary of Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

						< ---Therm Sales				
				Normal	Variation	<---Weather Gas		--->		
Line No.	Class Of Service	Meters	Actual HDD's	Weather HDD's	per HDD (Therms)	Actual a/	Normal Weather b/	Weather Adjustment	Base Gas c/	Total
	A	B	C	D	E	F	G	H=G-F	I	J=H+I
1	Residential									
2	Heating and Cooling	1,627,379	3,187	3,729	0.1397740	60,453,429	70,729,615	10,276,186	14,063,551	84,793,166
3	Non Heating and Non Cooling - IMA's	131,084	3,187	3,729	0.0076190	264,394	309,352	44,958	368,268	677,620
4	Non Heating and Non Cooling	42,794	3,187	3,729	0.0965330	1,100,079	1,287,100	187,021	416,434	1,703,534
5	Total - Residential	1,801,257				61,817,902	72,326,067	10,508,165	14,848,253	87,174,320
6										
7	Commercial and Industrial									
8	Heating and Cooling									
9	Less than 3075	53,982	3,187	3,729	0.2397700	3,467,503	4,057,018	589,515	1,279,120	5,336,138
10	More than 3075	40,679	3,187	3,729	3.0813470	33,508,268	39,197,035	5,688,767	29,657,369	68,854,404
11	Non Heating and Non Cooling	22,135	3,187	3,729	0.3998460	2,346,071	2,745,262	399,191	5,267,470	8,012,732
12	CHP	12	3,187	3,729	302.4376000	963,870	1,127,791	163,921	973,241	2,101,032
13	Total - Commercial and Industrial	116,808				40,285,712	47,127,106	6,841,394	37,177,200	84,304,306
14										
15	Group Metered Apartments									
16	Heating and Cooling									
17	Less than 3075	7,177	3,187	3,729	0.2524320	484,154	566,702	82,548	432,477	999,179
18	More than 3075	20,485	3,187	3,729	3.2184570	17,517,359	20,493,631	2,976,272	9,180,472	29,674,103
19	Non Heating and Non Cooling	10,430	3,187	3,729	0.4780260	1,326,063	1,551,590	225,527	2,378,258	3,929,848
20	Total - Group Metered Apartments	38,092				19,327,576	22,611,923	3,284,347	11,991,207	34,603,130
21										
22	Total Firm	1,956,157				121,431,190	142,065,096	20,633,906	64,016,660	206,081,756
23	Interruptible	1,327	3,187	3,729	38.56989	13,597,776	15,911,005	2,313,229	23,916,786	39,827,791
24	Special Contracts	36	3,187	3,729	d/	9,297,721	10,878,939	1,581,218	27,341,796	38,220,735
25	Total Throughput	1,957,520				144,326,687	168,855,040	24,528,353	115,275,242	284,130,282
		163,127								

a/ Schedule 2B, Column F
b/ Schedule 2B, Column G
c/ Schedule 2B, Column I
d/ Schedule 2B for noted classes

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Therm Sales: Weather Gas: Normal Weather	Therm Sales: Weather Adjustment	Therm Sales: Base Gas b/	Therm Sales: Total	Peak Day: Weather Gas	Peak Day: Base Gas	Peak Day: Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*DC Res Htg / HC*												
2	Mar-2024	135,420	516	634	0.1397740	9,766,949	12,000,476	2,233,527	1,105,356	13,105,832			
3	Feb-2024	135,697	699	811	0.1397740	13,257,872	15,382,166	2,124,294	1,119,452	16,501,618			
4	Jan-2024	135,801	655	763	0.1397740	12,432,849	14,482,846	2,049,997	1,132,153	15,614,999	1,138,887	36,521	1,175,408
5	Dec-2023	135,978	536	552	0.1397740	10,187,317	10,491,416	304,099	1,145,488	11,636,904			
6	Nov-2023	135,976	223	288	0.1397740	4,238,318	5,473,702	1,235,384	1,157,330	6,631,032			
7	Oct-2023	135,752	39	47	0.1397740	740,009	891,806	151,797	1,167,262	2,059,068			
8	Sep-2023	135,676	1	-	0.1397740	18,964	-	(18,964)	1,178,441	1,178,441			
9	Aug-2023	135,514	-	-	0.1397740	-	-	-	1,188,853	1,188,853			
10	Jul-2023	135,303	-	-	0.1397740	-	-	-	1,198,802	1,198,802			
11	Jun-2023	135,332	21	35	0.1397740	397,234	662,056	264,822	1,210,861	1,872,917			
12	May-2023	135,360	130	184	0.1397740	2,459,575	3,481,245	1,021,670	1,222,917	4,704,162			
13	Apr-2023	135,570	367	415	0.1397740	6,954,342	7,863,902	909,560	1,236,637	9,100,539			
14	Total	1,627,379	3,187	3,729		60,453,429	70,729,615	10,276,186	14,063,551	84,793,166	1,138,887	36,521	1,175,408
15													
16	*DC Res Non Htg - IMA*												
17	Mar-2024	10,820	516	634	0.0076190	42,538	52,265	9,727	30,398	82,663			
18	Feb-2024	10,857	699	811	0.0076190	57,821	67,086	9,265	30,502	97,588			
19	Jan-2024	10,890	655	763	0.0076190	54,346	63,307	8,961	30,594	93,901	4,978	987	5,965
20	Dec-2023	10,910	536	552	0.0076190	44,554	45,884	1,330	30,651	76,535			
21	Nov-2023	10,962	223	288	0.0076190	18,625	24,054	5,429	30,797	54,851			
22	Oct-2023	10,959	39	47	0.0076190	3,256	3,924	668	30,788	34,712			
23	Sep-2023	10,964	1	-	0.0076190	84	-	(84)	30,802	30,802			
24	Aug-2023	10,957	-	-	0.0076190	-	-	-	30,783	30,783			
25	Jul-2023	10,965	-	-	0.0076190	-	-	-	30,805	30,805			
26	Jun-2023	10,935	21	35	0.0076190	1,750	2,916	1,166	30,721	33,637			
27	May-2023	10,920	130	184	0.0076190	10,816	15,309	4,493	30,679	45,988			
28	Apr-2023	10,945	367	415	0.0076190	30,604	34,607	4,003	30,749	65,356			
29	Total	131,084	3,187	3,729		264,394	309,352	44,958	368,268	677,620	4,978	987	5,965

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

						< ----Therm Sales----					< ----Peak Day---- >		
						<----Weather Gas---->							
Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Actual	Normal Weather	Weather Adjustment	Base Gas b/	Total	Weather Gas	Base Gas	Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*DC Res Non Htg - OTH*												
2	Mar-2024	3,586	516	634	0.0965330	178,622	219,470	40,848	34,896	254,366			
3	Feb-2024	3,581	699	811	0.0965330	241,634	280,350	38,716	34,847	315,197			
4	Jan-2024	3,586	655	763	0.0965330	226,740	264,126	37,386	34,896	299,022	20,770	1,126	21,896
5	Dec-2023	3,589	536	552	0.0965330	185,701	191,244	5,543	34,925	226,169			
6	Nov-2023	3,589	223	288	0.0965330	77,260	99,780	22,520	34,925	134,705			
7	Oct-2023	3,591	39	47	0.0965330	13,519	16,293	2,774	34,945	51,238			
8	Sep-2023	3,570	1	-	0.0965330	345	-	(345)	34,740	34,740			
9	Aug-2023	3,548	-	-	0.0965330	-	-	-	34,526	34,526			
10	Jul-2023	3,547	-	-	0.0965330	-	-	-	34,516	34,516			
11	Jun-2023	3,542	21	35	0.0965330	7,180	11,967	4,787	34,468	46,435			
12	May-2023	3,550	130	184	0.0965330	44,550	63,055	18,505	34,546	97,601			
13	Apr-2023	3,515	367	415	0.0965330	124,528	140,815	16,287	34,205	175,020			
14	Total	42,794	3,187	3,729		1,100,079	1,287,100	187,021	416,434	1,703,534	20,770	1,126	21,896
15													
16	*DC C&I Htg / HC < 3075*												
17	Mar-2024	4,584	516	634	0.2397700	567,139	696,833	129,694	108,619	805,452			
18	Feb-2024	4,589	699	811	0.2397700	769,113	892,347	123,234	108,738	1,001,085			
19	Jan-2024	4,537	655	763	0.2397700	712,533	830,019	117,486	107,506	937,525	65,270	3,468	68,738
20	Dec-2023	4,528	536	552	0.2397700	581,924	599,295	17,371	107,292	706,587			
21	Nov-2023	4,509	223	288	0.2397700	241,090	311,363	70,273	106,842	418,205			
22	Oct-2023	4,480	39	47	0.2397700	41,893	50,486	8,593	106,155	156,641			
23	Sep-2023	4,447	1	-	0.2397700	1,066	-	(1,066)	105,373	105,373			
24	Aug-2023	4,471	-	-	0.2397700	-	-	-	105,942	105,942			
25	Jul-2023	4,467	-	-	0.2397700	-	-	-	105,847	105,847			
26	Jun-2023	4,461	21	35	0.2397700	22,462	37,436	14,974	105,705	143,141			
27	May-2023	4,464	130	184	0.2397700	139,143	196,941	57,798	105,776	302,717			
28	Apr-2023	4,445	367	415	0.2397700	391,140	442,298	51,158	105,326	547,624			
29	Total	53,982	3,187	3,729		3,467,503	4,057,018	589,515	1,279,120	5,336,138	65,270	3,468	68,738

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

						<-----Therm Sales	<-----Weather Gas----->	----->					
Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Actual	Normal Weather	Weather Adjustment	Base Gas b/	Total	<-----Peak Day Weather Gas	Base Gas	-----> Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*DC C&I Htg / HC > 3075*												
2	Mar-2024	3,419	516	634	3.0813470	5,436,125	6,679,269	1,243,144	2,534,980	9,214,249			
3	Feb-2024	3,417	699	811	3.0813470	7,359,745	8,538,989	1,179,244	2,525,778	11,064,767			
4	Jan-2024	3,428	655	763	3.0813470	6,918,672	8,059,460	1,140,788	2,526,164	10,585,624	633,771	81,489	715,260
5	Dec-2023	3,424	536	552	3.0813470	5,655,085	5,823,894	168,809	2,515,482	8,339,376			
6	Nov-2023	3,387	223	288	3.0813470	2,327,344	3,005,718	678,374	2,480,647	5,486,365			
7	Oct-2023	3,373	39	47	3.0813470	405,342	488,489	83,147	2,462,774	2,951,263			
8	Sep-2023	3,384	1	-	3.0813470	10,427	-	(10,427)	2,463,161	2,463,161			
9	Aug-2023	3,363	-	-	3.0813470	-	-	-	2,440,278	2,440,278			
10	Jul-2023	3,363	-	-	3.0813470	-	-	-	2,432,680	2,432,680			
11	Jun-2023	3,373	21	35	3.0813470	218,261	363,768	145,507	2,432,294	2,796,062			
12	May-2023	3,360	130	184	3.0813470	1,345,932	1,905,012	559,080	2,415,329	4,320,341			
13	Apr-2023	3,388	367	415	3.0813470	3,831,335	4,332,436	501,101	2,427,803	6,760,239			
14	Total	40,679	3,187	3,729		33,508,268	39,197,035	5,688,767	29,657,369	68,854,404	633,771	81,489	715,260
15													
16	*DC C&I Non Htg*												
17	Mar-2024	1,838	516	634	0.3998460	379,217	465,937	86,720	427,724	893,661			
18	Feb-2024	1,837	699	811	0.3998460	513,427	595,693	82,266	429,244	1,024,937			
19	Jan-2024	1,836	655	763	0.3998460	480,847	560,131	79,284	430,762	990,893	44,047	13,896	57,943
20	Dec-2023	1,839	536	552	0.3998460	394,130	405,895	11,765	433,221	839,116			
21	Nov-2023	1,844	223	288	0.3998460	164,421	212,347	47,926	436,158	648,505			
22	Oct-2023	1,846	39	47	0.3998460	28,787	34,691	5,904	438,393	473,084			
23	Sep-2023	1,845	1	-	0.3998460	738	-	(738)	439,916	439,916			
24	Aug-2023	1,844	-	-	0.3998460	-	-	-	441,437	441,437			
25	Jul-2023	1,844	-	-	0.3998460	-	-	-	443,196	443,196			
26	Jun-2023	1,849	21	35	0.3998460	15,526	25,876	10,350	446,162	472,038			
27	May-2023	1,856	130	184	0.3998460	96,475	136,549	40,074	449,622	586,171			
28	Apr-2023	1,857	367	415	0.3998460	272,503	308,143	35,640	451,637	759,780			
29	Total	22,135	3,187	3,729		2,346,071	2,745,262	399,191	5,267,470	8,012,732	44,047	13,896	57,943

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Therm Sales: Weather Gas: Normal Weather	Therm Sales: Weather Adjustment	Therm Sales: Base Gas b/	Therm Sales: Total	Peak Day: Weather Gas	Peak Day: Base Gas	Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*CI - Delivery CHP*												
2	Mar-2024	1	516	634	302.4376000	156,058	191,745	35,687	81,103	272,848			
3	Feb-2024	1	699	811	302.4376000	211,404	245,277	33,873	81,103	326,380			
4	Jan-2024	1	655	763	302.4376000	198,097	230,760	32,663	81,103	311,863	18,146	2,616	20,762
5	Dec-2023	1	536	552	302.4376000	162,107	166,946	4,839	81,103	248,049			
6	Nov-2023	1	223	288	302.4376000	67,444	87,102	19,658	81,103	168,205			
7	Oct-2023	1	39	47	302.4376000	11,795	14,215	2,420	81,103	95,318			
8	Sep-2023	1	1	-	302.4376000	302	-	(302)	81,103	81,103			
9	Aug-2023	1	-	-	302.4376000	-	-	-	81,103	81,103			
10	Jul-2023	1	-	-	302.4376000	-	-	-	81,103	81,103			
11	Jun-2023	1	21	35	302.4376000	6,351	10,585	4,234	81,103	91,688			
12	May-2023	1	130	184	302.4376000	39,317	55,649	16,332	81,103	136,752			
13	Apr-2023	1	367	415	302.4376000	110,995	125,512	14,517	81,103	206,615			
14	Total	12	3,187	3,729		963,870	1,127,791	163,921	973,241	2,101,032	18,146	2,616	20,762
15													
16	*DC GMA Htg / HC < 3075*												
17	Mar-2024	605	516	634	0.2524320	78,804	96,825	18,021	36,457	133,282			
18	Feb-2024	612	699	811	0.2524320	107,987	125,290	17,303	36,878	162,168			
19	Jan-2024	597	655	763	0.2524320	98,710	114,986	16,276	35,974	150,960	9,042	1,160	10,202
20	Dec-2023	595	536	552	0.2524320	80,506	82,909	2,403	35,854	118,763			
21	Nov-2023	602	223	288	0.2524320	33,888	43,766	9,878	36,276	80,042			
22	Oct-2023	596	39	47	0.2524320	5,868	7,071	1,203	35,914	42,985			
23	Sep-2023	583	1	-	0.2524320	147	-	(147)	35,131	35,131			
24	Aug-2023	590	-	-	0.2524320	-	-	-	35,553	35,553			
25	Jul-2023	596	-	-	0.2524320	-	-	-	35,914	35,914			
26	Jun-2023	598	21	35	0.2524320	3,170	5,283	2,113	36,035	41,318			
27	May-2023	608	130	184	0.2524320	19,952	28,240	8,288	36,637	64,877			
28	Apr-2023	595	367	415	0.2524320	55,122	62,332	7,210	35,854	98,186			
29	Total	7,177	3,187	3,729		484,154	566,702	82,548	432,477	999,179	9,042	1,160	10,202

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Normal Weather	Weather Adjustment	Base Gas b/	Total	Peak Day: Weather Gas	Base Gas	Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*DC GMA Htg / HC > 3075*												
2	Mar-2024	1,709	516	634	3.2184570	2,838,177	3,487,217	649,040	765,898	4,253,115			
3	Feb-2024	1,703	699	811	3.2184570	3,831,242	4,445,117	613,875	763,209	5,208,326			
4	Jan-2024	1,711	655	763	3.2184570	3,606,941	4,201,673	594,732	766,795	4,968,468	330,407	24,735	355,142
5	Dec-2023	1,713	536	552	3.2184570	2,955,084	3,043,296	88,212	767,691	3,810,987			
6	Nov-2023	1,699	223	288	3.2184570	1,219,399	1,574,830	355,431	761,417	2,336,247			
7	Oct-2023	1,701	39	47	3.2184570	213,509	257,306	43,797	762,313	1,019,619			
8	Sep-2023	1,714	1	-	3.2184570	5,516	-	(5,516)	768,139	768,139			
9	Aug-2023	1,709	-	-	3.2184570	-	-	-	765,898	765,898			
10	Jul-2023	1,705	-	-	3.2184570	-	-	-	764,106	764,106			
11	Jun-2023	1,711	21	35	3.2184570	115,642	192,737	77,095	766,795	959,532			
12	May-2023	1,699	130	184	3.2184570	710,861	1,006,141	295,280	761,417	1,767,558			
13	Apr-2023	1,711	367	415	3.2184570	2,020,988	2,285,314	264,326	766,795	3,052,109			
14	Total	20,485	3,187	3,729		17,517,359	20,493,631	2,976,272	9,180,472	29,674,103	330,407	24,735	355,142
15													
16	*DC GMA Non Htg*												
17	Mar-2024	871	516	634	0.4780260	214,842	263,973	49,131	196,062	460,035			
18	Feb-2024	875	699	811	0.4780260	292,373	339,219	46,846	197,428	536,647			
19	Jan-2024	870	655	763	0.4780260	272,403	317,318	44,915	196,762	514,080	24,953	6,347	31,300
20	Dec-2023	869	536	552	0.4780260	222,657	229,303	6,646	196,998	426,301			
21	Nov-2023	868	223	288	0.4780260	92,529	119,499	26,970	197,233	316,732			
22	Oct-2023	869	39	47	0.4780260	16,201	19,524	3,323	197,922	217,446			
23	Sep-2023	868	1	-	0.4780260	415	-	(415)	198,156	198,156			
24	Aug-2023	869	-	-	0.4780260	-	-	-	198,846	198,846			
25	Jul-2023	868	-	-	0.4780260	-	-	-	199,079	199,079			
26	Jun-2023	868	21	35	0.4780260	8,713	14,522	5,809	199,540	214,062			
27	May-2023	869	130	184	0.4780260	54,003	76,434	22,431	200,232	276,666			
28	Apr-2023	866	367	415	0.4780260	151,927	171,798	19,871	200,001	371,799			
29	Total	10,430	3,187	3,729		1,326,063	1,551,590	225,527	2,378,258	3,929,848	24,953	6,347	31,300

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

						< ---Therm Sales					<---Peak Day--->		
						<---Weather Gas--->							
Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Actual	Normal Weather	Weather Adjustment	Base Gas b/	Total	Weather Gas	Base Gas	Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*DC Interruptible*												
2	Mar-2024	110	516	634	38.5698900	2,189,227	2,689,864	500,637	1,982,552	4,672,416			
3	Feb-2024	109	699	811	38.5698900	2,938,678	3,409,540	470,862	1,964,529	5,374,069			
4	Jan-2024	110	655	763	38.5698900	2,778,961	3,237,171	458,210	1,982,552	5,219,723	254,561	63,953	318,514
5	Dec-2023	111	536	552	38.5698900	2,294,754	2,363,254	68,500	2,000,575	4,363,829			
6	Nov-2023	114	223	288	38.5698900	980,524	1,266,327	285,803	2,054,645	3,320,972			
7	Oct-2023	111	39	47	38.5698900	166,969	201,219	34,250	2,000,575	2,201,794			
8	Sep-2023	111	1	-	38.5698900	4,281	-	(4,281)	2,000,575	2,000,575			
9	Aug-2023	109	-	-	38.5698900	-	-	-	1,964,529	1,964,529			
10	Jul-2023	109	-	-	38.5698900	-	-	-	1,964,529	1,964,529			
11	Jun-2023	109	21	35	38.5698900	88,286	147,144	58,858	1,964,529	2,111,673			
12	May-2023	111	130	184	38.5698900	556,564	787,751	231,187	2,000,575	2,788,326			
13	Apr-2023	113	367	415	38.5698900	1,599,532	1,808,735	209,203	2,036,622	3,845,357			
14	Total	1,327	3,187	3,729		13,597,776	15,911,005	2,313,229	23,916,786	39,827,791	254,561	63,953	318,514
15													
16	*Special Contract 1*												
17	Mar-2024	2	516	634	1006.8410000	1,039,060	1,276,674	237,614	1,409,264.80	2,685,939			
18	Feb-2024	2	699	811	1006.8410000	1,407,564	1,633,096	225,532	1,409,264.80	3,042,361			
19	Jan-2024	2	655	763	1006.8410000	1,318,962	1,536,439	217,477	1,409,264.80	2,945,704	120,821	45,460	166,281
20	Dec-2023	2	536	552	1006.8410000	1,079,334	1,111,552	32,218	1,409,264.80	2,520,817			
21	Nov-2023	2	223	288	1006.8410000	449,051	579,940	130,889	1,409,264.80	1,989,205			
22	Oct-2023	2	39	47	1006.8410000	78,534	94,643	16,109	1,409,264.80	1,503,908			
23	Sep-2023	2	1	-	1006.8410000	2,014	-	(2,014)	1,409,264.80	1,409,265			
24	Aug-2023	2	-	-	1006.8410000	-	-	-	1,409,264.80	1,409,265			
25	Jul-2023	2	-	-	1006.8410000	-	-	-	1,409,264.80	1,409,265			
26	Jun-2023	2	21	35	1006.8410000	42,287	70,479	28,192	1,409,264.80	1,479,744			
27	May-2023	2	130	184	1006.8410000	261,779	370,517	108,738	1,409,264.80	1,779,782			
28	Apr-2023	2	367	415	1006.8410000	739,021	835,678	96,657	1,409,264.80	2,244,943			
29	Total	24	3,187	3,729		6,417,606	7,509,018	1,091,412	16,911,178	24,420,196	120,821	45,460	166,281

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Determination of Billing Period Normal Weather Therms Sales

Based on 12 Months Ending Mar 2024

Line No.	Month/ Year	Meters a/	Actual HDD's	Normal Weather HDD's	Variation per HDD (Therms)	Therm Sales: Weather Gas: Actual	Therm Sales: Weather Gas: Normal Weather	Therm Sales: Weather Adjustment	Therm Sales: Base Gas b/	Therm Sales: Total	Peak Day: Weather Gas	Peak Day: Base Gas	Peak Day: Total
	A	B	C	D	E	F=BxCxE	G=BxDxE	H=G-F	I	J=G+I	K	L	M=K+L
1	*Special Contract 2*												
2	Mar-2024	1	516	634	903.7065000	466,313	572,950	106,637	869,218	1,442,168			
3	Feb-2024	1	699	811	903.7065000	631,691	732,906	101,215	869,218	1,602,124			
4	Jan-2024	1	655	763	903.7065000	591,928	689,528	97,600	869,218	1,558,746	54,222	28,039	82,261
5	Dec-2023	1	536	552	903.7065000	484,387	498,846	14,459	869,218	1,368,064			
6	Nov-2023	1	223	288	903.7065000	201,527	260,267	58,740	869,218	1,129,485			
7	Oct-2023	1	39	47	903.7065000	35,245	42,474	7,229	869,218	911,692			
8	Sep-2023	1	1	-	903.7065000	904	-	(904)	869,218	869,218			
9	Aug-2023	1	-	-	903.7065000	-	-	-	869,218	869,218			
10	Jul-2023	1	-	-	903.7065000	-	-	-	869,218	869,218			
11	Jun-2023	1	21	35	903.7065000	18,978	31,630	12,652	869,218	900,848			
12	May-2023	1	130	184	903.7065000	117,482	166,282	48,800	869,218	1,035,500			
13	Apr-2023	1	367	415	903.7065000	331,660	375,038	43,378	869,218	1,244,256			
14	Total	12	3,187	3,729		2,880,115	3,369,921	489,806	10,430,618	13,800,539	54,222	28,039	82,261

a/ For the period outlined, meters are used for the calculations. However, months billed will be reviewed for use in future periods.
b/ Base Gas calculated by multiplying Base Gas Factor by Meters

Washington Gas Light Company
District of Columbia Jurisdiction

Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*DC Res Htg / HC*						
2	Mar-2024	134,809	9,929,458	73.66	516	60	-
3	Feb-2024	136,422	14,520,541	106.44	699	59	-
4	Jan-2024	129,692	13,323,881	102.74	655	58	-
5	Dec-2023	144,740	10,890,742	75.24	536	57	-
6	Nov-2023	138,935	5,413,194	38.96	223	56	-
7	Oct-2023	132,059	1,968,056	14.90	39	55	-
8	Sep-2023	136,513	1,622,364	11.88	1	54	-
9	Aug-2023	134,717	1,316,376	9.77	-	53	-
10	Jul-2023	136,571	1,655,214	12.12	-	52	-
11	Jun-2023	136,762	2,296,757	16.79	21	51	-
12	May-2023	133,100	3,331,233	25.03	130	50	-
13	Apr-2023	138,943	7,856,288	56.54	367	49	-
14	Mar-2023	147,849	11,897,666	80.47	465	48	-
15	Feb-2023	144,223	14,230,641	98.67	619	47	-
16	Jan-2023	130,797	14,128,021	108.02	733	46	-
17	Dec-2022	137,096	10,235,733	74.66	517	45	-
18	Nov-2022	136,497	5,474,859	40.11	219	44	-
19	Oct-2022	138,790	3,057,388	22.03	89	43	-
20	Sep-2022	137,971	1,654,552	11.99	-	42	-
21	Aug-2022	134,443	1,288,857	9.59	-	41	-
22	Jul-2022	137,871	1,695,558	12.30	-	40	-
23	Jun-2022	137,060	2,205,599	16.09	25	39	-
24	May-2022	137,472	4,610,716	33.54	175	38	-
25	Apr-2022	137,332	8,994,064	65.49	408	37	-
26	Mar-2022	136,694	11,368,012	83.16	533	36	-
27	Feb-2022	134,329	17,778,523	132.35	787	35	-
28	Jan-2022	138,160	15,713,847	113.74	747	34	-
29	Dec-2021	138,674	11,250,949	81.13	531	33	-
30	Nov-2021	136,460	5,080,258	37.23	189	32	-
31	Oct-2021	136,387	1,701,417	12.48	5	31	-
32	Sep-2021	136,129	1,601,237	11.76	-	30	-
33	Aug-2021	136,512	1,484,458	10.87	-	29	-
34	Jul-2021	136,143	1,699,180	12.48	2	28	1
35	Jun-2021	135,172	2,244,598	16.61	44	27	1
36	May-2021	136,479	4,390,784	32.17	176	26	1
37	Apr-2021	136,986	7,981,143	58.26	341	25	1
38	Mar-2021	127,828	13,254,713	103.69	650	24	1
39	Feb-2021	146,593	17,864,740	121.87	784	23	1
40	Jan-2021	135,886	17,030,174	125.33	787	22	1
41	Dec-2020	135,703	10,219,382	75.31	465	21	1
42	Nov-2020	135,568	5,231,876	38.59	191	20	1
43	Oct-2020	136,069	2,384,449	17.52	55	19	1
44	Sep-2020	135,641	1,486,025	10.96	6	18	1
45	Aug-2020	135,415	1,548,348	11.43	-	17	1
46	Jul-2020	137,727	1,828,638	13.28	-	16	1
47	Jun-2020	135,915	2,905,104	21.37	58	15	1
48	May-2020	132,460	6,112,557	46.15	271	14	1
49	Apr-2020	135,573	7,379,741	54.43	317	13	1
50	Mar-2020	134,393	11,259,394	83.78	521	12	1
51	Feb-2020	134,902	14,959,175	110.89	681	11	-
52	Jan-2020	135,021	14,386,291	106.55	673	10	-
53	Dec-2019	133,822	13,365,473	99.88	611	9	-
54	Nov-2019	133,499	6,965,878	52.18	284	8	-
55	Oct-2019	133,687	1,821,152	13.62	15	7	-
56	Sep-2019	134,609	1,658,983	12.32	-	6	-
57	Aug-2019	135,770	1,526,482	11.24	-	5	-
58	Jul-2019	132,542	1,529,430	11.54	-	4	-
59	Jun-2019	134,244	2,216,590	16.53	16	3	-
60	May-2019	134,223	3,318,002	24.72	71	2	-
61	Apr-2019	133,829	8,906,715	66.65	386	1	-
62	Total	8,169,509	405,053,474		16,634		

Statistical Information & Regression Coefficients (H, I, J, K, L)

Dependent Variable: RHTOT_UPC
Method: Least Squares
Date: 05/15/24 Time: 09:51
Sample: 2019M04 2024M03
Included observations: 60

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	13.39515	0.893364	14.99405	0
HDD	0.139774	0.001497	93.35707	0
TREND	-0.087212	0.023768	-3.669259	0.0005

R-squared	0.993536	Mean dependent var	49.48515
Adjusted R-squared	0.993309	S.D. dependent var	38.73734
S.E. of regression	3.168551	Akaike info criterion	5.193132
Sum squared resid	572.2637	Schwarz criterion	5.29785
Log likelihood	-152.794	Hannan-Quinn criter.	5.234093
F-statistic	4380.705	Durbin-Watson stat	1.908289
Prob(F-statistic)	0		

Coefficients:

C	Trend	Covid Dummy
13.395150	-0.087212	0.000000

Base Gas Calculations:

Date	Per Bill
Mar-2024	8.16
Feb-2024	8.25
Jan-2024	8.34
Dec-2023	8.42
Nov-2023	8.51
Oct-2023	8.60
Sep-2023	8.69
Aug-2023	8.77
Jul-2023	8.86
Jun-2023	8.95
May-2023	9.03
Apr-2023	9.12

Washington Gas Light Company
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Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*DC Res Non Htg - IMA*						
2	Mar-2024	10,812	70,148	6.49	516	60	-
3	Feb-2024	11,141	103,348	9.28	699	59	-
4	Jan-2024	10,616	81,335	7.66	655	58	-
5	Dec-2023	11,840	60,138	5.08	536	57	-
6	Nov-2023	11,254	51,713	4.60	223	56	-
7	Oct-2023	11,109	30,619	2.76	39	55	-
8	Sep-2023	11,180	21,735	1.94	1	54	-
9	Aug-2023	11,047	27,299	2.47	-	53	-
10	Jul-2023	11,121	37,608	3.38	-	52	-
11	Jun-2023	11,211	37,552	3.35	21	51	-
12	May-2023	11,095	37,754	3.40	130	50	-
13	Apr-2023	11,643	65,163	5.60	367	49	-
14	Mar-2023	11,467	77,288	6.74	465	48	-
15	Feb-2023	11,694	84,416	7.22	619	47	-
16	Jan-2023	14,579	93,385	6.41	733	46	-
17	Dec-2022	11,382	72,806	6.40	517	45	-
18	Nov-2022	11,365	46,565	4.10	219	44	-
19	Oct-2022	11,430	40,949	3.58	89	43	-
20	Sep-2022	11,497	36,167	3.15	-	42	-
21	Aug-2022	11,573	26,024	2.25	-	41	-
22	Jul-2022	11,633	29,799	2.56	-	40	-
23	Jun-2022	11,787	34,925	2.96	25	39	-
24	May-2022	11,816	40,759	3.45	175	38	-
25	Apr-2022	11,778	83,080	7.05	408	37	-
26	Mar-2022	11,885	90,463	7.61	533	36	-
27	Feb-2022	11,968	103,871	8.68	787	35	-
28	Jan-2022	11,779	102,867	8.73	747	34	-
29	Dec-2021	11,662	78,015	6.69	531	33	-
30	Nov-2021	11,578	40,013	3.46	189	32	-
31	Oct-2021	11,201	19,481	1.74	5	31	-
32	Sep-2021	11,586	35,607	3.07	-	30	-
33	Aug-2021	11,601	32,627	2.81	-	29	-
34	Jul-2021	11,734	36,209	3.09	2	28	1
35	Jun-2021	11,745	16,260	1.39	44	27	1
36	May-2021	11,944	50,679	4.24	176	26	1
37	Apr-2021	12,003	67,525	5.63	341	25	1
38	Mar-2021	11,871	95,771	8.07	650	24	1
39	Feb-2021	13,587	112,000	8.24	784	23	1
40	Jan-2021	12,365	112,402	9.09	787	22	1
41	Dec-2020	12,498	78,766	6.30	465	21	1
42	Nov-2020	12,544	61,932	4.94	191	20	1
43	Oct-2020	12,541	45,163	3.60	55	19	1
44	Sep-2020	12,676	36,805	2.90	6	18	1
45	Aug-2020	12,766	114,555	8.97	-	17	1
46	Jul-2020	12,959	42,809	3.30	-	16	1
47	Jun-2020	12,723	46,229	3.63	58	15	1
48	May-2020	12,453	66,803	5.36	271	14	1
49	Apr-2020	12,684	71,917	5.67	317	13	1
50	Mar-2020	12,421	82,445	6.64	521	12	1
51	Feb-2020	12,613	129,748	10.29	681	11	-
52	Jan-2020	12,593	97,696	7.76	673	10	-
53	Dec-2019	12,406	88,870	7.16	611	9	-
54	Nov-2019	12,444	67,939	5.46	284	8	-
55	Oct-2019	12,399	8,205	0.66	15	7	-
56	Sep-2019	12,382	17,414	1.41	-	6	-
57	Aug-2019	12,547	34,249	2.73	-	5	-
58	Jul-2019	12,500	34,038	2.72	-	4	-
59	Jun-2019	12,559	30,228	2.41	16	3	-
60	May-2019	12,488	44,652	3.58	71	2	-
61	Apr-2019	12,514	67,511	5.40	386	1	-
62	Total	718,288	3,552,337				

Statistical Information & Regression Coefficients

H	I	J	K	L
Dependent Variable: RIMATOT_UPC				
Method: Least Squares				
Date: 05/15/24 Time: 09:53				
Sample: 2019M04 2024M03				
Included observations: 60				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2.809405	0.204137	13.76235	0
HDD	0.007619	0.000523	14.57174	0
R-squared	0.785452	Mean dependent var		4.921552
Adjusted R-squared	0.781753	S.D. dependent var		2.383344
S.E. of regression	1.113425	Akaike info criterion		3.085524
Sum squared resid	71.90352	Schwarz criterion		3.155336
Log likelihood	-90.56573	Hannan-Quinn criter.		3.112831
F-statistic	212.3356	Durbin-Watson stat		1.817491
Prob(F-statistic)	0			

Coefficients:

C	Trend	Covid Dummy
2.809405	0.000000	0.000000

Base Gas Calculations:

Date	Per Bill
Mar-2024	2.81
Feb-2024	2.81
Jan-2024	2.81
Dec-2023	2.81
Nov-2023	2.81
Oct-2023	2.81
Sep-2023	2.81
Aug-2023	2.81
Jul-2023	2.81
Jun-2023	2.81
May-2023	2.81
Apr-2023	2.81

Washington Gas Light Company
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Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy	Statistical Information & Regression Coefficients				
	A	B	C	D=C/B	E	F	G	H	I	J	K	L
1	*DC Res Non Htg - OTH*											
2	Mar-2024	3,533	190,410	53.90	516	60	-	Dependent Variable: RNONTOT_UPC				
3	Feb-2024	3,592	279,296	77.75	699	59	-	Method: Least Squares				
4	Jan-2024	3,457	259,455	75.05	655	58	-	Date: 05/15/24 Time: 09:54				
5	Dec-2023	3,763	215,376	57.24	536	57	-	Sample: 2019M04 2024M03				
6	Nov-2023	3,676	118,734	32.30	223	56	-	Included observations: 60				
7	Oct-2023	3,439	43,928	12.77	39	55	-					
8	Sep-2023	3,558	35,484	9.97	1	54	-	Variable	Coefficient	Std. Error	t-Statistic	Prob.
9	Aug-2023	3,520	27,960	7.94	-	53	-					
10	Jul-2023	3,552	33,963	9.56	-	52	-	C	9.731134	0.457519	21.26937	0
11	Jun-2023	3,543	54,630	15.42	21	51	-	HDD	0.096533	0.001172	82.3802	0
12	May-2023	3,459	69,522	20.10	130	50	-					
13	Apr-2023	3,574	151,399	42.36	367	49	-	R-squared	0.991526	Mean dependent var		36.49339
14	Mar-2023	3,907	242,168	61.98	465	48	-	Adjusted R-squared	0.99138	S.D. dependent var		26.87775
15	Feb-2023	3,795	280,439	73.89	619	47	-	S.E. of regression	2.495445	Akaike info criterion		4.699576
16	Jan-2023	3,319	261,038	78.64	733	46	-	Sum squared resid	361.1803	Schwarz criterion		4.769388
17	Dec-2022	3,560	190,830	53.60	517	45	-	Log likelihood	-138.9873	Hannan-Quinn criter.		4.726884
18	Nov-2022	3,543	100,325	28.32	219	44	-	F-statistic	6786.498	Durbin-Watson stat		1.880243
19	Oct-2022	3,628	66,489	18.33	89	43	-	Prob(F-statistic)	0			
20	Sep-2022	3,567	45,697	12.81	-	42	-					
21	Aug-2022	3,509	28,234	8.05	-	41	-					
22	Jul-2022	3,630	39,051	10.76	-	40	-					
23	Jun-2022	3,594	45,763	12.73	25	39	-					
24	May-2022	3,624	91,092	25.13	175	38	-					
25	Apr-2022	3,638	170,305	46.82	408	37	-					
26	Mar-2022	3,638	213,455	58.67	533	36	-					
27	Feb-2022	3,599	334,758	93.00	787	35	-					
28	Jan-2022	3,654	301,303	82.46	747	34	-					
29	Dec-2021	3,676	212,352	57.76	531	33	-					
30	Nov-2021	3,665	108,261	29.54	189	32	-					
31	Oct-2021	3,745	41,757	11.15	5	31	-					
32	Sep-2021	3,689	35,468	9.61	-	30	-					
33	Aug-2021	3,724	32,036	8.60	-	29	-					
34	Jul-2021	3,733	38,281	10.26	2	28	1					
35	Jun-2021	3,692	49,288	13.35	44	27	1					
36	May-2021	3,658	92,318	25.24	176	26	1					
37	Apr-2021	3,685	155,927	42.32	341	25	1					
38	Mar-2021	3,449	250,169	72.53	650	24	1	Coefficients:				
39	Feb-2021	3,922	337,579	86.07	784	23	1			Covid		
40	Jan-2021	3,688	325,775	88.33	787	22	1	C	Trend	Dummy		
41	Dec-2020	3,636	202,218	55.62	465	21	1	9.731134	0.000000	0.000000		
42	Nov-2020	3,676	110,285	30.00	191	20	1					
43	Oct-2020	3,685	55,150	14.97	55	19	1					
44	Sep-2020	3,687	38,592	10.47	6	18	1	Base Gas Calculations:				
45	Aug-2020	3,692	35,051	9.50	-	17	1					
46	Jul-2020	3,792	41,701	11.00	-	16	1	Date	Per Bill			
47	Jun-2020	3,776	66,920	17.72	58	15	1	Mar-2024	9.73			
48	May-2020	3,612	123,241	34.12	271	14	1	Feb-2024	9.73			
49	Apr-2020	3,752	147,012	39.19	317	13	1	Jan-2024	9.73			
50	Mar-2020	3,739	216,869	58.01	521	12	1	Dec-2023	9.73			
51	Feb-2020	3,765	288,439	76.62	681	11	-	Nov-2023	9.73			
52	Jan-2020	3,731	276,335	74.07	673	10	-	Oct-2023	9.73			
53	Dec-2019	3,736	258,488	69.18	611	9	-	Sep-2023	9.73			
54	Nov-2019	3,754	144,755	38.56	284	8	-	Aug-2023	9.73			
55	Oct-2019	3,742	43,221	11.55	15	7	-	Jul-2023	9.73			
56	Sep-2019	3,767	40,239	10.68	-	6	-	Jun-2023	9.73			
57	Aug-2019	3,819	34,631	9.07	-	5	-	May-2023	9.73			
58	Jul-2019	3,750	35,050	9.35	-	4	-	Apr-2023	9.73			
59	Jun-2019	3,785	52,539	13.88	16	3	-					
60	May-2019	3,749	69,077	18.42	71	2	-					
61	Apr-2019	3,788	164,093	43.32	386	1	-					
62	Total	219,630	8,014,214									

Washington Gas Light Company
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Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*DC C&I Htg / HC < 3075*						
2	Mar-2024	4,626	638,500	138.03	516	60	-
3	Feb-2024	4,582	922,229	201.26	699	59	-
4	Jan-2024	4,449	794,129	178.52	655	58	-
5	Dec-2023	5,063	616,887	121.84	536	57	-
6	Nov-2023	4,636	286,815	61.87	223	56	-
7	Oct-2023	4,579	111,430	24.33	39	55	-
8	Sep-2023	4,567	89,196	19.53	1	54	-
9	Aug-2023	4,514	133,302	29.53	-	53	-
10	Jul-2023	4,489	109,193	24.33	-	52	-
11	Jun-2023	4,576	207,835	45.42	21	51	-
12	May-2023	4,474	248,719	55.59	130	50	-
13	Apr-2023	4,592	512,891	111.70	367	49	-
14	Mar-2023	4,560	601,751	131.96	465	48	-
15	Feb-2023	4,753	774,596	162.99	619	47	-
16	Jan-2023	4,457	808,831	181.49	733	46	-
17	Dec-2022	4,646	560,648	120.67	517	45	-
18	Nov-2022	4,656	265,966	57.13	219	44	-
19	Oct-2022	4,744	121,930	25.70	89	43	-
20	Sep-2022	4,544	83,507	18.38	-	42	-
21	Aug-2022	4,664	98,275	21.07	-	41	-
22	Jul-2022	4,733	181,503	38.35	-	40	-
23	Jun-2022	4,821	99,565	20.65	25	39	-
24	May-2022	4,731	279,675	59.12	175	38	-
25	Apr-2022	4,651	680,005	146.19	408	37	-
26	Mar-2022	4,573	737,444	161.27	533	36	-
27	Feb-2022	4,620	1,070,622	231.72	787	35	-
28	Jan-2022	4,603	861,385	187.13	747	34	-
29	Dec-2021	4,618	601,130	130.17	531	33	-
30	Nov-2021	4,671	291,291	62.36	189	32	-
31	Oct-2021	4,527	148,993	32.91	5	31	-
32	Sep-2021	4,536	2,121	0.47	-	30	-
33	Aug-2021	4,383	148,258	33.83	-	29	-
34	Jul-2021	4,465	216,837	48.56	2	28	1
35	Jun-2021	4,346	288,713	66.43	44	27	1
36	May-2021	4,423	270,033	61.06	176	26	1
37	Apr-2021	4,420	511,348	115.70	341	25	1
38	Mar-2021	4,103	840,005	204.74	650	24	1
39	Feb-2021	4,824	1,042,149	216.02	784	23	1
40	Jan-2021	4,368	871,206	199.45	787	22	1
41	Dec-2020	4,340	461,327	106.31	465	21	1
42	Nov-2020	4,369	210,321	48.14	191	20	1
43	Oct-2020	4,336	95,301	21.98	55	19	1
44	Sep-2020	4,364	60,058	13.76	6	18	1
45	Aug-2020	4,253	146,333	34.41	-	17	1
46	Jul-2020	4,331	124,220	28.68	-	16	1
47	Jun-2020	4,232	144,032	34.03	58	15	1
48	May-2020	4,163	346,114	83.13	271	14	1
49	Apr-2020	4,180	397,982	95.22	317	13	1
50	Mar-2020	4,197	687,844	163.91	521	12	1
51	Feb-2020	4,207	878,766	208.89	681	11	-
52	Jan-2020	4,199	844,328	201.06	673	10	-
53	Dec-2019	4,169	741,750	177.93	611	9	-
54	Nov-2019	4,132	335,404	81.17	284	8	-
55	Oct-2019	4,124	108,480	26.31	15	7	-
56	Sep-2019	4,104	85,753	20.90	-	6	-
57	Aug-2019	4,165	156,588	37.60	-	5	-
58	Jul-2019	4,153	128,222	30.87	-	4	-
59	Jun-2019	4,208	140,174	33.31	16	3	-
60	May-2019	4,105	274,676	66.91	71	2	-
61	Apr-2019	4,081	561,591	137.60	386	1	-
62	Total	266,998	24,058,173				

Statistical Information & Regression Coefficients (H, I, J, K, L)

Dependent Variable: CH1TOT_UPC
Method: ARMA Maximum Likelihood (BFGS)
Date: 05/15/24 Time: 09:54
Sample: 2019M04 2024M03
Included observations: 60
Convergence achieved after 5 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	23.6953	4.622643	5.125698	0
HDD	0.23977	0.010526	22.77863	0
AR(1)	0.467466	0.148051	3.157468	0.0026
SIGMASQ	176.4122	39.33862	4.484452	0

R-squared	0.960481	Mean dependent var	89.99242
Adjusted R-squared	0.958364	S.D. dependent var	67.37694
S.E. of regression	13.7482	Akaike info criterion	8.148143
Sum squared resid	10584.73	Schwarz criterion	8.287766
Log likelihood	-240.4443	Hannan-Quinn criter.	8.202757
F-statistic	453.6809	Durbin-Watson stat	1.864521
Prob(F-statistic)	0		

Inverted AR Roots 0.47

Coefficients:

C	Trend	Covid Dummy
23.695300	0.000000	0.000000

Base Gas Calculations:

Date	Per Bill
Mar-2024	23.70
Feb-2024	23.70
Jan-2024	23.70
Dec-2023	23.70
Nov-2023	23.70
Oct-2023	23.70
Sep-2023	23.70
Aug-2023	23.70
Jul-2023	23.70
Jun-2023	23.70
May-2023	23.70
Apr-2023	23.70

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Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*DC C&I Htg / HC > 3075*						
2	Mar-2024	3,274	7,048,511	2,152.83	699	60	-
3	Feb-2024	3,326	9,579,483	2,880.14	655	59	-
4	Jan-2024	3,141	9,179,131	2,922.18	536	58	-
5	Dec-2023	3,865	8,246,712	2,133.47	223	57	-
6	Nov-2023	3,389	4,892,685	1,443.55	39	56	-
7	Oct-2023	3,305	2,796,234	845.98	1	55	-
8	Sep-2023	3,290	2,280,981	693.37	-	54	-
9	Aug-2023	3,327	2,122,296	637.84	-	53	-
10	Jul-2023	3,305	2,143,434	648.48	21	52	-
11	Jun-2023	3,287	2,921,839	888.94	130	51	-
12	May-2023	3,186	3,753,702	1,178.12	367	50	-
13	Apr-2023	3,275	6,338,839	1,935.29	465	49	-
14	Mar-2023	3,490	7,231,983	2,072.39	619	48	-
15	Feb-2023	3,417	9,021,459	2,639.87	733	47	-
16	Jan-2023	3,233	9,550,134	2,954.38	517	46	-
17	Dec-2022	3,374	7,597,661	2,251.91	219	45	-
18	Nov-2022	3,262	4,735,162	1,451.42	89	44	-
19	Oct-2022	3,445	3,407,436	989.04	-	43	-
20	Sep-2022	3,177	2,257,032	710.48	-	42	-
21	Aug-2022	3,099	1,830,968	590.78	-	41	-
22	Jul-2022	3,176	2,234,307	703.59	25	40	-
23	Jun-2022	3,176	2,577,520	811.61	175	39	-
24	May-2022	3,205	3,976,575	1,240.86	408	38	-
25	Apr-2022	3,176	6,141,541	1,933.94	533	37	-
26	Mar-2022	3,113	7,424,332	2,384.87	787	36	-
27	Feb-2022	3,174	11,544,691	3,637.07	747	35	-
28	Jan-2022	3,173	9,736,572	3,068.47	531	34	-
29	Dec-2021	3,164	7,245,925	2,290.02	189	33	-
30	Nov-2021	3,201	4,125,400	1,288.73	5	32	-
31	Oct-2021	3,235	2,555,186	789.84	-	31	-
32	Sep-2021	3,148	2,189,717	695.61	-	30	-
33	Aug-2021	3,325	1,818,140	546.85	2	29	-
34	Jul-2021	3,293	2,247,454	682.54	44	28	1
35	Jun-2021	3,312	2,162,547	652.93	176	27	1
36	May-2021	3,326	3,574,466	1,074.67	341	26	1
37	Apr-2021	3,311	5,476,891	1,653.92	650	25	1
38	Mar-2021	3,184	7,631,403	2,396.99	784	24	1
39	Feb-2021	3,597	10,651,651	2,960.94	787	23	1
40	Jan-2021	3,367	9,689,070	2,877.74	465	22	1
41	Dec-2020	3,336	6,222,723	1,865.23	191	21	1
42	Nov-2020	3,336	3,767,922	1,129.64	55	20	1
43	Oct-2020	3,380	2,446,959	723.98	6	19	1
44	Sep-2020	3,364	1,832,906	544.82	-	18	1
45	Aug-2020	3,383	1,496,687	442.45	-	17	1
46	Jul-2020	3,478	1,710,467	491.75	58	16	1
47	Jun-2020	3,416	2,224,159	651.08	271	15	1
48	May-2020	3,313	3,931,228	1,186.67	317	14	1
49	Apr-2020	3,343	4,561,480	1,364.43	521	13	1
50	Mar-2020	3,396	8,582,723	2,527.48	681	12	1
51	Feb-2020	3,419	7,841,316	2,293.19	673	11	-
52	Jan-2020	3,369	8,947,122	2,655.35	611	10	-
53	Dec-2019	3,444	8,219,633	2,386.77	284	9	-
54	Nov-2019	3,370	5,238,323	1,554.61	15	8	-
55	Oct-2019	3,348	2,245,099	670.67	-	7	-
56	Sep-2019	3,375	2,167,622	642.22	-	6	-
57	Aug-2019	3,418	1,964,544	574.79	-	5	-
58	Jul-2019	3,355	1,929,560	575.19	16	4	-
59	Jun-2019	3,410	2,502,342	733.84	71	3	-
60	May-2019	3,407	3,347,209	982.44	386	2	-
61	Apr-2019	3,357	6,076,153	1,809.87	-	1	-
62	Total	199,141	297,195,241				

Statistical Information & Regression Coefficients (Columns H–L)

Dependent Variable: CH2TOT_UPC
Method: Least Squares
Date: 05/15/24 Time: 09:55
Sample: 2019M04 2024M03
Included observations: 60

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	605.6924	45.06996	13.43741	0
HDD	3.081347	0.063998	48.14782	0
TREND	2.25911	1.098942	2.055713	0.0445
COVID	-130.8675	41.97242	-3.117939	0.0029

R-squared	0.977193	Mean dependent var	1491.968
Adjusted R-squared	0.975971	S.D. dependent var	873.0468
S.E. of regression	135.3333	Akaike info criterion	12.7177
Sum squared resid	1025645	Schwarz criterion	12.85732
Log likelihood	-377.531	Hannan-Quinn criter.	12.77231
F-statistic	799.7918	Durbin-Watson stat	2.316766
Prob(F-statistic)	0.000000		

Coefficients:

C	Trend	Covid Dummy
605.892400	2.259110	-130.8675

Base Gas Calculations:

Date	Per Bill
Mar-2024	741.44
Feb-2024	739.18
Jan-2024	736.92
Dec-2023	734.66
Nov-2023	732.40
Oct-2023	730.14
Sep-2023	727.88
Aug-2023	725.63
Jul-2023	723.37
Jun-2023	721.11
May-2023	718.85
Apr-2023	716.59

Washington Gas Light Company
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Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*DC C&I Non Htg*						
2	Mar-2024	1,785	812,825	455.30	516	60	-
3	Feb-2024	1,860	1,029,848	553.76	699	59	-
4	Jan-2024	1,784	1,011,587	566.96	655	58	-
5	Dec-2023	2,002	879,320	439.20	536	57	-
6	Nov-2023	2,000	669,594	334.80	223	56	-
7	Oct-2023	1,808	484,132	267.83	39	55	-
8	Sep-2023	1,872	488,031	260.68	1	54	-
9	Aug-2023	1,871	396,431	211.89	-	53	-
10	Jul-2023	1,882	447,120	237.59	-	52	-
11	Jun-2023	1,848	532,430	288.09	21	51	-
12	May-2023	1,846	559,059	302.79	130	50	-
13	Apr-2023	1,951	835,287	428.07	367	49	-
14	Mar-2023	1,899	844,674	444.85	465	48	-
15	Feb-2023	1,920	980,257	510.58	619	47	-
16	Jan-2023	1,913	1,008,304	527.10	733	46	-
17	Dec-2022	1,951	788,842	404.28	517	45	-
18	Nov-2022	1,897	671,576	353.95	219	44	-
19	Oct-2022	1,954	611,990	313.16	89	43	-
20	Sep-2022	1,936	441,442	227.98	-	42	-
21	Aug-2022	1,924	359,081	186.65	-	41	-
22	Jul-2022	1,978	465,861	235.55	-	40	-
23	Jun-2022	1,931	507,835	262.96	25	39	-
24	May-2022	2,002	603,915	301.62	175	38	-
25	Apr-2022	1,975	782,909	396.42	408	37	-
26	Mar-2022	1,934	893,786	462.24	533	36	-
27	Feb-2022	1,912	1,061,120	554.97	787	35	-
28	Jan-2022	2,009	1,007,122	501.22	747	34	-
29	Dec-2021	2,058	860,854	418.37	531	33	-
30	Nov-2021	1,947	660,811	339.33	189	32	-
31	Oct-2021	2,015	499,041	247.61	5	31	-
32	Sep-2021	2,025	425,509	210.17	-	30	-
33	Aug-2021	2,043	413,861	202.55	-	29	-
34	Jul-2021	1,980	555,530	280.59	2	28	1
35	Jun-2021	2,002	419,749	209.62	44	27	1
36	May-2021	2,043	546,232	267.34	176	26	1
37	Apr-2021	2,078	643,635	309.78	341	25	1
38	Mar-2021	1,974	853,869	432.60	650	24	1
39	Feb-2021	2,317	1,104,625	476.80	784	23	1
40	Jan-2021	2,138	1,039,056	486.03	787	22	1
41	Dec-2020	2,092	729,478	348.72	465	21	1
42	Nov-2020	2,094	595,648	284.41	191	20	1
43	Oct-2020	2,163	425,514	196.69	55	19	1
44	Sep-2020	2,131	376,418	176.64	6	18	1
45	Aug-2020	2,116	345,722	163.41	-	17	1
46	Jul-2020	2,174	377,437	173.64	-	16	1
47	Jun-2020	2,151	350,235	162.83	58	15	1
48	May-2020	2,129	479,833	225.39	271	14	1
49	Apr-2020	2,075	619,389	298.50	317	13	1
50	Mar-2020	2,129	991,685	465.88	521	12	1
51	Feb-2020	2,172	1,298,226	597.66	681	11	-
52	Jan-2020	2,162	1,212,220	560.60	673	10	-
53	Dec-2019	2,181	1,235,966	566.83	611	9	-
54	Nov-2019	2,170	1,023,185	471.62	284	8	-
55	Oct-2019	2,162	675,538	312.44	15	7	-
56	Sep-2019	2,122	660,271	311.16	-	6	-
57	Aug-2019	2,208	582,123	263.67	-	5	-
58	Jul-2019	2,183	618,254	283.19	-	4	-
59	Jun-2019	2,219	747,186	336.77	16	3	-
60	May-2019	2,072	755,838	364.82	71	2	-
61	Apr-2019	2,223	996,413	448.16	386	1	-
62	Total	121,392	42,293,727				

