FC1180 - 2025 - G - 75

RECEIVED 2025 JAN 24 3:00 PM

OPC-DC
Office of the People's Counsel
ADVOCACY | EDUCATION | PROTECTION

**Sandra Mattavous-Frye, Esq.**
**People's Counsel**

January 24, 2025

**PUBLIC VERSION**

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W., Suite 800
Washington, D.C. 20005

**Re: Formal Case No. 1180, In the Matter of the Application of Washington Gas Light Company for the Authority to Increase Existing Rates