Statistical Information & Regression Coefficients

H	I	J	K	L

Dependent Variable: CNONTOT_UPC
Method: ARMA Maximum Likelihood (BFGS)
Date: 05/15/24 Time: 09:50
Sample: 2019M04 2024M03
Included observations: 60
Convergence achieved after 6 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	289.9638	18.04167	16.07189	0
HDD	0.399848	0.023038	17.35599	0
TREND	-0.954207	0.464373	-2.054827	0.0447
COVID	-80.39748	14.4792	-5.552618	0
AR(1)	0.35562	0.124671	2.852465	0.0061
SIGMASQ	1117.765	194.9545	5.733465	0

R-squared	0.925047	Mean dependent var	348.738
Adjusted R-squared	0.918107	S.D. dependent var	123.1487
S.E. of regression	35.241470	Akaike info criterion	10.05922
Sum squared resid	67065.9100	Schwarz criterion	10.26865
Log likelihood	-295.776500	Hannan-Quinn criter.	10.14114
F-statistic	133.289800	Durbin-Watson stat	1.904631
Prob(F-statistic)	0.000000		

Inverted AR Roots 0.360000

Coefficients:

C	Trend	Covid Dummy
289.963800	-0.954207	-80.397480

Base Gas Calculations:

Date	Per Bill
Mar-2024	232.71
Feb-2024	233.67
Jan-2024	234.62
Dec-2023	235.57
Nov-2023	236.53
Oct-2023	237.48
Sep-2023	238.44
Aug-2023	239.39
Jul-2023	240.35
Jun-2023	241.30
May-2023	242.25
Apr-2023	243.21

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Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*CI - Delivery CHP*						
2	Mar-2024	1	213,273	213,272.80	516	60	-
3	Feb-2024	1	223,168	223,168.20	699	59	-
4	Jan-2024	1	201,194	201,193.70	655	58	-
5	Dec-2023	1	180,659	180,659.30	536	57	-
6	Nov-2023	1	155,198	155,197.90	223	56	-
7	Oct-2023	1	110,880	110,879.80	39	55	-
8	Sep-2023	1	116,440	116,440.00	1	54	-
9	Aug-2023	1	54,051	54,051.00	-	53	-
10	Jul-2023	1	95,233	95,233.30	-	52	-
11	Jun-2023	1	133,811	133,810.90	21	51	-
12	May-2023	1	132,553	132,552.50	130	50	-
13	Apr-2023	1	197,628	197,628.20	367	49	-
14	Mar-2023	1	138,343	138,342.90	465	48	-
15	Feb-2023	1	301,424	301,424.30	619	47	-
16	Jan-2023	1	248,643	248,643.10	733	46	-
17	Dec-2022	1	280,694	280,693.80	517	45	-
18	Nov-2022	1	111,811	111,811.10	219	44	-
19	Oct-2022	1	64,752	64,752.40	89	43	-
20	Sep-2022	1	65,175	65,175.20	-	42	-
21	Aug-2022	1	91,522	91,521.90	-	41	-
22	Jul-2022	1	134,445	134,444.60	-	40	-
23	Jun-2022	1	116,256	116,256.40	25	39	-
24	May-2022	1	93,737	93,736.60	175	38	-
25	Apr-2022	1	228,038	228,038.20	408	37	-
26	Mar-2022	1	301,579	301,579.20	533	36	-
27	Feb-2022	1	311,051	311,050.80	787	35	-
28	Jan-2022	1	250,656	250,656.20	747	34	-
29	Dec-2021	1	338,828	338,828.00	531	33	-
30	Nov-2021	1	188,657	188,656.90	189	32	-
31	Oct-2021	1	118,660	118,659.60	5	31	-
32	Sep-2021	1	142,051	142,051.20	-	30	-
33	Aug-2021	1	92,973	92,972.90	-	29	-
34	Jul-2021	1	80,478	80,478.10	2	28	1
35	Jun-2021	1	99,979	99,978.50	44	27	1
36	May-2021	1	105,822	105,822.10	176	26	1
37	Apr-2021	1	256,017	256,016.80	341	25	1
38	Mar-2021	1	257,712	257,712.00	650	24	1
39	Feb-2021	1	292,132	292,132.10	784	23	1
40	Jan-2021	1	393,404	393,404.30	787	22	1
41	Dec-2020	1	251,725	251,725.40	465	21	1
42	Nov-2020	1	172,672	172,671.90	191	20	1
43	Oct-2020	1	137,094	137,094.10	55	19	1
44	Sep-2020	1	128,611	128,611.20	6	18	1
45	Aug-2020	1	83,373	83,373.40	-	17	1
46	Jul-2020	1	72,186	72,186.20	-	16	1
47	Jun-2020	1	78,109	78,109.40	58	15	1
48	May-2020	1	82,054	82,054.30	271	14	1
49	Apr-2020	1	293,992	293,991.80	317	13	1
50	Mar-2020	1	302,785	336,428.22	521	12	1
51	Feb-2020	1	334,671	334,671.10	681	11	-
52	Jan-2020	1	352,899	352,899.00	673	10	-
53	Dec-2019	1	324,314	324,313.60	611	9	-
54	Nov-2019	0	100,748	431,777.14	284	8	-
55	Oct-2019	-	-	-	15	7	-
56	Sep-2019	-	-	-	-	6	-
57	Aug-2019	-	-	-	-	5	-
58	Jul-2019	-	-	-	-	4	-
59	Jun-2019	-	-	-	16	3	-
60	May-2019	-	-	-	71	2	-
61	Apr-2019	-	-	-	386	1	-
62	Total	52	9,634,162				

Statistical Information & Regression Coefficients (H–L)

Dependent Variable: CHP_UPC
Method: ARMA Maximum Likelihood (BFGS)
Date: 05/15/24 Time: 09:56
Sample: 2019M04 2024M03
Included observations: 60
Convergence achieved after 5 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	81103.42	25610.6	3.166791	0.0025
HDD	302.4376	56.63231	5.340372	0
AR(1)	0.314825	0.140751	2.236742	0.0293
SIGMASQ	4.25E+09	4.85E+08	8.74778	0

R-squared	6.54E-01	Mean dependent var	166647.2
Adjusted R-squared	6.35E-01	S.D. dependent var	111670.3
S.E. of regression	67442.1	Akaike info criterion	25.14201
Sum squared resid	2.55E+11	Schwarz criterion	25.28163
Log likelihood	-750.260200	Hannan-Quinn criter.	25.19662
F-statistic	35.252630	Durbin-Watson stat	2.012908
Prob(F-statistic)	0.000000		
Inverted AR Roots	0.310000		

Coefficients:

C	Trend	Covid Dummy
81103.420000	0.000000	0.000000

Base Gas Calculations:

Date	Per Bill
Mar-2024	81,103.42
Feb-2024	81,103.42
Jan-2024	81,103.42
Dec-2023	81,103.42
Nov-2023	81,103.42
Oct-2023	81,103.42
Sep-2023	81,103.42
Aug-2023	81,103.42
Jul-2023	81,103.42
Jun-2023	81,103.42
May-2023	81,103.42
Apr-2023	81,103.42

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Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*DC GMA Htg / HC < 3075*						
2	Mar-2024	638	209,140	327.70	516	60	-
3	Feb-2024	660	112,455	170.33	699	59	-
4	Jan-2024	588	173,573	295.34	655	58	-
5	Dec-2023	632	141,291	223.40	536	57	-
6	Nov-2023	627	75,765	120.82	223	56	-
7	Oct-2023	616	30,459	49.48	39	55	-
8	Sep-2023	619	7,329	11.83	1	54	-
9	Aug-2023	600	37,048	61.78	-	53	-
10	Jul-2023	627	46,309	73.86	-	52	-
11	Jun-2023	621	57,656	92.84	21	51	-
12	May-2023	588	118,956	202.19	130	50	-
13	Apr-2023	586	82,980	141.51	367	49	-
14	Mar-2023	625	88,507	141.56	465	48	-
15	Feb-2023	598	96,590	161.63	619	47	-
16	Jan-2023	588	111,692	190.00	733	46	-
17	Dec-2022	634	69,901	110.33	517	45	-
18	Nov-2022	556	10,010	18.01	219	44	-
19	Oct-2022	605	35,530	58.75	89	43	-
20	Sep-2022	642	15,640	24.37	-	42	-
21	Aug-2022	594	52,309	88.05	-	41	-
22	Jul-2022	651	44,149	67.85	-	40	-
23	Jun-2022	596	53,133	89.08	25	39	-
24	May-2022	595	88,791	149.23	175	38	-
25	Apr-2022	588	115,847	196.90	408	37	-
26	Mar-2022	554	159,354	287.82	533	36	-
27	Feb-2022	579	140,084	241.81	787	35	-
28	Jan-2022	610	147,468	241.70	747	34	-
29	Dec-2021	625	120,701	193.14	531	33	-
30	Nov-2021	594	41,494	69.87	169	32	-
31	Oct-2021	594	15,635	26.30	5	31	-
32	Sep-2021	597	22,666	37.95	-	30	-
33	Aug-2021	589	32,895	55.89	-	29	-
34	Jul-2021	531	29,494	55.55	2	28	1
35	Jun-2021	534	35,790	66.97	44	27	1
36	May-2021	587	73,698	125.62	176	26	1
37	Apr-2021	583	125,773	215.60	341	25	1
38	Mar-2021	540	136,179	252.12	650	24	1
39	Feb-2021	620	162,145	261.47	784	23	1
40	Jan-2021	565	147,367	260.90	787	22	1
41	Dec-2020	545	81,199	149.12	465	21	1
42	Nov-2020	577	48,217	83.58	191	20	1
43	Oct-2020	587	37,790	64.43	55	19	1
44	Sep-2020	579	20,973	36.22	6	18	1
45	Aug-2020	580	28,532	49.20	-	17	1
46	Jul-2020	577	31,241	54.14	-	16	1
47	Jun-2020	579	47,089	81.34	58	15	1
48	May-2020	550	98,834	179.64	271	14	1
49	Apr-2020	664	107,652	162.01	317	13	1
50	Mar-2020	554	107,816	194.64	521	12	1
51	Feb-2020	578	133,815	231.33	681	11	-
52	Jan-2020	596	127,402	213.63	673	10	-
53	Dec-2019	529	109,214	206.62	611	9	-
54	Nov-2019	455	57,694	126.69	284	8	-
55	Oct-2019	536	26,313	49.09	15	7	-
56	Sep-2019	492	26,293	53.42	-	6	-
57	Aug-2019	460	22,100	47.99	-	5	-
58	Jul-2019	433	21,490	49.61	-	4	-
59	Jun-2019	472	28,835	61.10	16	3	-
60	May-2019	469	37,654	80.22	71	2	-
61	Apr-2019	469	61,941	131.96	386	1	-
62	Total	34,660	4,527,892				

Statistical Information & Regression Coefficients

H	I	J	K	L
Dependent Variable: GH1TOT_UPC				
Method: ARMA Maximum Likelihood (BFGS)				
Date: 05/15/24 Time: 09:57				
Sample: 2019M04 2024M03				
Included observations: 60				
Convergence achieved after 3 iterations				
Coefficient covariance computed using outer product of gradients				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	60.25869	14.61475	4.123143	0.0001
HDD	0.252432	0.031399	8.039491	0
AR(1)	0.305168	0.144576	2.110782	0.0393
SIGMASQ	1531.125	231.1549	6.623803	0
R-squared	0.770422	Mean dependent var		129.4255
Adjusted R-squared	0.758123	S.D. dependent var		82.3549
S.E. of regression	40.50297	Akaike info criterion		10.3066
Sum squared resid	91867.49	Schwarz criterion		10.44622
Log likelihood	-305.1979	Hannan-Quinn criter.		10.36121
F-statistic	62.64182	Durbin-Watson stat		1.838686
Prob(F-statistic)	0			
Inverted AR Roots	0.31			

Coefficients:

C	Trend	Covid Dummy
60.258690	0.000000	0.000000

Base Gas Calculations:

Date	Per Bill
Mar-2024	60.26
Feb-2024	60.26
Jan-2024	60.26
Dec-2023	60.26
Nov-2023	60.26
Oct-2023	60.26
Sep-2023	60.26
Aug-2023	60.26
Jul-2023	60.26
Jun-2023	60.26
May-2023	60.26
Apr-2023	60.26

Washington Gas Light Company
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Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*DC GMA Htg / HC > 3075*						
2	Mar-2024	1,626	3,450,456	2,122.27	516	60	-
3	Feb-2024	1,645	4,537,194	2,758.23	699	59	-
4	Jan-2024	1,565	4,146,785	2,649.59	655	58	-
5	Dec-2023	1,711	4,022,262	2,350.96	536	57	-
6	Nov-2023	1,662	2,098,072	1,262.66	223	56	-
7	Oct-2023	1,572	806,722	513.24	39	55	-
8	Sep-2023	1,603	680,292	424.27	1	54	-
9	Aug-2023	1,636	610,304	372.98	-	53	-
10	Jul-2023	1,604	674,182	420.39	-	52	-
11	Jun-2023	1,616	1,003,827	621.35	21	51	-
12	May-2023	1,607	1,419,540	883.16	130	50	-
13	Apr-2023	1,687	3,129,326	1,854.49	367	49	-
14	Mar-2023	1,645	3,586,429	2,180.33	465	48	-
15	Feb-2023	1,736	4,473,459	2,576.49	619	47	-
16	Jan-2023	1,517	4,311,771	2,841.99	733	46	-
17	Dec-2022	1,626	3,280,949	2,017.48	517	45	-
18	Nov-2022	1,604	2,176,440	1,356.55	219	44	-
19	Oct-2022	1,645	1,120,031	680.84	89	43	-
20	Sep-2022	1,604	722,357	450.32	-	42	-
21	Aug-2022	1,618	566,925	350.48	-	41	-
22	Jul-2022	1,597	642,796	402.54	-	40	-
23	Jun-2022	1,632	826,366	506.44	25	39	-
24	May-2022	1,632	1,822,159	1,116.68	175	38	-
25	Apr-2022	1,607	2,892,489	1,800.04	408	37	-
26	Mar-2022	1,595	3,440,266	2,156.86	533	36	-
27	Feb-2022	1,548	4,549,025	2,939.34	787	35	-
28	Jan-2022	1,623	4,538,380	2,796.18	747	34	-
29	Dec-2021	1,610	3,292,546	2,044.94	531	33	-
30	Nov-2021	1,641	1,738,908	1,059.97	189	32	-
31	Oct-2021	1,588	658,925	414.96	5	31	-
32	Sep-2021	1,614	615,759	381.61	-	30	-
33	Aug-2021	1,630	572,488	351.28	-	29	-
34	Jul-2021	1,670	752,240	450.57	2	28	1
35	Jun-2021	1,669	846,907	507.58	44	27	1
36	May-2021	1,698	1,758,825	1,035.76	176	26	1
37	Apr-2021	1,624	2,602,306	1,602.31	341	25	1
38	Mar-2021	1,623	3,788,189	2,333.88	650	24	1
39	Feb-2021	1,680	4,853,013	2,888.25	784	23	1
40	Jan-2021	1,621	4,670,591	2,880.77	787	22	1
41	Dec-2020	1,612	3,052,288	1,893.24	465	21	1
42	Nov-2020	1,615	1,831,503	1,134.41	191	20	1
43	Oct-2020	1,592	875,232	549.62	55	19	1
44	Sep-2020	1,625	649,601	399.85	6	18	1
45	Aug-2020	1,610	634,512	394.05	-	17	1
46	Jul-2020	1,640	706,617	430.77	-	16	1
47	Jun-2020	1,629	953,929	585.57	58	15	1
48	May-2020	1,635	2,282,808	1,395.87	271	14	1
49	Apr-2020	1,665	2,632,751	1,581.49	317	13	1
50	Mar-2020	1,633	3,429,093	2,099.83	521	12	1
51	Feb-2020	1,616	4,191,042	2,593.09	681	11	-
52	Jan-2020	1,631	4,046,864	2,480.75	673	10	-
53	Dec-2019	1,642	3,797,110	2,311.84	611	9	-
54	Nov-2019	1,646	2,408,194	1,463.09	284	8	-
55	Oct-2019	1,625	693,633	426.81	15	7	-
56	Sep-2019	1,773	703,141	396.62	-	6	-
57	Aug-2019	1,657	625,049	377.17	-	5	-
58	Jul-2019	1,647	643,311	390.49	-	4	-
59	Jun-2019	1,699	900,543	529.98	16	3	-
60	May-2019	1,722	1,406,154	816.68	71	2	-
60	Apr-2019	1,669	2,951,335	1,768.47	386	1	-
62	Total	98,015	131,094,207				

Statistical Information & Regression Coefficients (H–L)

Dependent Variable: GH2TOT_UPC
Method: ARMA Maximum Likelihood (BFGS)
Date: 05/15/24 Time: 09:58
Sample: 2019M04 2024M03
Included observations: 60
Convergence achieved after 4 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	448.1558	31.91568	14.04187	0
HDD	3.218457	0.066384	48.48261	0
AR(1)	0.341812	0.104854	3.259904	0.0019
SIGMASQ	7477.663	1689.512	4.425932	0

R-squared	0.990655	Mean dependent var	1339.628
Adjusted R-squared	0.990154	S.D. dependent var	902.0729
S.E. of regression	89.50856	Akaike info criterion	11.89296
Sum squared resid	448659.8	Schwarz criterion	12.03258
Log likelihood	-352.7887	Hannan-Quinn criter.	11.94757
F-statistic	1978.825	Durbin-Watson stat	2.028349
Prob(F-statistic)	0		
Inverted AR Roots	0.34		

Coefficients:

C	Trend	Covid Dummy
448.155800	0.000000	0.000000

Base Gas Calculations:

Date	Per Bill
Mar-2024	448.16
Feb-2024	448.16
Jan-2024	448.16
Dec-2023	448.16
Nov-2023	448.16
Oct-2023	448.16
Sep-2023	448.16
Aug-2023	448.16
Jul-2023	448.16
Jun-2023	448.16
May-2023	448.16
Apr-2023	448.16

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Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*DC GMA Non Htg*						
2	Mar-2024	857	387,341	451.78	516	60	-
3	Feb-2024	878	485,332	552.79	699	59	-
4	Jan-2024	831	470,308	566.02	655	58	-
5	Dec-2023	903	404,577	448.12	536	57	-
6	Nov-2023	864	332,250	384.34	223	56	-
7	Oct-2023	918	212,092	231.05	39	55	-
8	Sep-2023	881	205,020	232.77	1	54	-
9	Aug-2023	852	164,739	193.26	-	53	-
10	Jul-2023	865	198,058	228.85	-	52	-
11	Jun-2023	865	250,083	289.20	21	51	-
12	May-2023	913	257,798	282.29	130	50	-
13	Apr-2023	907	389,032	428.86	367	49	-
14	Mar-2023	900	440,407	489.40	465	48	-
15	Feb-2023	889	477,219	536.79	619	47	-
16	Jan-2023	836	487,885	583.88	733	46	-
17	Dec-2022	844	386,806	458.18	517	45	-
18	Nov-2022	854	316,963	371.09	219	44	-
19	Oct-2022	890	256,884	288.62	89	43	-
20	Sep-2022	847	191,187	225.65	-	42	-
21	Aug-2022	849	164,521	193.83	-	41	-
22	Jul-2022	857	230,591	268.96	-	40	-
23	Jun-2022	842	220,620	262.17	25	39	-
24	May-2022	848	280,163	330.43	175	38	-
25	Apr-2022	854	387,401	453.63	408	37	-
26	Mar-2022	843	390,956	463.84	533	36	-
27	Feb-2022	821	497,593	606.38	787	35	-
28	Jan-2022	856	497,934	581.45	747	34	-
29	Dec-2021	862	402,703	467.19	531	33	-
30	Nov-2021	786	295,291	375.51	189	32	-
31	Oct-2021	826	201,845	244.02	5	31	-
32	Sep-2021	841	182,965	217.62	-	30	-
33	Aug-2021	843	169,046	200.53	-	29	-
34	Jul-2021	893	188,367	210.92	2	28	1
35	Jun-2021	962	230,715	239.71	44	27	1
36	May-2021	852	281,212	330.10	176	26	1
37	Apr-2021	837	338,384	404.35	341	25	1
38	Mar-2021	789	464,300	588.82	650	24	1
39	Feb-2021	934	520,998	557.82	784	23	1
40	Jan-2021	787	509,970	648.38	787	22	1
41	Dec-2020	835	376,132	450.46	465	21	1
42	Nov-2020	837	299,468	357.59	191	20	1
43	Oct-2020	839	215,652	257.18	55	19	1
44	Sep-2020	837	183,436	219.28	6	18	1
45	Aug-2020	836	177,756	212.61	-	17	1
46	Jul-2020	845	207,666	245.69	-	16	1
47	Jun-2020	806	228,452	283.43	58	15	1
48	May-2020	832	348,890	419.34	271	14	1
49	Apr-2020	931	350,621	376.70	317	13	1
50	Mar-2020	850	398,663	468.78	521	12	1
51	Feb-2020	841	500,211	594.64	681	11	-
52	Jan-2020	778	437,968	563.30	673	10	-
53	Dec-2019	806	449,742	557.83	611	9	-
54	Nov-2019	829	368,225	443.93	284	8	-
55	Oct-2019	817	219,006	268.08	15	7	-
56	Sep-2019	863	204,976	237.40	-	6	-
57	Aug-2019	832	206,567	248.29	-	5	-
58	Jul-2019	844	204,032	241.81	-	4	-
59	Jun-2019	911	268,790	294.91	16	3	-
60	May-2019	919	308,438	335.66	71	2	-
61	Apr-2019	849	367,841	433.30	386	1	-
62	Total	51,315	19,091,889				

Statistical Information & Regression Coefficients

H | I | J | K | L

Dependent Variable: GNONTOT_UPC
Method: Least Squares
Date: 05/15/24 Time: 09:58
Sample: 2019M04 2024M03
Included observations: 60

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	257.0018	7.778134	33.04157	0
HDD	0.478026	0.013035	36.67123	0
TREND	-0.5317	0.206939	-2.56935	0.0128

R-squared	0.959405	Mean dependent var	373.3095
Adjusted R-squared	0.95798	S.D. dependent var	134.5803
S.E. of regression	27.5872	Akaike info criterion	9.521288
Sum squared resid	43380.07	Schwarz criterion	9.626005
Log likelihood	-282.6386	Hannan-Quinn criter.	9.562248
F-statistic	673.5527	Durbin-Watson stat	2.185983
Prob(F-statistic)	0.000000		

Coefficients:

C	Trend	Covid Dummy
257.001800	-0.531700	0.000000

Base Gas Calculations:

Date	Per Bill
Mar-2024	225.10
Feb-2024	225.63
Jan-2024	226.16
Dec-2023	226.69
Nov-2023	227.23
Oct-2023	227.76
Sep-2023	228.29
Aug-2023	228.82
Jul-2023	229.35
Jun-2023	229.89
May-2023	230.42
Apr-2023	230.95

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Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*DC Interruptible*						
2	Mar-2024	105	4,256,287	40,536.07	516	60	-
3	Feb-2024	101	5,212,470	51,608.61	699	59	-
4	Jan-2024	105	4,517,611	43,026.77	655	58	-
5	Dec-2023	102	4,052,004	39,621.61	536	57	-
6	Nov-2023	109	2,692,403	24,700.94	223	56	-
7	Oct-2023	101	1,896,869	18,818.14	39	55	-
8	Sep-2023	104	1,907,463	18,341.18	1	54	-
9	Aug-2023	106	1,589,971	14,999.73	-	53	-
10	Jul-2023	106	1,824,210	17,209.53	-	52	-
11	Jun-2023	106	2,377,769	22,431.78	21	51	-
12	May-2023	109	2,930,695	26,887.11	130	50	-
13	Apr-2023	106	4,448,719	41,969.05	367	49	-
14	Mar-2023	108	4,457,205	41,270.41	465	48	-
15	Feb-2023	107	5,112,515	47,780.51	619	47	-
16	Jan-2023	108	5,367,221	49,696.49	733	46	-
17	Dec-2022	106	3,730,130	35,189.91	517	45	-
18	Nov-2022	108	2,928,547	27,116.18	219	44	-
19	Oct-2022	108	2,167,549	20,069.90	89	43	-
20	Sep-2022	110	2,121,698	19,288.14	-	42	-
21	Aug-2022	120	1,133,123	9,442.69	-	41	-
22	Jul-2022	123	4,639,836	37,722.24	-	40	-
23	Jun-2022	105	1,524,743	14,521.36	25	39	-
24	May-2022	117	3,557,015	30,401.84	175	38	-
25	Apr-2022	126	4,507,010	35,769.92	408	37	-
26	Mar-2022	118	6,032,329	51,121.43	533	36	-
27	Feb-2022	118	5,389,630	45,674.83	787	35	-
28	Jan-2022	122	4,721,379	38,710.30	747	34	-
29	Dec-2021	117	4,196,011	35,853.23	531	33	-
30	Nov-2021	120	2,671,315	22,260.96	189	32	-
31	Oct-2021	121	2,156,298	17,820.64	5	31	-
32	Sep-2021	121	2,011,988	16,683.15	-	30	-
33	Aug-2021	124	1,746,836	14,087.38	-	29	-
34	Jul-2021	121	1,850,499	15,293.38	2	28	1
35	Jun-2021	122	2,284,220	18,723.12	44	27	1
36	May-2021	124	3,118,890	25,152.34	176	26	1
37	Apr-2021	122	4,253,914	34,868.15	341	25	1
38	Mar-2021	124	5,156,266	41,582.79	650	24	1
39	Feb-2021	124	5,478,769	44,183.62	784	23	1
40	Jan-2021	124	5,214,233	42,050.27	787	22	1
41	Dec-2020	124	3,726,714	30,054.14	465	21	1
42	Nov-2020	125	2,760,998	22,087.98	191	20	1
43	Oct-2020	127	2,208,243	17,387.74	55	19	1
44	Sep-2020	129	2,142,931	16,611.87	6	18	1
45	Aug-2020	139	2,306,384	16,644.18	-	17	1
46	Jul-2020	164	2,202,333	13,428.86	-	16	1
47	Jun-2020	130	2,867,696	22,059.20	58	15	1
48	May-2020	134	3,624,517	27,068.83	271	14	1
49	Apr-2020	130	3,955,564	30,427.42	317	13	1
50	Mar-2020	134	5,271,534	39,339.81	521	12	1
51	Feb-2020	134	5,537,068	41,321.40	681	11	-
52	Jan-2020	127	5,352,687	42,147.14	673	10	-
53	Dec-2019	131	4,900,593	37,409.11	611	9	-
54	Nov-2019	132	2,994,838	22,688.16	284	8	-
55	Oct-2019	133	2,357,323	17,724.24	15	7	-
56	Sep-2019	133	2,296,968	17,270.44	-	6	-
57	Aug-2019	134	2,108,643	15,736.14	-	5	-
58	Jul-2019	136	2,288,163	16,824.72	-	4	-
59	Jun-2019	136	2,683,056	19,728.35	16	3	-
60	May-2019	136	3,248,751	23,887.88	71	2	-
61	Apr-2019	137	5,548,747	40,630.21	386	1	-
62	Total	7,232	205,619,604				

Statistical Information & Regression Coefficients (H–L)

Dependent Variable: INTTOT_UPC
Method: Least Squares
Date: 05/15/24 Time: 09:59
Sample: 2019M04 2024M03
Included observations: 60

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	18023.2	891.7776	20.21042	0
HDD	38.56989	2.284033	16.88675	0

R-squared	0.830984	Mean dependent var	28716.06
Adjusted R-squared	0.82807	S.D. dependent var	11730.58
S.E. of regression	4864.027	Akaike info criterion	19.84989
Sum squared resid	1.37E+09	Schwarz criterion	19.9197
Log likelihood	-593.4966	Hannan-Quinn criter.	19.87719
F-statistic	285.1622	Durbin-Watson stat	1.799117
Prob(F-statistic)	0		

Coefficients:

C	Trend	Covid Dummy
18023.200000	0.000000	0.000000

Base Gas Calculations:

Date	Per Bill
Mar-2024	18,023.20
Feb-2024	18,023.20
Jan-2024	18,023.20
Dec-2023	18,023.20
Nov-2023	18,023.20
Oct-2023	18,023.20
Sep-2023	18,023.20
Aug-2023	18,023.20
Jul-2023	18,023.20
Jun-2023	18,023.20
May-2023	18,023.20
Apr-2023	18,023.20

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Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*Special Contract 1*						
2	Mar-2024	2	2,586,850	1,293,425.05	516	60	-
3	Feb-2024	2	3,076,628	1,538,313.90	699	59	-
4	Jan-2024	2	2,160,167	1,080,083.25	655	58	-
5	Dec-2023	2	1,897,365	948,682.55	536	57	-
6	Nov-2023	2	1,292,758	646,378.75	223	56	-
7	Oct-2023	2	1,639,227	819,613.45	39	55	-
8	Sep-2023	2	1,603,318	801,659.20	1	54	-
9	Aug-2023	2	1,557,514	778,757.05	-	53	-
10	Jul-2023	2	1,392,126	696,062.85	-	52	-
11	Jun-2023	2	1,727,846	863,923.20	21	51	-
12	May-2023	2	1,741,628	870,813.95	130	50	-
13	Apr-2023	2	2,602,451	1,301,225.25	367	49	-
14	Mar-2023	2	2,288,556	1,144,278.15	465	48	-
15	Feb-2023	2	2,471,305	1,235,652.60	619	47	-
16	Jan-2023	2	2,787,326	1,393,662.75	733	46	-
17	Dec-2022	2	2,002,268	1,001,134.05	517	45	-
18	Nov-2022	2	1,619,775	809,887.25	219	44	-
19	Oct-2022	2	1,229,727	614,863.45	89	43	-
20	Sep-2022	2	1,229,577	614,788.25	-	42	-
21	Aug-2022	2	1,202,611	601,305.55	-	41	-
22	Jul-2022	2	1,197,086	598,543.00	-	40	-
23	Jun-2022	2	1,672,626	836,313.20	25	39	-
24	May-2022	2	2,036,756	1,018,377.75	175	38	-
25	Apr-2022	2	2,567,936	1,283,967.90	408	37	-
26	Mar-2022	2	2,390,967	1,195,483.50	533	36	-
27	Feb-2022	2	2,044,751	1,022,375.60	787	35	-
28	Jan-2022	2	1,742,532	871,266.20	747	34	-
29	Dec-2021	2	1,754,383	877,191.40	531	33	-
30	Nov-2021	2	1,053,473	526,736.35	189	32	-
31	Oct-2021	2	1,232,273	616,136.50	5	31	-
32	Sep-2021	2	1,310,521	655,260.60	-	30	-
33	Aug-2021	2	1,392,761	696,380.70	-	29	-
34	Jul-2021	2	1,393,690	696,844.80	2	28	1
35	Jun-2021	2	1,298,971	649,485.40	44	27	1
36	May-2021	2	1,092,368	546,184.00	176	26	1
37	Apr-2021	2	2,623,764	1,311,882.10	341	25	1
38	Mar-2021	2	3,415,326	1,707,662.90	650	24	1
39	Feb-2021	2	3,602,036	1,801,017.95	784	23	1
40	Jan-2021	2	3,383,125	1,691,562.25	787	22	1
41	Dec-2020	2	2,137,334	1,068,667.05	465	21	1
42	Nov-2020	2	1,851,864	925,932.20	191	20	1
43	Oct-2020	2	1,748,976	874,488.15	55	19	1
44	Sep-2020	2	1,894,967	947,483.45	6	18	1
45	Aug-2020	2	1,798,797	899,398.40	-	17	1
46	Jul-2020	2	1,505,796	752,897.90	-	16	1
47	Jun-2020	2	1,375,628	687,814.00	58	15	1
48	May-2020	2	1,608,631	804,315.60	271	14	1
49	Apr-2020	2	2,060,328	1,030,163.85	317	13	1
50	Mar-2020	2	2,731,996	1,365,997.75	521	12	1
51	Feb-2020	2	3,172,111	1,586,055.25	681	11	-
52	Jan-2020	2	3,158,323	1,579,161.65	673	10	-
53	Dec-2019	2	2,572,621	1,286,310.45	611	9	-
54	Nov-2019	2	1,504,977	752,488.50	284	8	-
55	Oct-2019	2	1,419,801	709,900.30	15	7	-
56	Sep-2019	2	1,494,046	747,022.95	-	6	-
57	Aug-2019	2	1,504,073	752,036.65	-	5	-
58	Jul-2019	2	1,555,210	777,605.00	-	4	-
59	Jun-2019	2	1,338,586	669,292.80	16	3	-
60	May-2019	2	1,714,212	857,106.05	71	2	-
61	Apr-2019	2	3,076,148	1,538,074.05	386	1	-
62	Total	120	116,538,789				

Statistical Information & Regression Coefficients (H, I, J, K, L)

Dependent Variable: GSA_UPC
Method: ARMA Maximum Likelihood (BFGS)
Date: 05/15/24 Time: 10:01
Sample: 2019M04 2024M03
Included observations: 60
Convergence achieved after 4 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	704632.4	83500.11	8.4387	0
HDD	1006.841	154.641	6.510832	0
AR(1)	0.595357	0.110702	5.378005	0
SIGMASQ	2.63E+10	4.37E+09	6.025106	0

R-squared	0.755369	Mean dependent var	971156.6
Adjusted R-squared	0.742264	S.D. dependent var	330733.9
S.E. of regression	167906	Akaike info criterion	26.97183
Sum squared resid	1.58E+12	Schwarz criterion	27.11145
Log likelihood	-805	Hannan-Quinn criter.	27.02644
F-statistic	57.638840	Durbin-Watson stat	1.722491
Prob(F-statistic)	0.000000		

Inverted AR Roots 0.600000

Coefficients:

C	Trend	Covid Dummy
704632.400000	0.000000	0.000000

Base Gas Calculations:

Date	Per Bill
Mar-2024	704,632.40
Feb-2024	704,632.40
Jan-2024	704,632.40
Dec-2023	704,632.40
Nov-2023	704,632.40
Oct-2023	704,632.40
Sep-2023	704,632.40
Aug-2023	704,632.40
Jul-2023	704,632.40
Jun-2023	704,632.40
May-2023	704,632.40
Apr-2023	704,632.40

Washington Gas Light Company
District of Columbia Jurisdiction

Linear Regression Inputs and Results

Based on 60 Months Ending Mar 2024

Line No.	Month/ Year	Months Billed	Actual Therm Sales Total a/	Actual Therm Sales Per Bill	Actual HDD	Trend	Covid Dummy
	A	B	C	D=C/B	E	F	G
1	*Special Contract 2*						
2	Mar-2024	1	1,306,703	1,306,702.90	516	60	-
3	Feb-2024	1	1,556,384	1,556,383.60	699	59	-
4	Jan-2024	1	1,297,079	1,297,079.30	655	58	-
5	Dec-2023	1	1,160,091	1,160,090.50	536	57	-
6	Nov-2023	1	894,186	894,186.30	223	56	-
7	Oct-2023	1	846,950	846,950.40	39	55	-
8	Sep-2023	1	928,241	928,241.00	1	54	-
9	Aug-2023	1	926,924	926,924.20	-	53	-
10	Jul-2023	1	928,241	928,241.00	-	52	-
11	Jun-2023	1	772,471	772,471.30	21	51	-
12	May-2023	1	970,002	970,002.00	130	50	-
13	Apr-2023	1	1,310,296	1,310,296.00	367	49	-
14	Mar-2023	1	1,253,138	1,253,137.90	465	48	-
15	Feb-2023	1	1,412,822	1,412,821.80	619	47	-
16	Jan-2023	1	1,552,266	1,552,266.00	733	46	-
17	Dec-2022	1	1,189,999	1,189,999.20	517	45	-
18	Nov-2022	1	973,022	973,022.40	219	44	-
19	Oct-2022	1	817,106	817,106.40	89	43	-
20	Sep-2022	1	916,701	916,701.00	-	42	-
21	Aug-2022	1	921,572	921,572.40	-	41	-
22	Jul-2022	1	878,393	878,393.10	-	40	-
23	Jun-2022	1	1,023,786	1,023,786.20	25	39	-
24	May-2022	1	1,077,850	1,077,850.00	175	38	-
25	Apr-2022	1	1,337,049	1,337,048.80	408	37	-
26	Mar-2022	1	1,470,205	1,470,205.30	533	36	-
27	Feb-2022	1	1,820,398	1,820,397.70	787	35	-
28	Jan-2022	1	1,343,485	1,343,484.80	747	34	-
29	Dec-2021	1	1,248,969	1,248,968.60	531	33	-
30	Nov-2021	1	831,368	831,367.80	189	32	-
31	Oct-2021	1	895,696	895,696.40	5	31	-
32	Sep-2021	1	923,776	923,776.00	-	30	-
33	Aug-2021	1	1,848,953	1,848,953.10	-	29	-
34	Jul-2021	1	-	-	2	28	1
35	Jun-2021	1	1,044,048	1,044,048.20	44	27	1
36	May-2021	1	1,169,958	1,169,958.40	176	26	1
37	Apr-2021	1	1,350,475	1,350,475.20	341	25	1
38	Mar-2021	1	1,604,968	1,604,968.40	650	24	1
39	Feb-2021	1	1,623,742	1,623,742.40	784	23	1
40	Jan-2021	1	1,538,005	1,538,004.60	787	22	1
41	Dec-2020	1	913,585	913,585.20	465	21	1
42	Nov-2020	1	795,878	795,877.60	191	20	1
43	Oct-2020	1	925,611	925,611.20	55	19	1
44	Sep-2020	1	920,132	920,131.80	6	18	1
45	Aug-2020	1	845,614	845,613.80	-	17	1
46	Jul-2020	1	926,786	926,785.80	-	16	1
47	Jun-2020	1	878,252	878,251.50	58	15	1
48	May-2020	1	1,194,024	1,194,024.00	271	14	1
49	Apr-2020	1	1,314,347	1,314,346.50	317	13	1
50	Mar-2020	1	1,437,280	1,437,280.00	521	12	1
51	Feb-2020	1	1,658,938	1,658,937.60	681	11	-
52	Jan-2020	1	1,615,840	1,615,840.20	673	10	-
53	Dec-2019	1	1,303,728	1,303,728.00	611	9	-
54	Nov-2019	1	988,510	988,510.00	284	8	-
55	Oct-2019	1	648,723	648,722.50	15	7	-
56	Sep-2019	1	812,464	812,464.00	-	6	-
57	Aug-2019	1	860,076	860,075.80	-	5	-
58	Jul-2019	1	793,714	793,713.60	-	4	-
59	Jun-2019	1	955,222	955,222.00	16	3	-
60	May-2019	1	1,068,206	1,068,205.80	71	2	-
61	Apr-2019	1	1,363,097	1,363,096.70	386	1	-
62	Total	60	67,185,344				

Statistical Information & Regression Coefficients

H	I	J	K	L
Dependent Variable: AOC_UPC				
Method: Least Squares				
Date: 05/15/24 Time: 10:03				
Sample: 2019M04 2024M03				
Included observations: 60				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	869218.2	39,162	22	0.000
HDD	903.7065	100	9	0.000
R-squared	0.583268	Mean dependent var		1,119,756.000
Adjusted R-squared	0.5761	S.D. dependent var		328065.8000
S.E. of regression	213600	Akaike info criterion		27.4144
Sum squared resid	2.65E+12	Schwarz criterion		27.484
Log likelihood	-820.4309	Hannan-Quinn criter.		27.442
F-statistic	81.17807	Durbin-Watson stat		2.356
Prob(F-statistic)	0			

Coefficients:

C	Trend	Covid Dummy
869218.200000	0.000000	0.000000

Base Gas Calculations:

Date	Per Bill
Mar-2024	869,218.20
Feb-2024	869,218.20
Jan-2024	869,218.20
Dec-2023	869,218.20
Nov-2023	869,218.20
Oct-2023	869,218.20
Sep-2023	869,218.20
Aug-2023	869,218.20
Jul-2023	869,218.20
Jun-2023	869,218.20
May-2023	869,218.20
Apr-2023	869,218.20

ATTESTATION

I, PAUL H. RAAB, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

PAUL H. RAAB

7/22/24
DATE

WITNESS LAWSON
EXHIBIT WG (O)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	FORMAL CASE NO. 1180

WASHINGTON GAS LIGHT COMPANY
District of Columbia

PUBLIC VERSION

DIRECT TESTIMONY OF ANDREW LAWSON
Exhibit WG (O)
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Exhibit WG (O)
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Exhibits

WASHINGTON GAS LIGHT COMPANY

District of Columbia

DIRECT TESTIMONY OF ANDREW LAWSON

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Andrew Lawson. I am Manager of Regulatory Affairs for Washington Gas Light Company ("Washington Gas" or "Company"). My business address is 6801 Industrial Road, Springfield, Virginia 22151.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND.

A. I joined Washington Gas in 2006, and have been in my current role as Manager of Regulatory Affairs since January 2022. In my current capacity, I manage the Company's regulatory activities in each of its three jurisdictions. Prior to my employment with Washington Gas, I was a Regulatory Economist in 2004 with the Technical Staff of the Public Service Commission of Maryland. During my time at Washington Gas, in addition to working in Regulatory Affairs, I also have worked in the Rates Department and as Project Manager – Strategic Initiatives in the Company's Sales and Economic Development Department. I received a Bachelor of Science degree in Economics from Mary Washington College in Fredericksburg, Virginia.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN PROCEEDINGS BEFORE REGULATORY COMMISSIONS?

A. I testified before this Commission in Formal Case No. 1137, Formal Case No. 1154, Formal Case No. 1162 and Formal Case No. 1169, the Company's three most recent base rate cases and most recent accelerated pipe replacement proceeding. I have also sponsored testimony in Formal Case No. 1160 and Formal Case No. 1175. I have sponsored testimony before the Virginia State Corporation Commission on behalf of the Company and on several occasions before the Maryland Public Service Commission concerning various electric, gas, and water issues during my employment with the Maryland Public Service Commission.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide support for the following areas:

- Rate Design – I explain the Company's proposed rate design for firm and interruptible customers that will facilitate the recovery of the revenue requirement requested in this proceeding. This includes an adjustment of some of the Company's existing General Service Provision Charges as discussed in Section VII below.
- Weather Normalization Adjustment ("WNA") Mechanism – I present the mechanics of the Company's proposed weather normalization mechanism.
- Credit Card Payments – I propose to modify the treatment of customer fees related to customer credit and debit card payments to directly assign the costs of this activity to customers using these services.
- Tariff Pages – I sponsor clean and legislative tariff pages reflecting the Company's proposed tariff revisions.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes. I sponsor four (4) exhibits. Exhibit WG (O)-1 includes a summary of present and proposed rates in Schedule A, the proposed rate design calculations in Schedule B, and a summary of the amount and the percentage change in revenues for each customer class in Schedule C. Exhibit WG (O)-2, Schedule A contains calculations showing the impact of the proposed rates by month based on average normal weather usage for the various classes of firm service and Schedule B provides additional schedules comparing monthly bills at present and proposed rates for various usage levels. Exhibit WG (O)-3 provides example calculations of the Company's proposed WNA calculation. Exhibit WG (O)-4 shows the tariff changes in clean and legislative format. The above-designated exhibits were prepared by me or under my direction and supervision.

IV. PROPOSED RATE DESIGN AND IMPACT BY CLASS OF SERVICE

Q. HOW DOES THE COMPANY PROPOSE TO COLLECT ITS REQUESTED REVENUE REQUIREMENT FROM ITS CUSTOMERS?

A. Exhibit WG (O)-1, Workpaper 1 shows a calculation of the Relative Rate of Return ("ROR") for each customer class. This information is obtained from the Class Cost of Service Study included as Exhibit WG (F)-4 in the Direct Testimony of Company Witness Smith. As shown, six customer classes are earning RORs below the system average rate of return. Those classes are: Residential Heating; Residential Non-Heating – Other; Commercial & Industrial ("C&I") < 3,075 therms; Natural Gas Vehicles (as ordered by the Commission in

Formal Case No. 1169), Combined Heat and Power and Non-Firm. The Residential Heating and Commercial & Industrial < 3,075 classes are earning returns below, but relatively near, the system average, while the remainder of the under-earning classes are earning well below the system average. All other customer classes are earning at or above the system average ROR. I propose to apportion the revenue increase so that each customer class's rate of return moves closer to the system average rate of return, consistent with the Commission's directives in the Company's recent base rate cases.

As shown in Exhibit (O)-1, Schedule B, Page 1 the system average increase in tariff distribution revenues (Customer, Peak Usage and Distribution Charge revenue) is 30.29%. For classes earning below, but relatively near the system-average rate of return, I proposed to allocate an increase equal to 110% of the system average increase, or 33.32%. For the classes earning well below the system average, I proposed to allocate an increase equal to 125% of the system average increase, or 37.86%. The customer classes earning above the system average then receive the remainder of the revenue increase allocated among those classes based on each class's percentage of total base rate revenues of over-earning classes. This results in an increase to over-earning classes of 26.31% to total base rate revenues. This allocation of revenues is accomplished in Exhibit WG (O)-1, Schedule C, Page 2.

The Company proposes to collect its requested revenue requirement through the application of increases to the current rate structure, including increases to Customer, Distribution, and Peak Usage Charges and miscellaneous service fees, as described in my testimony below. The Company is proposing to increase Customer Charges by an equal percentage of 25% across all customer classes.

The balance of the revenue requirement allocated to Rate Schedule Nos. 1 and 1A is reflected in the proposed Distribution Charge. The amount allocated to Rate Schedule Nos. 2, 2A, 3, 3A, and 7 is further apportioned between the Peak Usage Charge and the Distribution Charge. Peak Usage charges were increased to maintain the current relationship between Peak Usage Charges revenues and total base rate revenues. The remainder of the revenue increase was allocated to Distribution Charges.

Q. WHAT IS THE OBJECTIVE OF THE COMPANY'S PROPOSED RATE DESIGN?

A. The objective of the Company's proposed rate design in this proceeding is to move toward rates that reflect how costs are incurred, whether they are customer or throughput-based, and to implement a modest movement toward parity of rate of return by customer class. This objective is accomplished through moderate changes that support gradualism consistent with Commission directives.

Q. PLEASE EXPLAIN THE PRESENT RATE STRUCTURE FOR RESIDENTIAL CUSTOMERS.

A. Residential customers receive sales and delivery service under Rate Schedule Nos. 1 and 1A, respectively. Rate Schedule No. 1 is considered a bundled service, in that the Company supplies and delivers gas to customers. Rate Schedule No. 1A describes the identical core distribution services and also describes the customer's decision to purchase gas from a Competitive Service Provider ("CSP") offering the sale of gas to Washington Gas customers.

Customers under Rate Schedule Nos. 1 and 1A are classified by the type of usage, either heating and/or cooling or non-heating and non-cooling. Non-heating and non-cooling customers are further differentiated based on whether they are individually metered apartments ("IMAs") or "Other than individually metered apartments."

Residential sales and delivery service customers are assessed the following charges on their monthly bill:

- Customer Charge: a fixed monthly charge for each of the twelve months for all customers.

	Present	Proposed
Residential Heating/Cooling	$16.55 per month	$20.70 per month
Residential Non-Heating - IMA	$12.00 per month	$15.00 per month
Residential Non-Heating - Other	$13.55 per month	$16.95 per month

- Distribution Charge: a volumetric charge based on the number of therms used by individual customers each billing month.

	Present	Proposed
Residential Heating/Cooling	$0.5638 per therm	$0.7778 per therm
Residential Non-Heating - IMA	$0.6610 per therm	$0.8653 per therm
Residential Non-Heating - Other	$0.6390 per therm	$0.9246 per therm

Q. PLEASE EXPLAIN THE PRESENT AND PROPOSED RATE STRUCTURE FOR NON-RESIDENTIAL CUSTOMERS.

A. Rate Schedule Nos. 2 and 3 are considered bundled services in that the Company supplies and delivers gas to customers for Commercial & Industrial and Group Metered Apartment ("GMA") service, respectively. Rate Schedule Nos. 2A, 3A, 4, 6, and 7 describe the core distribution services and also reflect the customer's decision to purchase gas from one of a number of CSPs offering gas sales to our customers.[1] Customers under Rate Schedule Nos. 2A and 3A are classified by the type of usage, as either heating and/or cooling or non-heating and non-cooling.

Non-residential sales and delivery service customers served under Rate Schedules 2, 2A, 3 and 3A, are assessed the following charges on their monthly bill:

- Customer Charge: a fixed monthly charge for each of the twelve months for all customers.

	Present	Proposed
C&I Heating/Cooling <3,075	$29.90 per month	$37.40 per month
C&I Heating/Cooling >3,075	$70.05 per month	$87.55 per month
C&I – Non-Heating-Non-Cooling	$28.50 per month	$35.65 per month
GMA Heating/Cooling <3,075	$28.50 per month	$35.65 per month
GMA Heating/Cooling >3,075	$70.05 per month	$87.60 per month
GMA – Non-Heating-Non-Cooling	$28.50 per month	$35.65 per month

- Distribution Charge: a tiered volumetric charge based on the number of therms used by individual customers each billing month.

[1] For Rate Schedule No. 4, which is closed to new customers, this discussion is applicable to the class of service for customer operated fueling locations. The Company no longer operates any fueling stations.

	Present	Proposed
C&I Heating/Cooling <3,075	$0.5821 per therm	$0.8010 per therm
C&I Heating/Cooling >3,075	$0.4796 per therm	$0.6063 per therm
C&I – Non-Heating-Non-Cooling	$0.4811 per therm	$0.6087 per therm
GMA Heating/Cooling <3,075	$0.4930 per therm	$0.6252 per therm
GMA Heating/Cooling >3,075	$0.4863 per therm	$0.6148 per therm
GMA – Non-Heating-Non-Cooling	$0.4841 per therm	$0.6124 per therm

- Peak Usage Charge: a fixed monthly charge applicable to the months of November through April based on a rate per therm that is applied to a customer's maximum billing month usage for the prior November through April period.

	Present	Proposed
C&I Heating/Cooling <3,075	$0.0519 per therm	$0.0692 per therm
C&I Heating/Cooling >3,075	$0.0421 per therm	$0.0532 per therm
C&I – Non-Heating-Non-Cooling	$0.0423 per therm	$0.0534 per therm
GMA Heating/Cooling <3,075	$0.0431 per therm	$0.0544 per therm
GMA Heating/Cooling >3,075	$0.0422 per therm	$0.0533 per therm
GMA – Non-Heating-Non-Cooling	$0.0423 per therm	$0.0534 per therm

Natural Gas Vehicle Service at Customer Operated Fueling Locations and Delivery Service for Natural Gas Vehicles are served under Rate Schedule No. 4 and are assessed the following charges on their monthly bill:

- Customer Charge: a fixed monthly charge for each of the twelve months for all customers.

	Present	Proposed
All Customers	$49.67 per month	$62.10 per month

- Distribution Charge: a volumetric charge based on the number of therms used each billing month.

	Present	Proposed
All therms	$0.0745 per therm	$0.1028 per therm

Interruptible Customers served under Rate Schedule No. 6 are assessed the following charges on their monthly bill:

- Customer Charge: a fixed monthly charge for each of the twelve months for all customers.

	Present	Proposed
All Customers	$121.00 per month	$151.25 per month

- Distribution Charge: a tiered volumetric charge based on the number of therms used each billing month.

	Present	Proposed
First 75,000 therms	$0.2094 per therm	$0.2887 per therm
Over 75,000 therms	$0.1932 per therm	$0.2663 per therm

Combined Heat and Power/Distributed Generation Customers served under Rate Schedule No. 7 are assessed the following charges on their monthly bill:

- Customer Charge: a fixed monthly charge for all twelve months for all customers.

	Present	Proposed
All Customers	$343.75 per month	$429.70 per month

- Distribution Charge: a volumetric charge based on the number of therms used each billing month.

	Present	Proposed
All Therms	$0.1033 per therm	$0.1430 per therm

- Peak Usage Charge: a fixed monthly charge billed during all months based on the Customer's peak monthly usage during the prior November through April period.

	Present	Proposed
All Therms	$0.0904 per therm	$0.1246 per therm

Q. PLEASE DESCRIBE THE COMPANY'S FIRM RATE DESIGN PROPOSAL INCLUDED IN EXHIBIT WG (O)-1.

A. Under the Company's proposal, the present two-part rate structure consisting of a Customer Charge and Distribution Charge for Residential customers and the three-part structure of a Customer Charge, Peak Usage Charge, and Distribution Charge for Commercial & Industrial and Group-

Metered Apartment customers will remain. The Company proposes to increase all Customer Charges by 25%.

After deducting the increase in revenue applicable to the proposed Customer Charges and the revenue increase attributable to General Service Provision charges, as described below in Section VII of my testimony, Washington Gas proposes to collect the balance of the requested increase through either the Distribution Charge or the Peak Usage Charge as shown on Exhibit WG (O)-1, Schedule C, Page 2.

The present rates and proposed rates are shown on Exhibit WG (O)-1, Schedule A, Pages 1 through 4. Page 3 of Schedule A reflects the present and proposed Customer Charge and Distribution Charge for Interruptible Rate Schedule No. 6. Schedules B and C of Exhibit WG (O)-1 detail the specific calculations of the rate design and show total revenues calculated at present and proposed rates, as well as the amount and percent increase by class of service that would result from the Company's proposal.

Q. PLEASE EXPLAIN THE OBJECTIVE OF YOUR MOVEMENT TO A HIGHER CUSTOMER CHARGE AS A COMPONENT OF THE RATE DESIGN IN THIS PROCEEDING.

A. The objective of the higher Customer Charge in the Company's proposed rate design is to better align the recovery of more of the Company's fixed costs through a fixed charge to customers, which is consistent with cost causation principles for rate design. The proposed increase toward cost-justified Customer Charges would establish rates that more properly reflect how costs are incurred, because many of the costs incurred by the Company do not vary based on the amount of gas consumed. These fixed components include costs such as customer billing, collections, and accounting expenses as well as the Company's capital investment in metering equipment and service connections. Higher Customer Charges also serve to spread a larger percentage of costs evenly throughout the year, creating a more predictable bill, and reduce the costs that are otherwise reflected in the Distribution Charge, thereby reducing the volatility of customers' winter bills.

Q. IS A HIGHER CUSTOMER CHARGE CONSISTENT WITH COMMISSION PRECEDENT?

A. Yes. As was the case in Formal Case No. 1169, the Company's rate design is heavily weighted towards collecting revenues on a volumetric basis. Even under the Company's proposed rate design, it is estimated that only 20% of the average Residential Heating Customer's bill is recovered through fixed customer charges compared to approximately 18.1% currently. The increase in the Customer Charge necessarily results in a relatively lower increase to the per-unit Distribution Charge. The Commission acknowledged that these facts support Washington Gas's proposed changes in its Order No. 17132 at 124 in Formal Case No. 1093. The Commission further supported the Company's proposed approach in Order No. 18712 at 130-131 in Formal Case No. 1137. In Formal Case No. 1169 the Commission approved a 10% increase to Customer Charges for all classes.

Q. DO THE PROPOSED CUSTOMER CHARGES REPRESENT A FULL RECOVERY OF ALL FIXED COSTS INCURRED IN SERVING CUSTOMERS?

A. No. The calculated Customer component by customer class far exceeds the proposed customer charges for most customer classes in this proceeding. However, the Company's current proposal is consistent with its past practice and Commission decision to gradually increase Customer Charges in recognition "that WGL is primarily a natural gas distribution company whose major costs are fixed and that those costs should be recoverable through fixed charges like the fixed monthly Customer Charge."[2] Based on the proposed customer charges in this proceeding, the fixed charges for Residential Heating Customers recover only about 53% of the fixed customer costs as shown in Exhibit WG (F)-4, Schedule CC, Page 28 of 31 of Company Witness Smith's Direct Testimony. For some of the larger non-residential classes, Customer Charges recover less than 18% of customer costs.

Q. PLEASE DESCRIBE THE DERIVATION OF THE PROPOSED FIRM DISTRIBUTION CHARGES AND PEAK USAGE CHARGE FOR NON-RESIDENTIAL CUSTOMERS.

A. The revenues resulting from proposed Customer Charges and miscellaneous tariff charges are deducted from the total requested revenue requirement for each class with the remainder to be collected through tariff Distribution Charges and the Peak Usage Charge. For the Commercial & Industrial and Group-Metered Apartments classes, an allocation is made to divide the allocated revenue balance between the Distribution Charge and the Peak Usage Charge. This allocation is made based on the pro forma revenue for each of these rate elements as presented in the Company's *pro forma* revenue calculation supported by Company Witnesses Banks and Tuoriniemi. Once the revenue allocations have been made, each amount is divided by the applicable test period therms to determine the proposed charges. The

[2] *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Services,* Formal Case No. 1137, Order No. 18712 at 142, para. 436.

proposed charges resulting from this calculation are summarized on Exhibit WG (O)-1, Schedule C, Page 2.

Q. WOULD YOUR RATE DESIGN RECOMMENDATION CHANGE IF LESS THAN THE FULL REVENUE REQUIREMENT REQUEST IS GRANTED BY THE COMMISSION?

A. Yes. The Company's rate design recommendation would change if the Commission were to grant an increase other than that requested by the Company. The Company recommends that its current proposal applicable to Customer Charges remain the same, and any variation in revenue requirements be assigned to the Residential Distribution Charges and Commercial & Industrial and Group-Metered Apartments Distribution and Peak Usage Charges, to be collected in a manner as set forth above. The Company makes this recommendation because, as described above, even at the full level proposed, the Customer Charges are already well below the level that is justified based on the incurrence of fixed costs for providing service.

Q. PLEASE DESCRIBE EXHIBIT WG (O)-2.

A. Exhibit WG (O)-2 includes schedules showing the impact of the proposed rates by month based on average normal weather usage for the various classes of service along with additional schedules comparing monthly bills at various usage levels. These schedules separately present the impacts for sales customers of Washington Gas (Rate Schedule Nos. 1, 2, and 3) that include the cost of gas provided by the Company and exclude the cost of gas for firm delivery service customers (Rate Schedule Nos. 1A, 2A, 3A, and 6) who purchase their gas supply from third-party suppliers.

Q. HAVE YOU PROVIDED PROOF OF THE CHANGE TO RATES BASED ON THE COMPANY'S REQUESTED REVENUE INCREASE?

A. Yes. As shown on Exhibit WG (O)-1, Schedule C, Pages 1 and 2, the proposed rates will generate the requested revenue requirement based on normal weather sales, once accounting for immaterial rounding.

V. WEATHER NORMALIZATION ADJUSTMENT ("WNA") MECHANISM

Q. PLEASE DESCRIBE THE WNA.

A. As proposed by the Company in this proceeding, the WNA is a rate mechanism to adjust customer bills during the WNA Period (October-May) to reduce the impact of weather variability from normal. Company Witness Tuoriniemi provides additional information related to the WNA, including benefits for customers and how the WNA better aligns the Company's rate structure with its cost structure.

Q. HOW WILL THE WNA CREDIT OR CHARGE BE DETERMINED?

A. Each month during the period October through May, the Company will calculate a revenue excess or deficiency, by rate class, based on the variation of experienced weather from the normal weather established by the Commission in the instant proceeding. The monthly balances, as calculated above, will accumulate during each month of the heating season. If at the close of a monthly period a net ***revenue excess*** is calculated, the Company will issue refunds during the billing cycle following the revenue calculation. That is, the credit adjustment for any given month will occur on bills rendered two months later. For example, the adjustment for the cumulative revenue excess in November 2025 will appear on the bills sent out in the January 2026 billing cycle (this is simply to allow for the computations and to update the billing system appropriately). At that time, the cumulative revenue excess/deficiency will be reset to zero, subject to reconciliation between credits to customers as designed and realized.

In the event of a ***revenue deficiency*** at the end of any month, the Company will continue to accrue any deficiency in each subsequent month until either the end of May or a calculation in subsequent months results in a cumulative revenue excess.

If at the end of the May usage period the Company calculates a net ***revenue deficiency***, the Company will defer the billing of the revenue adjustment until the next heating season. That is, the revenue collection will be spread over the following October to May period. The Company will apply carrying costs at a rate equal to the Company's authorized Short-Term Debt rate on a monthly basis to any revenue excess or deficiency.

Q. HOW WILL THE WNA CREDIT BE CALCULATED?

A. Any WNA credit due will be calculated by taking the net revenue excess by rate class and dividing it by the total normal weather therms by rate class for the month in which the credit is issued. This calculation will produce a factor per therm to be applied to all usage in the billing month. In the event that the revenue excess for a particular class is such that the above calculation does not produce a factor of at least $0.0001, the Company will carry forward that revenue credit until such time as either the revenue adjustment is large enough to produce a billable factor or revenue deficiencies in subsequent months have offset the credit.

Q. HOW WILL WNA CHARGES BE CALCULATED?

A. The Company will calculate a total revenue adjustment for each rate class and divide that amount by the total normal weather therms for each rate class over the period of October to May. If near-normal weather results in a small revenue adjustment, the Company will calculate the distribution charge adjustment over the maximum number of months (and associated therms) that allow a billable factor. For example, the Company's rates are rounded to the nearest $0.0001. If the calculated revenue adjustment divided by total October-May normal weather therms is less than $0.0001, the Company will bill the adjustment over a shorter number of months, such that the associated normal weather therms produce a factor of at least $0.0001. The Company will include this determination in its annual filing and reconciliation, which it proposes to make by August 1 of each year beginning with the first August after the WNA is made effective (i.e., if the proposed rates are effective for the winter of 2025, the first WNA report will be filed on August 1, 2026).

The Company has provided an example calculation in Exhibit WG (O)-3, which uses the Company's actual test year results to accrue a WNA revenue deficiency, show how carrying charges are calculated and develop a billing factor for the following WNA period. The Company has used its Residential Heating class as a representative example, but the methodology is equally applicable to all classes.

Q IS THE COMPANY PROPOSING A CAP ON THE WNA RATE ADJUSTMENT?

A. Yes. To further mitigate customer risk, the Company will limit any WNA factor resulting from the calculation above to no more than 15% of the rate class Distribution Charge per therm for either returning a revenue excess or collecting a revenue deficiency. The purpose of a cap on the WNA rate adjustment reflects the need to balance certain competing factors. A cap can minimize extraordinary bill impacts following an extremely warm winter or avoid creating a revenue deficiency that may not otherwise exist by returning too much revenue to customers when experiencing a revenue excess. However, the goal of minimizing bill impact must be balanced against the need to return excess revenue or collect a revenue deficiency in a timely manner. Failure to return revenue excesses or collect revenue deficiencies in a timely manner may create additional carrying costs to be added to the WNA balance and potentially creating a build-up of large revenue balances due.

As an example, assuming the rates proposed by the Company are adopted in this proceeding the Company's proposed cap would result in a WNA Adjustment of no more than +/- $0.0846 per therm for Residential Heating customers and no more than +/- $0.0719 for Commercial & Industrial >3,075 therms customers. Based on the average billing comparisons provided in Exhibit WG(O)-2, the proposed WNA Adjustment caps represent an approximate revenue shift between heating seasons of approximately 5% of the total bill for both the Residential Heating class and the Commercial & Industrial >3,075 class, the two classes for which I provide illustrative examples in Exhibit WG (O)-3.

Q. WILL A RECONCILIATION BE PERFORMED?

A. There will be two reconciliation processes. First, in the event of a credit issued during the WNA period, a reconciliation will be performed to determine the difference between the actual revenues credited to customers and targeted revenue credits. Any difference between those amounts will be added to the revenue deficiency or excess in the month in which the reconciliation is performed.

Second, at the end of each WNA billing period the actual billed revenue/credit amount, by rate class, will be subtracted from the allowed amount by rate class for that period to determine a reconciliation amount. Any amount resulting from that reconciliation will be rolled into the following WNA billing period as an adjustment to the accrued balance.

VI. CHANGES TO COST ASSIGNMENT FOR CREDIT/DEBIT CARD ACTIVITIES

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL TO CHANGE HOW VENDOR PROCESSING FEES ASSOCIATED WITH CREDIT/DEBIT CARD PAYMENTS ARE PAID?

A. The Company proposes a change to GSP No. 4 – Payments. Currently, the Company recovers in its revenue requirement an estimate of all vendor charges related to customer use of credit/debit cards for bill payment. The Company is seeking to eliminate its current payment of the vendor fee for the customer use of a credit/debit card to pay bills. If approved, customers that pay their bills using a credit or debit card will be responsible for directly paying any vendors' processing fees. Company Witness Tuoriniemi makes an adjustment in his calculation of revenue requirement for this proposed change, which lowers the Company's cost of service, and as a result customer bills by approximately $412,000 annually.[3]

Q. WHEN DID THE COMPANY BEGIN PAYING CREDIT/DEBIT CARD PROCESSING FEES TO VENDORS ON BEHALF OF ITS CUSTOMERS?

A. The Company payment of credit/debit fees was originally proposed in Formal Case No. 1093, effective in July of 2012. The Commission first approved an adjustment to include these costs in customer rates in Formal Case No. 1137.

Q. WHY DID THE COMPANY PROPOSE TO PAY CREDIT/DEBIT CARD PROCESSING FEES ON BEHALF OF CUSTOMERS?

A. At the time the Company proposed the "fee-free" debit/credit card program in Formal Case No. 1093, customers were required to pay a $4.55 processing fee directly to the payment processor for each credit/debit card transaction. At that time nearly 28,000 debit/credit card transactions were processed for District customers annually. Washington Gas also expected to negotiate a substantially lower processing fee per transaction of $1.00 for residential transactions and $2.00 for commercial transactions.[4] The Company estimated, based on the experience of some other utilities and through consultation with its bank, that the transaction volume would increase to nearly 73,000 transactions per year.[5] Based on those estimated transactions, the total cost to process debit/credit card payments was expected to be under $100,000 per year. The cost of the program was expected to be a modest

[3] Exhibit WG (D)-5, Adjustment No. 28.
[4] Formal Case No. 1093, Direct Testimony of Paul S. Buckley, Page 18, Lines 3-5.
[5] Formal Case No. 1093, Direct Testimony of Paul S. Buckley, Page 19, Lines 15-17.

investment that would help to facilitate the move from paper to electronic transactions, with potential to aid customers in avoiding disconnections.

Q. WHY IS THE COMPANY PROPOSING TO CHANGE GSP 4 IN THIS PROCEEDING?

A. The primary drivers of the proposed change are the growing costs of the program, as well as the narrowing of the cost difference between Company- and customer-paid transaction fees. The Company is pursuing this across its system and has already had this change to credit/debit card processing approved in Maryland. The Company is also currently pursuing a similar change to the treatment of credit/debit card processing fees in its Virginia jurisdiction.

As discussed above, Company payment of credit/debit fees was originally proposed to accelerate the transition from paper transactions to electronic mediums, which has been successful. However, the number of transactions and associated costs now far exceed the Company's original expectations. During the test year in Formal Case No. 1093 (TME September 2011), there were 28,000 debit/credit fee transactions in the District. During the test year, the number of transactions had grown by a factor of twelve, exceeding 330,000 transactions per year. During the test year, the Company paid approximately $480,000 in credit/debit transaction fees associated with the District, or approximately five times the amount expected when the program was approved.

Second, the cost spread between Company-paid fees and customer-paid fees has narrowed, and therefore savings per transaction attributable to the Company's role have declined since implementation of this program in 2012. At the time the "fee-free" credit card program was proposed and approved, the fee the Company negotiated, $1.00 per residential customer, was less than a quarter of the processing fee for direct customer payment ($4.55 per transaction). The Company anticipates that the vendor processing fee will be approximately $2.75 per transaction for direct paid residential accounts based on is current experience in Maryland, representing a substantial decrease in the cost for direct residential customer payments compared to what was available at the time the program was implemented.

The Company believes that directly assigning these costs to those customers who leverage credit/debit cards to pay their bills is more appropriate and believes customers will be better served by eliminating the subsidization of credit and debit card processing fees by customers who do not use credit/debit cards.

Q. DOES THE COMPANY BELIEVE THAT CHARGING CREDIT/DEBIT CARD FEES DIRECTLY TO THOSE CUSTOMERS WILL RESULT IN CUSTOMERS USING LOWER COST PAYMENT METHODS?

A. Yes. The Company recently implemented the same change proposed in this application in its Maryland jurisdiction. Since the implementation of customer-paid debit/credit card fees in Maryland, the number of credit and debit card transactions has decreased by nearly 20% through April 2024. The majority of those payments have migrated to check or e-check payments which are some of the least cost payment processing options available.

Q. DOES THE PROPOSED CHANGE NEGATIVELY IMPACT THE ABILITY OF A CUSTOMER TO PAY THEIR BILL?

A. No, for a number of reasons. First, the Company has many other bill payment methods available, including other electronic forms of payment.

Second, customers may continue to use credit/debits cards to pay bills but will pay a small fee directly for using those services, rather than those costs ultimately being borne by all customers, including customers who use checks or e-check payments. While customers who continue to use credit/debit cards for bill payment will be required to directly pay the vendor processing fee, they will also receive their share of the removal of these costs from the Company's revenue requirement.

Q. UNDER THIS PROPOSAL WILL THE COMPANY COLLECT AND REMIT FEES TO THE VENDOR?

A. No, under the Company's proposal, Washington Gas will not collect any fees, handle or store any credit card information, nor will it receive any benefit from the credit/debit card processing vendor as a result of the transaction. All transactions will occur directly between the customer making the payment and processing vendor.

VII. GENERAL SERVICE PROVISION CHARGES

Q. WHAT CHANGES DOES THE COMPANY PROPOSE TO MAKE TO THE GENERAL SERVICE PROVISIONS?

A. The Company is proposing to change several of the rates, specifically those included in its General Service Provisions 11, DISCONTINUANCE OF SERVICE; and 19, SERVICE INITIATION CHARGE.

Q. WHY IS THE COMPANY PROPOSING INCREASES TO THESE CHARGES IN THIS PROCEEDING?

A. It has been some time since the Company last increased these charges and it must ensure that these charges more closely reflect the cost of providing service. A review of the costs to provide these services during the test period of this proceeding indicates that the current levels of the charges are not sufficient and do not reflect the cost of providing the services. As a result, there is a subsidy by all firm customers in making these services available to a relatively small number of customers.

Q. WHAT BENEFIT WILL THE COMPANY RECEIVE BY INCREASING THESE CHARGES?

A. The Company will not directly benefit from increasing these charges. The charges are intended to directly assign more costs to those customers who cause the costs to be incurred. Any revenues that the Company receives from the application of these fees benefits all firm ratepayers by reducing the revenue requirement to be collected through the Customer, Peak Usage, and Distribution Charges. The benefit to firm customers will arise from lessening increases to the System and Distribution Charges. The specific increase amounts that I propose to exclude from firm base rates are summarized on Exhibit WG (O)-1, Schedule B, Page 5. As shown on the schedule, the proposed increases, excluding late payment charges, total $140,875.

Q. WHAT SPECIFIC CHANGES ARE BEING PROPOSED FOR GENERAL SERVICE PROVISION NO. 11, DISCONTINUANCE OF SERVICE?

A. There are three miscellaneous service charges pertaining to GSP No. 11 addressed in this proceeding. The rates for all charges are set forth in Appendix A to the Company's tariff. First, the Company currently charges $44.98 to reconnect a customer in an individual unit following a disconnection. Multi-unit customers are charged a reconnection fee of $14.50 per unit for four or more units. Additionally, should the customer make a payment to a Company representative at the customer's premises to avoid service disconnection, the customer is subject to a $13.12 charge for collections in the field.

During the test year the Company collected a total of $174,354 in revenues for Reconnect Charges, and less than $500 in Field Collection Charges. In this proceeding, to more closely align the charge for service with the cost of providing the service, I propose to increase the individual unit Reconnection Charges from $44.98 to $53.98 and the Multi-Unit Reconnect Charge from $14.50 per unit to $17.40 per unit. The proposed new charges above represent a 20% increase over current charges. I propose to increase the Field Collection Charge by no more than 10% from $13.12 to $14.40.

Finally, in addition to revising the General Service Provision charges contained in Appendix A to the Company's tariff, I propose certain language updates to P.S.C. of D.C. No. 3, Page Number 41A to remove some out of date and no longer applicable language from the tariff.

Q. HOW DID THE COMPANY DETERMINE THAT A 20% INCREASE TO THE RECONNECT CHARGES IS APPROPRIATE?

A. The Company uses contractor resources to perform the reconnect and field collection services discussed above. For a customer to require a reconnect under GSP No. 11, that customer will have been disconnected as described on page numbers 41 and 41A of the Company's tariff (P.S.C. of D.C. No. 3). The Company will incur costs both to disconnect the customer and to reconnect the customer. Based on its contract with its service provider, the Company incurs a contract fee of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to perform a customer reconnect. Additionally, the Company's contract with its service provider **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** for performing the disconnect that led to the reconnect. Therefore, the Company will have incurred a minimum cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for each customer being reconnected. Based on only the minimum contract charges the Company will have incurred when performing a reconnect, the Single Unit Reconnect Fee must increase by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to fully recover the minimum contract charges incurred. In weighing the impact of an increase in Reconnect Charge Revenue on the rates of the customer base against the impact of a large increase in the cost for individual customers to be reconnected to service, I believe that in this proceeding, the Reconnect Charge should not be increased by more than 20%.

Q. HOW DID THE COMPANY DETERMINE THAT A 10% INCREASE TO FIELD COLLECTION CHARGES IS APPROPRIATE?

A. Similarly, for collections made in the field to avoid disconnection, the Company's contract with its service contractor provides for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** Because there are very few collections in the field, as evidenced by the fact that only $433 in Field Collection Charges were collected during the test year, any increase in the Field Collection Charge is immaterial in offsetting the cost of service to the overall customer base. The immateriality of Field Collection Charges to the overall customer base, combined with the high likelihood that the Field Collection

Charge represents an increased hurdle to remaining connected customers that are likely struggling to pay their bills, leads me to the conclusion that any increase to the Field Collection Charge should be small, and no more than 10%. My proposed rate design in this proceeding assumes that Field Collection Charges will increase by 10%, however, this small increase ($43) has no impact on proposed rates. In total, the proposed increase to Reconnect Charges and Field Collection Charges generates an additional $34,914 in revenue that will not be collected though increases to Customer, Peak Usage and Distribution Charges.[6]

Q. WHAT OTHER CHARGES ARE YOU PROPOSING TO GENERAL SERVICE PROVISION NO. 11?

A. I propose several general tariff cleanup revisions to 1) remove outdated language regarding temporary measures previously adopted by the Commission; 2) remove the actual Reconnect Charge and Field Collection Charge amounts from the General Service Provision and make reference instead to the charges as described in Appendix A to the Company's tariff; and 3) remove outdated references to separate Reconnect Charges that are inconsistent with Appendix A of the Company's tariff.

Q. ARE YOU PROPOSING ANY CHANGES TO GENERAL SERVICE PROVISION NO. 19 – SERVICE INITITATION CHARGE?

A. Yes, specifically, I am proposing to increase the "Gas Not Flowing" service initiation fee from $37.17 to $44.60, or a 20% increase.

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[6] Reconnect Charge: $174,354 * 120%= $209,225
Field Collection Charge: $433 * 110% = $476
Test Year Total: $174,354 + $433 = $174,787
Adjusted Test Year Total: $209,225 + $476 = $209,701
Additional Revenue Generated by Increase: $209,701 - $174,787 = $34,914

Q. WHY ARE YOU PROPOSING TO INCREASE THE SERVICE INITIATION FEE IN INSTANCES WHERE GAS IS NOT FLOWING?

A. To restore gas service to a premise, the Company uses contractor resources to perform the gas "turn on" required to initiate service where gas is not currently flowing to a premise. As it is a similar service to the reconnect discussed above, the Company incurs a contract fee of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to restore gas flow. As the Service Initiation Charge when gas is not flowing is insufficient to recover the contract charges associated with restoring gas flow to the premise, this charge should be increased to be closer to the actual cost of providing service. Similar to my approach to increasing Reconnect Fees, I propose an increase of 20% to the "Gas Not Flowing" fee. In total, the proposed increase to Service Initiation Fee Charges generates an additional $105,962 in revenue that will not be collected though increases to Customer, Peak Usage and Distribution Charges.[7]

VIII. TARIFF REVISIONS

Q. PLEASE DESCRIBE THE TARIFF CHANGES THAT ARE BEING PROPOSED.

A. Exhibit WG (O)-4 contains the clean and legislative revisions to the tariff. The changes relate to new rates for the various customer classes, as well as the tariff modifications described in Section VII above.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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[7] Gas Not Flowing: $529,809 * 120%= $635,771
Additional Revenue Generated by Increase: $635,771 - $529,809 = $105,962

Washington Gas Light Company
District of Columbia

Comparison of Present and Proposed Residential Firm Service Rates
Rate Schedule Nos. 1 and 1A

Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No.	Description	Present	Proposed	Line No.
	A	B a/	C b/	
1	**Customer Charges**	Monthly Charges		1
2	Heating and/or Cooling	$ 16.55	$ 20.70	2
3	Non-Heating and Non-Cooling			3
4	(a) Individually Metered Apartments	$ 12.00	$ 15.00	4
5	(b) Other	$ 13.55	$ 16.95	5
6	**Distribution Charges**	Rates per Therm		6
7	Heating and/or Cooling	$ 0.5638	$ 0.7778	7
8	Non-Heating and Non-Cooling - IMA			8
9	(a) Individually Metered Apartments	$ 0.6610	$ 0.8653	9
10	(b) Other	$ 0.6390	$ 0.9246	10
11 12	Minimum Monthly Bill	Customer Charge	Customer Charge	11 12

a/ Present Customer Charges and Distibution Charge pursuant to tariff.

Washington Gas Light Company
District of Columbia

Comparison of Present and Proposed Commercial and Industrial Firm Service Rates
Rate Schedule Nos. 2 and 2A

Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No.	Description A	Present B a/	Proposed C b/	Line No.
1	**Customer Charges**	Monthly Charges		1
2	Heating and/or Cooling			2
3	(a) Annual Usage less than 3,075 therms	$ 29.90	$ 37.40	3
4	(b) Annual Usage 3,075 therms or more	$ 70.05	$ 87.55	4
5	Non-Heating and Non-Cooling	$ 28.50	$ 35.65	5
6	**Peak Usage Charge**	Rates per Therm		6
7	Billing Months November - April			7
8	Heating and/or Cooling			8
9	(a) Annual Usage less than 3,075 therms	$ 0.0519	$ 0.0692	9
10	(b) Annual Usage 3,075 therms or more	$ 0.0421	$ 0.0532	10
11	Non-Heating and Non-Cooling	$ 0.0423	$ 0.0534	11
12	**Distribution Charges**	Rates per Therm		12
13	Heating and/or Cooling			13
14	(a) Annual Usage less than 3,075 therms	$ 0.5821	$ 0.8010	14
15	(b) Annual Usage 3,075 therms or more	$ 0.4796	$ 0.6063	15
16	Non-Heating and Non-Cooling	$ 0.4811	$ 0.6087	16
17	Minimum Monthly Bill	Customer	Customer	17
18		Charge	Charge	18

a/ Present Customer Charges, Peak Usage Charge and Distibution Charge pursuant to tariff.

Washington Gas Light Company
District of Columbia

Comparison of Present and Proposed Group Metered Apartment Firm Service Rates
Rate Schedule Nos. 3 and 3A

Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No.	Description	Present		Proposed		Line No.
	A	B a/		C b/		
1	**Customer Charges**	Monthly Charges				1
2	Heating and/or Cooling					2
3	(a) Annual Usage less than 3,075 therms	$	28.50	$	35.65	3
4	(b) Annual Usage 3,075 therms or more	$	70.05	$	87.60	4
5	Non-Heating and Non-Cooling	$	28.50	$	35.65	5
6	**Peak Usage Charge**	Rates per Therm				6
7	Billing Months November - April					7
8	Heating and/or Cooling					8
9	(a) Annual Usage less than 3,075 therms	$	0.0431	$	0.0544	9
10	(b) Annual Usage 3,075 therms or more	$	0.0422	$	0.0533	10
11	Non-Heating and Non-Cooling	$	0.0423	$	0.0534	11
12	**Distribution Charges**	Rates per Therm				12
13	Heating and/or Cooling					13
14	(a) Annual Usage less than 3,075 therms	$	0.4930	$	0.6252	14
15	(b) Annual Usage 3,075 therms or more	$	0.4863	$	0.6148	15
16	Non-Heating and Non-Cooling	$	0.4841	$	0.6124	16
17	Minimum Monthly Bill	Customer		Customer		17
18		Charge		Charge		18

a/ Present Customer Charges, Peak Usage Charge and Distibution Charge pursuant to tariff.

Washington Gas Light Company
District of Columbia

Comparison of Present and Proposed Interruptible Service Rates
Rate Schedule Nos. 4, 6 and 7
Comparison of Present and Proposed General Service Provision Charges

Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No.	Description		Present		Proposed	Line No.
	A		B a/		C b/	
1	**Customer Charges (all billing months)**		Monthly Charges			1
2	Developmental Natural Gas Vehicles - Rate Schedule No. 4	$	49.67	$	62.10	2
3	Delivery Service - Rate Schedule No. 6	$	121.00	$	151.25	3
4	**Distribution Charges**		Rates per Therm			4
5	**Developmental Natural Gas Vehicle Service - Rate Schedule No. 4**					5
6	**Distribution Charges (Rates per Therm)**	$	0.0745	$	0.1028	6
7	**Interruptible Delivery Service - Rate Schedule No. 6**					
8	First 75,000 therms	$	0.2094	$	0.2887	8
9	Over 75,000 therms	$	0.1932	$	0.2663	9
10	**Delivery Service for Combined Heat and Power/Distributed Generation Facilities**					10
11	**- Rate Schedule No. 7**					11
12	**Customer Charges (all billing months)**	$	343.75	$	429.70	12
13	**Distribution Charges (Rates per Therm)**	$	0.1033	$	0.1430	13
14	**Peak Usage Charge (Rates per Therm)**	$	0.0904	$	0.1246	14
15	**General Service Provision Charges**		Individual Charges			15
16	GSP No. 5 - Metering					16
17	Meter Relocation Estimate Charge	$	72.00	$	72.00	17
18	GSP No. 11 - Discontinuance of Service					18
19	Reconnection Charges - single unit	$	44.98	$	53.98	19
20	Reconnection Charges - Four or more units	$	14.50	$	17.40	20
21	Field Collection Charge	$	13.12	$	14.43	21
22	GSP No. 18 - Dishonored Checks					22
23	Dishonored Check Charge	$	9.00	$	9.00	23
24	GSP No. 19 - Service Initiation Charge					24
25	Service Initiation Charge - Gas Flowing	$	33.00	$	33.00	25
26	Service Initiation Charge - Gas Not Flowing	$	37.17	$	44.60	26

a/ Present rates and charges pursuant to tariff.

Washington Gas Light Company
District of Columbia

Proposed Rate Design
Determination of Firm Distribution Charges and Peak Usage Charge

Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No.	Description	After Increase Reference	Before Increase	Increase	Revenue Produced	Line No.
	A	B	C	D	E=C+D	
1	Total Operating Revenue	Exhibit WG (D)-1, Page 1	$ 211,627,238	$ 45,572,411	$ 257,199,649	1
2	Less: Delivery Tax	Sch B, Page 3, Line 32	21,469,185	-	21,469,185	2
3	Less: Rights of Way Fee	Sch B, Page 3, Line 41	10,060,396	-	10,060,396	3
4	Less: Sustainable Energy Trust Fund	Sch B, Page 3, Line 35	21,524,022	-	21,524,022	4
5	Less: Non-tariff Customers	Sch B, Page 3, Line 21	3,958,400	1,089	3,959,489	5
6	Less: Energy Assistance Trust Fund	Sch B, Page 3, Line 38	2,393,492	-	2,393,492	6
7	Net Revenue for Tariff Rate Design	Line 1 - Sum of Lines 2 - 6	$ 152,221,743	$ 45,571,322	$ 197,793,065	7
8	Less: Other Operating Revenue					8
9	Late Payment Charges	Sch B, Page 2, Line 41	$ 3,577,696	$ 791,729	$ 4,369,425	9
10	Watergate Revenue	Sch B, Page 2, Line 42	-	-	-	10
11	Miscellaneous Service Revenue	Sch B, Page 2, Line 43	1,271,143	140,875	1,412,018	11
12	Total Other Operating Revenue	Line 9 + Line 10 + Line 11	$ 4,848,839	$ 932,604	$ 5,781,443	12
13	Net Revenue for Rate Schedules	Line 7 - Line 12	$ 147,372,904	$ 44,638,718	$ 192,011,622	13
14	Overall % increase				30.29%	14

Washington Gas Light Company
District of Columbia

Proposed Rate Design
Revenue Detail BEFORE INCREASE

Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No.	Description A	Reference B		D.C. Amount C=D+...+N	Residential Heating/Cooling D	Residential Non-htg IMA E	Residential Non-htg Other F	Commercial & Industrial Htg/Clg < 3,075 G	Commercial & Industrial Htg/Clg > 3,075 H	Commercial & Industrial CHP	Commercial & Industrial Non-heating I	Commercial & Industrial NGV c/	Group Metered Apartments Htg/Clg < 3,075 J	Group Metered Apartments Htg/Clg > 3,075 K	Group Metered Apartments Non-heating L	Interruptible M	Special Contract N	Line No.
1	**Customer Charge Revenue**																	1
2	Number of Bills	Normal Weather Study		1,957,550	1,627,379	131,084	42,794	53,982	40,679	12	22,135	30	7,177	20,485	10,430	1,327	36	2
3	Customer Charge per Bill	Tariff			$ 16.55	$ 12.00	$ 13.55	$ 29.90	$ 70.05	$ 343.75	$ 28.50	$ 49.67	$ 28.50	$ 70.05	$ 28.50	$ 121.00	$ 121.00	3
4	Customer Charge Revenue before correction	Line 2 x Line 3		$ 36,287,775	$ 26,933,122	$ 1,573,008	$ 579,859	$ 1,614,062	$ 2,849,564	$ 4,125	$ 630,848	$ 1,490	$ 204,545	$ 1,434,974	$ 297,255	$ 160,567	$ 4,356	4
5	Correction Factors	Cost of Service Workpapers		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	5
6	Customer Charge Revenue after correction	Line 4 x Line 5		$ 36,287,775	$ 26,933,122	$ 1,573,008	$ 579,859	$ 1,614,062	$ 2,849,564	$ 4,125	$ 630,848	$ 1,490	$ 204,545	$ 1,434,974	$ 297,255	$ 160,567	$ 4,356	6
7	**Peak Usage Charge Revenue**																	7
8	Therms from Maximum Usage Month	Exhibit WG (D)-5 Adj 1		16,621,656	-	-	-	785,545	9,533,168	280,694	1,166,597	-	115,023	4,209,429	531,201	N/A	-	8
9	Peak Usage Charge per Therm	Tariff			$ -	$ -	$ -	$ 0.0519	$ 0.0421	$ 0.0804	$ 0.0423	$ -	$ 0.0431	$ 0.0422	$ 0.0423	$ -	$ -	9
10	Number of Months Billed (Nov-Apr)	months per Tariff			-	-	-	6	6	12	6	-	6	6	6	-	-	10
11	Peak Usage Charge Revenue	Line 8 x Line 9 x Line 10		$ 4,483,667	$ -	$ -	$ -	$ 244,619	$ 2,408,078	$ 304,497	$ 296,082	$ -	$ 29,745	$ 1,065,827	$ 134,819	$ -	$ -	11
12	**Distribution Charge Revenue**																	12
13	Normal Weather Therms - Sales	Normal Weather Study		122,542,753	74,324,500	597,610	1,475,692	4,360,714	25,974,024	-	3,296,481	-	672,445	10,281,670	1,559,619	-	-	13
14	Normal Weather Therms - Delivery	Normal Weather Study		164,587,906	10,468,666	80,010	227,843	975,424	42,880,381	2,101,032	4,716,251	3,179,948	326,734	19,392,433	2,370,230	39,648,220	38,220,735	14
15	Total Normal Weather Therms - Throughput	Normal Weather Study		287,130,659	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	3,179,948	999,179	29,674,103	3,929,848	39,648,220	38,220,735	15
16	Total Normal Weather Therms	Line 15 + Line		287,130,659	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	3,179,948	999,179	29,674,103	3,929,848	39,648,220	38,220,735	16
17	Distribution Charge per Therm	Tariff			$ 0.5638	$ 0.6610	$ 0.6390	$ 0.5821	$ 0.4796	$ 0.1033	$ 0.4811	$ 0.0745	$ 0.4930	$ 0.4863	$ 0.4841	$ -	$ -	17
18	Net Distribution Charge Revenue before correction	Line 15 x Line 17	b/	$ 110,559,862	$ 47,806,387	$ 447,907	$ 1,088,558	$ 3,106,166	$ 33,022,572	$ 217,037	$ 3,854,925	$ 236,715	$ 492,595	$ 14,430,516	$ 1,902,440	$ -	$ 3,954,044	18
19	Correction Factors	Cost of Service Workpapers			1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	19
20	Distribution Charge Revenue after correction	Line 18 x Line 19		$ 110,559,862	$ 47,806,387	$ 447,907	$ 1,088,558	$ 3,106,166	$ 33,022,572	$ 217,037	$ 3,854,925	$ 236,715	$ 492,595	$ 14,430,516	$ 1,902,440	$ -	$ 3,954,044	20
21	Total Basic Tariff Rate Revenue	Lines 6 + 11 + 20		$ 151,331,304	$ 74,739,509	$ 2,020,915	$ 1,668,417	$ 4,964,847	$ 38,280,214	$ 525,659	$ 4,781,855	$ 238,205	$ 726,885	$ 16,931,317	$ 2,334,514	$ 160,567	$ 3,958,400	21
22	**Purchased Gas Charge Revenue**																	22
23	Purchased Gas Charge per Therm	Cost of Service Workpapers			$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018	$ 0.6018		$ 0.6018	$ 0.6018	$ 0.6018	$ -	$ 0.6018	23
24	Purchased Gas Charge Revenue	Line 13 x Line 23		$ 73,746,228	$ 44,726,484	$ 359,642	$ 888,071	$ 2,624,277	$ 15,631,167	$ -	$ 1,983,822	$ -	$ 404,677	$ 6,187,509	$ 938,579	$ -	$ -	24
25	**Delivery Tax Revenue**																	25
26	Delivery Tax rate per Therm	Cost of Service Workpapers			$ 0.07070	$ 0.07070	$ 0.07070	$ 0.07777	$ 0.07777	$ 0.07777	$ 0.07777		$ 0.07070	$ 0.07070	$ 0.07070	$ 0.07777	$ 0.07777	26
27	Delivery Tax Revenue	Line 16 x Line 26		$ 21,469,185	$ 5,994,877	$ 47,908	$ 120,440	$ 414,991	$ 5,354,807	$ 163,397	$ 623,150	$ 247,305	$ 70,642	$ 2,097,959	$ 277,840	$ 3,083,442	$ 2,972,427	27
28	**Sustainable Energy Trust Fund (SETF) Revenue**																	28
29	SETF rate per Therm	Cost of Service Workpapers			$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515		$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	29
30	SETF Revenue	Line 16 x Line 29		$ 21,524,022	$ 6,372,206	$ 50,923	$ 128,021	$ 401,011	$ 5,174,400	$ 157,893	$ 602,157	$ 185,126	$ 75,088	$ 2,230,009	$ 295,326	$ 2,979,564	$ 2,872,288	30
31	**Energy AssistanceTrust Fund (EATF) Revenue**																	31
32	EATF rate per Therm	Cost of Service Workpapers			$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834		$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	32
33	EATF Revenue	Line 16 x Line 32		$ 2,393,492	$ 708,827	$ 5,649	$ 14,200	$ 44,482	$ 573,963	$ 17,514	$ 66,793	$ 26,508	$ 8,329	$ 247,360	$ 32,759	$ 330,504	$ 318,604	33
34	**DC Rights of Way Fee Revenue**																	34
35	DC Rights of Way Fee per Therm	Cost of Service Workpapers			$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349		$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	35
36	DC Rights of Way Fee Revenue	Line 16 x Line 35		$ 10,080,398	$ 2,959,281	$ 23,649	$ 59,453	$ 186,231	$ 2,403,019	$ 73,326	$ 279,644	$ 150,517	$ 34,871	$ 1,035,626	$ 137,152	$ 1,383,723	$ 1,333,904	36
37	Total Sales/Delivery of Gas Revenue	21 + Ln 24 + Ln 27 + Ln 30+ Ln 33 + Ln :		$ 280,524,627	$ 135,501,184	$ 2,508,686	$ 2,878,602	$ 8,635,839	$ 67,417,578	$ 937,789	$ 8,337,421	$ 847,661	$ 1,320,492	$ 28,729,780	$ 4,016,172	$ 7,937,800	$ 11,455,623	37
38	Total Sales/Delivery of Gas Revenue - Firm Only	Line 37 less Column M		$ 269,069,004	$ 135,501,184	$ 2,508,686	$ 2,878,602	$ 8,635,839	$ 67,417,578	$ 937,789	$ 8,337,421	$ 847,661	$ 1,320,492	$ 28,729,780	$ 4,016,172	$ 7,937,800	N/A	38
39	Firm Sales/Delivery of Gas Factors	Class Line 38 / Sum Line 39		100.00%	50.35%	0.93%	1.07%	3.21%	25.06%	0.35%	3.10%	0.32%	0.49%	10.68%	1.49%	2.95%	N/A	39
40	**Other Operating Revenue**	footnote	a/															40
41	Late Payment Charges	Allocation on Line 39		$ 3,577,696	2,375,563	45,755	48,846	49,950	413,203	5,812	55,903	12,564	11,814	357,144	51,080	150,082	0	41
42	Watergate	Direct Assignment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	42
43	Miscellaneous Service Revenue	Allocation on Line 39		1,271,143	1,174,293	22,618	24,146	4,095	33,875	476	4,583	-	172	5,186	741	958	-	43
44	Total Other Operating Revenue	Line 41 + Line 42 + Line 43		$ 4,848,839	$ 3,549,856	$ 68,373	$ 72,992	$ 54,045	$ 447,078	$ 6,288	$ 60,486	$ 12,564	$ 11,985	$ 362,330	$ 51,801	$ 151,040	$ -	44
45	**Total Operating Revenue**	Line 37 + Line 44		$ 285,373,466	$ 139,051,040	$ 2,577,059	$ 2,951,594	$ 8,689,884	$ 67,864,656	$ 944,077	$ 8,397,907	$ 860,225	$ 1,332,477	$ 29,092,110	$ 4,067,973	$ 8,088,840	$ 11,455,623	45
46	**Total Sales/Delivery Revenue**	Line 45 - Line 44		$ 280,524,627	$ 135,501,184	$ 2,508,686	$ 2,878,602	$ 8,635,839	$ 67,417,578	$ 937,789	$ 8,337,421	$ 847,661	$ 1,320,492	$ 28,729,780	$ 4,016,172	$ 7,937,800	$ 11,455,623	46
47	**Total Non-Gas Revenue**	Line 45 - Line 24		$ 211,627,238	$ 94,322,556	$ 2,217,417	$ 2,063,523	$ 6,065,607	$ 52,233,489	$ 944,077	$ 6,414,085	$ 860,225	$ 927,800	$ 22,904,601	$ 3,129,394	$ 8,088,840	$ 11,455,623	47
48	**Total Non-Gas Sales/Delivery Revenue**	Line 47 - Line 44		$ 206,778,399	$ 90,772,700	$ 2,149,044	$ 1,990,531	$ 6,011,562	$ 51,786,411	$ 937,789	$ 6,353,599	$ 847,661	$ 915,815	$ 22,542,271	$ 3,077,593	$ 7,937,800	$ 11,455,623	48

a/ Column C total amounts from Exhibit WG (O)-1, Schedule B, Page 5.
b/ Special Contract revenues per revenue support workpapers
c/ NGV Sales Not Weather Normalized. Actual Revenues Used

Washington Gas Light Company
District of Columbia

Proposed Rate Design
Determination of Proposed Customer Charges and Calculation of Proposed Basic Rate Revenue by Customer Class

Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No	Description	Reference	DC Amount	Residential: Heating/Cooling	Residential: Non-htg IMA	Residential: Non-htg Other	Commercial & Industrial: Htg/Clg < 3,075	Commercial & Industrial: Htg/Clg > 3,075	Commercial & Industrial: CHP	Commercial & Industrial: Non-heating	Commercial & Industrial: NGV c/	Group Metered Apartments: Htg/Clg < 3,075	Group Metered Apartments: Htg/Clg > 3,075	Group Metered Apartments: Non-heating	Interruptible	Special Contract	Line No
	A	B	C=D+...+N	D	E	F	G	H		I		J	K	L	M	N	
1	**Customer Charge Revenue**																1
2	Current Customer Charges	Tariff		$ 16.55	$ 12.00	$ 13.55	$ 29.90	$ 70.05	$ 343.75	$ 28.50	$ 49.67	$ 28.50	$ 70.05	$ 28.50	$ 121.00	$ 121.00	2
3	Proposed Increase Percentage			25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	3
4	Proposed Increase Amount	Line 2 x Line 3		$ 4.14	$ 3.00	$ 3.39	$ 7.48	$ 17.51	$ 85.94	$ 7.13	$ 12.42	$ 7.13	$ 17.51	$ 7.13	$ 30.25	$ 30.25	4
5	Proposed Customer Charges (calculated)	Line 2 + Line 4		$ 20.69	$ 15.00	$ 16.94	$ 37.38	$ 87.56	$ 429.69	$ 35.63	$ 62.09	$ 35.63	$ 87.56	$ 35.63	$ 151.25	$ 151.25	5
6	Proposed Customer Charges (rounded)	Line 5 rounded		$ 20.70	$ 15.00	$ 16.95	$ 37.40	$ 87.55	$ 429.70	$ 35.65	$ 62.10	$ 35.65	$ 87.60	$ 35.65	$ 151.25	$ 151.25	6
7	Number of Bills (all billing months)	Normal Weather Study	1,957,550	1,627,379	131,084	42,794	53,962	40,679	12	22,135	30	7,177	20,485	10,430	1,327	36	7
8	Customer Charge Revenue before correction	Line 6 x Line 7	$ 45,383,198	$ 33,686,745	$ 1,966,260	$ 725,358	$ 2,018,927	$ 3,561,446	$ 5,156	$ 789,113	$ 1,863	$ 255,860	$ 1,794,486	$ 371,830	$ 200,709	$ 5,445	8
9	Correction Factors	Sch B, Page 2, Line 5		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	9
10	Customer Charge Revenue after correction	Line 8 x Line 9	$ 45,383,198	$ 33,686,745	$ 1,966,260	$ 725,358	$ 2,018,927	$ 3,561,446	$ 5,156	$ 789,113	$ 1,863	$ 255,860	$ 1,794,486	$ 371,830	$ 200,709	$ 5,445	10
11	**Peak Usage Charge Revenue**																11
12	Current Peak Usage Charge per Therm	Tariff		$ -	$ -	$ -	$ 0.0519	$ 0.0421	$ 0.0904	$ 0.0423	$ -	$ 0.0431	$ 0.0422	$ 0.0423	$ -	$ -	12
13	Proposed Increase per Therm	Line 14 - Line 12		-	-	-	0.0173	0.0111	0.0342	0.0111	-	0.0113	0.0111	0.0111	-	-	13
14	Proposed Peak Usage Charge			$ -	$ -	$ -	$ 0.0692	$ 0.0532	$ 0.1246	$ 0.0534	$ -	$ 0.0544	$ 0.0533	$ 0.0534	$ -	$ -	14
15	Therms from Maximum Usage Month	Exhibit WG (F)-5	16,621,656	-	-	-	785,545	9,533,168	280,694	1,166,597	-	115,023	4,209,429	531,201	-	-	15
16	Number of Months Billed (Nov-Apr)	6 months per Tariff		-	-	-	6	6	12	6	-	6	6	6	-	-	16
17	Peak Usage Charge Revenue	Line 14 x Line 15 x Line 16	$ 5,716,532	$ -	$ -	$ -	$ 326,158	$ 3,042,987	$ 419,693	$ 373,778	$ -	$ 37,543	$ 1,346,175	$ 170,197	$ -	$ -	17
18	**Distribution Charge Revenue**																18
19	Normal Weather Therms - Sales	Normal Weather Study	122,542,753	74,324,500	597,610	1,475,892	4,360,714	25,974,024	-	3,296,481	-	672,445	10,281,670	1,559,619	-	-	19
20	Normal Weather Therms - Delivery	Normal Weather Study	164,587,906	10,468,666	80,010	227,643	975,424	42,880,381	2,101,032	4,716,251	3,179,948	326,734	19,392,433	2,370,230	39,648,220	38,220,735	20
21	Total Normal Weather Therms - Throughput	Line 19 + Line 20	287,130,659	84,793,166	677,620	1,703,534	5,336,138	68,854,404	2,101,032	8,012,732	3,179,948	999,179	29,674,103	3,929,848	39,648,220	38,220,735	21
22	Distribution Charge per Therm			$ 0.7778	$ 0.8653	$ 0.9246	$ 0.8010	$ 0.6063	$ 0.1430	$ 0.6087	$ 0.1028	$ 0.6252	$ 0.6148	$ 0.6124	$ -	$ -	22
23	Net Distribution Charge Revenue before correction	Line 21 x Line 22	$ 144,867,933	$ 65,952,125	$ 586,345	$ 1,575,088	$ 4,274,246	$ 41,746,425	$ 300,448	$ 4,877,350	$ 326,899	$ 624,686	$ 18,243,638	$ 2,406,639	$ -	$ 3,954,044	23
24	Correction Factors	Sch B, Page 2, Line 19		1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	24
25	Distribution Charge Revenue after correction	Line 23 x Line 24	$ 144,867,933	$ 65,952,125	$ 586,345	$ 1,575,088	$ 4,274,246	$ 41,746,425	$ 300,448	$ 4,877,350	$ 326,899	$ 624,686	$ 18,243,638	$ 2,406,639	$ -	$ 3,954,044	25
26	Total Basic Tariff Rate Revenue	Lines 10 + 17 + 25	$ 195,967,663	$ 99,638,870	$ 2,552,605	$ 2,300,446	$ 6,619,331	$ 48,350,858	$ 725,297	$ 6,040,241	$ 328,762	$ 918,089	$ 21,384,299	$ 2,948,666	$ 200,709	$ 3,959,489	26
27	**Purchased Gas Charge Revenue**																27
28	Purchased Gas Charge per Therm	Sch B, Page 2, Line 23		0.6018	0.6018	0.6018	0.6018	0.6018	0.6018	0.6018	0.6018	0.6018	0.6018	0.6018	0.0000	0.0000	28
29	Purchased Gas Charge Revenue	Line 19 x Line 28	$ 73,746,228	$ 44,728,484	$ 359,642	$ 888,071	$ 2,624,277	$ 15,631,167	$ -	$ 1,983,822	$ -	$ 404,677	$ 6,187,509	$ 938,579	$ -	$ -	29
30	**Delivery Tax Revenue**																30
31	Delivery Tax rate per Therm	Cost of Service Workpapers		$ 0.07070	$ 0.07070	$ 0.07070	$ 0.07777	$ 0.07777	$ 0.07777	$ 0.07777	$ -	$ 0.07070	$ 0.07070	$ 0.07070	$ 0.07777	$ 0.07777	31
32	Delivery Tax Revenue	Line 21 x Line 31	$ 21,469,185	$ 5,994,877	$ 47,908	$ 120,440	$ 414,991	$ 5,354,807	$ 163,397	$ 623,150	$ 247,305	$ 70,642	$ 2,097,959	$ 277,840	$ 3,083,442	$ 2,972,427	32
33	**Sustained Energy Trust Fund (SETF) Revenue**																33
34	SETF rate per Therm	Cost of Service Workpapers		$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ -	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	$ 0.07515	34
35	SETF Revenue	Line 21 x Line 34	$ 21,524,022	$ 6,372,206	$ 50,923	$ 128,021	$ 401,011	$ 5,174,406	$ 157,893	$ 602,157	$ 185,126	$ 75,088	$ 2,230,009	$ 295,326	$ 2,979,564	$ 2,872,288	35
36	**Energy AssistanceTrust Fund (EATF) Revenue**																36
37	EATF rate per Therm	Cost of Service Workpapers		$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	$ 0.00834	37
38	EATF Revenue	Line 21 x Line 37	$ 2,393,492	$ 706,827	$ 5,649	$ 14,200	$ 44,482	$ 573,963	$ 17,514	$ 66,793	$ 26,508	$ 8,329	$ 247,360	$ 32,759	$ 330,504	$ 318,604	38
39	**DC Rights of Way Fee Revenue**																39
40	DC Rights of Way Fee per Therm	Sch B, Page 2, Line 35		$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ -	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	$ 0.0349	40
41	DC Rights of Way Fee Revenue	Line 21 x Line 40	$ 10,080,396	$ 2,959,281	$ 23,649	$ 59,453	$ 186,231	$ 2,403,019	$ 73,326	$ 279,644	$ 150,517	$ 34,871	$ 1,035,626	$ 137,152	$ 1,383,723	$ 1,333,904	41
42	Total Sales/Delivery of Gas Revenue	26 + Ln 29 + Ln 32 + Ln 35+ Ln 38 + Ln ·	$ 325,160,986	$ 160,400,545	$ 3,040,376	$ 3,510,631	$ 10,290,323	$ 77,488,222	$ 1,137,427	$ 9,595,807	$ 938,218	$ 1,511,696	$ 33,182,762	$ 4,630,324	$ 7,977,942	$ 11,456,712	42
43	Total Sales/Delivery of Gas Revenue - Firm Only	Line 42 less Column M	$ 313,704,274	$ 160,400,545	$ 3,040,376	$ 3,510,631	$ 10,290,323	$ 77,488,222	$ 1,137,427	$ 9,595,807	$ 938,218	$ 1,511,696	$ 33,182,762	$ 4,630,324	$ 7,977,942	N/A	43
44	Firm Sales/Delivery of Gas Factors	Class Line 43 / Sum Line 43	100.00%	43.03%	1.13%	1.30%	3.82%	28.80%	0.42%	3.57%	0.35%	0.56%	12.33%	1.72%	2.97%	N/A	44
45	**Other Operating Revenue**	footnote a/															45
46	Late Payment Charges	Allocation on Line 44	$ 4,369,425	2,901,265	55,880	59,655	61,004	504,643	7,098	68,274	15,345	14,426	436,178	82,359	183,295	0	46
47	Watergate	Direct Assignment		-	-	-	-	-	-	-	-	-	-	-	-	-	47
48	Miscellaneous Service Revenue	Allocation on Line 44	1,412,018	1,304,435	25,124	26,822	4,549	37,629	529	5,091	-	191	5,760	824	1,064	-	48
49	Total Other Operating Revenue	Line 46 + Line 47 + Line 48	$ 5,781,443	$ 4,205,700	$ 81,005	$ 86,477	$ 65,553	$ 542,273	$ 7,627	$ 73,364	$ 15,345	$ 14,619	$ 441,939	$ 83,183	$ 184,359	$ -	49
50	**Total Operating Revenue**	Line 42 + Line 49	$ 330,942,429	$ 164,606,245	$ 3,121,381	$ 3,597,108	$ 10,355,876	$ 78,030,495	$ 1,145,054	$ 9,669,171	$ 953,563	$ 1,526,315	$ 33,624,701	$ 4,693,507	$ 8,162,301	$ 11,456,712	50
51	**Total Sales/Delivery Revenue**	Line 50 - Line 49	$ 325,160,986	$ 160,400,545	$ 3,040,376	$ 3,510,631	$ 10,290,323	$ 77,488,222	$ 1,137,427	$ 9,595,807	$ 938,218	$ 1,511,696	$ 33,182,762	$ 4,630,324	$ 7,977,942	$ 11,456,712	51
52	**Total Non-Gas Revenue**	Line 50 - Line 29	$ 257,196,201	$ 119,877,761	$ 2,761,739	$ 2,709,037	$ 7,731,599	$ 62,399,328	$ 1,145,054	$ 7,685,349	$ 953,563	$ 1,121,638	$ 27,437,192	$ 3,754,928	$ 8,162,301	$ 11,456,712	52
53	**Total Non-Gas Sales/Delivery Revenue**	Line 52 - Line 49	$ 251,414,758	$ 115,672,061	$ 2,680,734	$ 2,622,560	$ 7,666,046	$ 61,857,055	$ 1,137,427	$ 7,611,985	$ 938,218	$ 1,107,019	$ 26,995,253	$ 3,691,745	$ 7,977,942	$ 11,456,712	53

a/ Column C total amounts from Exhibit WG (O)-1, Schedule B, Page 5

Washington Gas Light Company
District of Columbia

Proposed Rate Design
Comparison of Proposed Revenue Increase by Rate Element and by Customer Class

Based on 12 Months Ended December 31, 2021 - Pro Forma

Line No	Description	Reference	D.C Amount	Residential Heating/Cooling	Residential Non-htg IMA	Residential Non-htg Other	Commercial & Industrial Htg/Clg < 3,075	Commercial & Industrial Htg/Clg > 3,075	Commercial & Industrial CHP	Commercial & Industrial Non-heating	Group Metered Apartments NGV	Group Metered Apartments Htg/Clg < 3,075	Group Metered Apartments Htg/Clg > 3,075	Group Metered Apartments Non-heating	Interruptible	Special Contract	Line No
	A	B	C=D+...+N	D	E	F	G	H		I		J	K	L	M	N	
1	**Customer Charge Revenue**																1
2	Customer Charge Revenue - PRESENT	Sch B, Page 2, Line 5	$ 36,287,775	$ 26,933,122	$ 1,573,008	$ 579,859	$ 1,814,062	$ 2,849,564	$ 4,125	$ 630,848	$ 1,490	$ 204,545	$ 1,434,974	$ 297,255	$ 160,567	$ 4,356	2
3	Customer Charge Revenue - PROPOSED	Sch B, Page 3, Line 10	45,383,198	33,686,745	1,966,260	725,358	2,018,927	3,561,446	5,156	789,113	1,863	255,860	1,794,486	371,830	200,709	5,445	3
4	Customer Charge Revenue - CHANGE	Line 3 - Line 2	$ 9,095,423	$ 6,753,623	$ 393,252	$ 145,499	$ 404,865	$ 711,882	$ 1,031	$ 158,265	$ 373	$ 51,315	$ 359,512	$ 74,575	$ 40,142	$ 1,089	4
5	Change Percentage	Line 4 / Line 2	25.1%	25.1%	25.0%	25.1%	25.1%	25.0%	25.0%	25.1%	25.0%	25.1%	25.1%	25.1%	25.0%	25.0%	5
6	**Peak Usage Charge Revenue**																6
7	Peak Usage Charge Revenue - PRESENT	Sch B, Page 2, Line 11	$ 4,483,667	$ -	$ -	$ -	$ 244,619	$ 2,408,078	$ 304,497	$ 296,082	$ -	$ 29,745	$ 1,065,827	$ 134,819	$ -	$ -	7
8	Peak Usage Charge Revenue - PROPOSED	Sch B, Page 3, Line 17	5,716,532	-	-	-	326,158	3,042,987	419,693	373,778	-	37,543	1,346,175	170,197	-	-	8
9	Peak Usage Charge Revenue - CHANGE	Line 8 - Line 7	$ 1,232,865	$ -	$ -	$ -	$ 81,539	$ 634,909	$ 115,196	$ 77,696	$ -	$ 7,798	$ 280,348	$ 35,378	$ -	$ -	9
10	Change Percentage	Line 9 / Line 7	27.5%	0.0%	0.0%	0.0%	33.3%	26.4%	37.8%	26.2%	0.0%	26.2%	26.3%	26.2%	0.0%	0.0%	10
11	**Distribution Charge Revenue**																11
12	Distribution Charge Revenue - PRESENT	Sch B, Page 2, Line 20	$ 110,559,862	$ 47,806,387	$ 447,907	$ 1,088,558	$ 3,106,166	$ 33,022,572	$ 217,037	$ 3,654,925	$ 236,715	$ 492,595	$ 14,430,516	$ 1,902,440	$ -	$ 3,954,044	12
13	Distribution Charge Revenue - PROPOSED	Sch B, Page 3, Line 25	144,867,933	65,952,125	586,345	1,575,088	4,274,246	41,746,425	300,448	4,677,350	326,899	624,686	18,243,638	2,406,639	-	3,954,044	13
14	Distribution Charge Revenue - CHANGE	Line 13 - Line 12	$ 34,308,071	$ 18,145,738	$ 138,438	$ 486,530	$ 1,168,080	$ 8,723,853	$ 83,411	$ 1,022,425	$ 90,184	$ 132,091	$ 3,813,122	$ 504,199	$ -	$ -	14
15	Change Percentage	Line 14 / Line 12	31.0%	38.0%	30.9%	44.7%	37.6%	26.4%	38.4%	26.5%	38.1%	26.8%	26.4%	26.5%	0.0%	0.0%	15
16	**Purchased Gas Charge Revenue**																16
17	Purchased Gas Charge - PRESENT	Sch B, Page 2, Line 24	$ 73,746,226	$ 44,728,484	$ 359,642	$ 888,071	$ 2,624,277	$ 15,631,167	$ -	$ 1,983,822	$ -	$ 404,677	$ 6,187,509	$ 938,579	$ -	$ -	17
18	Purchased Gas Charge - PROPOSED	Sch B, Page 3, Line 29	73,746,226	44,728,484	359,642	888,071	2,624,277	15,631,167	-	1,983,822	-	404,677	6,187,509	938,579	-	-	18
19	Purchased Gas Charge - CHANGE	Line 18 - Line 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	19
20	Change Percentage	Line 19 / Line 17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	20
21	**DC Rights of Way Fee Revenue**																21
22	DC Rights of Way Fee - PRESENT	Sch B, Page 2, Line 36	$ 10,080,396	$ 2,959,281	$ 23,649	$ 59,453	$ 186,231	$ 2,403,019	$ 73,326	$ 279,644	$ 150,517	$ 34,871	$ 1,035,626	$ 137,152	$ 1,383,723	$ 1,333,904	22
23	DC Rights of Way Fee - PROPOSED	Sch B, Page 3, Line 41	10,080,396	2,959,281	23,649	59,453	186,231	2,403,019	73,326	279,644	150,517	34,871	1,035,626	137,152	1,383,723	1,333,904	23
24	DC Rights of Way Fee - CHANGE	Line 23 - Line 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	24
25	Change Percentage	Line 24 / Line 22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	25
26	**Sustainable Energy Trust Fund (SETF) Revenue**																26
27	SETF - PRESENT	Sch B, Page 2, Line 30	$ 21,524,022	$ 6,372,206	$ 50,923	$ 128,021	$ 401,011	$ 5,174,408	$ 157,693	$ 602,157	$ 185,126	$ 75,088	$ 2,230,009	$ 295,328	$ 2,979,564	$ 2,872,288	27
28	SETF - PROPOSED	Sch B, Page 3, Line 35	21,524,022	6,372,206	50,923	128,021	401,011	5,174,408	157,693	602,157	185,126	75,088	2,230,009	295,328	2,979,564	2,872,288	28
29	SETF - CHANGE	Line 28 - Line 27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	29
30	Change Percentage	Line 29 / Line 27	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	30
31	**Energy AssistanceTrust Fund (EATF) Revenue**																31
32	EATF - PRESENT	Sch B, Page 2, Line 33	$ 2,393,492	$ 706,827	$ 5,649	$ 14,200	$ 44,482	$ 573,963	$ 17,514	$ 66,793	$ 26,508	$ 8,329	$ 247,360	$ 32,759	$ 330,504	$ 318,604	32
33	EATF - PROPOSED	Sch B, Page 3, Line 38	2,393,492	706,827	5,649	14,200	44,482	573,963	17,514	66,793	26,508	8,329	247,360	32,759	330,504	318,604	33
34	EATF - CHANGE	Line 33 - Line 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	34
35	Change Percentage	Line 34 / Line 32	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	35
36	**Other Operating Revenue**																36
37	Other Operating Revenue - PRESENT	Sch B, Page 2, Line 44	$ 4,848,839	$ 3,549,856	$ 68,373	$ 72,992	$ 54,045	$ 447,078	$ 6,288	$ 60,486	$ 12,564	$ 11,985	$ 362,330	$ 51,801	$ 151,040	$ -	37
38	Other Operating Revenue - PROPOSED	Sch B, Page 3, Line 49	$ 5,781,443	4,205,700	81,005	86,477	65,553	542,273	7,627	73,364	15,345	14,619	441,939	63,183	184,359	-	38
39	Other Operating Revenue - CHANGE	Line 38 - Line 37	$ 932,604	$ 655,844	$ 12,632	$ 13,485	$ 11,508	$ 95,194	$ 1,339	$ 12,879	$ 2,780	$ 2,633	$ 79,609	$ 11,382	$ 33,319	$ -	39
40	Change Percentage	Line 39 / Line 37	19.2%	18.5%	18.5%	18.5%	21.3%	21.3%	21.3%	21.3%	22.1%	22.0%	22.0%	22.0%	22.1%	0.0%	40
41	**Delivery Tax Revenue**																41
42	Delivery Tax Revenue - PRESENT	Sch B, Page 2, Line 27	$ 21,469,185	$ 5,994,877	$ 47,908	$ 120,440	$ 414,991	$ 5,354,807	$ 163,397	$ 623,150	$ 247,305	$ 70,642	$ 2,097,959	$ 277,840	$ 3,083,442	$ 2,972,427	42
43	Delivery Tax Revenue - PROPOSED	Sch B, Page 3, Line 32	21,469,185	5,994,877	47,908	120,440	414,991	5,354,807	163,397	623,150	247,305	70,642	2,097,959	277,840	3,083,442	2,972,427	43
44	Delivery Tax Revenue - CHANGE	Line 43 - Line 42	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	44
45	Change Percentage	Line 44 / Line 42	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	45
46	**Total Operating Revenue**																46
47	Total Operating Revenue - PRESENT	Sch B, Page 2, Line 45	$ 285,373,466	$ 139,051,040	$ 2,577,059	$ 2,951,594	$ 8,689,884	$ 67,864,656	$ 944,077	$ 8,397,907	$ 860,225	$ 1,332,477	$ 29,092,110	$ 4,067,973	$ 8,088,840	$ 11,455,623	47
48	Total Operating Revenue - PROPOSED	Sch B, Page 3, Line 50	330,942,429	$ 164,606,245	$ 3,121,381	$ 3,597,108	$ 10,355,876	$ 78,030,495	$ 1,145,054	$ 9,669,171	$ 953,563	$ 1,526,315	$ 33,624,701	$ 4,693,507	$ 8,162,301	$ 11,456,712	48
49	Total Operating Revenue - CHANGE	Line 48 - Line 47	$ 45,568,963	$ 25,555,205	$ 544,322	$ 645,514	$ 1,665,992	$ 10,165,839	$ 200,977	$ 1,271,264	$ 93,337	$ 193,838	$ 4,532,591	$ 625,533	$ 73,461	$ 1,089	49
50	Change Percentage	Line 49 / Line 47	16.0%	18.4%	21.1%	21.9%	19.2%	15.0%	21.3%	15.1%	10.9%	14.5%	15.6%	15.4%	0.9%	0.0%	50
51	**Customer Class Revenue Responsibility**																51
52	Present	Class Line 47 / Sum Line 47	100.0%	52.9%	0.9%	1.0%	3.0%	23.8%	0.3%	2.9%	0.3%	0.5%	10.2%	1.4%	2.8%	4.0%	52
53	Proposed	Class Line 48 / Sum Line 48	100.0%	53.2%	0.9%	1.1%	3.1%	23.6%	0.3%	2.9%	0.3%	0.5%	10.2%	1.4%	2.5%	3.5%	53
54	Change	Line 53 - Line 52	0.0%	0.3%	0.0%	0.1%	0.1%	-0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.3%	-0.5%	54

Washington Gas Light Company
District of Columbia

Determination of Proposed Other Operating Revenue
Proposed Changes to Late Payment Charges and Miscellaneous Tariff Charges

Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No.	Description	Test Period Pro Forma Revenue	Present Tariff Charge	Computed Number of Orders	Proposed Charge	Proposed Revenue	Proposed Revenue Increase	Line No.
	A	B	C	D	E	F	G=F-B	
1	**Late Payment Charges a/**	$ 3,577,696				$ 4,369,425	$ 791,729	1
2	**Watergate Revenue**	$ -				$ -	$ -	2
3	**Miscellaneous Service Revenue**							3
4	General Service Provision No. 5							4
5	Estimate for Changing Location of Meters	$ -	$ 72.00	$ -	$ 72.00	$ -	$ -	5
6	General Service Provision No. 11							6
7	Reconnect Fees							7
8	Individual	174,354	44.98	3,876	53.98	209,225	34,871	8
9	Multi-family	-	14.50	-	17.40	-	-	9
10	Total Reconnect fees	$ 174,354		$ 3,876		$ 209,225	$ 34,871	10
11	Field Collection Charge	433	13.12	33	14.43	476	43	11
12	General Service Provision No. 18							12
13	Dishonored Checks	44,738	9.00	4,971	9.00	44,738	(0)	13
14	General Service Provision No. 19							14
15	Service Initiation Charge							15
16	Gas Flowing	308,761	33.00	9,356	33.00	308,761	(0)	16
17	Gas Not Flowing	529,809	37.17	14,254	44.60	635,771	105,962	17
18	Total Service Initation Charges	$ 838,570		$ 23,610		$ 944,532	$ 105,962	18
19	Rate Schedule No. 6							19
20	Interruptible Non-Compliance Meter Read Charge	$ -	100.00	-	100.00	$ -	$ -	20
21	Total Miscellaneous Tariff Charges	$ 1,058,096				$ 1,198,971	$ 140,875	21
22	Other Miscellaneous Service Revenue b/	213,047				213,047	-	22
23	Total Miscellaneous Service Revenue	$ 1,271,143				$ 1,412,018	$ 140,875	23
24	**Total Other Operating Revenue**							24
25	(Line 1 + Line 2 + Line 23)	$ 4,848,839				$ 5,781,443	$ 932,604	25

a/ Proposed amount determined as follows:

Ratemaking Late Payment Charge Factor (Cost of Service Workpapers)	1.7373%
Proposed Revenue Increase	$ 45,572,411
Increase to Late Payment Charges	$ 791,729

b/ Revenue Study Adjustment 1, Page 2, Lines 36+38 - NGV revenue moved into class rate design

Washington Gas Light Company
District of Columbia

Effect of Proposed Rates by Class of Firm Service in the District of Columbia

Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No.	Description	Total Number of Bills	Average Number of Customers	Adjusted Annual Therms	Gas Cost	Operating Revenues (000's) Excluding Gas Cost: Present Rates	Proposed Rates	Increase Amount	Increase Percent	Operating Revenues (000's) Including Gas Cost: Present Rates	Proposed Rates	Increase Amount	Increase Percent	Line No.
	A	B	C=B/12	D a/		E	F	G=F-E	H=G/E	I	J	K=J-I	L=K/I	
1	**SALE / DELIVERY OF GAS REVENUE**													1
2	**Residential**													2
3	Heating and/or Cooling	1,627,379	135,615	84,793,166	$ 44,728	$ 90,773	$ 115,673	$ 24,900	27.4%	$ 135,501	$ 160,401	$ 24,900	18.4%	3
4	Non-heating and Non-cooling													4
5	Individually Metered Apartments	131,084	10,924	677,620	360	2,149	2,680	531	24.7%	2,509	3,040	531	21.2%	5
6	Other	42,794	3,566	1,703,534	888	1,991	2,623	632	31.7%	2,879	3,511	632	22.0%	6
7	**Commercial and Industrial**													7
8	Heating and/or Cooling													8
9	Less than 3,075 therms	53,982	4,499	5,336,138	2,624	6,012	7,666	1,654	27.5%	8,636	10,290	1,654	19.2%	9
10	3,075 therms or more	40,679	3,390	68,854,404	15,631	51,787	61,857	10,070	19.5%	67,418	77,488	10,070	14.9%	10
11	Combined Heat and Power	12	1	2,101,032	-	938	1,137	199	21.2%	938	1,137	199	21.2%	11
12	Non-heating and Non-cooling	22,135	1,845	8,012,732	1,984	6,353	7,612	1,259	19.8%	8,337	9,596	1,259	15.1%	12
13	Natural Gas Vehicles	36	3	3,179,948	-	848	938	90	10.6%	848	938	90	10.6%	13
14	**Group Metered Apartments**													14
15	Heating and/or Cooling													15
16	Less than 3,075 therms	7,177	598	999,179	405	915	1,107	192	21.0%	1,320	1,512	192	14.6%	16
17	3,075 therms or more	20,485	1,707	29,674,103	6,188	22,542	26,995	4,453	19.8%	28,730	33,183	4,453	15.5%	17
18	Non-heating and Non-cooling	10,430	869	3,929,848	939	3,077	3,691	614	20.0%	4,016	4,630	614	15.3%	18
19	**Total Firm**	1,956,193	163,017	209,261,704	$ 73,747	$ 187,385	$ 231,979	$ 44,594	23.8%	$ 261,132	$ 305,726	$ 44,594	17.1%	19
20	**Interruptible**	1,327	111	39,648,220	-	7,938	7,978	40	0.5%	7,938	7,978	40	0.5%	20
21	**Special Contract**	36	3	38,220,735	-	11,456	11,457	1	0.0%	11,456	11,457	1	0.0%	21
22	**Total Sales / Delivery Revenue**	1,957,556	163,131	287,130,659	$ 73,747	$206,779	$251,414	$ 44,635	21.6%	$280,526	$325,161	$44,635	15.9%	22
23	**Other Operating Revenue**									4,849	$ 5,781	$ 933	19.2%	23
24	**Total Operating Revenue**									$ 285,375 b/	$ 330,942 c/	$ 45,568	16.0%	24

a/ Per Exhibit WG (O)-1, Schedule B, Page 2.

b/ Priced at present rates from Exhibit WG (O)-1, Schedule A. Includes other operating revenue from Schedule B.

c/ Priced at proposed rates from Exhibit WG (O)-1, Schedule A. Includes other operating revenue from Schedule B.

Washington Gas Light Company
District of Columbia

Proposed Rate Design
Workpaper

Based on 12 Months Ended March 31, 2024

Line No.	Description	Reference	DC Amount	Residential Heating/Cooling	Residential Non-htg MMA	Residential Non-htg Other	Commercial & Industrial Htg/Clg < 3,075	Commercial & Industrial Htg/Clg > 3,075	Commercial & Industrial CHP	Commercial & Industrial Non-heating	Commercial & Industrial NGV c/	Group Metered Apartments Htg/Clg < 3,075	Group Metered Apartments Htg/Clg > 3,075	Group Metered Apartments Non-heating	Interruptible	Special Contract	Line No.
	A	B	C=D+...+N	D	E	F	G	H		I		J	K	L	M	N	
1	Present Customer Charge Revenue		36,287,775	26,933,122	1,573,008	579,859	1,614,062	2,849,564	4,125	630,846	1,490	204,545	1,434,974	297,255	160,567	4,356	1
2	Present Peak Usage Charge Revenue		4,483,887	-	-	-	244,619	2,408,078	304,497	296,082	-	29,745	1,065,827	134,819	-	-	2
3	Present Distribution Charge Revenue		110,559,862	47,806,387	447,907	1,088,558	3,106,166	33,022,572	217,037	3,854,925	236,715	492,595	14,430,516	1,902,440	-	3,954,044	3
4	Total Base Rate Revenue		151,331,304	74,739,508	2,020,915	1,668,417	4,964,847	38,280,214	525,659	4,781,855	238,205	726,885	16,931,317	2,334,514	160,567	3,958,400	4
																	0
5	Relative ROR	Class Cost of Service study	4.77%	4.14%	7.35%	1.88%	4.24%	6.87%	-5.80%	10.60%	-1.91%	5.48%	5.95%	7.20%	1.97%	2.17%	5
6	Uniform Rate of Return	Class Cost of Service study	1.00	0.87	1.53	0.40	0.89	1.44	(1.22)	2.22	(0.40)	1.15	1.25	1.51	0.41	0.46	6
																	0
7	Required Increase to Tariff Rates	Sch B Page 1, Column D Line 5+13	44,638,718														7
8	Percentage Increase to Tariff Rates For Under Earning Classes	Schedule B Page 1 * Line 9	30.29%	33.32%		37.88%	33.32%		37.88%		37.88%						8
9	Under-Earning Classes Increase as a % of System Average			110%		125%	110%		125%		125%						9
10	Revenue Increase Attributable to Under-Earning Classes	Line 8 * Line 4 a/	27,518,518	24,902,158	-	631,697	1,654,218	-	199,025	-	90,189	-	-	-	40,142	1,089	10
																	0
11	Revenue as a % of Over-Earning Class Revenues	Line 4/ Sum of Line 4 classes			3.11%			58.82%		7.35%		1.12%	26.02%	3.59%			11
12	Remaining Revenue Increase for Over-Earning Classes	Line 12 Total * Line 11	17,120,200		531,665			10,070,808		1,258,017		191,230	4,454,313	614,167			12
13	% Increase to Tariff Revenues for Over-Earning Classes	Line 12/Line 4	26.31%		26.31%			26.31%		26.31%		26.31%	26.31%	26.31%			13
																	0
14	Total Base Rate Revenue After Increase	Line 4 + Line 10 + Line 13	195,970,022	99,641,666	2,552,580	2,300,114	6,619,065	48,351,022	724,684	6,039,872	328,394	918,115	21,385,630	2,948,681	200,709	3,959,489	14
																	0
15	Customer Charge Revenue After Increase	Schedule B, Page 3, Line 10	45,383,198	33,696,745	1,966,260	725,350	2,018,927	3,561,446	5,156	789,113	1,863	255,860	1,794,466	371,830	200,709	5,445	15
16	Peak Usage Revenue as a % of Total Revenues	Schedule B, Page 2, Line 11		0.00%	0.00%	0.00%	4.93%	6.29%	57.93%	6.19%		4.09%	6.30%	5.78%	-		16
17	Total Peak Usage Revenues After Increase	Line 16 * Line 14	5,715,586	-	-	-	326,123	3,041,598	419,786	373,976	-	37,570	1,346,226	170,267	-	-	17
18	Total Peak Usage Therms * Months Billed	Schedule B, Pg 2, Ln 8 * Ln 10	16,621,656	-	-	-	4,713,271	57,199,007	3,388,328	6,999,580	-	890,136	25,256,572	3,187,205		-	18
19	Proposed Peak Usage Rates	Line 17/18 Line 18 Rounded					0.0692	0.0532	0.1240	0.0534		0.0422	0.0533	0.0534			19
20	Revenue Generated By Peak Usage Rates	Line 19 * Line 18	5,716,532	-	-	-	326,150	3,042,987	419,693	373,776	-	37,543	1,346,175	170,197	-	-	20
																	0
21	Proposed Distribution Charge Revenue	Line 14 - Line 15 - Line 20	144,870,292	65,954,923	586,320	1,574,756	4,273,979	41,746,589	299,835	4,876,981	326,531	624,711	18,244,909	2,406,654	(0)	3,954,044	21
22	Normal Weather Therms	Schedule B, Page 2, Line 15	287,130,859	84,793,166	677,620	1,703,534	5,336,136	68,854,404	2,101,032	8,012,732	3,179,948	999,179	29,674,103	3,929,848	39,646,220		22
23	Proposed Distribution Rates	Line 21/Line 22 Rounded		0.7778	0.8653	0.9246	0.8010	0.6063	0.1430	0.6087	0.1028	0.6252	0.6148	0.6124	-		23
24	Revenue Generated By Rates	Line 22 * Line 23	144,867,933	65,952,125	586,345	1,575,088	4,274,246	41,746,425	300,446	4,877,350	326,899	624,686	18,243,638	2,406,639	-	3,954,044	24
25	Rounding Difference	Line 24 - Line 21	(2,359)	(2,798)	25	332	267	(164)	613	369	367	(25)	(1,330)	(15)	0	-	25
			195,967,663														

a/ Includes 25% increase to Customer Charges for Interruptible and Special Contract Customers

Washington Gas Light Company
District of Columbia

Class Cost of Service Study
Income Statement Summary - After Proposed Revenue Increase

Twelve Months Ended March 31, 2024 - Average Rate Base

Line No.	Description	Reference	DC Amount	Residential RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTr	Commercial & Industrial C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	NGV	Group Metered Apartments GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract	Line No	NON FIRM
	A	B	C=D+ , +M	D	E	F	G	H	H	I		J	K	L	M	N		M
1	**Requested Revenue Increase**																1	
2	System Charges		$ 9,095,423	$ 6,753,623	$ 393,252	$ 145,499	$ 404,865	$ 711,882	$ 1,031	$ 158,265	$ 373	$ 51,315	$ 359,512	$ 74,575	$ 40,142	$ 1,089	2	$ 40,142
3	Peak Usage Charges		1,232,865	-	-	-	81,539	634,909	115,198	77,696	-	7,798	280,348	35,378	-	-	3	-
4	Distribution Charges		34,308,071	18,145,738	138,438	486,530	1,168,080	8,723,853	83,411	1,022,425	90,184	132,091	3,813,122	504,199		-		3,075,921
5	Other Operating Revenue		932,604	655,844	12,632	13,485	11,508	95,194	1,339	12,879	2,780	2,633	79,609	11,382	33,319	-	3	33,319
6	Total Requested Revenue Increase	=SUM (Lines 2-5)	$ 45,568,963	$ 25,555,205	$ 544,322	$ 645,514	$ 1,665,992	$ 10,165,839	$ 200,977	$ 1,271,265	$ 93,337	$ 193,838	$ 4,532,592	$ 625,533	$ 73,461	$ 1,089	4	$ 3,149,382
7	Allowance for Uncollectible Accounts	Line 6 * 2.7046%	1,232,458	691,166	14,722	17,459	45,058	274,945	5,436	34,383	2,524	5,243	122,588	16,918	1,987	29	5	85,178
8	Requested Increase excluding Uncollectibles	Line 6 - Line 7	$ 44,336,505	$ 24,864,039	$ 529,600	$ 628,055	$ 1,620,934	$ 9,890,894	$ 195,541	$ 1,236,882	$ 90,813	$ 188,596	$ 4,410,003	$ 608,615	$ 71,474	$ 1,060	6	$ 3,064,204
9	State Income Taxes	8.250%	3,657,762	2,051,283	43,692	51,815	133,727	815,999	16,132	102,043	7,492	15,559	363,825	50,211	5,897	87	7	252,797
10	Federal Income Taxes	19.27%	8,542,536	4,790,679	102,041	121,011	312,313	1,905,728	37,676	238,316	17,497	36,338	849,697	117,265	13,771	204	8	590,395
9	**Class Cost of Service After Proposed Increase**																9	
10	After Increase Operating Revenue		$ 269,322,749	$ 119,936,538	$ 2,765,443	$ 2,711,639	$ 7,740,477	$ 62,448,547	$ 1,153,276	$ 7,693,995	$ 954,588	$ 1,123,411	$ 27,472,189	$ 3,761,148	$16,268,088	$ 15,295,433	10	$19,341,989
11	After Increase Operating Expenses																11	
12	Gas Purchased		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	12	$ -
13	Operation - other than Gas Purchased		58,371,490	30,297,863	1,075,549	778,437	1,832,386	10,510,945	498,019	1,355,560	153,540	254,123	4,936,345	692,286	3,215,695	2,770,763	13	$ 3,215,695
14	Maintenance		25,925,812	12,849,525	272,434	347,252	978,084	5,268,850	83,473	679,512	68,746	133,159	2,531,505	355,265	1,225,375	1,134,631	14	$ 1,225,375
15	Depreciation		31,830,254	14,795,151	214,109	380,073	914,761	6,846,949	140,095	746,149	114,178	122,763	3,256,656	389,522	1,998,405	1,913,425	15	$ 1,998,405
16	Amortization of Capitalized Software		1,878,281	867,415	12,401	22,163	53,603	405,598	8,417	44,057	6,844	7,227	192,795	22,987	119,886	114,887	16	$ 119,886
17	Amortization of General Plant		3,659,183	1,689,659	24,159	43,178	104,427	790,169	16,307	85,830	13,333	14,080	375,594	44,783	233,557	223,818	17	$ 233,557
18	Amortization of Unrecovered Plant Loss Chillum		100,274	41,976	184	764	2,408	23,262	669	1,629	63	336	12,162	921	9,443	6,456	18	$ 9,443
19	Interest on Customer Deposits		77,084	37,511	888	823	2,484	21,400	388	2,626	-	378	9,315	1,272	-	-	19	$ -
20	Interest on Supplier Refunds		-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	$ -
21	General Taxes		63,436,330	19,308,800	184,458	400,630	1,272,958	15,450,065	508,442	1,194,016	621,473	222,720	8,443,519	853,963	8,653,311	8,321,944	21	$ 8,653,311
22	Expenses Before Federal Income Taxes	Sum of Lines 12 - 21	$ 185,278,709	$ 79,888,100	$ 1,784,183	$ 1,973,319	$ 5,161,141	$ 39,315,239	$ 1,255,900	$ 4,109,378	$ 978,177	$ 754,787	$ 17,757,692	$ 2,361,000	$15,453,671	$ 14,485,925	22	$15,453,671
23	Income Taxes		16,057,690	7,749,622	219,620	120,822	507,984	4,822,289	(54,521)	811,897	(31,199)	74,020	1,945,807	296,989	(216,198)	(189,440)	23	(216,198)
24	Total Operating Expenses	Line 22 + Line 23	$ 201,336,399	$ 87,637,722	$ 2,003,802	$ 2,094,141	$ 5,669,124	$ 44,137,528	$ 1,201,379	$ 4,921,274	$ 946,977	$ 828,808	$ 19,703,699	$ 2,657,988	$15,237,473	$ 14,296,485	24	$15,237,473
25	After Increase Net Operating Income	Line 10 - Line 24	$ 67,986,349	$ 32,298,816	$ 761,641	$ 617,497	$ 2,071,352	$ 18,311,018	$ (48,103)	$ 2,772,721	$ 7,610	$ 294,604	$ 7,768,490	$ 1,103,159	$ 1,028,595	$ 998,948	25	$ 4,104,516
26	Net Income Adjustments																26	
27	AFUDC		$ 467,443	$ 214,915	$ 3,248	$ 5,468	$ 13,265	$ 100,336	$ 2,112	$ 10,946	$ 1,811	$ 1,800	$ 47,633	$ 5,703	$ 31,290	$ 28,916	27	$ 31,290
28	After Increase Net Operating Income - Adjusted	Line 25 + Line 27	$ 68,453,792	$ 32,513,731	$ 764,888	$ 622,966	$ 2,084,618	$ 18,411,354	$ (45,991)	$ 2,783,666	$ 9,421	$ 296,405	$ 7,816,123	$ 1,108,863	$ 1,059,884	$ 1,027,864	28	$ 4,135,806
29	Net Rate Base		$ 761,839,660	$ 350,094,408	$ 5,230,745	$ 8,870,552	$ 21,500,941	$ 163,735,868	$ 3,238,098	$ 17,812,622	$ 2,942,134	$ 2,919,659	$ 77,703,686	$ 9,278,720	$51,180,821	$ 47,331,405	29	$51,180,821
30	After Increase Return Earned		8.99%	9.29%	14.62%	7.02%	9.70%	11.24%	-1.42%	15.63%	0.32%	10.15%	10.06%	11.95%	2.07%	2.17%	30	8.08%
			UROR	1.03	1.63	0.78	1.08	1.25	(0.16)	1.74	0.04	1.13	1.12	1.33	0.23	0.24		0.90
			Before Increase URO	0.87	1.54	0.39	0.89	1.44	(1.22)	2.22	(0.40)	1.15	1.25	1.51	0.41	0.45		0.41
			UROR Change	0.17	0.08	0.39	0.19	(0.19)	1.06	(0.48)	0.44	(0.02)	(0.13)	(0.18)	(0.18)	(0.21)		0.49

a/ Composite tax rate determined as follows:	
State Income Tax	8.250%
Federal Income Tax	19.268%
Composite Tax Rate	27.518%
Compliment of Composite Tax Rate	72.483%
b/ Uncollectible Accounts Rate	2.7046%

Washington Gas Light Company
District of Columbia

Interruptible Delivery Service
Determination of Fixed Block Rates
Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No.	Description	Reference	Therms	Block Rates	Amount	Line No.
	A	B	C	D	E=CxD	
1	Block Rate Design					2
2	Block 1 - first 75,000 therms	a/	26,499,608	$ 0.2094	$ 5,549,018	3
3	Block 2 - over 75,000 therms	a/	13,328,184	$ 0.1932	$ 2,575,005	4
4	Total Block 1 and Block 2	Line 3 + Line 4	39,827,791		$ 8,124,023	5
	Increase/(Decrease:					
5	Block 1 - first 75,000 therms	b/	26,499,608	$ 0.2887	$ 7,649,990	6
6	Block 2 - over 75,000 therms	b/	13,328,184	$ 0.2663	$ 3,549,955	7
7	Total Block 1 and Block 2		39,827,791		$ 11,199,944	8
8	Increase to Interruptible Distribution Charges	Line 17 - Line 5			$ 3,075,921	9

9	a/ adjusted for curtailment	
10	b/ Revenue % recovered through Block 1	68.30%
11	Revenue % recovered through Block 2	31.70%
12	c/ Increase of 125% of the system Average	
13	% Revenue Increase	37.86%

Case No

Washington Gas Light Company
District of Columbia

Class Cost of Service Study
Income Statement Summary

Twelve Months Ended March 31, 2024 - Average Rate Base

Line No	Description	Reference	DC Amount	RES-HTG/CLG	RES-NON H/C-RMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075	C&I CHP	C&I NON H/C	NGV	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
				Residential			Commercial & Industrial					Group Metered Apartments				
	A	B	C=D+...+N	D	E	F	G	H		I		J	K	L	M	N
1	Operating Revenue		$ 223,753,796	$ 94,381,333	$ 2,221,121	$ 2,066,174	$ 6,074,494	$ 52,282,709	$ 952,299	$ 8,422,731	$ 881,251	$ 929,572	$ 22,839,587	$ 3,135,814	$ 16,192,807	$ 15,294,344
2	Operating Expenses															
3	Gas Purchased		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Operation - Other than Gas Purchased		57,139,032	29,606,697	1,060,828	760,978	1,787,327	10,236,000	492,583	1,321,177	151,015	248,880	4,813,756	675,346	3,213,708	2,770,733
5	Maintenance		25,925,812	12,849,525	272,434	347,252	978,084	5,286,850	83,473	679,512	68,746	133,159	2,531,505	355,285	1,225,375	1,134,631
6	Depreciation		31,830,254	14,795,151	214,109	380,073	914,781	6,846,949	140,085	746,149	114,178	122,763	3,256,656	389,522	1,998,405	1,913,425
7	Amortization of Capitalized Software		1,878,281	667,415	12,401	22,163	53,603	405,598	8,417	44,057	6,844	7,227	192,795	22,987	119,886	114,687
8	Amortization of General Plant		3,659,183	1,689,859	24,159	43,178	104,427	790,169	16,387	85,830	13,333	14,080	375,594	44,783	233,557	223,618
9	Amortization of Unrecovered Plant Loss Chillum		100,274	41,976	184	764	2,408	23,262	689	1,629	63	336	12,162	921	9,443	6,456
10	Interest on Customer Deposits		77,084	37,511	688	823	2,484	21,400	388	2,626	-	378	9,315	1,272	-	-
11	Interest on Supplier Refunds		-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	General Taxes		63,436,330	19,308,800	184,459	400,630	1,272,968	15,450,085	508,442	1,194,018	621,473	222,720	6,443,519	853,983	8,653,311	8,321,944
13	Expenses Before Federal Income Taxes	Sum of Lines 3 - 12	$ 184,046,251	$ 79,198,934	$ 1,769,461	$ 1,955,860	$ 5,116,082	$ 39,040,294	$ 1,250,464	$ 4,074,995	$ 975,652	$ 749,544	$ 17,835,303	$ 2,344,081	$15,451,684	$ 14,485,895
14	Income Taxes		3,857,392	907,660	73,887	(52,003)	61,943	2,100,562	(108,329)	471,538	(56,189)	22,123	732,285	129,513	(235,866)	(189,731)
15	Total Operating Expenses	Line 13 + Line 14	$ 187,903,644	$ 80,104,594	$ 1,843,348	$ 1,903,857	$ 5,178,025	$ 41,140,857	$ 1,142,135	$ 4,546,533	$ 919,463	$ 771,667	$ 18,367,588	$ 2,473,594	$15,215,819	$ 14,296,164
16	Net Operating Income	Line 1 - Line 15	$ 35,850,142	$ 14,276,739	$ 377,773	$ 162,267	$ 896,459	$ 11,141,851	$ (189,836)	$ 1,876,198	$ (58,213)	$ 157,905	$ 4,572,009	$ 662,020	$ 976,789	$ 998,180
17	Net Income Adjustments															
18	AFUDC		$ 467,443	214,915	3,249	5,469	13,265	100,336	2,112	10,945	1,811	1,800	47,633	5,703	31,290	28,916
19	Net Operating Income - Adjusted	Line 16 + Line 18	$ 36,317,585	$ 14,491,654	$ 381,021	$ 167,736	$ 909,724	$ 11,242,187	$ (187,724)	$ 1,887,143	$ (56,402)	$ 159,705	$ 4,619,642	$ 667,723	$ 1,008,078	$ 1,027,096
20	Net Rate Base		$ 761,838,880	$ 350,094,408	$ 5,230,745	$ 8,870,552	$ 21,500,941	$ 163,735,868	$ 3,239,088	$ 17,812,622	$ 2,942,134	$ 2,919,859	$ 77,703,686	$ 9,278,720	$51,180,821	$ 47,331,405
21	Return Earned	Line 19 / Line 20	4.77%	4.14%	7.29%	1.89%	4.23%	6.87%	-5.80%	10.59%	-1.92%	5.47%	5.95%	7.20%	1.97%	2.17%
				0.87	1.53	0.40	0.89	1.44	(1.22)	2.22	(0.40)	1.15	1.25	1.51	0.41	0.46

Washington Gas Light Company
District of Columbia Jurisdiction

Class Cost of Service Workpaper No. 3 - Directly Assigned Revenues

For the Twelve Months Ended March 31, 2024

Class	Allocation %	Forfeited Discounts Non POR By Tariff Class	Forfeited Discounts Non POR (Assigned)	Class Ratio	Forfeited Discounts Non POR Adj Assigned 1/ 2/	Forfeited Discounts Non POR Total	Forfeited Discounts POR By Tariff Class	Forfeited Discounts POR Assigned	Forfeited Discounts POR Eliminated 2/
	A	B (from SAP)	C = A * B	D	E = Adj Tot * D	F = C + E	G (from SAP)	H = A * G	I = - H
Res H/C	96.17%	2,240,772	2,154,956	66.40%	358,104	2,513,060	243,638	234,307	(234,307)
Res Non-Htg IMA	1.85%	2,240,772	41,506	1.28%	6,897	48,403	243,638	4,513	(4,513)
Res Non-Htg Other	1.98%	2,240,772	44,310	1.37%	7,363	51,673	243,638	4,818	(4,818)
C&I H/C <3075	9.52%	476,126	45,311	1.40%	7,530	52,841	79,202	7,537	(7,537)
C&I H/C >3075	78.73%	476,126	374,831	11.55%	62,288	437,119	79,202	62,352	(62,352)
C&I CHP	1.11%	476,126	5,272	0.16%	876	6,148	79,202	877	(877)
C&I Non-Htg	10.65%	476,126	50,711	1.56%	8,427	59,138	79,202	8,436	(8,436)
GMA H/C <3075	2.81%	361,013	10,717	0.33%	1,781	12,498	37,303	1,049	(1,049)
GMA H/C >3075	85.03%	361,013	323,978	9.98%	53,838	377,815	37,303	31,719	(31,719)
GMA Non-Htg	12.16%	361,013	46,318	1.43%	7,697	54,015	37,303	4,535	(4,535)
NGV Sales	100.00%	11,398	11,398	0.35%	1,894	13,292	-	-	-
Interruptible	100.00%	136,145	136,145	4.19%	22,624	158,769	-	-	-
Special Contract	100.00%	-	-	0.00%	-	-	-	-	-
Total			3,245,453	100.00%	539,319	3,784,772		360,143	(360,143)

Class	Allocation %	Reconnect Revenue By Tariff Class	Reconnect Revenue Assigned	Class Ratio	Reconnect Revenue Assigned	Reconnect Revenue Total	Returned Check Charge By Tariff Class	Returned Check Charge Assigned
	J	K (from SAP)	L = J * K	M	N = Adj Tot * M	O = L + N	P (from SAP)	Q = J * P
Res H/C	96.17%	169,362	162,876	93.42%	-	162,876	40,303	38,759
Res Non-Htg IMA	1.85%	169,362	3,137	1.80%	-	3,137	40,303	747
Res Non-Htg Other	1.98%	169,362	3,349	1.92%	-	3,349	40,303	797
C&I H/C <3075	9.52%	4,633	441	0.25%	-	441	3,563	339
C&I H/C >3075	78.73%	4,633	3,647	2.09%	-	3,647	3,563	2,805
C&I CHP	1.11%	4,633	51	0.03%	-	51	3,563	39
C&I Non-Htg	10.65%	4,633	493	0.28%	-	493	3,563	379
GMA H/C <3075	2.81%	(45)	(1)	0.00%	-	(1)	819	23
GMA H/C >3075	85.03%	(45)	(38)	-0.02%	-	(38)	819	696
GMA Non-Htg	12.16%	(45)	(5)	0.00%	-	(5)	819	100
Interruptible	100.00%	405	405	0.23%	-	405	54	54
Special Contract	100.00%	-	-	0.00%	-	-	-	-
Total			174,354	100.00%	-	174,354		44,738

Class	All Misc Revenues	Class Ratio
Res H/C	977,479	92.38%
Res Non-Htg IMA	18,827	1.78%
Res Non-Htg Other	20,099	1.90%
C&I H/C <3075	3,409	0.32%
C&I H/C >3075	28,198	2.66%
C&I CHP	397	0.04%
C&I Non-Htg	3,815	0.36%
GMA H/C <3075	143	0.01%
GMA H/C >3075	4,317	0.41%
GMA Non-Htg	617	0.06%
NGV Sales	-	0.00%
Interruptible	797	0.08%
Total	1,058,096	100.00%

Class	Allocation %	Service Initiation Charge By Tariff Class	Service Initiation Charge Assigned	Class Ratio	Service Initiation Charge Assigned 1/	Service Initiation Charge Total	Field Collection Charge By Tariff Class	Field Collection Charge Assigned
	R	S (from SAP)	T = R * S	U	V = Adj Tot * U	W = T + V	X (from SAP)	Y = R * X
Res H/C	96.17%	806,596	775,705	92.50%	-	775,705	144	139
Res Non-Htg IMA	1.85%	806,596	14,941	1.78%	-	14,941	144	3
Res Non-Htg Other	1.98%	806,596	15,950	1.90%	-	15,950	144	3
C&I H/C <3075	9.52%	27,334	2,601	0.31%	-	2,601	289	27
C&I H/C >3075	78.73%	27,334	21,518	2.57%	-	21,518	289	227
C&I CHP	10.65%	27,334	303	0.04%	-	303	289	3
C&I Non-Htg	1.11%	27,334	2,911	0.35%	-	2,911	289	31
GMA H/C <3075	2.81%	4,303	121	0.01%	-	121	-	-
GMA H/C >3075	85.03%	4,303	3,658	0.44%	-	3,658	-	-
GMA Non-Htg	12.16%	4,303	523	0.06%	-	523	-	-
Interruptible	100.00%	338	338	0.04%	-	338	-	-
Special Contract	100.00%	-	-	0.00%	-	-	-	-
Total			838,570	100.00%	-	838,570		433

_1/ Adjustment was calculated by jurisdiction (not by class) and is included in both Adjustment 1 - Revenues for which workpaper is included in Exhibit WG (D)-5. In class cost study, the adjustment was assigned to each customer class based on the proportion of the class per book revenues to total per book revenues

_2/ Forfeited discount for POR customers is excluded from the cost of service via Adjustment 7D

Washington Gas Light Company
District of Columbia

Summary of Bill Comparisons at Present and Proposed Rates
Annual and Average Month

Line No.	Description	Normal Therm Usage	Delivery Service (Rate Schedule Nos. 1A, 2A, 3A & 6)				Sales Service (Rate Schedule Nos. 1, 2 & 3)				Line No.
			Present Rates	Proposed Rates	Bill Increase Amount	Bill Increase Percent	Present Rates	Proposed Rates	Bill Increase Amount	Bill Increase Percent	
	A	B	C a/	D a/	E=D-C	F=E/C	G a/	H a/	I=H-G	J=I/G	
1	**Residential - Heating and/or Cooling**										1
2	Annual	627	$ 670.64	$ 854.63	$ 183.99	27.4%	$ 1,047.98	$ 1,231.97	$ 183.99	17.6%	2
3	Average Month	52	$ 55.89	$ 71.22	$ 15.33	27.4%	$ 87.33	$ 102.66	$ 15.33	17.6%	3
4	**Residential - Non-heating and Non-cooling**										4
5	Individually Metered Apartments										5
6	Annual	63	$ 197.49	$ 246.39	$ 48.90	24.8%	$ 235.43	$ 284.33	$ 48.90	20.8%	6
7	Average Month	5	$ 16.46	$ 20.53	$ 4.07	24.7%	$ 19.62	$ 23.69	$ 4.07	20.7%	7
8	Other than Apartments										8
9	Annual	477	$ 557.62	$ 734.64	$ 177.02	31.7%	$ 844.69	$ 1,021.71	$ 177.02	21.0%	9
10	Average Month	40	$ 46.47	$ 61.22	$ 14.75	31.7%	$ 70.39	$ 85.14	$ 14.75	21.0%	10
11	**Commercial & Industrial - Heating and/or Cooling**										11
12	Annual Usage Less Than 3,075 Therms										12
13	Annual	1,180	$ 1,336.64	$ 1,707.62	$ 370.98	27.8%	$ 2,046.75	$ 2,417.73	$ 370.98	18.1%	13
14	Average Month	98	$ 111.39	$ 142.30	$ 30.91	27.7%	$ 170.56	$ 201.48	$ 30.92	18.1%	14
15	Annual Usage 3,075 Therms or More										15
16	Annual	20,239	$ 15,192.07	$ 18,181.99	$ 2,989.92	19.7%	$ 27,371.90	$ 30,361.82	$ 2,989.92	10.9%	16
17	Average Month	1,687	$ 1,266.01	$ 1,515.17	$ 249.16	19.7%	$ 2,280.99	$ 2,530.15	$ 249.16	10.9%	17
18	**Commercial & Industrial - Non-heating and Non-cooling**										18
19	Annual	4,345	$ 3,395.55	$ 4,073.00	$ 677.45	20.0%	$ 6,010.36	$ 6,687.81	$ 677.45	11.3%	19
20	Average Month	362	$ 282.96	$ 339.42	$ 56.46	20.0%	$ 500.86	$ 557.32	$ 56.46	11.3%	20
21	**Group Metered Apartments - Heating and/or Cooling**										21
22	Annual Usage Less Than 3,075 Therms										22
23	Annual	1,664	$ 1,545.51	$ 1,869.27	$ 323.76	20.9%	$ 2,546.92	$ 2,870.68	$ 323.76	12.7%	23
24	Average Month	139	$ 128.79	$ 155.77	$ 26.98	20.9%	$ 212.24	$ 239.22	$ 26.98	12.7%	24
25	Annual Usage 3,075 Therms or More										25
26	Annual	17,379	$ 13,352.44	$ 15,999.89	$ 2,647.45	19.8%	$ 23,811.14	$ 26,458.59	$ 2,647.45	11.1%	26
27	Average Month	1,448	$ 1,112.70	$ 1,333.32	$ 220.62	19.8%	$ 1,984.26	$ 2,204.88	$ 220.62	11.1%	27
28	**Group Metered Apartments - Non-heating and Non-cooling**										28
29	Annual	4,518	$ 3,539.03	$ 4,245.31	$ 706.28	20.0%	$ 6,257.94	$ 6,964.22	$ 706.28	11.3%	29
30	Average Month	377	$ 294.92	$ 353.78	$ 58.86	20.0%	$ 521.50	$ 580.35	$ 58.85	11.3%	30
31	**Interruptible**										31
32	Annual	360,105	$ 144,948.80	$ 173,868.11	$ 28,919.31	20.0%					32
33	Average Month	30,009	$ 12,079.07	$ 14,489.01	$ 2,409.94	20.0%					33

a/ Priced at present and proposed rates from Exhibit WG (O)-1, Schedule A.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Average Usage Levels at Present and Proposed Rates

Residential Service - Rate Schedule Nos. 1 and 1A
Heating and/or Cooling

Line No.	Month	Average Therm Usage	Delivery Service (Rate Schedule No. 1A) Present Rates	Delivery Service Proposed Rates	Delivery Service Increase Amount	Delivery Service Increase Percent	Sales Service (Rate Schedule No. 1) Present Rates	Sales Service Proposed Rates	Sales Service Increase Amount	Sales Service Increase Percent	Line No.
	A	B	C a/	D a/	E=D-C	F=E/C	G b/	H b/	I=H-G	J=I/G	
1	January	115	$ 103.13	$ 131.89	$ 28.76	27.9%	$ 172.34	$ 201.10	$ 28.76	16.7%	1
2	February	122	108.41	138.67	30.26	27.9%	181.83	212.09	30.26	16.6%	2
3	March	97	89.59	114.50	24.91	27.8%	147.96	172.87	24.91	16.8%	3
4	April	67	66.99	85.48	18.49	27.6%	107.31	125.80	18.49	17.2%	4
5	May	35	42.89	54.53	11.64	27.1%	63.95	75.59	11.64	18.2%	5
6	June	14	27.09	34.24	7.15	26.4%	35.52	42.67	7.15	20.1%	6
7	July	9	23.32	29.40	6.08	26.1%	28.74	34.82	6.08	21.2%	7
8	August	9	23.32	29.40	6.08	26.1%	28.74	34.82	6.08	21.2%	8
9	September	9	23.32	29.40	6.08	26.1%	28.74	34.82	6.08	21.2%	9
10	October	15	27.84	35.20	7.36	26.4%	36.87	44.23	7.36	20.0%	10
11	November	49	53.44	68.07	14.63	27.4%	82.93	97.56	14.63	17.6%	11
12	December	86	81.30	103.85	22.55	27.7%	133.05	155.60	22.55	16.9%	12
13	Total	627	$ 670.64	$ 854.63	$ 183.99	27.4%	$ 1,047.98	$ 1,231.97	$ 183.99	17.6%	13
14	Average Month	52	$ 55.89	$ 71.22	$ 15.33	27.4%	$ 87.33	$ 102.66	$ 15.33	17.6%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 1. Excludes PGC.
(excludes RES credit applicable to qualifying customers).

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 1 including $0.6018 pro forma PGC.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Average Usage Levels at Present and Proposed Rates

Residential Service - Rate Schedule Nos. 1 and 1A
Non-Heating and Non-Cooling - Individually Metered Apartments

Line No.	Month	Average Therm Usage	Delivery Service (Rate Schedule No. 1A) Present Rates	Delivery Service Proposed Rates	Delivery Service Increase Amount	Delivery Service Increase Percent	Sales Service (Rate Schedule No. 1) Present Rates	Sales Service Proposed Rates	Sales Service Increase Amount	Sales Service Increase Percent	Line No.
	A	B	C a/	D a/	E=D-C	F=E/C	G b/	H b/	I=H-G	J=I/G	
1	January	9	$ 19.65	$ 24.49	$ 4.84	24.6%	$ 25.07	$ 29.91	$ 4.84	19.3%	1
2	February	9	19.65	24.49	4.84	24.6%	25.07	29.91	4.84	19.3%	2
3	March	8	18.81	23.44	4.63	24.6%	23.62	28.25	4.63	19.6%	3
4	April	6	17.10	21.32	4.22	24.7%	20.71	24.93	4.22	20.4%	4
5	May	4	15.39	19.21	3.82	24.8%	17.80	21.62	3.82	21.5%	5
6	June	3	14.54	18.16	3.62	24.9%	16.35	19.97	3.62	22.1%	6
7	July	3	14.54	18.16	3.62	24.9%	16.35	19.97	3.62	22.1%	7
8	August	3	14.54	18.16	3.62	24.9%	16.35	19.97	3.62	22.1%	8
9	September	3	14.54	18.16	3.62	24.9%	16.35	19.97	3.62	22.1%	9
10	October	3	14.54	18.16	3.62	24.9%	16.35	19.97	3.62	22.1%	10
11	November	5	16.25	20.27	4.02	24.7%	19.26	23.28	4.02	20.9%	11
12	December	7	17.94	22.37	4.43	24.7%	22.15	26.58	4.43	20.0%	12
13	Total	63	$ 197.49	$ 246.39	$ 48.90	24.8%	$ 235.43	$ 284.33	$ 48.90	20.8%	13
14	Average Month	5	$ 16.46	$ 20.53	$ 4.07	24.7%	$ 19.62	$ 23.69	$ 4.07	20.7%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 1. Excludes PGC.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 1 including $0.6018 pro forma PGC.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Average Usage Levels at Present and Proposed Rates

Residential Service - Rate Schedule Nos. 1 and 1A
Non-Heating and Non-Cooling - Other than Apartments

			Delivery Service (Rate Schedule No. 1A)				Sales Service (Rate Schedule No. 1)				
		Average			Increase				Increase		
Line No.	Month	Therm Usage	Present Rates	Proposed Rates	Amount	Percent	Present Rates	Proposed Rates	Amount	Percent	Line No.
	A	B	C a/	D a/	E=D-C	F=E/C	G b/	H b/	I=H-G	J=I/G	
1	January	83	$ 82.29	$ 109.39	$ 27.10	32.9%	$ 132.24	$ 159.34	$ 27.10	20.5%	1
2	February	88	86.42	114.95	28.53	33.0%	139.38	167.91	28.53	20.5%	2
3	March	71	72.35	96.03	23.68	32.7%	115.08	138.76	23.68	20.6%	3
4	April	50	54.96	72.64	17.68	32.2%	85.05	102.73	17.68	20.8%	4
5	May	27	35.90	47.01	11.11	30.9%	52.15	63.26	11.11	21.3%	5
6	June	13	24.32	31.43	7.11	29.2%	32.14	39.25	7.11	22.1%	6
7	July	10	21.83	28.09	6.26	28.7%	27.85	34.11	6.26	22.5%	7
8	August	10	21.83	28.09	6.26	28.7%	27.85	34.11	6.26	22.5%	8
9	September	10	21.83	28.09	6.26	28.7%	27.85	34.11	6.26	22.5%	9
10	October	14	25.15	32.54	7.39	29.4%	33.58	40.97	7.39	22.0%	10
11	November	38	45.02	59.27	14.25	31.7%	67.89	82.14	14.25	21.0%	11
12	December	63	65.72	87.11	21.39	32.5%	103.63	125.02	21.39	20.6%	12
13	Total	477	$ 557.62	$ 734.64	$ 177.02	31.7%	$ 844.69	$ 1,021.71	$ 177.02	21.0%	13
14	Average Month	40	$ 46.47	$ 61.22	$ 14.75	31.7%	$ 70.39	$ 85.14	$ 14.75	21.0%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 1. Excludes PGC.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 1 including $0.6018 pro forma PGC.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Average Usage Levels at Present and Proposed Rates

Commercial and Industrial Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - Less than 3,075 Therms

Line No.	Month	Average Therm Usage	Delivery Service (Rate Schedule No. 2A) Present Rates	Delivery Service Proposed Rates	Delivery Service Increase Amount	Delivery Service Increase Percent	Sales Service (Rate Schedule No. 2) Present Rates	Sales Service Proposed Rates	Sales Service Increase Amount	Sales Service Increase Percent	Line No.
	A	B	C a/	D a/	E=D-C	F=E/C	G b/	H b/	I=H-G	J=I/G	
1	January	207	$ 200.83	$ 257.43	$ 56.60	28.2%	$ 325.40	$ 382.00	$ 56.60	17.4%	1
2	February	218	209.33	268.33	59.00	28.2%	340.52	399.52	59.00	17.3%	2
3	March	176	176.93	226.74	49.81	28.2%	282.85	332.66	49.81	17.6%	3
4	April	123	136.07	174.27	38.20	28.1%	210.09	248.29	38.20	18.2%	4
5	May	68	82.34	104.73	22.39	27.2%	123.26	145.65	22.39	18.2%	5
6	June	32	54.58	69.08	14.50	26.6%	73.84	88.34	14.50	19.6%	6
7	July	24	48.41	61.16	12.75	26.3%	62.85	75.60	12.75	20.3%	7
8	August	24	48.41	61.16	12.75	26.3%	62.85	75.60	12.75	20.3%	8
9	September	24	48.41	61.16	12.75	26.3%	62.85	75.60	12.75	20.3%	9
10	October	35	56.88	72.05	15.17	26.7%	77.94	93.11	15.17	19.5%	10
11	November	93	112.94	144.57	31.63	28.0%	168.91	200.54	31.63	18.7%	11
12	December	156	161.51	206.94	45.43	28.1%	255.39	300.82	45.43	17.8%	12
13	Total	1,180	$ 1,336.64	$ 1,707.62	$ 370.98	27.8%	$ 2,046.75	$ 2,417.73	$ 370.98	18.1%	13
14	Average Month	98	$ 111.39	$ 142.30	$ 30.91	27.7%	$ 170.56	$ 201.48	$ 30.92	18.1%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2. Excludes PGC.
Includes Peak Usage Charge in the months November through April.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2 including $0.6018 pro forma PGC.
Includes Peak Usage Charge in the months November through April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Average Usage Levels at Present and Proposed Rates

Commercial and Industrial Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - 3,075 Therms or More

Line No.	Month	Average Therm Usage	Delivery Service (Rate Schedule No. 2A) Present Rates	Delivery Service Proposed Rates	Delivery Service Increase Amount	Delivery Service Increase Percent	Sales Service (Rate Schedule No. 2) Present Rates	Sales Service Proposed Rates	Sales Service Increase Amount	Sales Service Increase Percent	Line No.
	A	B	C a/	D a/	E=D-C	F=E/C	G b/	H b/	I=H-G	J=I/G	
1	January	3,088	$ 2,271.26	$ 2,715.95	$ 444.69	19.6%	$ 4,129.62	$ 4,574.31	$ 444.69	10.8%	1
2	February	3,238	2,371.58	2,835.28	463.70	19.6%	4,320.21	4,783.91	463.70	10.7%	2
3	March	2,695	2,008.48	2,403.38	394.90	19.7%	3,630.33	4,025.23	394.90	10.9%	3
4	April	1,995	1,540.40	1,846.61	306.21	19.9%	2,740.99	3,047.20	306.21	11.2%	4
5	May	1,286	929.98	1,110.41	180.43	19.4%	1,703.89	1,884.32	180.43	10.6%	5
6	June	829	624.39	746.92	122.53	19.6%	1,123.28	1,245.81	122.53	10.9%	6
7	July	723	553.51	662.61	109.10	19.7%	988.61	1,097.71	109.10	11.0%	7
8	August	726	555.52	665.00	109.48	19.7%	992.43	1,101.91	109.48	11.0%	8
9	September	728	556.86	666.60	109.74	19.7%	994.97	1,104.71	109.74	11.0%	9
10	October	875	655.15	783.51	128.36	19.6%	1,181.73	1,310.09	128.36	10.9%	10
11	November	1,620	1,289.64	1,548.34	258.70	20.1%	2,264.56	2,523.26	258.70	11.4%	11
12	December	2,436	1,835.30	2,197.38	362.08	19.7%	3,301.28	3,663.36	362.08	11.0%	12
13	Total	20,239	$ 15,192.07	$ 18,181.99	$ 2,989.92	19.7%	$ 27,371.90	$ 30,361.82	$ 2,989.92	10.9%	13
14	Average Month	1,687	$ 1,266.01	$ 1,515.17	$ 249.16	19.7%	$ 2,280.99	$ 2,530.15	$ 249.16	10.9%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2. Excludes PGC. Includes Peak Usage Charge in the months November through April.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2 including $0.6018 pro forma PGC. Includes Peak Usage Charge in the months November through April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Average Usage Levels at Present and Proposed Rates

Commercial and Industrial Service - Rate Schedule Nos. 2 and 2A
Non-Heating and Non-Cooling

Line No.	Month	Average Therm Usage	Delivery Service (Rate Schedule No. 2A) Present Rates	Delivery Service Proposed Rates	Delivery Service Increase Amount	Delivery Service Increase Percent	Sales Service (Rate Schedule No. 2) Present Rates	Sales Service Proposed Rates	Sales Service Increase Amount	Sales Service Increase Percent	Line No.
	A	B	C a/	D a/	E=D-C	F=E/C	G b/	H b/	I=H-G	J=I/G	
1	January	540	$ 414.00	$ 496.26	$ 82.26	19.9%	$ 738.97	$ 821.23	$ 82.26	11.1%	1
2	February	558	426.06	510.61	84.55	19.8%	761.86	846.41	84.55	11.1%	2
3	March	486	377.80	453.17	75.37	19.9%	670.27	745.64	75.37	11.2%	3
4	April	409	326.21	391.75	65.54	20.1%	572.35	637.89	65.54	11.5%	4
5	May	316	240.28	287.75	47.47	19.8%	430.45	477.92	47.47	11.0%	5
6	June	255	199.40	239.09	39.69	19.9%	352.86	392.55	39.69	11.2%	6
7	July	240	189.35	227.13	37.78	20.0%	333.78	371.56	37.78	11.3%	7
8	August	239	188.67	226.32	37.65	20.0%	332.50	370.15	37.65	11.3%	8
9	September	238	188.01	225.53	37.52	20.0%	331.24	368.76	37.52	11.3%	9
10	October	256	200.06	239.88	39.82	19.9%	354.12	393.94	39.82	11.2%	10
11	November	352	288.01	346.27	58.26	20.2%	499.84	558.10	58.26	11.7%	11
12	December	456	357.70	429.24	71.54	20.0%	632.12	703.66	71.54	11.3%	12
13	Total	4,345	$ 3,395.55	$ 4,073.00	$ 677.45	20.0%	$ 6,010.36	$ 6,687.81	$ 677.45	11.3%	13
14	Average Month	362	$ 282.96	$ 339.42	$ 56.46	20.0%	$ 500.86	$ 557.32	$ 56.46	11.3%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2. Excludes PGC.
Includes Peak Usage Charge in the months November through April.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2 including $0.6018 pro forma PGC.
Includes Peak Usage Charge in the months November through April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Average Usage Levels at Present and Proposed Rates

Group Metered Apartments Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - 3,075 Therms or More

			Delivery Service (Rate Schedule No. 2C)				Sales Service (Rate Schedule No. 2B)				
		Average	Present	Proposed	Increase		Present	Proposed	Increase		
Line No.	Month	Therm Usage	Rates	Rates	Amount	Percent	Rates	Rates	Amount	Percent	Line No.
	A	B	C a/	D a/	E=D-C	F=E/C	G b/	H b/	I=H-G	J=I/G	
1	January	2,904	$ 2,160.42	$ 2,585.07	$ 424.65	19.7%	$ 3,908.05	$ 4,332.70	$ 424.65	10.9%	1
2	February	3,058	2,264.43	2,708.87	444.44	19.6%	4,104.73	4,549.17	444.44	10.8%	2
3	March	2,489	1,880.14	2,251.47	371.33	19.8%	3,378.02	3,749.35	371.33	11.0%	3
4	April	1,784	1,403.99	1,684.72	280.73	20.0%	2,477.60	2,758.33	280.73	11.3%	4
5	May	1,040	772.46	923.65	151.19	19.6%	1,398.33	1,549.52	151.19	10.8%	5
6	June	561	448.94	538.58	89.64	20.0%	786.55	876.19	89.64	11.4%	6
7	July	448	372.62	447.74	75.12	20.2%	642.23	717.35	75.12	11.7%	7
8	August	448	372.62	447.74	75.12	20.2%	642.23	717.35	75.12	11.7%	8
9	September	448	372.62	447.74	75.12	20.2%	642.23	717.35	75.12	11.7%	9
10	October	599	474.61	569.14	94.53	19.9%	835.09	929.62	94.53	11.3%	10
11	November	1,375	1,127.75	1,355.93	228.18	20.2%	1,955.23	2,183.41	228.18	11.7%	11
12	December	2,225	1,701.84	2,039.24	337.40	19.8%	3,040.85	3,378.25	337.40	11.1%	12
13	Total	17,379	$ 13,352.44	$ 15,999.89	$ 2,647.45	19.8%	$ 23,811.14	$ 26,458.59	$ 2,647.45	11.1%	13
14	Average Month	1,448	$ 1,112.70	$ 1,333.32	$ 220.62	19.8%	$ 1,984.26	$ 2,204.88	$ 220.62	11.1%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3. Excludes PGC. Includes Peak Usage Charge in the months November through April.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3 including $0.6018 pro forma PGC. Includes Peak Usage Charge in the months November through April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Average Usage Levels at Present and Proposed Rates

Group Metered Apartments Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - Less than 3,075 Therms

Line No.	Month	Average Therm Usage	Delivery Service (Rate Schedule No. 2C) Present Rates	Proposed Rates	Increase Amount	Percent	Sales Service (Rate Schedule No. 2B) Present Rates	Proposed Rates	Increase Amount	Percent	Line No.
	A	B	C a/	D a/	E=D-C	F=E/C	G b/	H b/	I=H-G	J=I/G	
1	January	253	$ 212.49	$ 256.09	$ 43.60	20.5%	$ 364.75	$ 408.35	$ 43.60	12.0%	1
2	February	265	220.68	265.86	45.18	20.5%	380.16	425.34	45.18	11.9%	2
3	March	220	189.98	229.21	39.23	20.6%	322.38	361.61	39.23	12.2%	3
4	April	165	152.48	184.44	31.96	21.0%	251.78	283.74	31.96	12.7%	4
5	May	107	101.47	122.77	21.30	21.0%	165.86	187.16	21.30	12.8%	5
6	June	69	75.57	91.84	16.27	21.5%	117.09	133.36	16.27	13.9%	6
7	July	60	69.42	84.50	15.08	21.7%	105.53	120.61	15.08	14.3%	7
8	August	60	69.42	84.50	15.08	21.7%	105.53	120.61	15.08	14.3%	8
9	September	60	69.42	84.50	15.08	21.7%	105.53	120.61	15.08	14.3%	9
10	October	72	77.61	94.27	16.66	21.5%	120.94	137.60	16.66	13.8%	10
11	November	133	130.63	158.36	27.73	21.2%	210.67	238.40	27.73	13.2%	11
12	December	200	176.34	212.93	36.59	20.7%	296.70	333.29	36.59	12.3%	12
13	Total	1,664	$ 1,545.51	$ 1,869.27	$ 323.76	20.9%	$ 2,546.92	$ 2,870.68	$ 323.76	12.7%	13
14	Average Month	139	$ 128.79	$ 155.77	$ 26.98	20.9%	$ 212.24	$ 239.22	$ 26.98	12.7%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3. Excludes PGC.
Includes Peak Usage Charge in the months November through April.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3 including $0.6018 pro forma PGC.
Includes Peak Usage Charge in the months November through April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Average Usage Levels at Present and Proposed Rates

Group Metered Apartments Service - Rate Schedule Nos. 3 and 3A
Non-Heating and Non-Cooling

			Delivery Service (Rate Schedule No. 2C)				Sales Service (Rate Schedule No. 2B)				
		Average			Increase				Increase		
Line No.	Month	Therm Usage	Present Rates	Proposed Rates	Amount	Percent	Present Rates	Proposed Rates	Amount	Percent	Line No.
	A	B	C a/	D a/	E=D-C	F=E/C	G b/	H b/	I=H-G	J=I/G	
1	January	591	$ 452.28	$ 542.06	$ 89.78	19.9%	$ 807.94	$ 897.72	$ 89.78	11.1%	1
2	February	613	467.09	559.69	92.60	19.8%	835.99	928.59	92.60	11.1%	2
3	March	528	409.87	491.57	81.70	19.9%	727.62	809.32	81.70	11.2%	3
4	April	429	343.23	412.22	68.99	20.1%	601.40	670.39	68.99	11.5%	4
5	May	318	242.57	290.52	47.95	19.8%	433.94	481.89	47.95	11.0%	5
6	June	247	194.77	233.61	38.84	19.9%	343.41	382.25	38.84	11.3%	6
7	July	229	182.66	219.19	36.53	20.0%	320.47	357.00	36.53	11.4%	7
8	August	229	182.66	219.19	36.53	20.0%	320.47	357.00	36.53	11.4%	8
9	September	228	181.98	218.39	36.41	20.0%	319.19	355.60	36.41	11.4%	9
10	October	250	196.81	236.03	39.22	19.9%	347.26	386.48	39.22	11.3%	10
11	November	365	300.15	360.93	60.78	20.2%	519.81	580.59	60.78	11.7%	11
12	December	491	384.96	461.91	76.95	20.0%	680.44	757.39	76.95	11.3%	12
13	Total	4,518	$ 3,539.03	$ 4,245.31	$ 706.28	20.0%	$ 6,257.94	$ 6,964.22	$ 706.28	11.3%	13
14	Average Month	377	$ 294.92	$ 353.78	$ 58.86	20.0%	$ 521.50	$ 580.35	$ 58.85	11.3%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3. Excludes PGC.
Includes Peak Usage Charge in the months November through April.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3 including $0.6018 pro forma PGC.
Includes Peak Usage Charge in the months November through April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Average Usage Levels at Present and Proposed Rates

Interruptible Service - Rate Schedule No. 6

Line No.	Month	Average Therm Usage	Delivery Service (Rate Schedule No. 6) Present Rates	Proposed Rates	Increase Amount	Increase Percent	Line No.
	A	B	C a/	D a/	E=D-C	F=E/C	
1	January	47,452	$ 19,029.95	$ 22,823.14	$ 3,793.19	19.9%	1
2	February	49,303	19,767.55	23,707.53	3,939.98	19.9%	2
3	March	42,477	17,047.48	20,446.16	3,398.68	19.9%	3
4	April	34,030	13,681.48	16,410.31	2,728.83	19.9%	4
5	May	25,120	10,130.97	12,153.23	2,022.26	20.0%	5
6	June	19,373	7,840.87	9,407.40	1,566.53	20.0%	6
7	July	18,023	7,302.92	8,762.39	1,459.47	20.0%	7
8	August	18,023	7,302.92	8,762.39	1,459.47	20.0%	8
9	September	18,023	7,302.92	8,762.39	1,459.47	20.0%	9
10	October	19,836	8,025.38	9,628.62	1,603.24	20.0%	10
11	November	29,131	11,729.29	14,069.63	2,340.34	20.0%	11
12	December	39,314	15,787.07	18,934.92	3,147.85	19.9%	12
13	Total	360,105	$ 144,948.80	$ 173,868.11	$ 28,919.31	20.0%	13
14	Average Month	30,009	$ 12,079.07	$ 14,489.01	$ 2,409.94	20.0%	14

a/ Priced using present and proposed Customer Charge shown on Exhibit WG (O)-1, Schedule A, Page 4.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PRESENT Rates a/

Residential Service - Rate Schedule Nos. 1 and 1A
Heating and/or Cooling

Line No.	Month	Average Therm Usage	Customer Charge @ $16.55	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.5638	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	115	$ 16.55	$ -	$ 64.84	$ 81.39	$ 4.01	$ 8.13	$ 9.60	$ 103.13	$ 69.21	$ 172.34	1
2	February	122	16.55	-	68.78	85.33	4.26	8.63	10.19	108.41	73.42	181.83	2
3	March	97	16.55	-	54.69	71.24	3.39	6.86	8.10	89.59	58.37	147.96	3
4	April	67	16.55	-	37.77	54.32	2.34	4.74	5.59	66.99	40.32	107.31	4
5	May	35	16.55	-	19.73	36.28	1.22	2.47	2.92	42.89	21.06	63.95	5
6	June	14	16.55	-	7.89	24.44	0.49	0.99	1.17	27.09	8.43	35.52	6
7	July	9	16.55	-	5.07	21.62	0.31	0.64	0.75	23.32	5.42	28.74	7
8	August	9	16.55	-	5.07	21.62	0.31	0.64	0.75	23.32	5.42	28.74	8
9	September	9	16.55	-	5.07	21.62	0.31	0.64	0.75	23.32	5.42	28.74	9
10	October	15	16.55	-	8.46	25.01	0.52	1.06	1.25	27.84	9.03	36.87	10
11	November	49	16.55	-	27.63	44.18	1.71	3.46	4.09	53.44	29.49	82.93	11
12	December	86	$16.55	-	48.49	$65.04	3.00	6.08	7.18	$81.30	51.75	133.05	12
13	Total	627	$ 198.60	$ -	$ 353.49	$ 552.09	$ 21.87	$ 44.34	$ 52.34	$ 670.64	$ 377.34	$ 1,047.98	13
14	Average Month	52	$ 16.55	$ -	$ 29.46	$ 46.01	$ 1.82	$ 3.70	$ 4.36	$ 55.89	$ 31.45	$ 87.33	14

a/ Tariff rates are from Exhibit WG (O)-1, Schedule A, Page 1 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge applicable only to Rate Schedule Nos. 2, 2A, 3 and 3A.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PRESENT Rates a/

Residential Service - Rate Schedule Nos. 1 and 1A
Non-Heating and Non-Cooling - Individually Metered Apartments

Line No.	Month	Average Therm Usage	Customer Charge @ $12.00	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.6610	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	9	$ 12.00	$ -	$ 5.95	$ 17.95	$ 0.31	$ 0.64	$ 0.75	$ 19.65	$ 5.42	$ 25.07	1
2	February	9	12.00	-	5.95	17.95	0.31	0.64	0.75	19.65	5.42	25.07	2
3	March	8	12.00	-	5.29	17.29	0.28	0.57	0.67	18.81	4.81	23.62	3
4	April	6	12.00	-	3.97	15.97	0.21	0.42	0.50	17.10	3.61	20.71	4
5	May	4	12.00	-	2.64	14.64	0.14	0.28	0.33	15.39	2.41	17.80	5
6	June	3	12.00	-	1.98	13.98	0.10	0.21	0.25	14.54	1.81	16.35	6
7	July	3	12.00	-	1.98	13.98	0.10	0.21	0.25	14.54	1.81	16.35	7
8	August	3	12.00	-	1.98	13.98	0.10	0.21	0.25	14.54	1.81	16.35	8
9	September	3	12.00	-	1.98	13.98	0.10	0.21	0.25	14.54	1.81	16.35	9
10	October	3	12.00	-	1.98	13.98	0.10	0.21	0.25	14.54	1.81	16.35	10
11	November	5	12.00	-	3.31	15.31	0.17	0.35	0.42	16.25	3.01	19.26	11
12	December	7	12.00	-	4.63	16.63	0.24	0.49	0.58	17.94	4.21	22.15	12
13	Total	63	$ 144.00	$ -	$ 41.64	$ 185.64	$ 2.16	$ 4.44	$ 5.25	$ 197.49	$ 37.94	$ 235.43	13
14	Average Month	5	$ 12.00	$ -	$ 3.47	$ 15.47	$ 0.18	$ 0.37	$ 0.44	$ 16.46	$ 3.16	$ 19.62	14

a/ Tariff rates are from Exhibit WG (O)-1, Schedule A, Page 1 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge applicable only to Rate Schedule Nos. 2, 2A, 3 and 3A.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PRESENT Rates a/

Residential Service - Rate Schedule Nos. 1 and 1A
Non-Heating and Non-Cooling - Other

Line No.	Month	Average Therm Usage	Customer Charge @ $13.55	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.6390	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	83	$ 13.55	$ -	$ 53.04	$ 66.59	$ 2.90	$ 5.87	$ 6.93	$ 82.29	$ 49.95	$ 132.24	1
2	February	88	13.55	-	56.23	69.78	3.07	6.22	7.35	86.42	52.96	139.38	2
3	March	71	13.55	-	45.37	58.92	2.48	5.02	5.93	72.35	42.73	115.08	3
4	April	50	13.55	-	31.95	45.50	1.75	3.54	4.17	54.96	30.09	85.05	4
5	May	27	13.55	-	17.25	30.80	0.94	1.91	2.25	35.90	16.25	52.15	5
6	June	13	13.55	-	8.31	21.86	0.45	0.92	1.09	24.32	7.82	32.14	6
7	July	10	13.55	-	6.39	19.94	0.35	0.71	0.83	21.83	6.02	27.85	7
8	August	10	13.55	-	6.39	19.94	0.35	0.71	0.83	21.83	6.02	27.85	8
9	September	10	13.55	-	6.39	19.94	0.35	0.71	0.83	21.83	6.02	27.85	9
10	October	14	13.55	-	8.95	22.50	0.49	0.99	1.17	25.15	8.43	33.58	10
11	November	38	13.55	-	24.28	37.83	1.33	2.69	3.17	45.02	22.87	67.89	11
12	December	63	13.55	-	40.26	53.81	2.20	4.45	5.26	65.72	37.91	103.63	12
13	Total	477	$ 162.60	$ -	$ 304.81	$ 467.41	$ 16.66	$ 33.74	$ 39.81	$ 557.62	$ 287.07	$ 844.69	13
14	Average Month	40	$ 13.55	$ -	$ 25.40	$ 38.95	$ 1.39	$ 2.81	$ 3.32	$ 46.47	$ 23.92	$ 70.39	14

a/ Tariff rates are from Exhibit WG (O)-1, Schedule A, Page 1 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge applicable only to Rate Schedule Nos. 2, 2A, 3 and 3A.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PRESENT Rates a/

Commercial and Industrial Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - Less than 3,075 Therms

Line No.	Month	Average Therm Usage	Customer Charge @ $29.90	Peak Usage Charge @ $0.0519	Distribution Charge @ $0.5821	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	207	$ 29.90	$ 11.31	$ 120.49	$ 161.70	$ 7.22	$ 14.63	$ 17.28	$ 200.83	$ 124.57	$ 325.40	1
2	February	218	29.90	11.31	126.90	168.11	7.61	15.41	18.20	209.33	131.19	340.52	2
3	March	176	29.90	11.31	102.45	143.66	6.14	12.44	14.69	176.93	105.92	282.85	3
4	April	123	29.90	11.31	71.60	112.81	4.29	8.70	10.27	136.07	74.02	210.09	4
5	May	68	29.90	-	39.58	69.48	2.37	4.81	5.68	82.34	40.92	123.26	5
6	June	32	29.90	-	18.63	48.53	1.12	2.26	2.67	54.58	19.26	73.84	6
7	July	24	29.90	-	13.97	43.87	0.84	1.70	2.00	48.41	14.44	62.85	7
8	August	24	29.90	-	13.97	43.87	0.84	1.70	2.00	48.41	14.44	62.85	8
9	September	24	29.90	-	13.97	43.87	0.84	1.70	2.00	48.41	14.44	62.85	9
10	October	35	29.90	-	20.37	50.27	1.22	2.47	2.92	56.88	21.06	77.94	10
11	November	93	29.90	11.31	54.14	95.35	3.25	6.58	7.76	112.94	55.97	168.91	11
12	December	156	29.90	11.31	90.81	132.02	5.44	11.03	13.02	161.51	93.88	255.39	12
13	Total	1,180	$ 358.80	$ 67.86	$ 686.88	$ 1,113.54	$ 41.18	$ 83.43	$ 98.49	$ 1,336.64	$ 710.11	$ 2,046.75	13
14	Average Month	98	$ 29.90	$ 5.66	$ 57.24	$ 92.80	$ 3.43	$ 6.95	$ 8.21	$ 111.39	$ 59.18	$ 170.56	14

a/ Tariff rates are from Exhibit WG (O)-1, Schedule A, Page 2 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PRESENT Rates a/

Commercial and Industrial Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - 3,075 Therms or More

Line No.	Month	Average Therm Usage	Customer Charge @ $70.05	Peak Usage Charge @ $0.0421	Distribution Charge @ $0.4796	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	3,088	$ 70.05	$ 136.32	$ 1,481.00	$ 1,687.37	$ 107.77	$ 218.32	$ 257.80	$ 2,271.26	$ 1,858.36	$ 4,129.62	1
2	February	3,238	70.05	136.32	1,552.94	1,759.31	113.01	228.93	270.33	2,371.58	1,948.63	4,320.21	2
3	March	2,695	70.05	136.32	1,292.52	1,498.89	94.06	190.54	224.99	2,008.48	1,621.85	3,630.33	3
4	April	1,995	70.05	136.32	956.80	1,163.17	69.63	141.05	166.55	1,540.40	1,200.59	2,740.99	4
5	May	1,286	70.05	-	616.77	686.82	44.88	90.92	107.36	929.98	773.91	1,703.89	5
6	June	829	70.05	-	397.59	467.64	28.93	58.61	69.21	624.39	498.89	1,123.28	6
7	July	723	70.05	-	346.75	416.80	25.23	51.12	60.36	553.51	435.10	988.61	7
8	August	726	70.05	-	348.19	418.24	25.34	51.33	60.61	555.52	436.91	992.43	8
9	September	728	70.05	-	349.15	419.20	25.41	51.47	60.78	556.86	438.11	994.97	9
10	October	875	70.05	-	419.65	489.70	30.54	61.86	73.05	655.15	526.58	1,181.73	10
11	November	1,620	70.05	136.32	776.95	983.32	56.54	114.53	135.25	1,289.64	974.92	2,264.56	11
12	December	2,436	70.05	136.32	1,168.31	1,374.68	85.02	172.23	203.37	1,835.30	1,465.98	3,301.28	12
13	Total	20,239	$ 840.60	$ 817.92	$ 9,706.62	$ 11,365.14	$ 706.36	$ 1,430.91	$ 1,689.66	$ 15,192.07	$ 12,179.83	$ 27,371.90	13
14	Average Month	1,687	$ 70.05	$ 68.16	$ 808.89	$ 947.10	$ 58.86	$ 119.24	$ 140.81	$ 1,266.01	$ 1,014.99	$ 2,280.99	14

a/ Tariff rates are from Exhibit WG (O)-1, Schedule A, Page 2 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PRESENT Rates a/

Commercial and Industrial Service - Rate Schedule Nos. 2 and 2A
Non-heating and Non-cooling

Line No.	Month	Average Therm Usage	Customer Charge @ $28.50	Peak Usage Charge @ $0.0423	Distribution Charge @ $0.4811	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	540	$ 28.50	$ 23.60	$ 259.79	$ 311.89	$ 18.85	$ 38.18	$ 45.08	$ 414.00	$ 324.97	$ 738.97	1
2	February	558	28.50	23.60	268.45	320.55	19.47	39.45	46.59	426.06	335.80	761.86	2
3	March	486	28.50	23.60	233.81	285.91	16.96	34.36	40.57	377.80	292.47	670.27	3
4	April	409	28.50	23.60	196.77	248.87	14.27	28.92	34.15	326.21	246.14	572.35	4
5	May	316	28.50	-	152.03	180.53	11.03	22.34	26.38	240.28	190.17	430.45	5
6	June	255	28.50	-	122.68	151.18	8.90	18.03	21.29	199.40	153.46	352.86	6
7	July	240	28.50	-	115.46	143.96	8.38	16.97	20.04	189.35	144.43	333.78	7
8	August	239	28.50	-	114.98	143.48	8.34	16.90	19.95	188.67	143.83	332.50	8
9	September	238	28.50	-	114.50	143.00	8.31	16.83	19.87	188.01	143.23	331.24	9
10	October	256	28.50	-	123.16	151.66	8.93	18.10	21.37	200.06	154.06	354.12	10
11	November	352	28.50	23.60	169.35	221.45	12.28	24.89	29.39	288.01	211.83	499.84	11
12	December	456	28.50	23.60	219.38	271.48	15.91	32.24	38.07	357.70	274.42	632.12	12
13	Total	4,345	$ 342.00	$ 141.60	$ 2,090.36	$ 2,573.96	$ 151.63	$ 307.21	$ 362.75	$ 3,395.55	$ 2,614.81	$ 6,010.36	13
14	Average Month	362	$ 28.50	$ 11.80	$ 174.20	$ 214.50	$ 12.64	$ 25.60	$ 30.23	$ 282.96	$ 217.90	$ 500.86	14

a/ Tariff rates are from Exhibit WG (O)-1, Schedule A, Page 2 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PRESENT Rates a/

Group Metered Apartments Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - 3,075 Therms or More

Line No.	Month	Average Therm Usage	Customer Charge @ $ 70.05	Peak Usage Charge @ $0.0422	Distribution Charge @ $0.4863	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	2,904	$ 70.05	$ 129.05	$ 1,412.22	$ 1,611.32	$ 101.35	$ 205.31	$ 242.44	$ 2,160.42	$ 1,747.63	$ 3,908.05	1
2	February	3,058	70.05	129.05	1,487.11	1,686.21	106.72	216.20	255.30	2,264.43	1,840.30	4,104.73	2
3	March	2,489	70.05	129.05	1,210.40	1,409.50	86.87	175.97	207.80	1,880.14	1,497.88	3,378.02	3
4	April	1,784	70.05	129.05	867.56	1,066.66	62.26	126.13	148.94	1,403.99	1,073.61	2,477.60	4
5	May	1,040	70.05	-	505.75	575.80	36.30	73.53	86.83	772.46	625.87	1,398.33	5
6	June	561	70.05	-	272.81	342.86	19.58	39.66	46.84	448.94	337.61	786.55	6
7	July	448	70.05	-	217.86	287.91	15.64	31.67	37.40	372.62	269.61	642.23	7
8	August	448	70.05	-	217.86	287.91	15.64	31.67	37.40	372.62	269.61	642.23	8
9	September	448	70.05	-	217.86	287.91	15.64	31.67	37.40	372.62	269.61	642.23	9
10	October	599	70.05	-	291.29	361.34	20.91	42.35	50.01	474.61	360.48	835.09	10
11	November	1,375	70.05	129.05	668.66	867.76	47.99	97.21	114.79	1,127.75	827.48	1,955.23	11
12	December	2,225	70.05	129.05	1,082.02	1,281.12	77.65	157.31	185.76	1,701.84	1,339.01	3,040.85	12
13	Total	17,379	$ 840.60	$ 774.30	$ 8,451.40	$ 10,066.30	$ 606.55	$ 1,228.68	$ 1,450.91	$ 13,352.44	$ 10,458.70	$ 23,811.14	13
14	Average Month	1,448	$ 70.05	$ 64.53	$ 704.28	$ 838.86	$ 50.55	$ 102.39	$ 120.91	$ 1,112.70	$ 871.56	$ 1,984.26	14

a/ Tariff rates are from Exhibit WG (O)-1, Schedule A, Page 3 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PRESENT Rates a/

Group Metered Apartments Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - Less than 3,075 Therms

Line No.	Month	Average Therm Usage	Customer Charge @ $ 28.50	Peak Usage Charge @ $0.0431	Distribution Charge @ $0.4930	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	253	$ 28.50	$ 11.42	$ 124.73	$ 164.65	$ 8.83	$ 17.89	$ 21.12	$ 212.49	$ 152.26	$ 364.75	1
2	February	265	28.50	11.42	130.65	170.57	9.25	18.74	22.12	220.68	159.48	380.16	2
3	March	220	28.50	11.42	108.46	148.38	7.68	15.55	18.37	189.98	132.40	322.38	3
4	April	165	28.50	11.42	81.35	121.27	5.76	11.67	13.78	152.48	99.30	251.78	4
5	May	107	28.50	-	52.75	81.25	3.73	7.56	8.93	101.47	64.39	165.86	5
6	June	69	28.50	-	34.02	62.52	2.41	4.88	5.76	75.57	41.52	117.09	6
7	July	60	28.50	-	29.58	58.08	2.09	4.24	5.01	69.42	36.11	105.53	7
8	August	60	28.50	-	29.58	58.08	2.09	4.24	5.01	69.42	36.11	105.53	8
9	September	60	28.50	-	29.58	58.08	2.09	4.24	5.01	69.42	36.11	105.53	9
10	October	72	28.50	-	35.50	64.00	2.51	5.09	6.01	77.61	43.33	120.94	10
11	November	133	28.50	11.42	65.57	105.49	4.64	9.40	11.10	130.63	80.04	210.67	11
12	December	200	28.50	11.42	98.60	138.52	6.98	14.14	16.70	176.34	120.36	296.70	12
13	Total	1,664	$ 342.00	$ 68.52	$ 820.37	$ 1,230.89	$ 58.06	$ 117.64	$ 138.92	$ 1,545.51	$ 1,001.41	$ 2,546.92	13
14	Average Month	139	$ 28.50	$ 5.71	$ 68.36	$ 102.57	$ 4.84	$ 9.80	$ 11.58	$ 128.79	$ 83.45	$ 212.24	14

a/ Tariff rates are from Exhibit WG (O)-1, Schedule A, Page 3 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PRESENT Rates a/

Group Metered Apartments Service - Rate Schedule Nos. 3 and 3A
Non-heating and Non-cooling

Line No.	Month	Average Therm Usage	Customer Charge @ $ 28.50	Peak Usage Charge @ $0.0423	Distribution Charge @ $0.4841	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	591	$ 28.50	$ 25.93	$ 286.10	$ 340.53	$ 20.63	$ 41.78	$ 49.34	$ 452.28	$ 355.66	$ 807.94	1
2	February	613	28.50	25.93	296.75	351.18	21.39	43.34	51.18	467.09	368.90	835.99	2
3	March	528	28.50	25.93	255.60	310.03	18.43	37.33	44.08	409.87	317.75	727.62	3
4	April	429	28.50	25.93	207.68	262.11	14.97	30.33	35.82	343.23	258.17	601.40	4
5	May	318	28.50	-	153.94	182.44	11.10	22.48	26.55	242.57	191.37	433.94	5
6	June	247	28.50	-	119.57	148.07	8.62	17.46	20.62	194.77	148.64	343.41	6
7	July	229	28.50	-	110.86	139.36	7.99	16.19	19.12	182.66	137.81	320.47	7
8	August	229	28.50	-	110.86	139.36	7.99	16.19	19.12	182.66	137.81	320.47	8
9	September	228	28.50	-	110.37	138.87	7.96	16.12	19.03	181.98	137.21	319.19	9
10	October	250	28.50	-	121.03	149.53	8.73	17.68	20.87	196.81	150.45	347.26	10
11	November	365	28.50	25.93	176.70	231.13	12.74	25.81	30.47	300.15	219.66	519.81	11
12	December	491	28.50	25.93	237.69	292.12	17.14	34.71	40.99	384.96	295.48	680.44	12
13	Total	4,518	$ 342.00	$ 155.58	$ 2,187.15	$ 2,684.73	$ 157.69	$ 319.42	$ 377.19	$ 3,539.03	$ 2,718.91	$ 6,257.94	13
14	Average Month	377	$ 28.50	$ 12.97	$ 182.26	$ 223.73	$ 13.14	$ 26.62	$ 31.43	$ 294.92	$ 226.58	$ 521.50	14

a/ Tariff rates are from Exhibit WG (O)-1, Schedule A, Page 3 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PRESENT Rates

Interruptible Service - Rate Schedule No. 6

Line No.	Month	Average Therm Usage	Block 1 Therms	Block 2 Therms	Customer Charge @ $ 121.00	Block 1 Distribution Charge Revenue @ $ 0.2094	Block 2 Distribution Charge Revenue @ $ 0.1932	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	Total Revenue	Line No.
	A	B	C	D	E	F	G	H=F+G	I	J	K	L=H+I+J+K	M=E+L	
1	January	47,452	47,452	-	$ 121.00	$ 9,936.45	$ -	$ 9,936.45	$ 1,656.07	$ 3,354.86	$ 3,961.57	$ 18,908.95	$ 19,029.95	1
2	February	49,303	49,303	-	121.00	10,324.05	-	10,324.05	1,720.67	3,485.72	4,116.11	19,646.55	19,767.55	2
3	March	42,477	42,477	-	121.00	8,894.68	-	8,894.68	1,482.45	3,003.12	3,546.23	16,926.48	17,047.48	3
4	April	34,030	34,030	-	121.00	7,125.88	-	7,125.88	1,187.65	2,405.92	2,841.03	13,560.48	13,681.48	4
5	May	25,120	25,120	-	121.00	5,260.13	-	5,260.13	876.69	1,775.98	2,097.17	10,009.97	10,130.97	5
6	June	19,373	19,373	-	121.00	4,056.71	-	4,056.71	676.12	1,369.67	1,617.37	7,719.87	7,840.87	6
7	July	18,023	18,023	-	121.00	3,774.02	-	3,774.02	629.00	1,274.23	1,504.67	7,181.92	7,302.92	7
8	August	18,023	18,023	-	121.00	3,774.02	-	3,774.02	629.00	1,274.23	1,504.67	7,181.92	7,302.92	8
9	September	18,023	18,023	-	121.00	3,774.02	-	3,774.02	629.00	1,274.23	1,504.67	7,181.92	7,302.92	9
10	October	19,836	19,836	-	121.00	4,153.66	-	4,153.66	692.28	1,402.41	1,656.03	7,904.38	8,025.38	10
11	November	29,131	29,131	-	121.00	6,100.03	-	6,100.03	1,016.67	2,059.56	2,432.03	11,608.29	11,729.29	11
12	December	39,314	39,314	-	121.00	8,232.35	-	8,232.35	1,372.06	2,779.50	3,282.16	15,666.07	15,787.07	12
13	Total	360,105	360,105	0	$ 1,452.00	$ 75,406.00	$ -	$ 75,406.00	$ 12,567.66	$ 25,459.43	$ 30,063.71	$ 143,496.80	$ 144,948.80	13
14	Average Month	30,009	30,009	0	$ 121.00	$ 6,283.83	$ -	$ 6,283.83	$ 1,047.31	$ 2,121.62	$ 2,505.31	$ 11,958.07	$ 12,079.07	14

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PROPOSED Rates a/

Residential Service - Rate Schedule Nos. 1 and 1A
Heating and/or Cooling

Line No.	Month	Average Therm Usage	Customer Charge @ $20.70	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.7778	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	115	$ 20.70	$ -	$ 89.45	$ 110.15	$ 4.01	$ 8.13	$ 9.60	$ 131.89	$ 69.21	$ 201.10	1
2	February	122	20.70	-	94.89	115.59	4.26	8.63	10.19	138.67	73.42	212.09	2
3	March	97	20.70	-	75.45	96.15	3.39	6.86	8.10	114.50	58.37	172.87	3
4	April	67	20.70	-	52.11	72.81	2.34	4.74	5.59	85.48	40.32	125.80	4
5	May	35	20.70	-	27.22	47.92	1.22	2.47	2.92	54.53	21.06	75.59	5
6	June	14	20.70	-	10.89	31.59	0.49	0.99	1.17	34.24	8.43	42.67	6
7	July	9	20.70	-	7.00	27.70	0.31	0.64	0.75	29.40	5.42	34.82	7
8	August	9	20.70	-	7.00	27.70	0.31	0.64	0.75	29.40	5.42	34.82	8
9	September	9	20.70	-	7.00	27.70	0.31	0.64	0.75	29.40	5.42	34.82	9
10	October	15	20.70	-	11.67	32.37	0.52	1.06	1.25	35.20	9.03	44.23	10
11	November	49	20.70	-	38.11	58.81	1.71	3.46	4.09	68.07	29.49	97.56	11
12	December	86	20.70	-	66.89	87.59	3.00	6.08	7.18	103.85	51.75	155.60	12
13	Total	627	$ 248.40	$ -	$ 487.68	$ 736.08	$ 21.87	$ 44.34	$ 52.34	$ 854.63	$ 377.34	$ 1,231.97	13
14	Average Month	52	$ 20.70	$ -	$ 40.64	$ 61.34	$ 1.82	$ 3.70	$ 4.36	$ 71.22	$ 31.45	$ 102.66	14

a/ Tariff rates from Exhibit WG (O)-1, Schedule A, Page 1 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge applicable only to Rate Schedule Nos. 2, 2A, 3 and 3A.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PROPOSED Rates a/

Residential Service - Rate Schedule Nos. 1 and 1A
Non-Heating and Non-Cooling - Individually Metered Apartments

Line No.	Month	Average Therm Usage	Customer Charge @ $15.00	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.8653	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	9	$ 15.00	$ -	$ 7.79	$ 22.79	$ 0.31	$ 0.64	$ 0.75	$ 24.49	$ 5.42	$ 29.91	1
2	February	9	15.00	-	7.79	22.79	0.31	0.64	0.75	24.49	5.42	29.91	2
3	March	8	15.00	-	6.92	21.92	0.28	0.57	0.67	23.44	4.81	28.25	3
4	April	6	15.00	-	5.19	20.19	0.21	0.42	0.50	21.32	3.61	24.93	4
5	May	4	15.00	-	3.46	18.46	0.14	0.28	0.33	19.21	2.41	21.62	5
6	June	3	15.00	-	2.60	17.60	0.10	0.21	0.25	18.16	1.81	19.97	6
7	July	3	15.00	-	2.60	17.60	0.10	0.21	0.25	18.16	1.81	19.97	7
8	August	3	15.00	-	2.60	17.60	0.10	0.21	0.25	18.16	1.81	19.97	8
9	September	3	15.00	-	2.60	17.60	0.10	0.21	0.25	18.16	1.81	19.97	9
10	October	3	15.00	-	2.60	17.60	0.10	0.21	0.25	18.16	1.81	19.97	10
11	November	5	15.00	-	4.33	19.33	0.17	0.35	0.42	20.27	3.01	23.28	11
12	December	7	15.00	-	6.06	21.06	0.24	0.49	0.58	22.37	4.21	26.58	12
13	Total	63	$ 180.00	$ -	$ 54.54	$ 234.54	$ 2.16	$ 4.44	$ 5.25	$ 246.39	$ 37.94	$ 284.33	13
14	Average Month	5	$ 15.00	$ -	$ 4.55	$ 19.55	$ 0.18	$ 0.37	$ 0.44	$ 20.53	$ 3.16	$ 23.69	14

a/ Tariff rates from Exhibit WG (O)-1, Schedule A, Page 1 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge applicable only to Rate Schedule Nos. 2, 2A, 3 and 3A.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PROPOSED Rates a/

Residential Service - Rate Schedule Nos. 1 and 1A
Non-Heating and Non-Cooling - Other

Line No.	Month	Average Therm Usage	Customer Charge @ $16.95	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.9246	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	83	$ 16.95	$ -	$ 76.74	$ 93.69	$ 2.90	$ 5.87	$ 6.93	$ 109.39	$ 49.95	$ 159.34	1
2	February	88	16.95	-	81.36	98.31	3.07	6.22	7.35	114.95	52.96	167.91	2
3	March	71	16.95	-	65.65	82.60	2.48	5.02	5.93	96.03	42.73	138.76	3
4	April	50	16.95	-	46.23	63.18	1.75	3.54	4.17	72.64	30.09	102.73	4
5	May	27	16.95	-	24.96	41.91	0.94	1.91	2.25	47.01	16.25	63.26	5
6	June	13	16.95	-	12.02	28.97	0.45	0.92	1.09	31.43	7.82	39.25	6
7	July	10	16.95	-	9.25	26.20	0.35	0.71	0.83	28.09	6.02	34.11	7
8	August	10	16.95	-	9.25	26.20	0.35	0.71	0.83	28.09	6.02	34.11	8
9	September	10	16.95	-	9.25	26.20	0.35	0.71	0.83	28.09	6.02	34.11	9
10	October	14	16.95	-	12.94	29.89	0.49	0.99	1.17	32.54	8.43	40.97	10
11	November	38	16.95	-	35.13	52.08	1.33	2.69	3.17	59.27	22.87	82.14	11
12	December	63	16.95	-	58.25	75.20	2.20	4.45	5.26	87.11	37.91	125.02	12
13	Total	477	$ 203.40	$ -	$ 441.03	$ 644.43	$ 16.66	$ 33.74	$ 39.81	$ 734.64	$ 287.07	$ 1,021.71	13
14	Average Month	40	$ 16.95	$ -	$ 36.75	$ 53.70	$ 1.39	$ 2.81	$ 3.32	$ 61.22	$ 23.92	$ 85.14	14

a/ Tariff rates from Exhibit WG (O)-1, Schedule A, Page 1 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge applicable only to Rate Schedule Nos. 2, 2A, 3 and 3A.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PROPOSED Rates a/

Commercial and Industrial Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - Less than 3,075 Therms

Line No.	Month	Average Therm Usage	Customer Charge @ $37.40	Peak Usage Charge @ $0.0692	Distribution Charge @ $0.8010	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	207	$ 37.40	$ 15.09	$ 165.81	$ 218.30	$ 7.22	$ 14.63	$ 17.28	$ 257.43	$ 124.57	$ 382.00	1
2	February	218	37.40	15.09	174.62	227.11	7.61	15.41	18.20	268.33	131.19	399.52	2
3	March	176	37.40	15.09	140.98	193.47	6.14	12.44	14.69	226.74	105.92	332.66	3
4	April	123	37.40	15.09	98.52	151.01	4.29	8.70	10.27	174.27	74.02	248.29	4
5	May	68	37.40	-	54.47	91.87	2.37	4.81	5.68	104.73	40.92	145.65	5
6	June	32	37.40	-	25.63	63.03	1.12	2.26	2.67	69.08	19.26	88.34	6
7	July	24	37.40	-	19.22	56.62	0.84	1.70	2.00	61.16	14.44	75.60	7
8	August	24	37.40	-	19.22	56.62	0.84	1.70	2.00	61.16	14.44	75.60	8
9	September	24	37.40	-	19.22	56.62	0.84	1.70	2.00	61.16	14.44	75.60	9
10	October	35	37.40	-	28.04	65.44	1.22	2.47	2.92	72.05	21.06	93.11	10
11	November	93	37.40	15.09	74.49	126.98	3.25	6.58	7.76	144.57	55.97	200.54	11
12	December	156	37.40	15.09	124.96	177.45	5.44	11.03	13.02	206.94	93.88	300.82	12
13	Total	1,180	$ 448.80	$ 90.54	$ 945.18	$ 1,484.52	$ 41.18	$ 83.43	$ 98.49	$ 1,707.62	$ 710.11	$ 2,417.73	13
14	Average Month	98	$ 37.40	$ 7.55	$ 78.77	$ 123.71	$ 3.43	$ 6.95	$ 8.21	$ 142.30	$ 59.18	$ 201.48	14

a/ Tariff rates from Exhibit WG (O)-1, Schedule A, Page 2 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PROPOSED Rates a/

Commercial and Industrial Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - 3,075 Therms or More

Line No.	Month	Average Therm Usage	Customer Charge @ $87.55	Peak Usage Charge @ $0.0532	Distribution Charge @ $0.6063	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	3,088	$ 87.55	$ 172.26	$ 1,872.25	$ 2,132.06	$ 107.77	$ 218.32	$ 257.80	$ 2,715.95	$ 1,858.36	$ 4,574.31	1
2	February	3,238	87.55	172.26	1,963.20	2,223.01	113.01	228.93	270.33	2,835.28	1,948.63	4,783.91	2
3	March	2,695	87.55	172.26	1,633.98	1,893.79	94.06	190.54	224.99	2,403.38	1,621.85	4,025.23	3
4	April	1,995	87.55	172.26	1,209.57	1,469.38	69.63	141.05	166.55	1,846.61	1,200.59	3,047.20	4
5	May	1,286	87.55	-	779.70	867.25	44.88	90.92	107.36	1,110.41	773.91	1,884.32	5
6	June	829	87.55	-	502.62	590.17	28.93	58.61	69.21	746.92	498.89	1,245.81	6
7	July	723	87.55	-	438.35	525.90	25.23	51.12	60.36	662.61	435.10	1,097.71	7
8	August	726	87.55	-	440.17	527.72	25.34	51.33	60.61	665.00	436.91	1,101.91	8
9	September	728	87.55	-	441.39	528.94	25.41	51.47	60.78	666.60	438.11	1,104.71	9
10	October	875	87.55	-	530.51	618.06	30.54	61.86	73.05	783.51	526.58	1,310.09	10
11	November	1,620	87.55	172.26	982.21	1,242.02	56.54	114.53	135.25	1,548.34	974.92	2,523.26	11
12	December	2,436	87.55	172.26	1,476.95	1,736.76	85.02	172.23	203.37	2,197.38	1,465.98	3,663.36	12
13	Total	20,239	$ 1,050.60	$ 1,033.56	$ 12,270.90	$ 14,355.06	$ 706.36	$ 1,430.91	$ 1,689.66	$ 18,181.99	$ 12,179.83	$ 30,361.82	13
14	Average Month	1,687	$ 87.55	$ 86.13	$ 1,022.58	$ 1,196.26	$ 58.86	$ 119.24	$ 140.81	$ 1,515.17	$ 1,014.99	$ 2,530.15	14

a/ Tariff rates from Exhibit WG (O)-1, Schedule A, Page 2 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PROPOSED Rates a/

Commercial and Industrial Service - Rate Schedule Nos. 2 and 2A
Non-heating and Non-cooling

Line No.	Month	Average Therm Usage	Customer Charge @ $35.65	Peak Usage Charge @ $0.0534	Distribution Charge @ $0.6087	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	540	$ 35.65	$ 29.80	$ 328.70	$ 394.15	$ 18.85	$ 38.18	$ 45.08	$ 496.26	$ 324.97	$ 821.23	1
2	February	558	35.65	29.80	339.65	405.10	19.47	39.45	46.59	510.61	335.80	846.41	2
3	March	486	35.65	29.80	295.83	361.28	16.96	34.36	40.57	453.17	292.47	745.64	3
4	April	409	35.65	29.80	248.96	314.41	14.27	28.92	34.15	391.75	246.14	637.89	4
5	May	316	35.65	-	192.35	228.00	11.03	22.34	26.38	287.75	190.17	477.92	5
6	June	255	35.65	-	155.22	190.87	8.90	18.03	21.29	239.09	153.46	392.55	6
7	July	240	35.65	-	146.09	181.74	8.38	16.97	20.04	227.13	144.43	371.56	7
8	August	239	35.65	-	145.48	181.13	8.34	16.90	19.95	226.32	143.83	370.15	8
9	September	238	35.65	-	144.87	180.52	8.31	16.83	19.87	225.53	143.23	368.76	9
10	October	256	35.65	-	155.83	191.48	8.93	18.10	21.37	239.88	154.06	393.94	10
11	November	352	35.65	29.80	214.26	279.71	12.28	24.89	29.39	346.27	211.83	558.10	11
12	December	456	35.65	29.80	277.57	343.02	15.91	32.24	38.07	429.24	274.42	703.66	12
13	Total	4,345	$ 427.80	$ 178.80	$ 2,644.81	$ 3,251.41	$ 151.63	$ 307.21	$ 362.75	$ 4,073.00	$ 2,614.81	$ 6,687.81	13
14	Average Month	362	$ 35.65	$ 14.90	$ 220.40	$ 270.95	$ 12.64	$ 25.60	$ 30.23	$ 339.42	$ 217.90	$ 557.32	14

a/ Tariff rates from Exhibit WG (O)-1, Schedule A, Page 2 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PROPOSED Rates a/

Group Metered Apartments Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - 3,075 Therms or More

Line No.	Month	Average Therm Usage	Customer Charge @ $ 87.60	Peak Usage Charge @ $0.0533	Distribution Charge @ $0.6148	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	2,904	$ 87.60	$ 162.99	$ 1,785.38	$ 2,035.97	$ 101.35	$ 205.31	$ 242.44	$ 2,585.07	$ 1,747.63	$ 4,332.70	1
2	February	3,058	87.60	162.99	1,880.06	2,130.65	106.72	216.20	255.30	2,708.87	1,840.30	4,549.17	2
3	March	2,489	87.60	162.99	1,530.24	1,780.83	86.87	175.97	207.80	2,251.47	1,497.88	3,749.35	3
4	April	1,784	87.60	162.99	1,096.80	1,347.39	62.26	126.13	148.94	1,684.72	1,073.61	2,758.33	4
5	May	1,040	87.60	-	639.39	726.99	36.30	73.53	86.83	923.65	625.87	1,549.52	5
6	June	561	87.60	-	344.90	432.50	19.58	39.66	46.84	538.58	337.61	876.19	6
7	July	448	87.60	-	275.43	363.03	15.64	31.67	37.40	447.74	269.61	717.35	7
8	August	448	87.60	-	275.43	363.03	15.64	31.67	37.40	447.74	269.61	717.35	8
9	September	448	87.60	-	275.43	363.03	15.64	31.67	37.40	447.74	269.61	717.35	9
10	October	599	87.60	-	368.27	455.87	20.91	42.35	50.01	569.14	360.48	929.62	10
11	November	1,375	87.60	162.99	845.35	1,095.94	47.99	97.21	114.79	1,355.93	827.48	2,183.41	11
12	December	2,225	87.60	162.99	1,367.93	1,618.52	77.65	157.31	185.76	2,039.24	1,339.01	3,378.25	12
13	Total	17,379	$ 1,051.20	$ 977.94	$ 10,684.61	$ 12,713.75	$ 606.55	$ 1,228.68	$ 1,450.91	$ 15,999.89	$ 10,458.70	$ 26,458.59	13
14	Average Month	1,448	$ 87.60	$ 81.50	$ 890.38	$ 1,059.48	$ 50.55	$ 102.39	$ 120.91	$ 1,333.32	$ 871.56	$ 2,204.88	14

a/ Tariff rates from Exhibit WG (O)-1, Schedule A, Page 3 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PROPOSED Rates a/

Group Metered Apartments Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - Less than 3,075 Therms

Line No.	Month	Average Therm Usage	Customer Charge @ $ 35.65	Peak Usage Charge @ $0.0544	Distribution Charge @ $0.6252	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	253	$ 35.65	$ 14.42	$ 158.18	$ 208.25	$ 8.83	$ 17.89	$ 21.12	$ 256.09	$ 152.26	$ 408.35	1
2	February	265	35.65	14.42	165.68	215.75	9.25	18.74	22.12	265.86	159.48	425.34	2
3	March	220	35.65	14.42	137.54	187.61	7.68	15.55	18.37	229.21	132.40	361.61	3
4	April	165	35.65	14.42	103.16	153.23	5.76	11.67	13.78	184.44	99.30	283.74	4
5	May	107	35.65	-	66.90	102.55	3.73	7.56	8.93	122.77	64.39	187.16	5
6	June	69	35.65	-	43.14	78.79	2.41	4.88	5.76	91.84	41.52	133.36	6
7	July	60	35.65	-	37.51	73.16	2.09	4.24	5.01	84.50	36.11	120.61	7
8	August	60	35.65	-	37.51	73.16	2.09	4.24	5.01	84.50	36.11	120.61	8
9	September	60	35.65	-	37.51	73.16	2.09	4.24	5.01	84.50	36.11	120.61	9
10	October	72	35.65	-	45.01	80.66	2.51	5.09	6.01	94.27	43.33	137.60	10
11	November	133	35.65	14.42	83.15	133.22	4.64	9.40	11.10	158.36	80.04	238.40	11
12	December	200	35.65	14.42	125.04	175.11	6.98	14.14	16.70	212.93	120.36	333.29	12
13	Total	1,664	$ 427.80	$ 86.52	$ 1,040.33	$ 1,554.65	$ 58.06	$ 117.64	$ 138.92	$ 1,869.27	$ 1,001.41	$ 2,870.68	13
14	Average Month	139	$ 35.65	$ 7.21	$ 86.69	$ 129.55	$ 4.84	$ 9.80	$ 11.58	$ 155.77	$ 83.45	$ 239.22	14

a/ Tariff rates from Exhibit WG (O)-1, Schedule A, Page 3 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PROPOSED Rates a/

Group Metered Apartments Service - Rate Schedule Nos. 3 and 3A
Non-heating and Non-cooling

Line No.	Month	Average Therm Usage	Customer Charge @ $ 35.65	Peak Usage Charge @ $0.0534	Distribution Charge @ $0.6124	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C	D b/	E	F=C+D+E	G	H	I	J=F+G+H+I	K	L=J+K	
1	January	591	$ 35.65	$ 32.73	$ 361.93	$ 430.31	$ 20.63	$ 41.78	$ 49.34	$ 542.06	$ 355.66	$ 897.72	1
2	February	613	35.65	32.73	375.40	443.78	21.39	43.34	51.18	559.69	368.90	928.59	2
3	March	528	35.65	32.73	323.35	391.73	18.43	37.33	44.08	491.57	317.75	809.32	3
4	April	429	35.65	32.73	262.72	331.10	14.97	30.33	35.82	412.22	258.17	670.39	4
5	May	318	35.65	-	194.74	230.39	11.10	22.48	26.55	290.52	191.37	481.89	5
6	June	247	35.65	-	151.26	186.91	8.62	17.46	20.62	233.61	148.64	382.25	6
7	July	229	35.65	-	140.24	175.89	7.99	16.19	19.12	219.19	137.81	357.00	7
8	August	229	35.65	-	140.24	175.89	7.99	16.19	19.12	219.19	137.81	357.00	8
9	September	228	35.65	-	139.63	175.28	7.96	16.12	19.03	218.39	137.21	355.60	9
10	October	250	35.65	-	153.10	188.75	8.73	17.68	20.87	236.03	150.45	386.48	10
11	November	365	35.65	32.73	223.53	291.91	12.74	25.81	30.47	360.93	219.66	580.59	11
12	December	491	35.65	32.73	300.69	369.07	17.14	34.71	40.99	461.91	295.48	757.39	12
13	Total	4,518	$ 427.80	$ 196.38	$ 2,766.83	$ 3,391.01	$ 157.69	$ 319.42	$ 377.19	$ 4,245.31	$ 2,718.91	$ 6,964.22	13
14	Average Month	377	$ 35.65	$ 16.37	$ 230.57	$ 282.58	$ 13.14	$ 26.62	$ 31.43	$ 353.78	$ 226.58	$ 580.35	14

a/ Tariff rates from Exhibit WG (O)-1, Schedule A, Page 3 and all other rates from pro forma adjustments to cost of service.

b/ Peak Usage Charge is based on the November through April maximum month usage in Column B.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for AVERAGE Usage Levels at PROPOSED Rates

Interruptible Service - Rate Schedule No. 6

Line No.	Month	Average Therm Usage	Block 1 Therms	Block 2 Therms	Customer Charge @ $ 151.25	Block 1 Distribution Charge Revenue @ $ 0.2887	Block 2 Distribution Charge Revenue @ $ 0.2663	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	Total Revenue	Line No.
	A	B	C	D	E	F	G	H=F+G	I	J	K	L=H+I+J+K	M=E+L	
1	January	47,452	47,452	-	$ 151.25	$ 13,699.39	$ -	$ 13,699.39	$ 1,656.07	$ 3,354.86	$ 3,961.57	$ 22,671.89	$ 22,823.14	1
2	February	49,303	49,303	-	151.25	14,233.78	0.00	14,233.78	1,720.67	3,485.72	4,116.11	23,556.28	23,707.53	2
3	March	42,477	42,477	-	151.25	12,263.11	0.00	12,263.11	1,482.45	3,003.12	3,546.23	20,294.91	20,446.16	3
4	April	34,030	34,030	-	151.25	9,824.46	0.00	9,824.46	1,187.65	2,405.92	2,841.03	16,259.06	16,410.31	4
5	May	25,120	25,120	-	151.25	7,252.14	0.00	7,252.14	876.69	1,775.98	2,097.17	12,001.98	12,153.23	5
6	June	19,373	19,373	-	151.25	5,592.99	0.00	5,592.99	676.12	1,369.67	1,617.37	9,256.15	9,407.40	6
7	July	18,023	18,023	-	151.25	5,203.24	0.00	5,203.24	629.00	1,274.23	1,504.67	8,611.14	8,762.39	7
8	August	18,023	18,023	-	151.25	5,203.24	0.00	5,203.24	629.00	1,274.23	1,504.67	8,611.14	8,762.39	8
9	September	18,023	18,023	-	151.25	5,203.24	0.00	5,203.24	629.00	1,274.23	1,504.67	8,611.14	8,762.39	9
10	October	19,836	19,836	-	151.25	5,726.65	0.00	5,726.65	692.28	1,402.41	1,656.03	9,477.37	9,628.62	10
11	November	29,131	29,131	-	151.25	8,410.12	0.00	8,410.12	1,016.67	2,059.56	2,432.03	13,918.38	14,069.63	11
12	December	39,314	39,314	-	151.25	11,349.95	0.00	11,349.95	1,372.06	2,779.50	3,282.16	18,783.67	18,934.92	12
13	Total	360,105	360,105	0	$ 1,815.00	$ 103,962.31	$ -	$ 103,962.31	$ 12,567.66	$ 25,459.43	$ 30,063.71	$ 172,053.11	$ 173,868.11	13
14	Average Month	30,009	30,009	0	$ 151.25	$ 8,663.53	$ -	$ 8,663.53	$ 1,047.31	$ 2,121.62	$ 2,505.31	$ 14,337.76	$ 14,489.01	14

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - Less than 3,075 Therms
Summer (June - August)

		Delivery Service (Rate Schedule No. 2A)				Sales Service (Rate Schedule No. 2)				
				Increase				Increase		
Line No.	Therm Usage	Present Rates	Proposed Rates	Amount	Percent	Present Rates	Proposed Rates	Amount	Percent	Line No.
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	30	$ 53.03	$ 67.10	$ 14.07	26.5%	$ 71.08	$ 85.15	$ 14.07	19.8%	1
2	40	60.75	77.01	16.26	26.8%	84.82	101.08	16.26	19.2%	2
3	50	68.47	86.91	18.44	26.9%	98.56	117.00	18.44	18.7%	3
4	60	76.17	96.80	20.63	27.1%	112.28	132.91	20.63	18.4%	4
5	70	83.88	106.70	22.82	27.2%	126.01	148.83	22.82	18.1%	5
6	80	91.60	116.61	25.01	27.3%	139.74	164.75	25.01	17.9%	6
7	90	99.30	126.50	27.20	27.4%	153.46	180.66	27.20	17.7%	7
8	100	107.02	136.41	29.39	27.5%	167.20	196.59	29.39	17.6%	8
9	150	145.59	185.92	40.33	27.7%	235.86	276.19	40.33	17.1%	9
10	200	184.14	235.42	51.28	27.8%	304.50	355.78	51.28	16.8%	10
11	300	261.26	334.43	73.17	28.0%	441.80	514.97	73.17	16.6%	11
12	400	338.37	433.43	95.06	28.1%	579.09	674.15	95.06	16.4%	12

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2. Excludes PGC. Includes Customer Charge and excludes Peak Usage Charge.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2 including $0.6018 pro forma PGC. Includes Customer Charge and excludes Peak Usage Charge.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - Less than 3,075 Therms
Winter (November - April)

Line No.	Therm Usage	Delivery Service (Rate Schedule No. 2A)				Sales Service (Rate Schedule No. 2)				Line No.
		Present Rates	Proposed Rates	Increase Amount	Increase Percent	Present Rates	Proposed Rates	Increase Amount	Increase Percent	
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	60	$ 85.05	$ 108.65	$ 23.60	27.7%	$ 121.16	$ 144.76	$ 23.60	19.5%	1
2	70	92.76	118.55	25.79	27.8%	134.89	160.68	25.79	19.1%	2
3	80	100.48	128.46	27.98	27.8%	148.62	176.60	27.98	18.8%	3
4	90	108.18	138.35	30.17	27.9%	162.34	192.51	30.17	18.6%	4
5	100	115.90	148.26	32.36	27.9%	176.08	208.44	32.36	18.4%	5
6	150	154.47	197.77	43.30	28.0%	244.74	288.04	43.30	17.7%	6
7	200	193.02	247.27	54.25	28.1%	313.38	367.63	54.25	17.3%	7
8	250	231.59	296.78	65.19	28.1%	382.04	447.23	65.19	17.1%	8
9	300	270.14	346.28	76.14	28.2%	450.68	526.82	76.14	16.9%	9
10	350	308.71	395.79	87.08	28.2%	519.34	606.42	87.08	16.8%	10
11	400	347.25	445.28	98.03	28.2%	587.97	686.00	98.03	16.7%	11
12	500	424.37	544.29	119.92	28.3%	725.27	845.19	119.92	16.5%	12
13	600	501.49	643.30	141.81	28.3%	862.57	1,004.38	141.81	16.4%	13
14	700	578.61	742.31	163.70	28.3%	999.87	1,163.57	163.70	16.4%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2. Excludes PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 171 therm maximum usage month.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2 including $0.6018 pro forma PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 171 therm maximum usage month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - 3,075 Therms or More
Summer (June - August)

Line No.	Therm Usage	Delivery Service (Rate Schedule No. 2A) Present Rates	Proposed Rates	Increase Amount	Percent	Sales Service (Rate Schedule No. 2) Present Rates	Proposed Rates	Increase Amount	Percent	Line No.
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	100	$ 136.92	$ 167.09	$ 30.17	22.0%	$ 197.10	$ 227.27	$ 30.17	15.3%	1
2	150	170.36	206.87	36.51	21.4%	260.63	297.14	36.51	14.0%	2
3	200	203.79	246.63	42.84	21.0%	324.15	366.99	42.84	13.2%	3
4	250	237.23	286.41	49.18	20.7%	387.68	436.86	49.18	12.7%	4
5	300	270.66	326.17	55.51	20.5%	451.20	506.71	55.51	12.3%	5
6	400	337.52	405.70	68.18	20.2%	578.24	646.42	68.18	11.8%	6
7	500	404.39	485.24	80.85	20.0%	705.29	786.14	80.85	11.5%	7
8	600	471.26	564.78	93.52	19.8%	832.34	925.86	93.52	11.2%	8
9	700	538.13	644.32	106.19	19.7%	959.39	1,065.58	106.19	11.1%	9
10	800	605.00	723.86	118.86	19.6%	1,086.44	1,205.30	118.86	10.9%	10
11	900	671.87	803.40	131.53	19.6%	1,213.49	1,345.02	131.53	10.8%	11
12	1,000	738.74	882.94	144.20	19.5%	1,340.54	1,484.74	144.20	10.8%	12

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2. Excludes PGC. Includes Customer Charge and excludes Peak Usage Charge.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2 including $0.6018 pro forma PGC. Includes Customer Charge and excludes Peak Usage Charge.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - 3,075 Therms or More
Winter (November - April)

		Delivery Service (Rate Schedule No. 2A)				Sales Service (Rate Schedule No. 2)				
		Present	Proposed	Increase		Present	Proposed	Increase		
Line No.	Therm Usage	Rates	Rates	Amount	Percent	Rates	Rates	Amount	Percent	Line No.
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	100	$ 254.38	$ 315.51	$ 61.13	24.0%	$ 314.56	$ 375.69	$ 61.13	19.4%	1
2	250	354.69	434.83	80.14	22.6%	505.14	585.28	80.14	15.9%	2
3	500	521.85	633.66	111.81	21.4%	822.75	934.56	111.81	13.6%	3
4	750	689.03	832.52	143.49	20.8%	1,140.38	1,283.87	143.49	12.6%	4
5	1,000	856.20	1,031.36	175.16	20.5%	1,458.00	1,633.16	175.16	12.0%	5
6	1,250	1,023.38	1,230.22	206.84	20.2%	1,775.63	1,982.47	206.84	11.6%	6
7	1,500	1,190.54	1,429.05	238.51	20.0%	2,093.24	2,331.75	238.51	11.4%	7
8	1,750	1,357.72	1,627.91	270.19	19.9%	2,410.87	2,681.06	270.19	11.2%	8
9	2,000	1,524.88	1,826.74	301.86	19.8%	2,728.48	3,030.34	301.86	11.1%	9
10	2,500	1,859.22	2,224.43	365.21	19.6%	3,363.72	3,728.93	365.21	10.9%	10
11	3,000	2,193.57	2,622.13	428.56	19.5%	3,998.97	4,427.53	428.56	10.7%	11
12	3,500	2,527.91	3,019.82	491.91	19.5%	4,634.21	5,126.12	491.91	10.6%	12
13	4,000	2,862.25	3,417.51	555.26	19.4%	5,269.45	5,824.71	555.26	10.5%	13
14	5,000	3,530.94	4,212.90	681.96	19.3%	6,539.94	7,221.90	681.96	10.4%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2. Excludes PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 2,790 therm maximum usage month.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2 including $0.6018 pro forma PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 2,790 therm maximum usage month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Non-Heating and Non-Cooling
Summer (June - August)

		Delivery Service (Rate Schedule No. 2A)				Sales Service (Rate Schedule No. 2)				
				Increase				Increase		
Line No.	Therm Usage	Present Rates	Proposed Rates	Amount	Percent	Present Rates	Proposed Rates	Amount	Percent	Line No.
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	100	$ 95.52	$ 115.43	$ 19.91	20.8%	$ 155.70	$ 175.61	$ 19.91	12.8%	1
2	150	129.04	155.33	26.29	20.4%	219.31	245.60	26.29	12.0%	2
3	200	162.54	195.21	32.67	20.1%	282.90	315.57	32.67	11.5%	3
4	250	196.06	235.11	39.05	19.9%	346.51	385.56	39.05	11.3%	4
5	300	229.56	274.99	45.43	19.8%	410.10	455.53	45.43	11.1%	5
6	400	296.57	354.76	58.19	19.6%	537.29	595.48	58.19	10.8%	6
7	500	363.59	434.54	70.95	19.5%	664.49	735.44	70.95	10.7%	7
8	600	430.61	514.32	83.71	19.4%	791.69	875.40	83.71	10.6%	8
9	700	497.63	594.10	96.47	19.4%	918.89	1,015.36	96.47	10.5%	9
10	800	564.65	673.88	109.23	19.3%	1,046.09	1,155.32	109.23	10.4%	10
11	900	631.67	753.66	121.99	19.3%	1,173.29	1,295.28	121.99	10.4%	11
12	1,000	698.69	833.44	134.75	19.3%	1,300.49	1,435.24	134.75	10.4%	12

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2. Excludes PGC. Includes Customer Charge. Excludes Peak Usage Charge.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2 including $0.6018 pro forma PGC. Includes Customer Charge. Excludes Peak Usage Charge.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Non-Heating and Non-Cooling
Winter (November - April)

		Delivery Service (Rate Schedule No. 2A)				Sales Service (Rate Schedule No. 2)				
				Increase				Increase		
Line No.	Therm Usage	Present Rates	Proposed Rates	Amount	Percent	Present Rates	Proposed Rates	Amount	Percent	Line No.
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	100	$ 122.38	$ 149.34	$ 26.96	22.0%	$ 182.56	$ 209.52	$ 26.96	14.8%	1
2	150	155.90	189.24	33.34	21.4%	246.17	279.51	33.34	13.5%	2
3	200	189.40	229.12	39.72	21.0%	309.76	349.48	39.72	12.8%	3
4	250	222.92	269.02	46.10	20.7%	373.37	419.47	46.10	12.3%	4
5	300	256.42	308.90	52.48	20.5%	436.96	489.44	52.48	12.0%	5
6	400	323.43	388.67	65.24	20.2%	564.15	629.39	65.24	11.6%	6
7	500	390.45	468.45	78.00	20.0%	691.35	769.35	78.00	11.3%	7
8	600	457.47	548.23	90.76	19.8%	818.55	909.31	90.76	11.1%	8
9	700	524.49	628.01	103.52	19.7%	945.75	1,049.27	103.52	10.9%	9
10	800	591.51	707.79	116.28	19.7%	1,072.95	1,189.23	116.28	10.8%	10
11	900	658.53	787.57	129.04	19.6%	1,200.15	1,329.19	129.04	10.8%	11
12	1,000	725.55	867.35	141.80	19.5%	1,327.35	1,469.15	141.80	10.7%	12

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2. Excludes PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 635 therm maximum usage month.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 2 including $0.6018 pro forma PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 635 therm maximum usage month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - Less than 3,075 Therms
Summer (June - August)

		Delivery Service (Rate Schedule No. 2C)				Sales Service (Rate Schedule No. 2B)				
				Increase				Increase		
Line No.	Therm Usage	Present Rates	Proposed Rates	Amount	Percent	Present Rates	Proposed Rates	Amount	Percent	Line No.
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	30	$ 48.96	$ 60.08	$ 11.12	22.7%	$ 67.01	$ 78.13	$ 11.12	16.6%	1
2	40	55.79	68.23	12.44	22.3%	79.86	92.30	12.44	15.6%	2
3	50	62.61	76.37	13.76	22.0%	92.70	106.46	13.76	14.8%	3
4	60	69.42	84.50	15.08	21.7%	105.53	120.61	15.08	14.3%	4
5	70	76.24	92.64	16.40	21.5%	118.37	134.77	16.40	13.9%	5
6	80	83.07	100.80	17.73	21.3%	131.21	148.94	17.73	13.5%	6
7	90	89.88	108.93	19.05	21.2%	144.04	163.09	19.05	13.2%	7
8	100	96.71	117.08	20.37	21.1%	156.89	177.26	20.37	13.0%	8
9	150	130.82	157.80	26.98	20.6%	221.09	248.07	26.98	12.2%	9
10	200	164.92	198.51	33.59	20.4%	285.28	318.87	33.59	11.8%	10
11	300	233.13	279.94	46.81	20.1%	413.67	460.48	46.81	11.3%	11
12	400	301.33	361.36	60.03	19.9%	542.05	602.08	60.03	11.1%	12

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3. Excludes PGC. Includes Customer Charge and excludes Peak Usage Charge.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3 including $0.6018 pro forma PGC. Includes Customer Charge and excludes Peak Usage Charge.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - Less than 3,075 Therms
Winter (November - April)

		Delivery Service (Rate Schedule No. 2C)				Sales Service (Rate Schedule No. 2B)				
				Increase				Increase		
Line No.	Therm Usage	Present Rates	Proposed Rates	Amount	Percent	Present Rates	Proposed Rates	Amount	Percent	Line No.
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	60	$ 77.52	$ 94.72	$ 17.20	22.2%	$ 113.63	$ 130.83	$ 17.20	15.1%	1
2	70	84.34	102.86	18.52	22.0%	126.47	144.99	18.52	14.6%	2
3	80	91.17	111.02	19.85	21.8%	139.31	159.16	19.85	14.2%	3
4	90	97.98	119.15	21.17	21.6%	152.14	173.31	21.17	13.9%	4
5	100	104.81	127.30	22.49	21.5%	164.99	187.48	22.49	13.6%	5
6	150	138.92	168.02	29.10	20.9%	229.19	258.29	29.10	12.7%	6
7	200	173.02	208.73	35.71	20.6%	293.38	329.09	35.71	12.2%	7
8	250	207.13	249.45	42.32	20.4%	357.58	399.90	42.32	11.8%	8
9	300	241.23	290.16	48.93	20.3%	421.77	470.70	48.93	11.6%	9
10	350	275.34	330.88	55.54	20.2%	485.97	541.51	55.54	11.4%	10
11	400	309.43	371.58	62.15	20.1%	550.15	612.30	62.15	11.3%	11
12	500	377.64	453.01	75.37	20.0%	678.54	753.91	75.37	11.1%	12
13	600	445.85	534.44	88.59	19.9%	806.93	895.52	88.59	11.0%	13
14	700	514.06	615.87	101.81	19.8%	935.32	1,037.13	101.81	10.9%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3. Excludes PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 171 therm maximum usage month.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3 including $0.6018 pro forma PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 171 therm maximum usage month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - 3,075 Therms or More
Summer (June - August)

		Delivery Service (Rate Schedule No. 2C)				Sales Service (Rate Schedule No. 2B)				
				Increase				Increase		
Line No.	Therm Usage	Present Rates	Proposed Rates	Amount	Percent	Present Rates	Proposed Rates	Amount	Percent	Line No.
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	100	$ 137.59	$ 167.99	$ 30.40	22.1%	$ 197.77	$ 228.17	$ 30.40	15.4%	1
2	150	171.37	208.19	36.82	21.5%	261.64	298.46	36.82	14.1%	2
3	200	205.13	248.38	43.25	21.1%	325.49	368.74	43.25	13.3%	3
4	250	238.91	288.58	49.67	20.8%	389.36	439.03	49.67	12.8%	4
5	300	272.67	328.77	56.10	20.6%	453.21	509.31	56.10	12.4%	5
6	400	340.20	409.15	68.95	20.3%	580.92	649.87	68.95	11.9%	6
7	500	407.74	489.54	81.80	20.1%	708.64	790.44	81.80	11.5%	7
8	600	475.28	569.93	94.65	19.9%	836.36	931.01	94.65	11.3%	8
9	700	542.82	650.32	107.50	19.8%	964.08	1,071.58	107.50	11.2%	9
10	800	610.36	730.71	120.35	19.7%	1,091.80	1,212.15	120.35	11.0%	10
11	900	677.90	811.10	133.20	19.6%	1,219.52	1,352.72	133.20	10.9%	11
12	1,000	745.44	891.49	146.05	19.6%	1,347.24	1,493.29	146.05	10.8%	12

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3. Excludes PGC. Includes Customer Charge and excludes Peak Usage Charge.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3 including $0.6018 pro forma PGC. Includes Customer Charge and excludes Peak Usage Charge.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - 3,075 Therms or More
Winter (November - April)

		Delivery Service (Rate Schedule No. 2C)				Sales Service (Rate Schedule No. 2B)				
				Increase				Increase		
Line No.	Therm Usage	Present Rates	Proposed Rates	Amount	Percent	Present Rates	Proposed Rates	Amount	Percent	Line No.
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	100	$ 241.90	$ 299.74	$ 57.84	23.9%	$ 302.08	$ 359.92	$ 57.84	19.1%	1
2	250	343.22	420.33	77.11	22.5%	493.67	570.78	77.11	15.6%	2
3	500	512.05	621.29	109.24	21.3%	812.95	922.19	109.24	13.4%	3
4	750	680.91	822.27	141.36	20.8%	1,132.26	1,273.62	141.36	12.5%	4
5	1,000	849.75	1,023.24	173.49	20.4%	1,451.55	1,625.04	173.49	12.0%	5
6	1,250	1,018.61	1,224.22	205.61	20.2%	1,770.86	1,976.47	205.61	11.6%	6
7	1,500	1,187.44	1,425.18	237.74	20.0%	2,090.14	2,327.88	237.74	11.4%	7
8	1,750	1,356.30	1,626.16	269.86	19.9%	2,409.45	2,679.31	269.86	11.2%	8
9	2,000	1,525.13	1,827.12	301.99	19.8%	2,728.73	3,030.72	301.99	11.1%	9
10	2,500	1,862.82	2,229.06	366.24	19.7%	3,367.32	3,733.56	366.24	10.9%	10
11	3,000	2,200.52	2,631.01	430.49	19.6%	4,005.92	4,436.41	430.49	10.7%	11
12	3,500	2,538.21	3,032.95	494.74	19.5%	4,644.51	5,139.25	494.74	10.7%	12
13	4,000	2,875.90	3,434.89	558.99	19.4%	5,283.10	5,842.09	558.99	10.6%	13
14	5,000	3,551.29	4,238.78	687.49	19.4%	6,560.29	7,247.78	687.49	10.5%	14

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3. Excludes PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 2,790 therm maximum usage month.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3 including $0.6018 pro forma PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 2,790 therm maximum usage month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Non-Heating and Non-Cooling
Summer (June - August)

		Delivery Service (Rate Schedule No. 2C)				Sales Service (Rate Schedule No. 2B)				
				Increase				Increase		
Line No.	Therm Usage	Present Rates	Proposed Rates	Amount	Percent	Present Rates	Proposed Rates	Amount	Percent	Line No.
	A	B a/	C a/	D=C-B	E=D/B	F b/	G b/	H=G-F	I=H/F	
1	100	$ 95.82	$ 115.80	$ 19.98	20.9%	$ 156.00	$ 175.98	$ 19.98	12.8%	1
2	150	129.49	155.88	26.39	20.4%	219.76	246.15	26.39	12.0%	2
3	200	163.14	195.95	32.81	20.1%	283.50	316.31	32.81	11.6%	3
4	250	196.81	236.03	39.22	19.9%	347.26	386.48	39.22	11.3%	4
5	300	230.46	276.10	45.64	19.8%	411.00	456.64	45.64	11.1%	5
6	400	297.77	356.24	58.47	19.6%	538.49	596.96	58.47	10.9%	6
7	500	365.09	436.39	71.30	19.5%	665.99	737.29	71.30	10.7%	7
8	600	432.41	516.54	84.13	19.5%	793.49	877.62	84.13	10.6%	8
9	700	499.73	596.69	96.96	19.4%	920.99	1,017.95	96.96	10.5%	9
10	800	567.05	676.84	109.79	19.4%	1,048.49	1,158.28	109.79	10.5%	10
11	900	634.37	756.99	122.62	19.3%	1,175.99	1,298.61	122.62	10.4%	11
12	1,000	701.69	837.14	135.45	19.3%	1,303.49	1,438.94	135.45	10.4%	12

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3. Excludes PGC. Includes Customer Charge. Excludes Peak Usage Charge.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3 including $0.6018 pro forma PGC. Includes Customer Charge. Excludes Peak Usage Charge.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons
for Specific Usage Levels at Present and Proposed Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Non-Heating and Non-Cooling
Winter (November - April)

		Delivery Service (Rate Schedule No. 2C)				Sales Service (Rate Schedule No. 2B)				
				Increase				Increase		
Line No.	Therm Usage A	Present Rates B a/	Proposed Rates C a/	Amount D=C-B	Percent E=D/B	Present Rates F b/	Proposed Rates G b/	Amount H=G-F	Percent I=H/F	Line No.
1	100	$ 121.50	$ 148.22	$ 26.72	22.0%	$ 181.68	$ 208.40	$ 26.72	14.7%	1
2	150	155.17	188.30	33.13	21.4%	245.44	278.57	33.13	13.5%	2
3	200	188.82	228.37	39.55	20.9%	309.18	348.73	39.55	12.8%	3
4	250	222.49	268.45	45.96	20.7%	372.94	418.90	45.96	12.3%	4
5	300	256.14	308.52	52.38	20.4%	436.68	489.06	52.38	12.0%	5
6	400	323.45	388.66	65.21	20.2%	564.17	629.38	65.21	11.6%	6
7	500	390.77	468.81	78.04	20.0%	691.67	769.71	78.04	11.3%	7
8	600	458.09	548.96	90.87	19.8%	819.17	910.04	90.87	11.1%	8
9	700	525.41	629.11	103.70	19.7%	946.67	1,050.37	103.70	11.0%	9
10	800	592.73	709.26	116.53	19.7%	1,074.17	1,190.70	116.53	10.8%	10
11	900	660.05	789.41	129.36	19.6%	1,201.67	1,331.03	129.36	10.8%	11
12	1,000	727.37	869.56	142.19	19.5%	1,329.17	1,471.36	142.19	10.7%	12

a/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3. Excludes PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 635 therm maximum usage month.

b/ Priced at present and proposed rates shown on Exhibit WG (O)-1, Schedule A, Page 3 including $0.6018 pro forma PGC. Includes Customer Charge. Includes Peak Usage Charge based on a 635 therm maximum usage month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - Less than 3,075 Therms
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 29.90	Peak Usage Charge @ $ -	Distribution Charge @ $0.5821	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	30	$ 29.90	$ -	$ 17.46	$ 47.36	$ 1.05	$ 2.12	$ 2.50	$ 53.03	$ 18.05	$ 71.08	1
2	40	29.90	-	23.28	53.18	1.40	2.83	3.34	60.75	24.07	84.82	2
3	50	29.90	-	29.11	59.01	1.75	3.54	4.17	68.47	30.09	98.56	3
4	60	29.90	-	34.93	64.83	2.09	4.24	5.01	76.17	36.11	112.28	4
5	70	29.90	-	40.75	70.65	2.44	4.95	5.84	83.88	42.13	126.01	5
6	80	29.90	-	46.57	76.47	2.79	5.66	6.68	91.60	48.14	139.74	6
7	90	29.90	-	52.39	82.29	3.14	6.36	7.51	99.30	54.16	153.46	7
8	100	29.90	-	58.21	88.11	3.49	7.07	8.35	107.02	60.18	167.20	8
9	150	29.90	-	87.32	117.22	5.24	10.61	12.52	145.59	90.27	235.86	9
10	200	29.90	-	116.42	146.32	6.98	14.14	16.70	184.14	120.36	304.50	10
11	300	29.90	-	174.63	204.53	10.47	21.21	25.05	261.26	180.54	441.80	11
12	400	29.90	-	232.84	262.74	13.96	28.28	33.39	338.37	240.72	579.09	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - Less than 3,075 Therms
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $29.90	Peak Usage Charge @ $0.0519	Distribution Charge @ $0.5821	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	60	$ 29.90	$ 8.88	$ 34.93	$ 73.71	$ 2.09	$ 4.24	$ 5.01	$ 85.05	$ 36.11	$ 121.16	1
2	70	29.90	8.88	40.75	79.53	2.44	4.95	5.84	92.76	42.13	134.89	2
3	80	29.90	8.88	46.57	85.35	2.79	5.66	6.68	100.48	48.14	148.62	3
4	90	29.90	8.88	52.39	91.17	3.14	6.36	7.51	108.18	54.16	162.34	4
5	100	29.90	8.88	58.21	96.99	3.49	7.07	8.35	115.90	60.18	176.08	5
6	150	29.90	8.88	87.32	126.10	5.24	10.61	12.52	154.47	90.27	244.74	6
7	200	29.90	8.88	116.42	155.20	6.98	14.14	16.70	193.02	120.36	313.38	7
8	250	29.90	8.88	145.53	184.31	8.73	17.68	20.87	231.59	150.45	382.04	8
9	300	29.90	8.88	174.63	213.41	10.47	21.21	25.05	270.14	180.54	450.68	9
10	350	29.90	8.88	203.74	242.52	12.22	24.75	29.22	308.71	210.63	519.34	10
11	400	29.90	8.88	232.84	271.62	13.96	28.28	33.39	347.25	240.72	587.97	11
12	500	29.90	8.88	291.05	329.83	17.45	35.35	41.74	424.37	300.90	725.27	12
13	600	29.90	8.88	349.26	388.04	20.94	42.42	50.09	501.49	361.08	862.57	13
14	700	29.90	8.88	407.47	446.25	24.43	49.49	58.44	578.61	421.26	999.87	14

a/ Peak Usage Charge applicable in the months of November - April and assumes 171 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - 3,075 Therms or More
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 70.05	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.4796	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 70.05	$ -	$ 47.96	$ 118.01	$ 3.49	$ 7.07	$ 8.35	$ 136.92	$ 60.18	$ 197.10	1
2	150	70.05	-	71.94	141.99	5.24	10.61	12.52	170.36	90.27	260.63	2
3	200	70.05	-	95.92	165.97	6.98	14.14	16.70	203.79	120.36	324.15	3
4	250	70.05	-	119.90	189.95	8.73	17.68	20.87	237.23	150.45	387.68	4
5	300	70.05	-	143.88	213.93	10.47	21.21	25.05	270.66	180.54	451.20	5
6	400	70.05	-	191.84	261.89	13.96	28.28	33.39	337.52	240.72	578.24	6
7	500	70.05	-	239.80	309.85	17.45	35.35	41.74	404.39	300.90	705.29	7
8	600	70.05	-	287.76	357.81	20.94	42.42	50.09	471.26	361.08	832.34	8
9	700	70.05	-	335.72	405.77	24.43	49.49	58.44	538.13	421.26	959.39	9
10	800	70.05	-	383.68	453.73	27.92	56.56	66.79	605.00	481.44	1,086.44	10
11	900	70.05	-	431.64	501.69	31.41	63.63	75.14	671.87	541.62	1,213.49	11
12	1,000	70.05	-	479.60	549.65	34.90	70.70	83.49	738.74	601.80	1,340.54	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - 3,075 Therms or More
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $70.05	Peak Usage Charge @ $0.0421	Distribution Charge @ $0.4796	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 70.05	$ 117.46	$ 47.96	$ 235.47	$ 3.49	$ 7.07	$ 8.35	$ 254.38	$ 60.18	$ 314.56	1
2	250	70.05	117.46	119.90	307.41	8.73	17.68	20.87	354.69	150.45	505.14	2
3	500	70.05	117.46	239.80	427.31	17.45	35.35	41.74	521.85	300.90	822.75	3
4	750	70.05	117.46	359.70	547.21	26.18	53.03	62.61	689.03	451.35	1,140.38	4
5	1,000	70.05	117.46	479.60	667.11	34.90	70.70	83.49	856.20	601.80	1,458.00	5
6	1,250	70.05	117.46	599.50	787.01	43.63	88.38	104.36	1,023.38	752.25	1,775.63	6
7	1,500	70.05	117.46	719.40	906.91	52.35	106.05	125.23	1,190.54	902.70	2,093.24	7
8	1,750	70.05	117.46	839.30	1,026.81	61.08	123.73	146.10	1,357.72	1,053.15	2,410.87	8
9	2,000	70.05	117.46	959.20	1,146.71	69.80	141.40	166.97	1,524.88	1,203.60	2,728.48	9
10	2,500	70.05	117.46	1,199.00	1,386.51	87.25	176.75	208.71	1,859.22	1,504.50	3,363.72	10
11	3,000	70.05	117.46	1,438.80	1,626.31	104.70	212.10	250.46	2,193.57	1,805.40	3,998.97	11
12	3,500	70.05	117.46	1,678.60	1,866.11	122.15	247.45	292.20	2,527.91	2,106.30	4,634.21	12
13	4,000	70.05	117.46	1,918.40	2,105.91	139.60	282.80	333.94	2,862.25	2,407.20	5,269.45	13
14	5,000	70.05	117.46	2,398.00	2,585.51	174.50	353.50	417.43	3,530.94	3,009.00	6,539.94	14

a/ Peak Usage Charge applicable in the months of November - April and assumes 2,790 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Non-heating and Non-cooling
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 28.50	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.4811	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 28.50	$ -	$ 48.11	$ 76.61	$ 3.49	$ 7.07	$ 8.35	$ 95.52	$ 60.18	$ 155.70	1
2	150	28.50	-	72.17	100.67	5.24	10.61	12.52	129.04	90.27	219.31	2
3	200	28.50	-	96.22	124.72	6.98	14.14	16.70	162.54	120.36	282.90	3
4	250	28.50	-	120.28	148.78	8.73	17.68	20.87	196.06	150.45	346.51	4
5	300	28.50	-	144.33	172.83	10.47	21.21	25.05	229.56	180.54	410.10	5
6	400	28.50	-	192.44	220.94	13.96	28.28	33.39	296.57	240.72	537.29	6
7	500	28.50	-	240.55	269.05	17.45	35.35	41.74	363.59	300.90	664.49	7
8	600	28.50	-	288.66	317.16	20.94	42.42	50.09	430.61	361.08	791.69	8
9	700	28.50	-	336.77	365.27	24.43	49.49	58.44	497.63	421.26	918.89	9
10	800	28.50	-	384.88	413.38	27.92	56.56	66.79	564.65	481.44	1,046.09	10
11	900	28.50	-	432.99	461.49	31.41	63.63	75.14	631.67	541.62	1,173.29	11
12	1,000	28.50	-	481.10	509.60	34.90	70.70	83.49	698.69	601.80	1,300.49	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Non-heating and Non-cooling
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $28.50	Peak Usage Charge @ $0.0423	Distribution Charge @ $0.4811	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 28.50	$ 26.86	$ 48.11	$ 103.47	$ 3.49	$ 7.07	$ 8.35	$ 122.38	$ 60.18	$ 182.56	1
2	150	28.50	26.86	72.17	127.53	5.24	10.61	12.52	155.90	90.27	246.17	2
3	200	28.50	26.86	96.22	151.58	6.98	14.14	16.70	189.40	120.36	309.76	3
4	250	28.50	26.86	120.28	175.64	8.73	17.68	20.87	222.92	150.45	373.37	4
5	300	28.50	26.86	144.33	199.69	10.47	21.21	25.05	256.42	180.54	436.96	5
6	400	28.50	26.86	192.44	247.80	13.96	28.28	33.39	323.43	240.72	564.15	6
7	500	28.50	26.86	240.55	295.91	17.45	35.35	41.74	390.45	300.90	691.35	7
8	600	28.50	26.86	288.66	344.02	20.94	42.42	50.09	457.47	361.08	818.55	8
9	700	28.50	26.86	336.77	392.13	24.43	49.49	58.44	524.49	421.26	945.75	9
10	800	28.50	26.86	384.88	440.24	27.92	56.56	66.79	591.51	481.44	1,072.95	10
11	900	28.50	26.86	432.99	488.35	31.41	63.63	75.14	658.53	541.62	1,200.15	11
12	1,000	28.50	26.86	481.10	536.46	34.90	70.70	83.49	725.55	601.80	1,327.35	12

a/ Peak Usage Charge applicable in the months of November - April and assumes 635 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - Less than 3,075 Therms
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 28.50	Peak Usage Charge @ $ -	Distribution Charge @ $0.4930	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	30	$ 28.50	$ -	$ 14.79	$ 43.29	$ 1.05	$ 2.12	$ 2.50	$ 48.96	$ 18.05	$ 67.01	1
2	40	28.50	-	19.72	48.22	1.40	2.83	3.34	55.79	24.07	79.86	2
3	50	28.50	-	24.65	53.15	1.75	3.54	4.17	62.61	30.09	92.70	3
4	60	28.50	-	29.58	58.08	2.09	4.24	5.01	69.42	36.11	105.53	4
5	70	28.50	-	34.51	63.01	2.44	4.95	5.84	76.24	42.13	118.37	5
6	80	28.50	-	39.44	67.94	2.79	5.66	6.68	83.07	48.14	131.21	6
7	90	28.50	-	44.37	72.87	3.14	6.36	7.51	89.88	54.16	144.04	7
8	100	28.50	-	49.30	77.80	3.49	7.07	8.35	96.71	60.18	156.89	8
9	150	28.50	-	73.95	102.45	5.24	10.61	12.52	130.82	90.27	221.09	9
10	200	28.50	-	98.60	127.10	6.98	14.14	16.70	164.92	120.36	285.28	10
11	300	28.50	-	147.90	176.40	10.47	21.21	25.05	233.13	180.54	413.67	11
12	400	28.50	-	197.20	225.70	13.96	28.28	33.39	301.33	240.72	542.05	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - Less than 3,075 Therms
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $ 28.50	Peak Usage Charge @ $0.0431	Distribution Charge @ $0.4930	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	60	$ 28.50	$ 8.10	$ 29.58	$ 66.18	$ 2.09	$ 4.24	$ 5.01	$ 77.52	$ 36.11	$ 113.63	1
2	70	28.50	$ 8.10	34.51	71.11	2.44	4.95	5.84	84.34	42.13	126.47	2
3	80	28.50	$ 8.10	39.44	76.04	2.79	5.66	6.68	91.17	48.14	139.31	3
4	90	28.50	$ 8.10	44.37	80.97	3.14	6.36	7.51	97.98	54.16	152.14	4
5	100	28.50	$ 8.10	49.30	85.90	3.49	7.07	8.35	104.81	60.18	164.99	5
6	150	28.50	$ 8.10	73.95	110.55	5.24	10.61	12.52	138.92	90.27	229.19	6
7	200	28.50	$ 8.10	98.60	135.20	6.98	14.14	16.70	173.02	120.36	293.38	7
8	250	28.50	$ 8.10	123.25	159.85	8.73	17.68	20.87	207.13	150.45	357.58	8
9	300	28.50	$ 8.10	147.90	184.50	10.47	21.21	25.05	241.23	180.54	421.77	9
10	350	28.50	$ 8.10	172.55	209.15	12.22	24.75	29.22	275.34	210.63	485.97	10
11	400	28.50	$ 8.10	197.20	233.80	13.96	28.28	33.39	309.43	240.72	550.15	11
12	500	28.50	$ 8.10	246.50	283.10	17.45	35.35	41.74	377.64	300.90	678.54	12
13	600	28.50	$ 8.10	295.80	332.40	20.94	42.42	50.09	445.85	361.08	806.93	13
14	700	28.50	$ 8.10	345.10	381.70	24.43	49.49	58.44	514.06	421.26	935.32	14

a/ Peak Usage Charge applicable in the months of November - April and assumes 188 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - 3,075 Therms or More
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 70.05	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.4863	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 70.05	$ -	$ 48.63	$ 118.68	$ 3.49	$ 7.07	$ 8.35	$ 137.59	$ 60.18	$ 197.77	1
2	150	70.05	-	72.95	143.00	5.24	10.61	12.52	171.37	90.27	261.64	2
3	200	70.05	-	97.26	167.31	6.98	14.14	16.70	205.13	120.36	325.49	3
4	250	70.05	-	121.58	191.63	8.73	17.68	20.87	238.91	150.45	389.36	4
5	300	70.05	-	145.89	215.94	10.47	21.21	25.05	272.67	180.54	453.21	5
6	400	70.05	-	194.52	264.57	13.96	28.28	33.39	340.20	240.72	580.92	6
7	500	70.05	-	243.15	313.20	17.45	35.35	41.74	407.74	300.90	708.64	7
8	600	70.05	-	291.78	361.83	20.94	42.42	50.09	475.28	361.08	836.36	8
9	700	70.05	-	340.41	410.46	24.43	49.49	58.44	542.82	421.26	964.08	9
10	800	70.05	-	389.04	459.09	27.92	56.56	66.79	610.36	481.44	1,091.80	10
11	900	70.05	-	437.67	507.72	31.41	63.63	75.14	677.90	541.62	1,219.52	11
12	1,000	70.05	-	486.30	556.35	34.90	70.70	83.49	745.44	601.80	1,347.24	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - 3,075 Therms or More
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $70.05	Peak Usage Charge @ $0.0422	Distribution Charge @ $0.4863	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 70.05	$ 104.31	$ 48.63	$ 222.99	$ 3.49	$ 7.07	$ 8.35	$ 241.90	$ 60.18	$ 302.08	1
2	250	70.05	$ 104.31	121.58	295.94	8.73	17.68	20.87	343.22	150.45	493.67	2
3	500	70.05	$ 104.31	243.15	417.51	17.45	35.35	41.74	512.05	300.90	812.95	3
4	750	70.05	$ 104.31	364.73	539.09	26.18	53.03	62.61	680.91	451.35	1,132.26	4
5	1,000	70.05	$ 104.31	486.30	660.66	34.90	70.70	83.49	849.75	601.80	1,451.55	5
6	1,250	70.05	$ 104.31	607.88	782.24	43.63	88.38	104.36	1,018.61	752.25	1,770.86	6
7	1,500	70.05	$ 104.31	729.45	903.81	52.35	106.05	125.23	1,187.44	902.70	2,090.14	7
8	1,750	70.05	$ 104.31	851.03	1,025.39	61.08	123.73	146.10	1,356.30	1,053.15	2,409.45	8
9	2,000	70.05	$ 104.31	972.60	1,146.96	69.80	141.40	166.97	1,525.13	1,203.60	2,728.73	9
10	2,500	70.05	$ 104.31	1,215.75	1,390.11	87.25	176.75	208.71	1,862.82	1,504.50	3,367.32	10
11	3,000	70.05	$ 104.31	1,458.90	1,633.26	104.70	212.10	250.46	2,200.52	1,805.40	4,005.92	11
12	3,500	70.05	$ 104.31	1,702.05	1,876.41	122.15	247.45	292.20	2,538.21	2,106.30	4,644.51	12
13	4,000	70.05	$ 104.31	1,945.20	2,119.56	139.60	282.80	333.94	2,875.90	2,407.20	5,283.10	13
14	5,000	70.05	$ 104.31	2,431.50	2,605.86	174.50	353.50	417.43	3,551.29	3,009.00	6,560.29	14

a/ Peak Usage Charge applicable in the months of November - April and assumes 2,472 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Non-heating and Non-cooling
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 28.50	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.4841	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 28.50	$ -	$ 48.41	$ 76.91	$ 3.49	$ 7.07	$ 8.35	$ 95.82	$ 60.18	$ 156.00	1
2	150	28.50	-	72.62	101.12	5.24	10.61	12.52	129.49	90.27	219.76	2
3	200	28.50	-	96.82	125.32	6.98	14.14	16.70	163.14	120.36	283.50	3
4	250	28.50	-	121.03	149.53	8.73	17.68	20.87	196.81	150.45	347.26	4
5	300	28.50	-	145.23	173.73	10.47	21.21	25.05	230.46	180.54	411.00	5
6	400	28.50	-	193.64	222.14	13.96	28.28	33.39	297.77	240.72	538.49	6
7	500	28.50	-	242.05	270.55	17.45	35.35	41.74	365.09	300.90	665.99	7
8	600	28.50	-	290.46	318.96	20.94	42.42	50.09	432.41	361.08	793.49	8
9	700	28.50	-	338.87	367.37	24.43	49.49	58.44	499.73	421.26	920.99	9
10	800	28.50	-	387.28	415.78	27.92	56.56	66.79	567.05	481.44	1,048.49	10
11	900	28.50	-	435.69	464.19	31.41	63.63	75.14	634.37	541.62	1,175.99	11
12	1,000	28.50	-	484.10	512.60	34.90	70.70	83.49	701.69	601.80	1,303.49	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PRESENT Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Non-heating and Non-cooling
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $ 28.50	Peak Usage Charge @ $0.0423	Distribution Charge @ $0.4841	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 28.50	$ 25.68	$ 48.41	$ 102.59	$ 3.49	$ 7.07	$ 8.35	$ 121.50	$ 60.18	$ 181.68	1
2	150	28.50	$ 25.68	72.62	126.80	5.24	10.61	12.52	155.17	90.27	245.44	2
3	200	28.50	$ 25.68	96.82	151.00	6.98	14.14	16.70	188.82	120.36	309.18	3
4	250	28.50	$ 25.68	121.03	175.21	8.73	17.68	20.87	222.49	150.45	372.94	4
5	300	28.50	$ 25.68	145.23	199.41	10.47	21.21	25.05	256.14	180.54	436.68	5
6	400	28.50	$ 25.68	193.64	247.82	13.96	28.28	33.39	323.45	240.72	564.17	6
7	500	28.50	$ 25.68	242.05	296.23	17.45	35.35	41.74	390.77	300.90	691.67	7
8	600	28.50	$ 25.68	290.46	344.64	20.94	42.42	50.09	458.09	361.08	819.17	8
9	700	28.50	$ 25.68	338.87	393.05	24.43	49.49	58.44	525.41	421.26	946.67	9
10	800	28.50	$ 25.68	387.28	441.46	27.92	56.56	66.79	592.73	481.44	1,074.17	10
11	900	28.50	$ 25.68	435.69	489.87	31.41	63.63	75.14	660.05	541.62	1,201.67	11
12	1,000	28.50	$ 25.68	484.10	538.28	34.90	70.70	83.49	727.37	601.80	1,329.17	12

a/ Peak Usage Charge applicable in the months of November - April and assumes 607 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - Less than 3,075 Therms
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 37.40	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.8010	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	30	$ 37.40	$ -	$ 24.03	$ 61.43	$ 1.05	$ 2.12	$ 2.50	$ 67.10	$ 18.05	$ 85.15	1
2	40	37.40	-	32.04	69.44	1.40	2.83	3.34	77.01	24.07	101.08	2
3	50	37.40	-	40.05	77.45	1.75	3.54	4.17	86.91	30.09	117.00	3
4	60	37.40	-	48.06	85.46	2.09	4.24	5.01	96.80	36.11	132.91	4
5	70	37.40	-	56.07	93.47	2.44	4.95	5.84	106.70	42.13	148.83	5
6	80	37.40	-	64.08	101.48	2.79	5.66	6.68	116.61	48.14	164.75	6
7	90	37.40	-	72.09	109.49	3.14	6.36	7.51	126.50	54.16	180.66	7
8	100	37.40	-	80.10	117.50	3.49	7.07	8.35	136.41	60.18	196.59	8
9	150	37.40	-	120.15	157.55	5.24	10.61	12.52	185.92	90.27	276.19	9
10	200	37.40	-	160.20	197.60	6.98	14.14	16.70	235.42	120.36	355.78	10
11	300	37.40	-	240.30	277.70	10.47	21.21	25.05	334.43	180.54	514.97	11
12	400	37.40	-	320.40	357.80	13.96	28.28	33.39	433.43	240.72	674.15	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - Less than 3,075 Therms
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $37.40	Peak Usage Charge @ $0.0692	Distribution Charge @ $0.8010	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	60	$ 37.40	$ 11.85	$ 48.06	$ 97.31	$ 2.09	$ 4.24	$ 5.01	$ 108.65	$ 36.11	$ 144.76	1
2	70	37.40	11.85	56.07	105.32	2.44	4.95	5.84	118.55	42.13	160.68	2
3	80	37.40	11.85	64.08	113.33	2.79	5.66	6.68	128.46	48.14	176.60	3
4	90	37.40	11.85	72.09	121.34	3.14	6.36	7.51	138.35	54.16	192.51	4
5	100	37.40	11.85	80.10	129.35	3.49	7.07	8.35	148.26	60.18	208.44	5
6	150	37.40	11.85	120.15	169.40	5.24	10.61	12.52	197.77	90.27	288.04	6
7	200	37.40	11.85	160.20	209.45	6.98	14.14	16.70	247.27	120.36	367.63	7
8	250	37.40	11.85	200.25	249.50	8.73	17.68	20.87	296.78	150.45	447.23	8
9	300	37.40	11.85	240.30	289.55	10.47	21.21	25.05	346.28	180.54	526.82	9
10	350	37.40	11.85	280.35	329.60	12.22	24.75	29.22	395.79	210.63	606.42	10
11	400	37.40	11.85	320.40	369.65	13.96	28.28	33.39	445.28	240.72	686.00	11
12	500	37.40	11.85	400.50	449.75	17.45	35.35	41.74	544.29	300.90	845.19	12
13	600	37.40	11.85	480.60	529.85	20.94	42.42	50.09	643.30	361.08	1,004.38	13
14	700	37.40	11.85	560.70	609.95	24.43	49.49	58.44	742.31	421.26	1,163.57	14

a/ Peak Usage Charge applicable in the months of November - April and assumes 171 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - 3,075 Therms or More
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 87.55	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.6063	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 87.55	$ -	$ 60.63	$ 148.18	$ 3.49	$ 7.07	$ 8.35	$ 167.09	$ 60.18	$ 227.27	1
2	150	87.55	-	90.95	178.50	5.24	10.61	12.52	206.87	90.27	297.14	2
3	200	87.55	-	121.26	208.81	6.98	14.14	16.70	246.63	120.36	366.99	3
4	250	87.55	-	151.58	239.13	8.73	17.68	20.87	286.41	150.45	436.86	4
5	300	87.55	-	181.89	269.44	10.47	21.21	25.05	326.17	180.54	506.71	5
6	400	87.55	-	242.52	330.07	13.96	28.28	33.39	405.70	240.72	646.42	6
7	500	87.55	-	303.15	390.70	17.45	35.35	41.74	485.24	300.90	786.14	7
8	600	87.55	-	363.78	451.33	20.94	42.42	50.09	564.78	361.08	925.86	8
9	700	87.55	-	424.41	511.96	24.43	49.49	58.44	644.32	421.26	1,065.58	9
10	800	87.55	-	485.04	572.59	27.92	56.56	66.79	723.86	481.44	1,205.30	10
11	900	87.55	-	545.67	633.22	31.41	63.63	75.14	803.40	541.62	1,345.02	11
12	1,000	87.55	-	606.30	693.85	34.90	70.70	83.49	882.94	601.80	1,484.74	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Heating and/or Cooling - 3,075 Therms or More
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $87.55	Peak Usage Charge @ $0.0532	Distribution Charge @ $0.6063	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 87.55	$ 148.42	$ 60.63	$ 296.60	$ 3.49	$ 7.07	$ 8.35	$ 315.51	$ 60.18	$ 375.69	1
2	250	87.55	148.42	151.58	387.55	8.73	17.68	20.87	434.83	150.45	585.28	2
3	500	87.55	148.42	303.15	539.12	17.45	35.35	41.74	633.66	300.90	934.56	3
4	750	87.55	148.42	454.73	690.70	26.18	53.03	62.61	832.52	451.35	1,283.87	4
5	1,000	87.55	148.42	606.30	842.27	34.90	70.70	83.49	1,031.36	601.80	1,633.16	5
6	1,250	87.55	148.42	757.88	993.85	43.63	88.38	104.36	1,230.22	752.25	1,982.47	6
7	1,500	87.55	148.42	909.45	1,145.42	52.35	106.05	125.23	1,429.05	902.70	2,331.75	7
8	1,750	87.55	148.42	1,061.03	1,297.00	61.08	123.73	146.10	1,627.91	1,053.15	2,681.06	8
9	2,000	87.55	148.42	1,212.60	1,448.57	69.80	141.40	166.97	1,826.74	1,203.60	3,030.34	9
10	2,500	87.55	148.42	1,515.75	1,751.72	87.25	176.75	208.71	2,224.43	1,504.50	3,728.93	10
11	3,000	87.55	148.42	1,818.90	2,054.87	104.70	212.10	250.46	2,622.13	1,805.40	4,427.53	11
12	3,500	87.55	148.42	2,122.05	2,358.02	122.15	247.45	292.20	3,019.82	2,106.30	5,126.12	12
13	4,000	87.55	148.42	2,425.20	2,661.17	139.60	282.80	333.94	3,417.51	2,407.20	5,824.71	13
14	5,000	87.55	148.42	3,031.50	3,267.47	174.50	353.50	417.43	4,212.90	3,009.00	7,221.90	14

a/ Peak Usage Charge applicable in the months of November - April and assumes 2,790 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Non-heating and Non-cooling
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 35.65	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.6087	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 35.65	$ -	$ 60.87	$ 96.52	$ 3.49	$ 7.07	$ 8.35	$ 115.43	$ 60.18	$ 175.61	1
2	150	35.65	-	91.31	126.96	5.24	10.61	12.52	155.33	90.27	245.60	2
3	200	35.65	-	121.74	157.39	6.98	14.14	16.70	195.21	120.36	315.57	3
4	250	35.65	-	152.18	187.83	8.73	17.68	20.87	235.11	150.45	385.56	4
5	300	35.65	-	182.61	218.26	10.47	21.21	25.05	274.99	180.54	455.53	5
6	400	35.65	-	243.48	279.13	13.96	28.28	33.39	354.76	240.72	595.48	6
7	500	35.65	-	304.35	340.00	17.45	35.35	41.74	434.54	300.90	735.44	7
8	600	35.65	-	365.22	400.87	20.94	42.42	50.09	514.32	361.08	875.40	8
9	700	35.65	-	426.09	461.74	24.43	49.49	58.44	594.10	421.26	1,015.36	9
10	800	35.65	-	486.96	522.61	27.92	56.56	66.79	673.88	481.44	1,155.32	10
11	900	35.65	-	547.83	583.48	31.41	63.63	75.14	753.66	541.62	1,295.28	11
12	1,000	35.65	-	608.70	644.35	34.90	70.70	83.49	833.44	601.80	1,435.24	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Commercial and Industrial Firm Service - Rate Schedule Nos. 2 and 2A
Non-heating and Non-cooling
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $35.65	Peak Usage Charge @ $0.0534	Distribution Charge @ $0.6087	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 35.65	$ 33.91	$ 60.87	$ 130.43	$ 3.49	$ 7.07	$ 8.35	$ 149.34	$ 60.18	$ 209.52	1
2	150	35.65	33.91	91.31	160.87	5.24	10.61	12.52	189.24	90.27	279.51	2
3	200	35.65	33.91	121.74	191.30	6.98	14.14	16.70	229.12	120.36	349.48	3
4	250	35.65	33.91	152.18	221.74	8.73	17.68	20.87	269.02	150.45	419.47	4
5	300	35.65	33.91	182.61	252.17	10.47	21.21	25.05	308.90	180.54	489.44	5
6	400	35.65	33.91	243.48	313.04	13.96	28.28	33.39	388.67	240.72	629.39	6
7	500	35.65	33.91	304.35	373.91	17.45	35.35	41.74	468.45	300.90	769.35	7
8	600	35.65	33.91	365.22	434.78	20.94	42.42	50.09	548.23	361.08	909.31	8
9	700	35.65	33.91	426.09	495.65	24.43	49.49	58.44	628.01	421.26	1,049.27	9
10	800	35.65	33.91	486.96	556.52	27.92	56.56	66.79	707.79	481.44	1,189.23	10
11	900	35.65	33.91	547.83	617.39	31.41	63.63	75.14	787.57	541.62	1,329.19	11
12	1,000	35.65	33.91	608.70	678.26	34.90	70.70	83.49	867.35	601.80	1,469.15	12

a/ Peak Usage Charge applicable in the months of November - April and assumes 635 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - Less than 3,075 Therms
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 35.65	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.6252	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	30	$ 35.65	$ -	$ 18.76	$ 54.41	$ 1.05	$ 2.12	$ 2.50	$ 60.08	$ 18.05	$ 78.13	1
2	40	35.65	-	25.01	60.66	1.40	2.83	3.34	68.23	24.07	92.30	2
3	50	35.65	-	31.26	66.91	1.75	3.54	4.17	76.37	30.09	106.46	3
4	60	35.65	-	37.51	73.16	2.09	4.24	5.01	84.50	36.11	120.61	4
5	70	35.65	-	43.76	79.41	2.44	4.95	5.84	92.64	42.13	134.77	5
6	80	35.65	-	50.02	85.67	2.79	5.66	6.68	100.80	48.14	148.94	6
7	90	35.65	-	56.27	91.92	3.14	6.36	7.51	108.93	54.16	163.09	7
8	100	35.65	-	62.52	98.17	3.49	7.07	8.35	117.08	60.18	177.26	8
9	150	35.65	-	93.78	129.43	5.24	10.61	12.52	157.80	90.27	248.07	.9
10	200	35.65	-	125.04	160.69	6.98	14.14	16.70	198.51	120.36	318.87	10
11	300	35.65	-	187.56	223.21	10.47	21.21	25.05	279.94	180.54	460.48	11
12	400	35.65	-	250.08	285.73	13.96	28.28	33.39	361.36	240.72	602.08	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - Less than 3,075 Therms
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $ 35.65	Peak Usage Charge @ $0.0544	Distribution Charge @ $0.6252	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	60	$ 35.65	$ 10.22	$ 37.51	$ 83.38	$ 2.09	$ 4.24	$ 5.01	$ 94.72	$ 36.11	$ 130.83	1
2	70	35.65	$ 10.22	43.76	89.63	2.44	4.95	5.84	102.86	42.13	144.99	2
3	80	35.65	$ 10.22	50.02	95.89	2.79	5.66	6.68	111.02	48.14	159.16	3
4	90	35.65	$ 10.22	56.27	102.14	3.14	6.36	7.51	119.15	54.16	173.31	4
5	100	35.65	$ 10.22	62.52	108.39	3.49	7.07	8.35	127.30	60.18	187.48	5
6	150	35.65	$ 10.22	93.78	139.65	5.24	10.61	12.52	168.02	90.27	258.29	6
7	200	35.65	$ 10.22	125.04	170.91	6.98	14.14	16.70	208.73	120.36	329.09	7
8	250	35.65	$ 10.22	156.30	202.17	8.73	17.68	20.87	249.45	150.45	399.90	8
9	300	35.65	$ 10.22	187.56	233.43	10.47	21.21	25.05	290.16	180.54	470.70	9
10	350	35.65	$ 10.22	218.82	264.69	12.22	24.75	29.22	330.88	210.63	541.51	10
11	400	35.65	$ 10.22	250.08	295.95	13.96	28.28	33.39	371.58	240.72	612.30	11
12	500	35.65	$ 10.22	312.60	358.47	17.45	35.35	41.74	453.01	300.90	753.91	12
13	600	35.65	$ 10.22	375.12	420.99	20.94	42.42	50.09	534.44	361.08	895.52	13
14	700	35.65	$ 10.22	437.64	483.51	24.43	49.49	58.44	615.87	421.26	1,037.13	14

a/ Peak Usage Charge applicable in the months of November - April and assumes 188 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - 3,075 Therms or More
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 87.60	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.6148	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 87.60	$ -	$ 61.48	$ 149.08	$ 3.49	$ 7.07	$ 8.35	$ 167.99	$ 60.18	$ 228.17	1
2	150	87.60	-	92.22	179.82	5.24	10.61	12.52	208.19	90.27	298.46	2
3	200	87.60	-	122.96	210.56	6.98	14.14	16.70	248.38	120.36	368.74	3
4	250	87.60	-	153.70	241.30	8.73	17.68	20.87	288.58	150.45	439.03	4
5	300	87.60	-	184.44	272.04	10.47	21.21	25.05	328.77	180.54	509.31	5
6	400	87.60	-	245.92	333.52	13.96	28.28	33.39	409.15	240.72	649.87	6
7	500	87.60	-	307.40	395.00	17.45	35.35	41.74	489.54	300.90	790.44	7
8	600	87.60	-	368.88	456.48	20.94	42.42	50.09	569.93	361.08	931.01	8
9	700	87.60	-	430.36	517.96	24.43	49.49	58.44	650.32	421.26	1,071.58	9
10	800	87.60	-	491.84	579.44	27.92	56.56	66.79	730.71	481.44	1,212.15	10
11	900	87.60	-	553.32	640.92	31.41	63.63	75.14	811.10	541.62	1,352.72	11
12	1,000	87.60	-	614.80	702.40	34.90	70.70	83.49	891.49	601.80	1,493.29	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Heating and/or Cooling - 3,075 Therms or More
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $ 87.60	Peak Usage Charge @ $0.0533	Distribution Charge @ $0.6148	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 87.60	$ 131.75	$ 61.48	$ 280.83	$ 3.49	$ 7.07	$ 8.35	$ 299.74	$ 60.18	$ 359.92	1
2	250	87.60	$ 131.75	153.70	373.05	8.73	17.68	20.87	420.33	150.45	570.78	2
3	500	87.60	$ 131.75	307.40	526.75	17.45	35.35	41.74	621.29	300.90	922.19	3
4	750	87.60	$ 131.75	461.10	680.45	26.18	53.03	62.61	822.27	451.35	1,273.62	4
5	1,000	87.60	$ 131.75	614.80	834.15	34.90	70.70	83.49	1,023.24	601.80	1,625.04	5
6	1,250	87.60	$ 131.75	768.50	987.85	43.63	88.38	104.36	1,224.22	752.25	1,976.47	6
7	1,500	87.60	$ 131.75	922.20	1,141.55	52.35	106.05	125.23	1,425.18	902.70	2,327.88	7
8	1,750	87.60	$ 131.75	1,075.90	1,295.25	61.08	123.73	146.10	1,626.16	1,053.15	2,679.31	8
9	2,000	87.60	$ 131.75	1,229.60	1,448.95	69.80	141.40	166.97	1,827.12	1,203.60	3,030.72	9
10	2,500	87.60	$ 131.75	1,537.00	1,756.35	87.25	176.75	208.71	2,229.06	1,504.50	3,733.56	10
11	3,000	87.60	$ 131.75	1,844.40	2,063.75	104.70	212.10	250.46	2,631.01	1,805.40	4,436.41	11
12	3,500	87.60	$ 131.75	2,151.80	2,371.15	122.15	247.45	292.20	3,032.95	2,106.30	5,139.25	12
13	4,000	87.60	$ 131.75	2,459.20	2,678.55	139.60	282.80	333.94	3,434.89	2,407.20	5,842.09	13
14	5,000	87.60	$ 131.75	3,074.00	3,293.35	174.50	353.50	417.43	4,238.78	3,009.00	7,247.78	14

a/ Peak Usage Charge applicable in the months of November - April and assumes 2,472 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Non-heating and Non-cooling
Summer (June - August)

Line No.	Therm Usage	Customer Charge @ $ 35.65	Peak Usage Charge @ $0.0000	Distribution Charge @ $0.6124	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 35.65	$ -	$ 61.24	$ 96.89	$ 3.49	$ 7.07	$ 8.35	$ 115.80	$ 60.18	$ 175.98	1
2	150	35.65	-	91.86	127.51	5.24	10.61	12.52	155.88	90.27	246.15	2
3	200	35.65	-	122.48	158.13	6.98	14.14	16.70	195.95	120.36	316.31	3
4	250	35.65	-	153.10	188.75	8.73	17.68	20.87	236.03	150.45	386.48	4
5	300	35.65	-	183.72	219.37	10.47	21.21	25.05	276.10	180.54	456.64	5
6	400	35.65	-	244.96	280.61	13.96	28.28	33.39	356.24	240.72	596.96	6
7	500	35.65	-	306.20	341.85	17.45	35.35	41.74	436.39	300.90	737.29	7
8	600	35.65	-	367.44	403.09	20.94	42.42	50.09	516.54	361.08	877.62	8
9	700	35.65	-	428.68	464.33	24.43	49.49	58.44	596.69	421.26	1,017.95	9
10	800	35.65	-	489.92	525.57	27.92	56.56	66.79	676.84	481.44	1,158.28	10
11	900	35.65	-	551.16	586.81	31.41	63.63	75.14	756.99	541.62	1,298.61	11
12	1,000	35.65	-	612.40	648.05	34.90	70.70	83.49	837.14	601.80	1,438.94	12

a/ Peak Usage Charge applicable in the months of November - April.

Washington Gas Light Company
District of Columbia

Monthly Bill Comparisons for SPECIFIC Usage Levels at PROPOSED Rates

Group Metered Apartments Firm Service - Rate Schedule Nos. 3 and 3A
Non-heating and Non-cooling
Winter (November - April)

Line No.	Therm Usage	Customer Charge @ $ 35.65	Peak Usage Charge @ $0.0534	Distribution Charge @ $0.6124	Sub-total Distribution Revenue	ROW Fee @ $0.0349	Delivery Tax @ $0.07070	SETF & EATF @ $0.08349	Total Distribution Revenue	PGC Revenue @ $0.6018	Total Sales Revenue	Line No.
	A	B	C a/	D	E=B+C+D	F	G	H	I=E+F+G+H	J	K=I+J	
1	100	$ 35.65	$ 32.42	$ 61.24	$ 129.31	$ 3.49	$ 7.07	$ 8.35	$ 148.22	$ 60.18	$ 208.40	1
2	150	35.65	$ 32.42	91.86	159.93	5.24	10.61	12.52	188.30	90.27	278.57	2
3	200	35.65	$ 32.42	122.48	190.55	6.98	14.14	16.70	228.37	120.36	348.73	3
4	250	35.65	$ 32.42	153.10	221.17	8.73	17.68	20.87	268.45	150.45	418.90	4
5	300	35.65	$ 32.42	183.72	251.79	10.47	21.21	25.05	308.52	180.54	489.06	5
6	400	35.65	$ 32.42	244.96	313.03	13.96	28.28	33.39	388.66	240.72	629.38	6
7	500	35.65	$ 32.42	306.20	374.27	17.45	35.35	41.74	468.81	300.90	769.71	7
8	600	35.65	$ 32.42	367.44	435.51	20.94	42.42	50.09	548.96	361.08	910.04	8
9	700	35.65	$ 32.42	428.68	496.75	24.43	49.49	58.44	629.11	421.26	1,050.37	9
10	800	35.65	$ 32.42	489.92	557.99	27.92	56.56	66.79	709.26	481.44	1,190.70	10
11	900	35.65	$ 32.42	551.16	619.23	31.41	63.63	75.14	789.41	541.62	1,331.03	11
12	1,000	35.65	$ 32.42	612.40	680.47	34.90	70.70	83.49	869.56	601.80	1,471.36	12

a/ Peak Usage Charge applicable in the months of November - April and assumes 607 therms used in the peak month.

Washington Gas Light Company
District of Columbia

Summary of Months Billed, Customer Charges and Therms

Based on 12 Months Ended March 31, 2024 - Pro Forma

Line No.	Class of Service	Number of Months Billed	Number of Customer Charges	Normal Weather Therms	Adjusted Normal Therms	Line No.
	A	B	C	D	F=D	
1	**FIRM**					1
2	**Residential**					2
3	Heating and/or Cooling	1,627,379	1,627,379	84,793,166	84,793,166	3
4	Non-heating & Non-cooling					4
5	Individually Metered Apartments	131,084	131,084	677,620	677,620	5
6	Other	42,794	42,794	1,703,534	1,703,534	6
7	Total Residential	1,801,257	1,801,257	87,174,320	87,174,320	7
8	**Commercial & Industrial**					8
9	Heating and/or Cooling					9
10	Less than 3,075 therms	53,982	53,982	5,336,138	5,336,138	10
11	3,075 therms or more	40,679	40,679	68,854,404	68,854,404	11
12	Non-heating & Non-cooling	22,135	22,135	8,012,732	8,012,732	12
13	Total Commercial & Industrial	116,796	116,796	82,203,274	82,203,274	13
14	**Group Metered Apartments**					14
15	Heating and/or Cooling					15
16	Less than 3,075 therms	7,177	7,177	999,179	999,179	16
17	3,075 therms or more	20,485	20,485	29,674,103	29,674,103	17
18	Non-heating & Non-cooling	10,430	10,430	3,929,848	3,929,848	18
19	Total Group Metered Apartments	38,092	38,092	34,603,130	34,603,130	19
20	**Total Firm**	1,956,145	1,956,145	203,980,724	203,980,724	20
21	**INTERRUPTIBLE**	1,327	1,327	39,827,791	39,827,791	21
22	**Special Contracts**	36	36	38,220,735	38,220,735	22
23	**Total Firm and Interruptible**	1,957,508	1,957,508	282,029,250	282,029,250	23

Washington Gas Light Company
District of Columbia

Normal Weather Study Data Supporting
Monthly Bill Comparisons for Average Usage Levels

Residential Service - Rate Schedule Nos. 1 and 1A
Heating and/or Cooling

Line No.	Month	Normal Weather Therms	Base Gas Adj.	Net Normal Weather Therms	Number of Customers	Bills for Customer Charge	Average Therm Usage	Line No.
	A	B a/	C	D=B+C	E	F	G=D/E	
1	January	15,614,999	-	15,614,999	135,801	135,801	115	1
2	February	16,501,618	-	16,501,618	135,697	135,697	122	2
3	March	13,105,832	-	13,105,832	135,420	135,420	97	3
4	April	9,100,539	-	9,100,539	135,570	135,570	67	4
5	May	4,704,162	-	4,704,162	135,360	135,360	35	5
6	June	1,872,917	-	1,872,917	135,332	135,332	14	6
7	July	1,198,802	-	1,198,802	135,303	135,303	9	7
8	August	1,188,853	-	1,188,853	135,514	135,514	9	8
9	September	1,178,441	-	1,178,441	135,676	135,676	9	9
10	October	2,059,068	-	2,059,068	135,752	135,752	15	10
11	November	6,631,032	-	6,631,032	135,976	135,976	49	11
12	December	11,636,904	-	11,636,904	135,978	135,978	86	12
13	Total	84,793,166	-	84,793,166	1,627,379	1,627,379	627	13
14	Winter (Nov - Apr)			72,590,924				14
15	Summer (May - Oct)			12,202,243				15

a/ Normal Weather Study, Exhibit WG (N)-4, Schedule 1B

Washington Gas Light Company
District of Columbia

Normal Weather Study Data Supporting
Monthly Bill Comparisons for Average Usage Levels

Residential Service - Rate Schedule Nos. 1 and 1A
Non-Heating and Non-Cooling
Individually Metered Apartments

Line No.	Month	Normal Weather Therms	Base Gas Adj.	Net Normal Weather Therms	Number of Customers	Bills for Customer Charge	Average Therm Usage	Line No.
	A	B a/	C	D=B+C	E	F	G=D/E	
1	January	93,901	-	93,901	10,890	10,890	9	1
2	February	97,588	-	97,588	10,857	10,857	9	2
3	March	82,663	-	82,663	10,820	10,820	8	3
4	April	65,356	-	65,356	10,945	10,945	6	4
5	May	45,988	-	45,988	10,920	10,920	4	5
6	June	33,637	-	33,637	10,935	10,935	3	6
7	July	30,805	-	30,805	10,965	10,965	3	7
8	August	30,783	-	30,783	10,957	10,957	3	8
9	September	30,802	-	30,802	10,964	10,964	3	9
10	October	34,712	-	34,712	10,959	10,959	3	10
11	November	54,851	-	54,851	10,962	10,962	5	11
12	December	76,535	-	76,535	10,910	10,910	7	12
13	Total	677,620	-	677,620	131,084	131,084	63	13
14	Winter (Nov - Apr)			470,893				14
15	Summer (May - Oct)			206,727				15

a/ Normal Weather Study, Exhibit WG (N)-4, Schedule 1B

Washington Gas Light Company
District of Columbia

Normal Weather Study Data Supporting
Monthly Bill Comparisons for Average Usage Levels

Present and Proposed Residential Service Rate Schedule Nos. 1 and 1A
Non-Heating and Non-Cooling
Other than Individually Metered Apartments

Line No.	Month	Normal Weather Therms	Base Gas Adj.	Net Normal Weather Therms	Number of Customers	Bills for Customer Charge	Average Therm Usage	Line No.
	A	B a/	C	D=B+C	E	F	G=D/E	
1	January	299,022	-	299,022	3,586	3,586	83	1
2	February	315,197	-	315,197	3,581	3,581	88	2
3	March	254,366	-	254,366	3,586	3,586	71	3
4	April	175,020	-	175,020	3,515	3,515	50	4
5	May	97,601	-	97,601	3,550	3,550	27	5
6	June	46,435	-	46,435	3,542	3,542	13	6
7	July	34,516	-	34,516	3,547	3,547	10	7
8	August	34,526	-	34,526	3,548	3,548	10	8
9	September	34,740	-	34,740	3,570	3,570	10	9
10	October	51,238	-	51,238	3,591	3,591	14	10
11	November	134,705	-	134,705	3,589	3,589	38	11
12	December	226,169	-	226,169	3,589	3,589	63	12
13	Total	1,703,534	-	1,703,534	42,794	42,794	477	13
14	Winter (Nov - Apr)			1,404,479				14
15	Summer (May - Oct)			299,055				15

a/ Normal Weather Study, Exhibit WG (N)-4, Schedule 1B

Washington Gas Light Company
District of Columbia

Normal Weather Study Data Supporting
Monthly Bill Comparisons for Average Usage Levels

Present and Proposed Firm Service Other Than Residential Rate Schedule Nos. 2 and 2A
Commercial and Industrial
Heating and/or Cooling
(a) - Normal Weather Annual Usage Less Than 3,075 Therms

Line No.	Month	Normal Weather Therms	Base Gas Adj.	Net Normal Weather Therms	Number of Customers	Bills for Customer Charge	Average Therm Usage	Line No.
	A	B a/	C	D=B+C	E	F	G=D/E	
1	January	937,525	-	937,525	4,537	4,537	207	1
2	February	1,001,085	-	1,001,085	4,589	4,589	218	2
3	March	805,452	-	805,452	4,584	4,584	176	3
4	April	547,624	-	547,624	4,445	4,445	123	4
5	May	302,717	-	302,717	4,464	4,464	68	5
6	June	143,141	-	143,141	4,461	4,461	32	6
7	July	105,847	-	105,847	4,467	4,467	24	7
8	August	105,942	-	105,942	4,471	4,471	24	8
9	September	105,373	-	105,373	4,447	4,447	24	9
10	October	156,641	-	156,641	4,480	4,480	35	10
11	November	418,205	-	418,205	4,509	4,509	93	11
12	December	706,587	-	706,587	4,528	4,528	156	12
13	Total	5,336,138	-	5,336,138	53,982	53,982	1,180	13
14	Winter (Nov - Apr)			4,416,478				14
15	Summer (May - Oct)			919,660				15

a/ Normal Weather Study, Exhibit WG (N)-4, Schedule 1B

Washington Gas Light Company
District of Columbia

Normal Weather Study Data Supporting
Monthly Bill Comparisons for Average Usage Levels

Present and Proposed Firm Service Other Than Residential Rate Schedule Nos. 2 and 2A
Commercial and Industrial
Heating and/or Cooling
(b) - Normal Weather Annual Usage 3,075 Therms or More

Line No.	Month	Normal Weather Therms	Base Gas Adj.	Net Normal Weather Therms	Number of Customers	Bills for Customer Charge	Average Therm Usage	Line No.
	A	B a/	C	D=B+C	E	F	G=D/E	
1	January	10,585,624	-	10,585,624	3,428	3,428	3,088	1
2	February	11,064,767	-	11,064,767	3,417	3,417	3,238	2
3	March	9,214,249	-	9,214,249	3,419	3,419	2,695	3
4	April	6,760,239	-	6,760,239	3,388	3,388	1,995	4
5	May	4,320,341	-	4,320,341	3,360	3,360	1,286	5
6	June	2,796,062	-	2,796,062	3,373	3,373	829	6
7	July	2,432,680	-	2,432,680	3,363	3,363	723	7
8	August	2,440,278	-	2,440,278	3,363	3,363	726	8
9	September	2,463,161	-	2,463,161	3,384	3,384	728	9
10	October	2,951,263	-	2,951,263	3,373	3,373	875	10
11	November	5,486,365	-	5,486,365	3,387	3,387	1,620	11
12	December	8,339,376	-	8,339,376	3,424	3,424	2,436	12
13	Total	68,854,404	-	68,854,404	40,679	40,679	20,239	13
14	Winter (Nov - Apr)			51,450,620				14
15	Summer (May - Oct)			17,403,784				15

a/ Normal Weather Study, Exhibit WG (N)-4, Schedule 1B

Washington Gas Light Company
District of Columbia

Normal Weather Study Data Supporting
Monthly Bill Comparisons for Average Usage Levels

Present and Proposed Firm Service Other Than Residential Rate Schedule Nos. 2 and 2A
Commercial and Industrial
Non-Heating and Non-Cooling

Line No.	Month	Normal Weather Therms	Base Gas Adj.	Net Normal Weather Therms	Number of Customers	Bills for Customer Charge	Average Therm Usage	Line No.
	A	B a/	C	D=B+C	E	F	G=D/E	
1	January	990,893	-	990,893	1,836	1,836	540	1
2	February	1,024,937	-	1,024,937	1,837	1,837	558	2
3	March	893,661	-	893,661	1,838	1,838	486	3
4	April	759,780	-	759,780	1,857	1,857	409	4
5	May	586,171	-	586,171	1,856	1,856	316	5
6	June	472,038	-	472,038	1,849	1,849	255	6
7	July	443,196	-	443,196	1,844	1,844	240	7
8	August	441,437	-	441,437	1,844	1,844	239	8
9	September	439,916	-	439,916	1,845	1,845	238	9
10	October	473,084	-	473,084	1,846	1,846	256	10
11	November	648,505	-	648,505	1,844	1,844	352	11
12	December	839,116	-	839,116	1,839	1,839	456	12
13	Total	8,012,732	-	8,012,732	22,135	22,135	4,345	13
14	Winter (Nov - Apr)			5,156,890				14
15	Summer (May - Oct)			2,855,842				15

a/ Normal Weather Study, Exhibit WG (N)-4, Schedule 1B

Washington Gas Light Company
District of Columbia

Normal Weather Study Data Supporting
Monthly Bill Comparisons for Average Usage Levels

Present and Proposed Firm Service Other Than Residential Rate Schedule Nos. 3 and 3A
Group Metered Apartments
Heating and/or Cooling
(b) - Normal Weather Annual Usage 3,075 Therms or More

Line No.	Month	Normal Weather Therms	Base Gas Adj.	Net Normal Weather Therms	Number of Customers	Bills for Customer Charge	Average Therm Usage	Line No.
	A	B a/	C	D=B+C	E	F	G=D/E	
1	January	4,968,468	-	4,968,468	1,711	1,711	2,904	1
2	February	5,208,326	-	5,208,326	1,703	1,703	3,058	2
3	March	4,253,115	-	4,253,115	1,709	1,709	2,489	3
4	April	3,052,109	-	3,052,109	1,711	1,711	1,784	4
5	May	1,767,558	-	1,767,558	1,699	1,699	1,040	5
6	June	959,532	-	959,532	1,711	1,711	561	6
7	July	764,106	-	764,106	1,705	1,705	448	7
8	August	765,898	-	765,898	1,709	1,709	448	8
9	September	768,139	-	768,139	1,714	1,714	448	9
10	October	1,019,619	-	1,019,619	1,701	1,701	599	10
11	November	2,336,247	-	2,336,247	1,699	1,699	1,375	11
12	December	3,810,987	-	3,810,987	1,713	1,713	2,225	12
13	Total	29,674,103	-	29,674,103	20,485	20,485	17,379	13
14	Winter (Nov - Apr)			23,629,251				14
15	Summer (May - Oct)			6,044,851				15

a/ Normal Weather Study, Exhibit WG (N)-4, Schedule 1B

Washington Gas Light Company
District of Columbia

Normal Weather Study Data Supporting
Monthly Bill Comparisons for Average Usage Levels

Present and Proposed Firm Service Other Than Residential Rate Schedule Nos. 3 and 3A
Group Metered Apartments
Heating and/or Cooling
(a) - Normal Weather Annual Usage Less Than 3,075 Therms

Line No.	Month	Normal Weather Therms	Base Gas Adj.	Net Normal Weather Therms	Number of Customers	Bills for Customer Charge	Average Therm Usage	Line No.
	A	B a/	C	D=B+C	E	F	G=D/E	
1	January	150,960	-	150,960	597	597	253	1
2	February	162,168	-	162,168	612	612	265	2
3	March	133,282	-	133,282	605	605	220	3
4	April	98,186	-	98,186	595	595	165	4
5	May	64,877	-	64,877	608	608	107	5
6	June	41,318	-	41,318	598	598	69	6
7	July	35,914	-	35,914	596	596	60	7
8	August	35,553	-	35,553	590	590	60	8
9	September	35,131	-	35,131	583	583	60	9
10	October	42,985	-	42,985	596	596	72	10
11	November	80,042	-	80,042	602	602	133	11
12	December	118,763	-	118,763	595	595	200	12
13	Total	999,179	-	999,179	7,177	7,177	1,664	13
14	Winter (Nov - Apr)			743,401				14
15	Summer (May - Oct)			255,778				15

a/ Normal Weather Study, Exhibit WG (N)-4, Schedule 1B

Washington Gas Light Company
District of Columbia

Normal Weather Study Data Supporting
Monthly Bill Comparisons for Average Usage Levels

Present and Proposed Firm Service Other Than Residential Rate Schedule Nos. 3 and 3A
Group Metered Apartments
Non-Heating and Non-Cooling

Line No.	Month	Normal Weather Therms	Base Gas Adj.	Net Normal Weather Therms	Number of Customers	Bills for Customer Charge	Average Therm Usage	Line No.
	A	B a/	C	D=B+C	E	F	G=D/E	
1	January	514,080	-	514,080	870	870	591	1
2	February	536,647	-	536,647	875	875	613	2
3	March	460,035	-	460,035	871	871	528	3
4	April	371,799	-	371,799	866	866	429	4
5	May	276,666	-	276,666	869	869	318	5
6	June	214,062	-	214,062	868	868	247	6
7	July	199,079	-	199,079	868	868	229	7
8	August	198,846	-	198,846	869	869	229	8
9	September	198,156	-	198,156	868	868	228	9
10	October	217,446	-	217,446	869	869	250	10
11	November	316,732	-	316,732	868	868	365	11
12	December	426,301	-	426,301	869	869	491	12
13	Total	3,929,848	-	3,929,848	10,430	10,430	4,518	13
14	Winter (Nov - Apr)			2,625,593				14
15	Summer (May - Oct)			1,304,255				15

a/ Normal Weather Study, Exhibit WG (N)-4, Schedule 1B

Washington Gas Light Company
District of Columbia

Financial Data Supporting
Monthly Bill Comparisons for Average Usage Levels

Present and Proposed Interruptible Service - Rate Schedule Nos. 6

Line No.	Month	Normal Weather Therms	Base Gas Adj.	Net Normal Weather Therms	Number of Customers	Bills for Customer Charge	Average Therm Usage	Line No.
	A	B a/	C	D=B+C	E	F	G=D/E	
1	January	5,219,723	-	5,219,723	110	110	47,452	1
2	February	5,374,069	-	5,374,069	109	109	49,303	2
3	March	4,672,416	-	4,672,416	110	110	42,477	3
4	April	3,845,357	-	3,845,357	113	113	34,030	4
5	May	2,788,326	-	2,788,326	111	111	25,120	5
6	June	2,111,673	-	2,111,673	109	109	19,373	6
7	July	1,964,529	-	1,964,529	109	109	18,023	7
8	August	1,964,529	-	1,964,529	109	109	18,023	8
9	September	2,000,575	-	2,000,575	111	111	18,023	9
10	October	2,201,794	-	2,201,794	111	111	19,836	10
11	November	3,320,972	-	3,320,972	114	114	29,131	11
12	December	4,363,829	-	4,363,829	111	111	39,314	12
13	Total	39,827,791	-	39,827,791	1,327	1,327	360,105	13
14	Winter (Nov - Apr)			26,796,365				14
15	Summer (May - Oct)			13,031,426				15

a/ Normal Weather Study, Exhibit WG (N)-4, Schedule 1B

DC Residential Heating and/or Cooling WNA Revenue Adjustment

Line No.	Month	Months Billed (no. of customers billed)	Variation per HDD	HDD Variance a/	Volume Adjustment	Distribution Rate /d	Revenue Adjustment Due/ (Owed)	WNA Credits /(Charges)	Cumulative Revenue Adjustment	Carrying Cost on Revenue Due	Cumulative Revenues Plus Carrying Costs	Normal Weather Therms
	A	B	C	D	E=B*C*D	F	G=E*F	H	I=G+H cumulative	I b/	J	K
1	October-23	135,752	0.139774	(8)	151,797	$ 0.5638	$ 85,583	$ -	$ 85,583	$ 152	$ 85,735	2,059,068
2	November-23	135,976	0.139774	(65)	1,235,384	$ 0.5638	$ 696,509	$ -	$ 782,092	$ 1,537	$ 783,780	6,631,032
3	December-23	135,978	0.139774	(16)	304,099	$ 0.5638	$ 171,451	$ -	$ 953,543	$ 3,074	$ 958,305	11,636,904
4	January-24	135,801	0.139774	(108)	2,049,996	$ 0.5638	$ 1,155,788	$ -	$ 2,109,331	$ 5,424	$ 2,119,516	15,614,999
5	February-24	135,697	0.139774	(112)	2,124,294	$ 0.5638	$ 1,197,677	$ -	$ 3,307,008	$ 9,591	$ 3,326,785	16,501,618
6	March-24	135,420	0.139774	(118)	2,233,527	$ 0.5638	$ 1,259,263		$ 4,566,271	$ 13,942	$ 4,599,990	13,105,832
7	April-24	135,570	0.139774	(48)	909,560	$ 0.5638	$ 512,810	$ -	$ 5,079,081	$ 17,080	$ 5,129,880	9,100,539
8	May-24	135,360	0.139774	(54)	1,021,670	$ 0.5638	$ 576,018	$ -	$ 5,655,099	$ 19,008	$ 5,724,907	4,704,162
9	June-24					$ 0.5638	$ -		$ 5,655,099	$ 20,028	$ 5,744,935	
10	July-24					$ 0.5638	$ -		$ 5,655,099	$ 20,028	$ 5,764,964	
11	August-24					$ 0.5638	$ -		$ 5,655,099	$ 20,028	$ 5,784,992	
12	September-24					$ 0.5638	$ -		$ 5,655,099	$ 20,028	$ 5,805,021	
13	October-24	135,752	0.139774	1	(18,975)	$ 0.5638	$ (10,698)	$ (150,628)	$ 5,493,773	$ 19,743	$ 5,663,438	2,059,068
14	November-24	135,976	0.139774	30	(570,177)	$ 0.5638	$ (321,466)	$ (485,082)	$ 4,687,225	$ 18,029	$ 4,874,919	6,631,032
15	December-24	135,978	0.139774	(16)	304,099	$ 0.5638	$ 171,451	$ (851,278)	$ 4,007,398	$ 15,397	$ 4,210,488	11,636,904
16	January-25	135,801	0.139774	60	(1,138,887)	$ 0.5638	$ (642,104)	$ (1,142,289)	$ 2,223,005	$ 11,033	$ 2,437,128	15,614,999
17	February-25	135,697	0.139774	(15)	284,504	$ 0.5638	$ 160,403	$ (1,207,148)	$ 1,176,259	$ 6,020	$ 1,396,402	16,501,618
18	March-25	135,420	0.139774	29	(548,918)	$ 0.5638	$ (309,480)	$ (958,735)	$ (91,956)	$ 1,920	$ 130,107	13,105,832
19	April-25	135,570	0.139774	20	(378,983)	$ 0.5638	$ (213,671)	$ (665,735)	$ (971,362)	$ (1,883)	$ (751,182)	9,100,539
20	May-25 c/	135,360	0.139774	(13)	245,958	$ 0.5638	$ 138,671	$ 90,036	$ (742,655)	$ (3,035)	$ (525,510)	4,704,162

Line No.	WNA Adjustment for October 24-May-25		
22	Cummulative Revenue Shortfall (Oct 23-May 24)		$ 5,655,099
23	Carrying Costs on Shortfall		$ 149,922
24	Total WNA Charges /Credit Due		$ 5,805,021
25	Normal Weather Therms	=Col K	79,354,153
26	Calculated WNA Rate	=Ln 24/Ln25	$ 0.0732
27	Rate Cap Per Tariff	=Col F *.1	$ 0.0846
28	Lesser of calculated rate or rate cap to be billed		$ 0.0732

21 WNA Adjustment for October 24-May-25

29 May WNA Adjustment Rate: ($91,956-$1,920) * 4,704,162 NW Therms = $0.0191 per therm credit in May

a/ Assumed HDDs for October 2024-May2025 are random variances assuming a slightly colder than normal winter period
b/ Carrying costs calculated as two month average of cummulative revenue adjsutment *(Short-term debt rate/12)
c/ WNA Charges Cease in May 2025 as cummulative revenue adjustment becomes an excess which is to be returned net of carrying charges

DC Commercial & Industrial > 3,075 Therms WNA Revenue Adjustment

Line No.	Month	Months Billed (no. of customers billed)	Variation per HDD	HDD Variance a/	Volume Adjustment	Distribution Rate /d	Revenue Adjustment Due/ (Owed)	WNA Credits /(Charges)	Cumulative Revenue Adjustment	Carrying Cost on Revenue Due	Cumulative Revenues Plus Carrying Costs	Normal Weather Therms
	A	B	C	D	E=B*C*D	F	G=E*F	H	I=G+H cumulative	I = H *STD rate/12	J	K
1	October-23	3,373	3.081347	(8)	83,147	$ 0.4796	$ 39,877	$ -	$ 39,877	$ 71	$ 39,948	2,951,263
2	November-23	3,387	3.081347	(65)	678,374	$ 0.4796	$ 325,348	$ -	$ 365,225	$ 717	$ 366,013	5,486,365
3	December-23	3,424	3.081347	(16)	168,809	$ 0.4796	$ 80,961	$ -	$ 446,186	$ 1,437	$ 448,411	8,339,376
4	January-24	3,428	3.081347	(108)	1,140,789	$ 0.4796	$ 547,122	$ -	$ 993,308	$ 2,549	$ 998,082	10,585,624
5	February-24	3,417	3.081347	(112)	1,179,244	$ 0.4796	$ 565,565	$ -	$ 1,558,873	$ 4,519	$ 1,568,166	11,064,767
6	March-24	3,419	3.081347	(118)	1,243,145	$ 0.4796	$ 596,212		$ 2,155,085	$ 6,577	$ 2,170,955	9,214,249
7	April-24	3,388	3.081347	(48)	501,101	$ 0.4796	$ 240,328	$ -	$ 2,395,413	$ 8,058	$ 2,419,341	6,760,239
8	May-24	3,360	3.081347	(54)	559,080	$ 0.4796	$ 268,135	$ -	$ 2,663,548	$ 8,959	$ 2,696,435	4,320,341
9	June-24					$ 0.4796	$ -		$ 2,663,548	$ 9,433	$ 2,705,868	
10	July-24					$ 0.4796	$ -		$ 2,663,548	$ 9,433	$ 2,715,302	
11	August-24					$ 0.4796	$ -		$ 2,663,548	$ 9,433	$ 2,724,735	
12	September-24					$ 0.4796	$ -		$ 2,663,548	$ 9,433	$ 2,734,169	
13	October-24	3,373	3.081347	1	(10,393)	$ 0.4796	$ (4,984)	$ (137,414)	$ 2,521,150	$ 9,181	$ 2,600,952	2,951,263
14	November-24	3,387	3.081347	30	(313,096)	$ 0.4796	$ (150,161)	$ (255,451)	$ 2,115,538	$ 8,211	$ 2,203,551	5,486,365
15	December-24	3,424	3.081347	(16)	168,809	$ 0.4796	$ 80,961	$ (388,290)	$ 1,808,209	$ 6,948	$ 1,903,170	8,339,376
16	January-25	3,428	3.081347	60	(633,771)	$ 0.4796	$ (303,957)	$ (492,878)	$ 1,011,374	$ 4,993	$ 1,111,328	10,585,624
17	February-25	3,417	3.081347	(15)	157,934	$ 0.4796	$ 75,745	$ (515,187)	$ 571,932	$ 2,804	$ 674,690	11,064,767
18	March-25	3,419	3.081347	29	(305,519)	$ 0.4796	$ (146,527)	$ (429,025)	$ (3,620)	$ 1,006	$ 100,144	9,214,249
19	April-25	3,388	3.081347	20	(208,792)	$ 0.4796	$ (100,137)	$ (314,764)	$ (418,521)	$ (748)	$ (315,504)	6,760,239
20	May-25	3,360	3.081347	(13)	134,593	$ 0.4796	$ 64,551	$ 2,614	$ (351,356)	$ (1,363)	$ (249,703)	4,320,341

21	WNA Adjustment for October 24-May-25		
22	Cummulative Revenue Shortfall (Oct 23-May 24)		$ 2,663,548
23	Carrying Costs on Shortfall		$ 70,621
24	Total WNA Charges /Credit Due		$ 2,734,169
25	Normal Weather Therms	=Col K	58,722,224
26	Calculated WNA Rate	=Ln 24/Ln25	$ 0.0466
27	Rate Cap Per Tariff	=Col F *.15	$ 0.0719
28	Lesser of calculated rate or rate cap to be billed		$ 0.0466
29	May WNA Adjustment Rate: ($3,620-$1,006) * 4,320,341 NW Therms = $0.0006 per therm credit in May		

a/ Assumed HDDs for October 2024-May2025 are random variances assuming a slightly colder than normal winter period
b/ Carrying costs calculated as two month average of cummulative revenue adjsutment *(Short-term debt rate/12)

Formal Case 1180

Exhibit WG(O)-4

Proposed Tariff Changes

Legislative Version

TABLE OF CONTENTS

WASHINGTON GAS LIGHT COMPANY
Residential Service

Rate Schedule No. 1

AVAILABILITY
This schedule is available in the District of Columbia portion of the Company's service area for firm gas service to any customers classified residential as defined in Section 1A. of the General Service Provisions, subject to the provision for Emergency or Stand-by Service included herein.

RATE FOR MONTHLY CONSUMPTION

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

Heating and/or Cooling All billing months	$20.70~~16.55~~ per customer
Non-Heating and Non-Cooling All billing months	
(a) Individually Metered Apartment	$15.00~~12.00~~ per customer
(b) Other	$16.95~~13.55~~ per customer

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

Heating and/or Cooling All gas delivered during the billing month	77.78~~56.38~~ ¢ per therm
Non-Heating and Non-Cooling All gas delivered during the billing month	
(a) Individually Metered Apartment	86.53 ~~66.10~~ ¢ per therm
(b) Other	92.46 ~~63.90~~ ¢ per therm

Purchased Gas Charge
The "purchased gas charge" is the amount the Company charges for each therm of gas consumed by the customer. Such charge is a measure of the costs of the Company to purchase gas to be distributed to the customer for use at the customer's premises.

The gas consumed under this schedule shall be billed an amount per therm representing the average unit cost of purchased gas in accordance with Section 16 of the General Service Provisions.

DISTRIBUTION CHARGE ADJUSTMENT
The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

GAS SUPPLY REALIGNMENT ADJUSTMENT
The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Residential Service - Rate Schedule No. 1
(continued)

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Service Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers, other than Residential Essential Service (RES) customers, billed under this rate schedule shall have a Residential Essential Service Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

Residential Firm Delivery Service - Rate Schedule No. 1A(continued)

RATE FOR MONTHLY DELIVERIES

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

Heating and/or Cooling
All billing months — $20.70 ~~16.55~~ per customer

Non-Heating and Non-Cooling
All billing months

(a) Individually Metered Apartment — $15.00 ~~12.00~~ per customer
(b) Other — $16.95 ~~13.55~~ per customer

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of gas to the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

Heating and/or Cooling
All gas delivered during the billing month — 77.78 ~~56.38~~¢ per therm

Non-Heating and Non-Cooling
All gas delivered during the billing month

(a) Individually Metered Apartment — 86.53 ~~66.10~~¢ per therm
(b) Other — 92.46 ~~63.90~~¢ per therm

Transitional Cost Charge

A charge per therm shall be billed for all therms delivered during the billing month to recover Company supplier transitional costs which shall be equal to the amount per therm included in the calculation of the current months' Purchased Gas Charge as set forth in General Service Provision No. 16.

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Residential Firm Delivery Service Pilot Program - Rate Schedule No. 1A
(continued)

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Service Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers, other than Residential Essential Service (RES) customers, billed under this rate schedule shall have a Residential Essential Service Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

WASHINGTON GAS LIGHT COMPANY

Firm Commercial and Industrial Sales Service

Rate Schedule No. 2

AVAILABILITY

This schedule is available in the District of Columbia portion of the Company's service area for firm gas service to any customer classified as Commercial and Industrial as defined in Section 1A of the General Service Provisions, subject to the provision for Emergency or Stand-by Service included herein.

RATE FOR MONTHLY CONSUMPTION

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

Heating and/or Cooling

All billing months:

(a) Normal Weather Annual Usage less than 3,075 therms	$37.40~~29.90~~ per customer
(b) Normal Weather Annual Usage 3,075 therms or more	$87.55~~70.05~~ per customer

Applicability of (a) or (b) shall be determined each year in accordance with Section 1A. of the General Service Provisions.

Non-Heating and Non-Cooling

All billing months/all customers	$35.65~~28.50~~ per customer

Peak Usage Charge

"Peak usage" is a measure of the amount of gas delivered to the customer for which the Company must incur substantial costs for investment, operation and maintenance of gas distribution facilities, and additional distribution facilities to accommodate customers' increased gas deliveries. Increased usage or decreased usage by a customer has a corresponding increase or decrease on the Company's costs and therefore on the level of the "peak usage charge" the Company must bill a customer.

Firm Commercial and Industrial Sales Service - Rate Schedule No. 2 (continued)

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced during the current November - April billing period. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. During the initial application of the Peak Usage Charge, November 1994 through April 1995, customers shall be deemed to have commenced service subsequent to April 1994 for purposes of establishing the maximum billing month's usage. The rate is:

Billing Months of November - April inclusive:

(a) Normal Weather Annual Usage Less than 3,075 therms	6.92~~5.19~~ ¢ per therm of maximum months usage
(b) Normal Weather Annual Usage 3,075 therms of more	5.32~~4.21~~ ¢ per therm of maximum months usage
(c) Non-Heating and Non-Cooling	5.34~~4.23~~ ¢ per therm of maximum months usage

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

All gas delivered during the billing month

Heating and/or Cooling

(a) Normal Weather Annual Usage Less than 3,075 therms	80.10~~58.21~~¢ per therm
(b) Normal Weather Annual Usage 3,075 therms or more	60.63~~47.96~~¢ per therm
Non-Heating and Non-Cooling	60.87~~48.11~~¢ per therm

Purchased Gas Charge

The "purchased gas charge" is the amount the Company charges for each therm of gas consumed by the customer. Such charge is a measure of the costs of the Company to purchase gas to be distributed to the customer for use at the customer's premises.

The gas consumed under this schedule shall be billed an amount per therm representing the average unit cost of purchased gas in accordance with Section 16 of the General Service Provisions.

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Firm Commercial and Industrial Sales Service - Rate Schedule No. 2
(continued)

DISTRICT OF COLUMBIA ENERGY ASSISTANCE TRUST FUND SURCHARGE

A per therm surcharge shall be billed effective October 1, 2008 in addition to any other billings under this rate schedule. All customers other than those participating under the Residential Essential Service Rider in Rate Schedule Nos. 1 and 1A shall contribute to the Energy Assistance Trust Fund through this surcharge. The surcharge is established in accordance with the applicable section of the District of Columbia's Clean and Affordable Energy Act of 2008 (Energy Act of 2008). This fund shall be used solely to fund the existing low-income programs in the District of Columbia, as defined by the Energy Act of 2008, that are managed by the District Department of Energy & Environment.

EMERGENCY OR STAND-BY SERVICE

Gas service is not available under this Rate Schedule to any customer for equipment requiring an aggregate of more than 200 cubic feet per hour for emergency, stand-by or intermittent alternate use in conjunction with another fuel.

This provision does not apply to gas-fired equipment used to generate emergency electric power for lighting, air-conditioning, elevator operation or for other uses similar in nature.

GENERAL SERVICE PROVISIONS

Except as otherwise specifically provided herein, the application of this schedule is subject to the General Service Provisions of the Company as they may be in effect from time to time, and as filed with the Public Service Commission.

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers billed under this rate schedule shall have a Residential Essential Service (RES) Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

Firm Commercial and Industrial Delivery Service
Rate Schedule No. 2A (continued)

Heating and/or Cooling
All billing months

(a) Normal Weather Annual Usage less than 3,075 therms — $37.40~~29.90~~ per customer

(b) Normal Weather Annual Usage 3,075 therms or more — $87.55~~70.05~~ per customer

Non-Heating and Non-Cooling — $35.65~~28.50~~ per customer
All billing months/all customers

Peak Usage Charge

"Peak usage" is a measure of the amount of gas delivered to the customer for which the Company must incur substantial costs for investment, operation and maintenance of gas distribution facilities, and additional distribution facilities to accommodate customers' increased gas deliveries. Increased usage or decreased usage by a customer has a corresponding increase or decrease on the Company's costs and therefore on the level of the "peak usage charge" the Company must bill a customer.

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced during the current November – April billing period. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. The rate is:

Billing Months of November - April inclusive:

(a) Normal Weather Annual Usage Less than 3,075 therms — 6.92~~5.19~~ ¢ per therm of maximum months usage

(b) Normal Weather Annual Usage 3,075 therms of more — 5.32~~4.21~~ ¢ per therm of maximum months usage

(c) Non-Heating and Non-Cooling — 5.34~~4.23~~ ¢ per therm of maximum months usage

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

All gas delivered during the billing month

Heating and/or Cooling

(a) Normal Weather Annual Usage Less than 3,075 therms — 80.10~~58.21~~¢ per therm

(b) Normal Weather Annual Usage 3,075 therms or more — 60.63~~47.96~~¢ per therm

Non-Heating and Non-Cooling — 60.87~~48.11~~¢ per therm

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Firm Commercial and Industrial Delivery Service - Rate Schedule No. 2A
(continued)

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Service Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers billed under this rate schedule shall have a Residential Essential Service (RES) Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

WASHINGTON GAS LIGHT COMPANY

Firm Group Metered Apartment Sales Service

Rate Schedule No. 3

AVAILABILITY

This schedule is available in the District of Columbia portion of the Company's service area for firm gas service to any customer classified as Group Metered Apartment as defined in Section 1A of the General Service Provisions, subject to the provision for Emergency or Stand-by Service included herein.

RATE FOR MONTHLY CONSUMPTION

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

Heating and/or Cooling

All billing months:

(a) Normal Weather Annual Usage less than 3,075 therms	$35.65~~28.50~~ per customer
(b) Normal Weather Annual Usage 3,075 therms or more	$87.60~~70.05~~ per customer

Applicability of (a) or (b) shall be determined each year in accordance with Section 1A. of the General Service Provisions.

Non-Heating and Non-Cooling

All billing months/all customers	$35.65~~28.50~~ per customer

Peak Usage Charge

"Peak usage" is a measure of the amount of gas delivered to the customer for which the Company must incur substantial costs for investment, operation and maintenance of gas distribution facilities, and additional distribution facilities to accommodate customers' increased gas deliveries. Increased usage or decreased usage by a customer has a corresponding increase or decrease on the Company's costs and therefore on the level of the "peak usage charge" the Company must bill a customer.

Firm Group Metered Apartment Sales Service - Rate Schedule No. 3
(continued)

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced during the current November - April billing period. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. During the initial application of the Peak Usage Charge, November 1994 through April 1995, customers shall be deemed to have commenced service subsequent to April 1994 for purposes of establishing the maximum billing month's usage. The rate is:

Billing Months of November - April inclusive:

(a) Normal Weather Annual Usage Less than 3,075 therms	5.44 ~~4.31~~ ¢ per therm of maximum months usage
(b) Normal Weather Annual Usage 3,075 therms of more	5.33 ~~4.22~~ ¢ per therm of maximum months usage
(c) Non-Heating and Non-Cooling	5.34 ~~4.23~~ ¢ per therm of maximum months usage

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

All gas delivered during the billing month

Heating and/or Cooling

(a) Normal Weather Annual Usage less than 3,075 therms	62.52 ~~49.30~~ ¢ per therm
(b) Normal Weather Annual Usage 3,075 therms or more	61.48 ~~48.63~~ ¢ per therm
Non-Heating and Non-Cooling	61.24 ~~48.41~~ ¢ per therm

Purchased Gas Charge

The "purchased gas charge" is the amount the Company charges for each therm of gas consumed by the customer. Such charge is a measure of the costs of the Company to purchase gas to be distributed to the customer for use at the customer's premises.

The gas consumed under this schedule shall be billed an amount per therm representing the average unit cost of purchased gas in accordance with Section 16 of the General Service Provisions.

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Firm Group Metered Apartment Sales Service - Rate Schedule No. 3
(continued)

DISTRICT OF COLUMBIA ENERGY ASSISTANCE TRUST FUND SURCHARGE

A per therm surcharge shall be billed effective October 1, 2008 in addition to any other billings under this rate schedule. All customers other than those participating under the Residential Essential Service Rider in Rate Schedule Nos. 1 and 1A shall contribute to the Energy Assistance Trust Fund through this surcharge. The surcharge is established in accordance with the applicable section of the District of Columbia's Clean and Affordable Energy Act of 2008 (Energy Act of 2008). This fund shall be used solely to fund the existing low-income programs in the District of Columbia, as defined by the Energy Act of 2008, that are managed by the District Department of Energy & Environment.

EMERGENCY OR STAND-BY SERVICE

Gas service is not available under this Rate Schedule to any customer for equipment requiring an aggregate of more than 200 cubic feet per hour for emergency, stand-by or intermittent alternate use in conjunction with another fuel.

This provision does not apply to gas-fired equipment used to generate emergency electric power for lighting, air-conditioning, elevator operation or for other uses similar in nature.

GENERAL SERVICE PROVISIONS

Except as otherwise specifically provided herein, the application of this schedule is subject to the General Service Provisions of the Company as they may be in effect from time to time, and as filed with the Public Service Commission.

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers billed under this rate schedule shall have a Residential Essential Service (RES) Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

Firm Group Metered Apartment Delivery Service – Rate Schedule No. 3A (continued)

Heating and/or Cooling
All billing months

(a) Normal Weather Annual Usage less than 3,075 therms	$35.65~~28.50~~ per customer
(b) Normal Weather Annual Usage 3,075 therms or more	$87.60~~70.05~~ per customer

Non-Heating and Non-Cooling
All billing months/all customers — $35.65~~28.50~~ per customer

Peak Usage Charge
"Peak usage" is a measure of the amount of gas delivered to the customer for which the Company must incur substantial costs for investment, operation and maintenance of gas distribution facilities, and additional distribution facilities to accommodate customers' increased gas deliveries. Increased usage or decreased usage by a customer has a corresponding increase or decrease on the Company's costs and therefore on the level of the "peak usage charge" the Company must bill a customer.

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced during the current November – April billing period. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. The rate is:

Billing Months of November - April inclusive:

(a) Normal Weather Annual Usage Less than 3,075 therms	5.44~~4.31~~ ¢ per therm of maximum months usage
(b) Normal Weather Annual Usage 3,075 therms of more	5.33~~4.22~~ ¢ per therm of maximum months usage
(c) Non-Heating and Non-Cooling	5.344.23 ¢ per therm of maximum months usage

Distribution Charge
The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

All gas delivered during the billing month
Heating and/or Cooling

(a) Normal Weather Annual Usage less than 3,075 therms	62.52~~49.30~~¢ per therm
(b) Normal Weather Annual Usage 3,075 therms or more	61.48~~48.63~~¢ per therm
Non-Heating and Non-Cooling	61.24~~48.41~~¢ per therm

GAS SUPPLY REALIGNMENT ADJUSTMENT
The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Firm Group Metered Apartment Delivery Service - Rate Schedule No. 3A
(continued)

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Service Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers billed under this rate schedule shall have a Residential Essential Service (RES) Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

WASHINGTON GAS LIGHT COMPANY

Developmental Natural Gas Vehicle Service

Rate Schedule No. 4

As of May 19, 2014 this Rate Schedule is closed to new customers

AVAILABILITY

Service hereunder is available to a limited number of applicants in the District of Columbia of the Company's service area for the sale of compressed gas and for the sale or delivery of gas to be used as Compressed Natural Gas (CNG) to fuel a vehicle or vehicles, to any customer who shall, by contract in writing, agree to the terms set forth below for service at refueling facilities operated at either Company or customer locations.

COMPRESSED NATURAL GAS VEHICLE SERVICE
AT COMPANY OPERATED REFUELING LOCATIONS

This part of the service is available for refueling vehicles with compressed natural gas when the capacity of the Company's compression facilities and the available gas supply are sufficient to provide the quantities requested by the customer; and the customer executes a Natural Gas Vehicle Service Agreement.

Rate For Monthly Consumption

Commodity Charges

For service during first eighteen months	86.42¢	per GGE*
For service after eighteen months:		
0 to 500 gallons per month	$1.04	per GGE*
501 to 3,000 gallons per month	98.34¢	per GGE*
Greater than 3,000 gallons per month	90.39¢	per GGE*

GGE indicates Gasoline Gallon Equivalent. The gasoline gallon equivalent shall be determined by accordance with local standards. In the absence of such standards the gasoline gallon equivalent shall be 5.34 lbs., plus or minus 2%, as measured by the mass motion or sonic nozzle CNG dispensing equipment. The point of sale price to the consumer shall be displayed in gasoline gallon equivalents with the pounds of natural gas displayed on the dispenser where possible.

The above basic Commodity Charges are subject to the Gasoline Adjustment Charge.

The above basic charges are also subject to a Tax Adjustment Surcharge for any change in taxes included in the above Commodity Charges. Commodity charges include District of Columbia Motor

Developmental Natural Gas Vehicle Service
Rate Schedule No. 4
(continued)

(e) The customer executes a Natural Gas Vehicle Service Agreement for not less than 12 months or not less than 18 months if the Company provides facilities.

Rate For Monthly Consumption

Monthly Customer Charge	$ 62.10~~49.67~~
Distribution Charge	10.28~~7.45~~ ¢ per therm

Purchased Gas Charge

Gas consumed under the above service shall be charged an amount per therm representing the average unit cost of purchased gas in accordance with Section 16 of the General Service Provisions including adjustments for applicable taxes.

Sales taxes are not included in the above basic charges and shall be collected as a separately stated charge on the monthly for service. The Company is under no obligation to determine if a customer is exempt from taxation. Customers seeking tax exemption must file such verification with the Company.

Monthly Facilities Charge

Customer provided facilities	None
Company provided facilities:	
For demonstration installations selected at the sole discretion of the Company and only for the first eighteen months of service	None
For all other installations selected at the sole discretion of the Company and demonstration installations after eighteen months	.3% per month of original cost of investment provided by Company

Developmental Natural Gas Vehicle Service - Rate Schedule No. 4
(continued)

DELIVERY SERVICE FOR NATURAL GAS VEHICLES

This part of service is available for delivery of customer owned natural gas for use in customer compression facilities, without minimum volume requirements, as follows:

(a) The capacity of the Company's facilities and the available gas supply are sufficient to provide the quantities requested by the customer.

(b) The customer has purchased, or has agreed to purchase, under a contract with an initial term of not less than one year an adequate supply of natural gas of a quality acceptable to the Company, and has made, or has caused to be made, arrangements by which such volumes of natural gas can be delivered, either directly or by displacement, into the Company's distribution system at the customer's expense.

(c) The customer warrants that is has good and legal title to all gas supplied to the Company, and agrees to indemnify and hold the Company harmless from any loss, claims or damages in regard to such title.

(d) The customer is responsible for making any filings or reports, as required, pertaining to the acquisition and use of gas and the transportation of the gas from the customer's source to the Company's interconnection with the delivering pipeline suppliers.

(e) The customer's gas supply source or pipeline transporter agrees to provide on a timely basis no later than the tenth calendar day of each month, daily delivery data for such gas delivered to the Company during the preceding calendar month.

(f) Delivery revenues hereunder shall be excluded in computations under the DCA section of the PGC provision.

(g) The customer executes a Natural Gas Vehicle Delivery Service Agreement for not less than one year.

Rate For Delivery Service

Monthly Customer Charge	$62.10~~49.67~~
Distribution Charge	10.28~~7.45~~¢ per therm

Sales taxes are not included in the above basic charges and shall be collected as a separately stated charge on the monthly bill for service. The Company is under no obligation to determine if a customer is exempt from taxation. Customers seeking tax exemption must file such verification with the Company.

Interruptible Delivery Service - Rate Schedule No. 6
(continued)

RATE FOR MONTHLY USAGE

Customer Charge

(All billing months)	$151.25 ~~121.00~~ per customer

Delivery Charge (Per therm)

All gas delivered during the billing month: First 75,000 therms	28.87 ~~20.94~~¢
Over 75,000 therms	26.63 ~~19.32~~¢

Large volume customers with existing contracts are excluded from these rates.

Transitional Cost Surcharge

A surcharge of $.0025 per therm for all therms delivered shall be billed in addition to the above charges for monthly deliveries. However, in no event shall such charge exceed the average cost per therm included in the Purchased Gas Charge (PGC) factor.

POSTING

Customers taking service under this rate schedule may have access to the Company's Electronic Bulletin Board (see Information Services). The charge for access is included in the Customer Charge.

Monthly rates (Delivery Charge) for service shall be posted via the Electronic Bulletin Board the day before the earliest nomination deadline of the Company's interstate pipelines each calendar month.

MINIMUM MONTHLY BILL

The minimum monthly bill shall be the Customer Charge, the applicable Transitional Cost Surcharge plus the following as applicable:

Customers with annual usage greater than 250,000 therms:	$2,200
All others:	$ 225

DELIVERY TAX CHARGE

For bills rendered on and after December 2, 2005, all customer gas consumption under this rate schedule shall also be billed an amount per therm for District of Columbia Delivery Tax in accordance with the applicable sections of the District of Columbia Official Code. This charge replaces the Gross Receipts Tax Charge that was based on the effective tax rate along with the billing of revenues to which it applied.

Delivery Service For Combined Heat and Power/Distributed Generation Facilities
Rate Schedule No. 7 (continued)

RATE FOR MONTHLY DELIVERIES

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

All billing months/all customers $429.70 ~~343.75~~ per customer

Peak Usage Charge

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced as of the current billing month. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. The rate is:

All billing months/all customers 12.46 ~~9.04¢~~ per therm of maximum months usage

Volumetric Charge

All gas delivered during the billing month 14.30 ~~10.33¢~~ per therm

The rates discussed above shall be in addition to the following:

Transitional Cost Charge

A charge per therm shall be billed for all therms delivered during the billing month to recover Company supplier transitional costs which shall be equal to the amount per therm included in the calculation of the current months' Purchased Gas Charge as set forth in General Service Provision No. 16.

TERMS AND CONDITIONS

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

DELIVERY TAX CHARGE

All customer gas consumption under this rate schedule shall also be billed an amount per therm for District of Columbia Delivery Tax in accordance with the applicable sections of the District of Columbia Official Code.

GENERAL SERVICE PROVISIONS (continued)

The Company will endeavor to process payments in the following manner:

"Day of payment" is defined as the date on which a customer's payment is marked received by the utility to the customer's account.

Generally, payments are considered received on the business day they are received if: (1) the payment is received at the payment lockbox in time for same-day processing, and (2) accompanied by an utility bill payment remittance coupon. Payment posting timelines vary by payment method. For the purpose of electronic payments and walk-in payments, a "business day" is defined as the 24 hour period ending at 3:00 p.m. on each Tuesday through Friday. The period between 3:01p.m. Friday and 3:00 p.m. Monday is defined as the Monday business day.

MAILED IN PAYMENTS

For payments mailed to the utility's published lockbox mailing address, payment processing is batched into two groups: Standard mail payments and Non-Standard mail payments.

"Standard mail payments" are customer payments mailed to the utility's published lockbox address that include the utility bill payment remittance coupon and a check or money order payable to the utility. Standard mail payments received by 6:00 a.m. shall be posted to the customer's account on the day received. Those received after 6:00 a.m. will be credited as expeditiously as possible, and no later than the next business day after the payment is received.

"Non-standard mail payments" are customer payments mailed to the utility's published lockbox address and require special handling. Examples include: payments with multiple checks, multiple coupons, checks without a coupon, or a single check with multiple coupons that do not balance to the amount of the check. Non-standard mail payments shall be posted to the customer's account no later than the second business day after the day the payment is received. This includes payments a customer may initiate electronically through their bank or an independent payment processor, if the bank or processor then remits a check to the utility.

Payments delivered to other company offices, or payments without adequate information to identify the account to which the payment belongs, will be credited to the customer's account as expeditiously as possible.

ELECTRONIC PAYMENTS

Payments received through electronic banking file transmissions (bill payer services), shall be posted to the customer's account on the day the file is received. The automatic payment program payments shall be posted to the customer account on the due date the same day deducted from customer bank account. Payments made through the company's website or telephone or billing systems payments shall be posted on the next business day after the payment file is received, as long as the payment is made before 4:00 p.m. Payments made after 4:00 p.m. shall be posted on the second business day. Credit card payments are credited on the day the payment file is received from the credit card processor, which is normally the next business day. ~~Residential and small commercial customers who enroll in e-bill and/or pay via the Company's online bill payment system may pay by credit card or debit card without paying a service fee. Fee-free credit and debit card payments may also be made via the Company's automated telephone system.~~ Customers who pay bills using a credit/debit card payment will be responsible for any vendor fees that result from bill payment directly to the payment processing vendor.

IN-PERSON PAYMENTS

Payments received by the utility at its walk-in offices on any business day will be credited no later than the next business day. Payments delivered to unattended drop boxes before 8:00 a.m. will be credited as expeditiously as possible, and no later than the second business day after drop-off.

GENERAL SERVICE PROVISIONS (continued)

11. DISCONTINUANCE OF SERVICE (continued)

(2) Failure, after five days' written notice, to make or increase a deposit as required under DEPOSITS TO GUARANTEE PAYMENT OF BILLS AND TERMS OF CREDIT, Section 3.

(3) Failure to pay any bill for gas service after the Company has made a reasonable attempt to effect collection and has given the customer written notice that he has 5 days, excluding Sundays and holidays, in which to make settlement on his account or have his service denied.

(4) After five days' written notice for refusal of, or inability of the Company to obtain, reasonable access to premises.

(5) Tampering with, damage to or loss of property of the Company on the customer's premises for which the customer is liable as provided under METERING, Section 5, or improper character, condition or use of customer's piping or appliances according to requirements under CUSTOMER'S PIPING AND APPLIANCES, Section 9. The Company may discontinue service without notice for reason (5).

~~e.~~ When it becomes necessary for the Company to discontinue gas service to a customer for any of the foregoing reasons, service will be reinstated only after all bills for service then due have been paid and satisfactory arrangement made for the extension of credit and after a reconnection fee shall have been paid to reimburse the Company for its attendant expenses as shown in Appendix A to this tariff ~~follows:~~

~~Period~~	~~Reconnection Charges Multi- family Per Dwelling unit (4 or More Units)~~	~~Other~~
~~Week Day and Saturday~~		
~~7 a.m. - 5 p.m.~~	~~$ 14.50*~~	~~$ 44.98~~
~~After 5 p.m.~~	~~$ 21.75 **~~	~~$ 69.16~~
~~Sunday and Holidays~~	~~$ 21.75**~~	~~$ 69.16~~

~~Pursuant to Order No. 15134 issued on December 9, 2008, for the months of January, February and March 2009, security deposits will be assessed, but over a three month period, and not be required to be paid before reconnection. The reconnection charge will be assessed the month following the reconnection, rather than at the time of reconnection. An installment plan for the reconnection charge will be considered on a case-by-case basis. Customers are expected to pay their arrearage as a condition for reconnection. For customers who cannot afford to pay their full balance, but can make a substantial up front payment toward their arrearage, either on their own or through assistance grants such as the Washington Area Fuel Fund (WAFF) or fuel assistance, the Company will review the customer's prior payment history and attempt, in good faith, to reach a negotiated payment plan on the difference. If the customer honors the terms of the payment plan, late payment charges and other collection actions will be suspended during the payment plan period. By Commission Order No. 15134, the Company's interim measures apply only during the 2008-2009 winter heating season and shall expire on March 31, 2009. In addition, Order No. 15134 provides that as of April 1, 2009, the Company's approved tariff in effect prior to the Order shall apply to all customers without further notice.~~

~~However, should the customer make a payment to a Company representative at the customer's premises to avoid discontinuance of service, the customer shall be subject to a $7.49 charge.~~

~~* Not less than $58.00 in the aggregate.~~
~~** Not less than $87.00 in the aggregate.~~

~~RESERVED FOR FUTURE USE~~GENERAL SERVICE PROVISIONS (continued)

28. WEATHER NORMALIZATION ADJUSTMENT

I. PROVISION FOR ADJUSTMENT

All firm service customers served under the Company's Rate Schedule Nos. 1, 1A, 2, 2A, 3, 3A and 7 shall be subject to a Weather Normalization Adjustment (WNA) as computed in II. below. The WNA will not be assessed to Residential Essential Service customers. The WNA shall be included as an adjustment to the distribution charge on each customer bill during the WNA period (October-May). At the end of each billing period a reconciliation amount shall be calculated as described in III. below.

II. COMPUTATION

A. The following information is derived from the test year in the most recent rate case:

1) Variation per HDD by class, sales and delivery, by month as determined in the Company's most recent rate case.

2) Tariff rate per therm by class

3) Normal weather HDDs – 3,694 (October-May)

B. During each applicable WNA period month (October-May each year), the Company will calculate a monthly revenue adjustment as described below:

The formula for the monthly revenue adjustment is:

1) Volume Adjustment = (Normal HDDs as shown in II.A.3. - actual HDDs) x (Variation per HDD by class as shown in II.A.1.) x (Total number of bills for the month)

2) Total Revenue Adjustment = Volume Adjustment x Tariff rate per therm by class.

C. The monthly revenue adjustment as calculated in B. above will accrue during each month of the WNA period, including carrying costs on the cumulative revenue excess or deficiency equal to the Company's Short Term Debt rate as determined in its most recent base rate proceeding. If at any point, the cumulative revenue adjustment results a net revenue excess, the Company will refund the cumulative revenue excess two months after the period in which it is calculated. The calculation of the WNA credit is shown in D. below. Once refunded, those revenues will be removed from the cumulative revenue adjustment accrual and the Company will continue to accrue the monthly revenue adjustments through May. If at the end of the October – May WNA period, the Company calculates a cumulative revenue deficiency, the Company will calculate a per therm adjustment to the distribution charge to be billed over the following October-May WNA period as described in E. below.

D. The Adjustment factor per therm for a WNA credit is calculated as follows:

Adjustment Factor per therm = Total Revenue Adjustment (Net of Carrying Costs) / (Normal Weather Therms during month in which the refund is billed)

~~RESERVED FOR FUTURE USE~~

GENERAL SERVICE PROVISIONS (continued)

If, the calculation above results in a factor less than \$0.0001, the Company will carry forward that revenue credit until such time as the revenue adjustment is large enough to produce a billable factor or revenue deficiencies in subsequent months to offset the credit.

E. The Adjustment factor per therm for a WNA charge is calculated as follows:

Adjustment Factor per therm = Total Revenue Adjustment(Net of Carrying Costs) / (October-May Normal Weather Therms)

If the calculated revenue adjustment divided by total October-May normal weather therms is less than \$0.0001 per therm, the Company will bill the adjustment over the appropriate number of months such that the associated normal weather therms produce a factor of at least \$0.0001. Additionally, the Company will limit any WNA factor resulting from the calculation above to no more than a monthly amount of +/- 15% of each participating rate class's volumetric distribution rate per therm.

III. RECONCILIATION

In the event of a credit issued during the WNA period, a reconciliation will be performed to determine the difference between the actual revenues credited to customers and targeted revenue credits. Any difference between those amounts will be netted against the accrued revenue adjustment in the month in which the reconciliation is performed.

At the end of each WNA billing period the actual billed revenue amount by rate class will be subtracted from the allowed amount by rate class for that period to determine a reconciliation amount. Any amount resulting from that reconciliation will be rolled into the following WNA billing period as an adjustment to the accrued balance.

IV. FILING

If Company calculations result in the issuance of a WNA credit during the WNA period, the Company will file a copy of the computation of the WNA rates that provide the basis for the credits by the 15th of the month prior to the next billing period, if applicable. The Company shall file annually with the Commission Secretary by August 1st each year, or the next business day if the first falls on a weekend, a copy of the computation of the WNA rates that provide the basis for the charges.

V. GENERAL

Late Payment Charges, if any, and all applicable taxes shall apply to the WNA in a manner consistent with the applicability to the Distribution Charge portion of the customer bill.

APPENDIX A

Washington Gas Light Company
District of Columbia

Summary of Tariff Charges

Line No.	GSP No.	Description	Rate	Line No.
1	5	Metering		1
2		Meter Relocation Estimate Charge	$72.00	2
3	11	Discontinuance of Service		3
4		Reconnect Charge – Single unit	$ 53.98~~44.98~~	4
5		Reconnect Charge – Multi-unit a/	$ 17.40~~14.50~~	5
6		Field Collection Charge	$ 14.43~~13.12~~	6
7	18	Dishonored Payments		7
8		Dishonored Check Charge	$9.00	8
9	19	Service Initiation Charge		9
10		Gas Flowing	$ 33.00	10
11		Gas Not Flowing	$ 44.60~~37.17~~	11

Line No.	Rate Schedule	Description	Rate	Line No.
12	3 & 3A	Interruptible Sales & Delivery Service		12
13		Interruptible Non-Compliance Meter Read Charge	$100.00	13

a/ Charge per unit for four or more multiple dwelling units.

ISSUED: ~~May 26, 2015~~ August 5, 2024
For service rendered on and after ~~October 23, 2015~~ May 1, 2025
James D. Steffes ~~Roberta W. Sims~~ Sr. Vice President, ~~Rates and~~ Regulatory Affairs

Formal Case 1180

Exhibit WG(O)-4

Proposed Tariff Changes

Clean Version

TABLE OF CONTENTS

WASHINGTON GAS LIGHT COMPANY
Residential Service

Rate Schedule No. 1

AVAILABILITY
This schedule is available in the District of Columbia portion of the Company's service area for firm gas service to any customers classified residential as defined in Section 1A. of the General Service Provisions, subject to the provision for Emergency or Stand-by Service included herein.

RATE FOR MONTHLY CONSUMPTION

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

Heating and/or Cooling	
All billing months	\$20.70 per customer
Non-Heating and Non-Cooling	
All billing months	
(a) Individually Metered Apartment	\$15.00 per customer
(b) Other	\$16.95per customer

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

Heating and/or Cooling	
All gas delivered during the billing month	77.78 ¢ per therm
Non-Heating and Non-Cooling	
All gas delivered during the billing month	
(a) Individually Metered Apartment	86.53 ¢ per therm
(b) Other	92.46 ¢ per therm

Purchased Gas Charge
The "purchased gas charge" is the amount the Company charges for each therm of gas consumed by the customer. Such charge is a measure of the costs of the Company to purchase gas to be distributed to the customer for use at the customer's premises.

The gas consumed under this schedule shall be billed an amount per therm representing the average unit cost of purchased gas in accordance with Section 16 of the General Service Provisions.

DISTRIBUTION CHARGE ADJUSTMENT
The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

GAS SUPPLY REALIGNMENT ADJUSTMENT
The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Residential Service - Rate Schedule No. 1
(continued)

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Service Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers, other than Residential Essential Service (RES) customers, billed under this rate schedule shall have a Residential Essential Service Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

Residential Firm Delivery Service - Rate Schedule No. 1A(continued)

RATE FOR MONTHLY DELIVERIES

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

Heating and/or Cooling	
All billing months	$20.70 per customer
Non-Heating and Non-Cooling	
All billing months	
(a) Individually Metered Apartment	$15.00 per customer
(b) Other	$16.95 per customer

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of gas to the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

Heating and/or Cooling	
All gas delivered during the billing month	77.78 ¢ per therm
Non-Heating and Non-Cooling	
All gas delivered during the billing month	
(a) Individually Metered Apartment	86.53 ¢ per therm
(b) Other	92.46 ¢ per therm

Transitional Cost Charge

A charge per therm shall be billed for all therms delivered during the billing month to recover Company supplier transitional costs which shall be equal to the amount per therm included in the calculation of the current months' Purchased Gas Charge as set forth in General Service Provision No. 16.

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Residential Firm Delivery Service Pilot Program - Rate Schedule No. 1A
(continued)

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Service Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers, other than Residential Essential Service (RES) customers, billed under this rate schedule shall have a Residential Essential Service Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

WASHINGTON GAS LIGHT COMPANY

Firm Commercial and Industrial Sales Service

Rate Schedule No. 2

AVAILABILITY

This schedule is available in the District of Columbia portion of the Company's service area for firm gas service to any customer classified as Commercial and Industrial as defined in Section 1A of the General Service Provisions, subject to the provision for Emergency or Stand-by Service included herein.

RATE FOR MONTHLY CONSUMPTION

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

Heating and/or Cooling

All billing months:

(a) Normal Weather Annual Usage less than 3,075 therms	\$37.40 per customer
(b) Normal Weather Annual Usage 3,075 therms or more	\$87.55 per customer

Applicability of (a) or (b) shall be determined each year in accordance with Section 1A. of the General Service Provisions.

Non-Heating and Non-Cooling

All billing months/all customers	\$35.65 per customer

Peak Usage Charge

"Peak usage" is a measure of the amount of gas delivered to the customer for which the Company must incur substantial costs for investment, operation and maintenance of gas distribution facilities, and additional distribution facilities to accommodate customers' increased gas deliveries. Increased usage or decreased usage by a customer has a corresponding increase or decrease on the Company's costs and therefore on the level of the "peak usage charge" the Company must bill a customer.

Firm Commercial and Industrial Sales Service - Rate Schedule No. 2 (continued)

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced during the current November - April billing period. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. During the initial application of the Peak Usage Charge, November 1994 through April 1995, customers shall be deemed to have commenced service subsequent to April 1994 for purposes of establishing the maximum billing month's usage. The rate is:

Billing Months of November - April inclusive:

(a) Normal Weather Annual Usage Less than 3,075 therms	6.92 ¢ per therm of maximum months usage
(b) Normal Weather Annual Usage 3,075 therms of more	5.32 ¢ per therm of maximum months usage
(c) Non-Heating and Non-Cooling	5.34 ¢ per therm of maximum months usage

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

All gas delivered during the billing month

Heating and/or Cooling

(a) Normal Weather Annual Usage Less than 3,075 therms	80.10 ¢ per therm
(b) Normal Weather Annual Usage 3,075 therms or more	60.63 ¢ per therm
Non-Heating and Non-Cooling	60.87 ¢ per therm

Purchased Gas Charge

The "purchased gas charge" is the amount the Company charges for each therm of gas consumed by the customer. Such charge is a measure of the costs of the Company to purchase gas to be distributed to the customer for use at the customer's premises.

The gas consumed under this schedule shall be billed an amount per therm representing the average unit cost of purchased gas in accordance with Section 16 of the General Service Provisions.

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Firm Commercial and Industrial Sales Service - Rate Schedule No. 2
(continued)

DISTRICT OF COLUMBIA ENERGY ASSISTANCE TRUST FUND SURCHARGE

A per therm surcharge shall be billed effective October 1, 2008 in addition to any other billings under this rate schedule. All customers other than those participating under the Residential Essential Service Rider in Rate Schedule Nos. 1 and 1A shall contribute to the Energy Assistance Trust Fund through this surcharge. The surcharge is established in accordance with the applicable section of the District of Columbia's Clean and Affordable Energy Act of 2008 (Energy Act of 2008). This fund shall be used solely to fund the existing low-income programs in the District of Columbia, as defined by the Energy Act of 2008, that are managed by the District Department of Energy & Environment.

EMERGENCY OR STAND-BY SERVICE

Gas service is not available under this Rate Schedule to any customer for equipment requiring an aggregate of more than 200 cubic feet per hour for emergency, stand-by or intermittent alternate use in conjunction with another fuel.

This provision does not apply to gas-fired equipment used to generate emergency electric power for lighting, air-conditioning, elevator operation or for other uses similar in nature.

GENERAL SERVICE PROVISIONS

Except as otherwise specifically provided herein, the application of this schedule is subject to the General Service Provisions of the Company as they may be in effect from time to time, and as filed with the Public Service Commission.

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers billed under this rate schedule shall have a Residential Essential Service (RES) Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

Firm Commercial and Industrial Delivery Service
Rate Schedule No. 2A (continued)

Heating and/or Cooling
All billing months

(a)	Normal Weather Annual Usage less than 3,075 therms	\$37.40 per customer
(b)	Normal Weather Annual Usage 3,075 therms or more	\$87.55 per customer

Non-Heating and Non-Cooling
All billing months/all customers — \$35.65 per customer

Peak Usage Charge

"Peak usage" is a measure of the amount of gas delivered to the customer for which the Company must incur substantial costs for investment, operation and maintenance of gas distribution facilities, and additional distribution facilities to accommodate customers' increased gas deliveries. Increased usage or decreased usage by a customer has a corresponding increase or decrease on the Company's costs and therefore on the level of the "peak usage charge" the Company must bill a customer.

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced during the current November – April billing period. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. The rate is:

Billing Months of November - April inclusive:

(a)	Normal Weather Annual Usage Less than 3,075 therms	6.92 ¢ per therm of maximum months usage
(b)	Normal Weather Annual Usage 3,075 therms of more	5.32 ¢ per therm of maximum months usage
(c)	Non-Heating and Non-Cooling	5.34 ¢ per therm of maximum months usage

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

All gas delivered during the billing month

Heating and/or Cooling

(a)	Normal Weather Annual Usage Less than 3,075 therms	80.10 ¢ per therm
(b)	Normal Weather Annual Usage 3,075 therms or more	60.63 ¢ per therm

Non-Heating and Non-Cooling — 60.87 ¢ per therm

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Firm Commercial and Industrial Delivery Service - Rate Schedule No. 2A
(continued)

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Service Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers billed under this rate schedule shall have a Residential Essential Service (RES) Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

WASHINGTON GAS LIGHT COMPANY

Firm Group Metered Apartment Sales Service

Rate Schedule No. 3

AVAILABILITY

This schedule is available in the District of Columbia portion of the Company's service area for firm gas service to any customer classified as Group Metered Apartment as defined in Section 1A of the General Service Provisions, subject to the provision for Emergency or Stand-by Service included herein.

RATE FOR MONTHLY CONSUMPTION

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

Heating and/or Cooling

All billing months:

(a) Normal Weather Annual Usage less than 3,075 therms	$35.65 per customer
(b) Normal Weather Annual Usage 3,075 therms or more	$87.60 per customer

Applicability of (a) or (b) shall be determined each year in accordance with Section 1A. of the General Service Provisions.

Non-Heating and Non-Cooling

All billing months/all customers	$35.65 per customer

Peak Usage Charge

"Peak usage" is a measure of the amount of gas delivered to the customer for which the Company must incur substantial costs for investment, operation and maintenance of gas distribution facilities, and additional distribution facilities to accommodate customers' increased gas deliveries. Increased usage or decreased usage by a customer has a corresponding increase or decrease on the Company's costs and therefore on the level of the "peak usage charge" the Company must bill a customer.

Firm Group Metered Apartment Sales Service - Rate Schedule No. 3
(continued)

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced during the current November - April billing period. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. During the initial application of the Peak Usage Charge, November 1994 through April 1995, customers shall be deemed to have commenced service subsequent to April 1994 for purposes of establishing the maximum billing month's usage. The rate is:

Billing Months of November - April inclusive:

(a) Normal Weather Annual Usage Less than 3,075 therms	5.44 ¢ per therm of maximum months usage
(b) Normal Weather Annual Usage 3,075 therms of more	5.33 ¢ per therm of maximum months usage
(c) Non-Heating and Non-Cooling	5.34 ¢ per therm of maximum months usage

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

All gas delivered during the billing month

Heating and/or Cooling

(a) Normal Weather Annual Usage less than 3,075 therms	62.52 ¢ per therm
(b) Normal Weather Annual Usage 3,075 therms or more	61.48 ¢ per therm
Non-Heating and Non-Cooling	61.24 ¢ per therm

Purchased Gas Charge

The "purchased gas charge" is the amount the Company charges for each therm of gas consumed by the customer. Such charge is a measure of the costs of the Company to purchase gas to be distributed to the customer for use at the customer's premises.

The gas consumed under this schedule shall be billed an amount per therm representing the average unit cost of purchased gas in accordance with Section 16 of the General Service Provisions.

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Firm Group Metered Apartment Sales Service - Rate Schedule No. 3
(continued)

DISTRICT OF COLUMBIA ENERGY ASSISTANCE TRUST FUND SURCHARGE

A per therm surcharge shall be billed effective October 1, 2008 in addition to any other billings under this rate schedule. All customers other than those participating under the Residential Essential Service Rider in Rate Schedule Nos. 1 and 1A shall contribute to the Energy Assistance Trust Fund through this surcharge. The surcharge is established in accordance with the applicable section of the District of Columbia's Clean and Affordable Energy Act of 2008 (Energy Act of 2008). This fund shall be used solely to fund the existing low-income programs in the District of Columbia, as defined by the Energy Act of 2008, that are managed by the District Department of Energy & Environment.

EMERGENCY OR STAND-BY SERVICE

Gas service is not available under this Rate Schedule to any customer for equipment requiring an aggregate of more than 200 cubic feet per hour for emergency, stand-by or intermittent alternate use in conjunction with another fuel.

This provision does not apply to gas-fired equipment used to generate emergency electric power for lighting, air-conditioning, elevator operation or for other uses similar in nature.

GENERAL SERVICE PROVISIONS

Except as otherwise specifically provided herein, the application of this schedule is subject to the General Service Provisions of the Company as they may be in effect from time to time, and as filed with the Public Service Commission.

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers billed under this rate schedule shall have a Residential Essential Service (RES) Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

Firm Group Metered Apartment Delivery Service – Rate Schedule No. 3A (continued)

Heating and/or Cooling
All billing months

(a) Normal Weather Annual Usage less than 3,075 therms	\$35.65 per customer
(b) Normal Weather Annual Usage 3,075 therms or more	\$87.60 per customer

Non-Heating and Non-Cooling

All billing months/all customers	\$35.65 per customer

Peak Usage Charge

"Peak usage" is a measure of the amount of gas delivered to the customer for which the Company must incur substantial costs for investment, operation and maintenance of gas distribution facilities, and additional distribution facilities to accommodate customers' increased gas deliveries. Increased usage or decreased usage by a customer has a corresponding increase or decrease on the Company's costs and therefore on the level of the "peak usage charge" the Company must bill a customer.

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced during the current November – April billing period. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. The rate is:

Billing Months of November - April inclusive:

(a) Normal Weather Annual Usage Less than 3,075 therms	5.44 ¢ per therm of maximum months usage
(b) Normal Weather Annual Usage 3,075 therms of more	5.33 ¢ per therm of maximum months usage
(c) Non-Heating and Non-Cooling	5.34 ¢ per therm of maximum months usage

Distribution Charge

The "distribution charge" is the amount the Company charges for delivering each therm of purchased gas consumed by the customer. Such charge is a measure of the costs of the Company to provide, maintain and operate a system of underground piping to distribute purchased gas to the service piping located on the customer's property.

All gas delivered during the billing month

Heating and/or Cooling

(a) Normal Weather Annual Usage less than 3,075 therms	62.52 ¢ per therm
(b) Normal Weather Annual Usage 3,075 therms or more	61.48 ¢ per therm
Non-Heating and Non-Cooling	61.24 ¢ per therm

GAS SUPPLY REALIGNMENT ADJUSTMENT

The Distribution charge shall be subject to the Gas Supply Realignment Charge (GSRA) in accordance with General Service Provision No. 21.

Firm Group Metered Apartment Delivery Service - Rate Schedule No. 3A
(continued)

PLANT RECOVERY ADJUSTMENT (PRA)

Customers billed under this rate schedule shall have a Plant Recovery Adjustment (PRA) applied to their bills as an adjustment to the distribution charge on a monthly basis as set forth in General Service Provision No. 26.

ACCELERATED PIPE REPLACEMENT PLAN (APRP)

Customers billed under this rate schedule shall have an Accelerated Pipe Replacement Plan (APRP) adjustment applied to their bills as set forth in General Service Provision No. 28.

RESIDENTIAL ESSENTIAL SERVICE (RES) SURCHARGE

Customers billed under this rate schedule shall have a Residential Essential Service (RES) Surcharge applied to their bills as set forth in General Service Provision No. 29.

WEATHER NORMALIZATION ("WNA")

Customers billed under this rate schedule shall have a WNA applied to their bills as set forth in General Service Provision No. 30.

WASHINGTON GAS LIGHT COMPANY

Developmental Natural Gas Vehicle Service

Rate Schedule No. 4

As of May 19, 2014 this Rate Schedule is closed to new customers

AVAILABILITY

Service hereunder is available to a limited number of applicants in the District of Columbia of the Company's service area for the sale of compressed gas and for the sale or delivery of gas to be used as Compressed Natural Gas (CNG) to fuel a vehicle or vehicles, to any customer who shall, by contract in writing, agree to the terms set forth below for service at refueling facilities operated at either Company or customer locations.

COMPRESSED NATURAL GAS VEHICLE SERVICE
AT COMPANY OPERATED REFUELING LOCATIONS

This part of the service is available for refueling vehicles with compressed natural gas when the capacity of the Company's compression facilities and the available gas supply are sufficient to provide the quantities requested by the customer; and the customer executes a Natural Gas Vehicle Service Agreement.

Rate For Monthly Consumption

Commodity Charges

For service during first eighteen months	86.42¢	per GGE*
For service after eighteen months:		
0 to 500 gallons per month	$1.04	per GGE*
501 to 3,000 gallons per month	98.34¢	per GGE*
Greater than 3,000 gallons per month	90.39¢	per GGE*

GGE indicates Gasoline Gallon Equivalent. The gasoline gallon equivalent shall be determined by accordance with local standards. In the absence of such standards the gasoline gallon equivalent shall be 5.34 lbs., plus or minus 2%, as measured by the mass motion or sonic nozzle CNG dispensing equipment. The point of sale price to the consumer shall be displayed in gasoline gallon equivalents with the pounds of natural gas displayed on the dispenser where possible.

The above basic Commodity Charges are subject to the Gasoline Adjustment Charge.

The above basic charges are also subject to a Tax Adjustment Surcharge for any change in taxes included in the above Commodity Charges. Commodity charges include District of Columbia Motor

Developmental Natural Gas Vehicle Service
Rate Schedule No. 4
(continued)

(e) The customer executes a Natural Gas Vehicle Service Agreement for not less than 12 months or not less than 18 months if the Company provides facilities.

Rate For Monthly Consumption

Monthly Customer Charge	$ 62.10
Distribution Charge	10.28 ¢ per therm

Purchased Gas Charge

Gas consumed under the above service shall be charged an amount per therm representing the average unit cost of purchased gas in accordance with Section 16 of the General Service Provisions including adjustments for applicable taxes.

Sales taxes are not included in the above basic charges and shall be collected as a separately stated charge on the monthly for service. The Company is under no obligation to determine if a customer is exempt from taxation. Customers seeking tax exemption must file such verification with the Company.

Monthly Facilities Charge

Customer provided facilities	None
Company provided facilities:	
For demonstration installations selected at the sole discretion of the Company and only for the first eighteen months of service	None
For all other installations selected at the sole discretion of the Company and demonstration installations after eighteen months	.3% per month of original cost of investment provided by Company

Developmental Natural Gas Vehicle Service - Rate Schedule No. 4
(continued)

DELIVERY SERVICE FOR NATURAL GAS VEHICLES

This part of service is available for delivery of customer owned natural gas for use in customer compression facilities, without minimum volume requirements, as follows:

(a) The capacity of the Company's facilities and the available gas supply are sufficient to provide the quantities requested by the customer.

(b) The customer has purchased, or has agreed to purchase, under a contract with an initial term of not less than one year an adequate supply of natural gas of a quality acceptable to the Company, and has made, or has caused to be made, arrangements by which such volumes of natural gas can be delivered, either directly or by displacement, into the Company's distribution system at the customer's expense.

(c) The customer warrants that is has good and legal title to all gas supplied to the Company, and agrees to indemnify and hold the Company harmless from any loss, claims or damages in regard to such title.

(d) The customer is responsible for making any filings or reports, as required, pertaining to the acquisition and use of gas and the transportation of the gas from the customer's source to the Company's interconnection with the delivering pipeline suppliers.

(e) The customer's gas supply source or pipeline transporter agrees to provide on a timely basis no later than the tenth calendar day of each month, daily delivery data for such gas delivered to the Company during the preceding calendar month.

(f) Delivery revenues hereunder shall be excluded in computations under the DCA section of the PGC provision.

(g) The customer executes a Natural Gas Vehicle Delivery Service Agreement for not less than one year.

Rate For Delivery Service

Monthly Customer Charge	$62.10
Distribution Charge	10.28¢ per therm

Sales taxes are not included in the above basic charges and shall be collected as a separately stated charge on the monthly bill for service. The Company is under no obligation to determine if a customer is exempt from taxation. Customers seeking tax exemption must file such verification with the Company.

Interruptible Delivery Service - Rate Schedule No. 6
(continued)

RATE FOR MONTHLY USAGE

Customer Charge

(All billing months)	$151.25 per customer

Delivery Charge (Per therm)

All gas delivered during the billing month:

First 75,000 therms	28.87 ¢
Over 75,000 therms	26.63 ¢

Large volume customers with existing contracts are excluded from these rates.

Transitional Cost Surcharge

A surcharge of $.0025 per therm for all therms delivered shall be billed in addition to the above charges for monthly deliveries. However, in no event shall such charge exceed the average cost per therm included in the Purchased Gas Charge (PGC) factor.

POSTING

Customers taking service under this rate schedule may have access to the Company's Electronic Bulletin Board (see Information Services). The charge for access is included in the Customer Charge.

Monthly rates (Delivery Charge) for service shall be posted via the Electronic Bulletin Board the day before the earliest nomination deadline of the Company's interstate pipelines each calendar month.

MINIMUM MONTHLY BILL

The minimum monthly bill shall be the Customer Charge, the applicable Transitional Cost Surcharge plus the following as applicable:

Customers with annual usage greater than 250,000 therms:	$2,200
All others:	$ 225

DELIVERY TAX CHARGE

For bills rendered on and after December 2, 2005, all customer gas consumption under this rate schedule shall also be billed an amount per therm for District of Columbia Delivery Tax in accordance with the applicable sections of the District of Columbia Official Code. This charge replaces the Gross Receipts Tax Charge that was based on the effective tax rate along with the billing of revenues to which it applied.

Delivery Service For Combined Heat and Power/Distributed Generation Facilities
Rate Schedule No. 7 (continued)

RATE FOR MONTHLY DELIVERIES

Customer Charge

The "customer charge" is a measure of the costs of the Company's facilities and other costs that do not vary with the amount of gas the customer consumes.

All billing months/all customers	\$429.70 per customer

Peak Usage Charge

The peak usage charge is a monthly charge, re-established each November billing period based on application of the peak usage rate to the customer's maximum billing month's usage during the immediately preceding November through April billing periods. For customers commencing service subsequent to the April billing period, the peak usage rate shall be applied to the maximum billing month's usage experienced as of the current billing month. The maximum billing month is defined as the month in which the maximum average daily consumption (total therms/cycle billing days) occurs. The rate is:

All billing months/all customers	12.46 ¢ per therm of maximum months usage

Volumetric Charge

All gas delivered during the billing month	14.30 ¢ per therm

The rates discussed above shall be in addition to the following:

Transitional Cost Charge

A charge per therm shall be billed for all therms delivered during the billing month to recover Company supplier transitional costs which shall be equal to the amount per therm included in the calculation of the current months' Purchased Gas Charge as set forth in General Service Provision No. 16.

TERMS AND CONDITIONS

DISTRIBUTION CHARGE ADJUSTMENT

The "distribution charge" specified in this schedule shall be subject to an adjustment per therm in accordance with Subsection IV of Section 16 of the General Service Provisions.

DELIVERY TAX CHARGE

All customer gas consumption under this rate schedule shall also be billed an amount per therm for District of Columbia Delivery Tax in accordance with the applicable sections of the District of Columbia Official Code.

ISSUED: August 5, 2024
Effective for service rendered on and after May 1, 2025
James Steffes – Sr. Vice President, Regulatory Affairs

GENERAL SERVICE PROVISIONS (continued)

The Company will endeavor to process payments in the following manner:

"Day of payment" is defined as the date on which a customer's payment is marked received by the utility to the customer's account.

Generally, payments are considered received on the business day they are received if: (1) the payment is received at the payment lockbox in time for same-day processing, and (2) accompanied by an utility bill payment remittance coupon. Payment posting timelines vary by payment method. For the purpose of electronic payments and walk-in payments, a "business day" is defined as the 24 hour period ending at 3:00 p.m. on each Tuesday through Friday. The period between 3:01p.m. Friday and 3:00 p.m. Monday is defined as the Monday business day.

MAILED IN PAYMENTS

For payments mailed to the utility's published lockbox mailing address, payment processing is batched into two groups: Standard mail payments and Non-Standard mail payments.

"Standard mail payments" are customer payments mailed to the utility's published lockbox address that include the utility bill payment remittance coupon and a check or money order payable to the utility. Standard mail payments received by 6:00 a.m. shall be posted to the customer's account on the day received. Those received after 6:00 a.m. will be credited as expeditiously as possible, and no later than the next business day after the payment is received.

"Non-standard mail payments" are customer payments mailed to the utility's published lockbox address and require special handling. Examples include: payments with multiple checks, multiple coupons, checks without a coupon, or a single check with multiple coupons that do not balance to the amount of the check. Non-standard mail payments shall be posted to the customer's account no later than the second business day after the day the payment is received. This includes payments a customer may initiate electronically through their bank or an independent payment processor, if the bank or processor then remits a check to the utility.

Payments delivered to other company offices, or payments without adequate information to identify the account to which the payment belongs, will be credited to the customer's account as expeditiously as possible.

ELECTRONIC PAYMENTS

Payments received through electronic banking file transmissions (bill payer services), shall be posted to the customer's account on the day the file is received. The automatic payment program payments shall be posted to the customer account on the due date the same day deducted from customer bank account. Payments made through the company's website or telephone or billing systems payments shall be posted on the next business day after the payment file is received, as long as the payment is made before 4:00 p.m. Payments made after 4:00 p.m. shall be posted on the second business day. Credit card payments are credited on the day the payment file is received from the credit card processor, which is normally the next business day. Customers who pay bills using a credit/debit card payment will be responsible for any vendor fees that result from bill payment directly to the payment processing vendor.

IN-PERSON PAYMENTS

Payments received by the utility at its walk-in offices on any business day will be credited no later than the next business day. Payments delivered to unattended drop boxes before 8:00 a.m. will be credited as expeditiously as possible, and no later than the second business day after drop-off.

GENERAL SERVICE PROVISIONS (continued)

11. DISCONTINUANCE OF SERVICE (continued)

(2) Failure, after five days' written notice, to make or increase a deposit as required under DEPOSITS TO GUARANTEE PAYMENT OF BILLS AND TERMS OF CREDIT, Section 3.

(3) Failure to pay any bill for gas service after the Company has made a reasonable attempt to effect collection and has given the customer written notice that he has 5 days, excluding Sundays and holidays, in which to make settlement on his account or have his service denied.

(4) After five days' written notice for refusal of, or inability of the Company to obtain, reasonable access to premises.

(5) Tampering with, damage to or loss of property of the Company on the customer's premises for which the customer is liable as provided under METERING, Section 5, or improper character, condition or use of customer's piping or appliances according to requirements under CUSTOMER'S PIPING AND APPLIANCES, Section 9. The Company may discontinue service without notice for reason (5).

c. When it becomes necessary for the Company to discontinue gas service to a customer for any of the foregoing reasons, service will be reinstated only after all bills for service then due have been paid and satisfactory arrangement made for the extension of credit and after a reconnection fee shall have been paid to reimburse the Company for its attendant expenses as shown in Appendix A to this tariff.

GENERAL SERVICE PROVISIONS (continued)

28. WEATHER NORMALIZATION ADJUSTMENT

I. PROVISION FOR ADJUSTMENT

All firm service customers served under the Company's Rate Schedule Nos. 1, 1A, 2, 2A, 3, 3A and 7 shall be subject to a Weather Normalization Adjustment (WNA) as computed in II. below. The WNA will not be assessed to Residential Essential Service customers. The WNA shall be included as an adjustment to the distribution charge on each customer bill during the WNA period (October-May). At the end of each billing period a reconciliation amount shall be calculated as described in III. below.

II. COMPUTATION

A. The following information is derived from the test year in the most recent rate case:

1) Variation per HDD by class, sales and delivery, by month as determined in the Company's most recent rate case.

2) Tariff rate per therm by class

3) Normal weather HDDs – 3,694 (October-May)

B. During each applicable WNA period month (October-May each year), the Company will calculate a monthly revenue adjustment as described below:

The formula for the monthly revenue adjustment is:

1) Volume Adjustment = (Normal HDDs as shown in II.A.3. - actual HDDs) x (Variation per HDD by class as shown in II.A.1.) x (Total number of bills for the month)

2) Total Revenue Adjustment = Volume Adjustment x Tariff rate per therm by class.

C. The monthly revenue adjustment as calculated in B. above will accrue during each month of the WNA period, including carrying costs on the cumulative revenue excess or deficiency equal to the Company's Short Term Debt rate as determined in its most recent base rate proceeding. If at any point, the cumulative revenue adjustment results a net revenue excess, the Company will refund the cumulative revenue excess two months after the period in which it is calculated. The calculation of the WNA credit is shown in D. below. Once refunded, those revenues will be removed from the cumulative revenue adjustment accrual and the Company will continue to accrue the monthly revenue adjustments through May. If at the end of the October – May WNA period, the Company calculates a cumulative revenue deficiency, the Company will calculate a per therm adjustment to the distribution charge to be billed over the following October-May WNA period as described in E. below.

D. The Adjustment factor per therm for a WNA credit is calculated as follows:

Adjustment Factor per therm = Total Revenue Adjustment (Net of Carrying Costs) / (Normal Weather Therms during month in which the refund is billed)

GENERAL SERVICE PROVISIONS (continued)

If, the calculation above results in a factor less than \$0.0001, the Company will carry forward that revenue credit until such time as the revenue adjustment is large enough to produce a billable factor or revenue deficiencies in subsequent months to offset the credit.

E. The Adjustment factor per therm for a WNA charge is calculated as follows:

Adjustment Factor per therm = Total Revenue Adjustment(Net of Carrying Costs) / (October-May Normal Weather Therms)

If the calculated revenue adjustment divided by total October-May normal weather therms is less than \$0.0001 per therm, the Company will bill the adjustment over the appropriate number of months such that the associated normal weather therms produce a factor of at least \$0.0001. Additionally, the Company will limit any WNA factor resulting from the calculation above to no more than a monthly amount of +/- 15% of each participating rate class's volumetric distribution rate per therm.

III. RECONCILIATION

In the event of a credit issued during the WNA period, a reconciliation will be performed to determine the difference between the actual revenues credited to customers and targeted revenue credits. Any difference between those amounts will be netted against the accrued revenue adjustment in the month in which the reconciliation is performed.

At the end of each WNA billing period the actual billed revenue amount by rate class will be subtracted from the allowed amount by rate class for that period to determine a reconciliation amount. Any amount resulting from that reconciliation will be rolled into the following WNA billing period as an adjustment to the accrued balance.

IV. FILING

If Company calculations result in the issuance of a WNA credit during the WNA period, the Company will file a copy of the computation of the WNA rates that provide the basis for the credits by the 15th of the month prior to the next billing period, if applicable. The Company shall file annually with the Commission Secretary by August 1st each year, or the next business day if the first falls on a weekend, a copy of the computation of the WNA rates that provide the basis for the charges.

V. GENERAL

Late Payment Charges, if any, and all applicable taxes shall apply to the WNA in a manner consistent with the applicability to the Distribution Charge portion of the customer bill.

APPENDIX A

Washington Gas Light Company
District of Columbia

Summary of Tariff Charges

Line No.	GSP No.	Description	Rate	Line No.
1	5	Metering		1
2		Meter Relocation Estimate Charge	$72.00	2
3	11	Discontinuance of Service		3
4		Reconnect Charge – Single unit	$ 53.98	4
5		Reconnect Charge – Multi-unit a/	$ 17.40	5
6		Field Collection Charge	$ 14.43	6
7	18	Dishonored Payments		7
8		Dishonored Check Charge	$9.00	8
9	19	Service Initiation Charge		9
10		Gas Flowing	$ 33.00	10
11		Gas Not Flowing	$ 44.60	11

Line No.	Rate Schedule	Description	Rate	Line No.
12	3 & 3A	Interruptible Sales & Delivery Service		12
13		Interruptible Non-Compliance Meter Read Charge	$100.00	13

a/ Charge per unit for four or more multiple dwelling units.

ISSUED: August 5, 2024
For service rendered on and after May 1, 2025
James D. Steffes– Sr. Vice President, Regulatory Affairs

ATTESTATION

I, R. ANDREW LAWSON, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

R. ANDREW LAWSON

07/30/2024
DATE

CERTIFICATE OF SERVICE

I, the undersigned counsel, hereby certify that on this 5th day of August 2024, I caused copies of the foregoing document to be hand-delivered, mailed, postage-prepaid, or electronically delivered to the following:

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JOHN C. DODGE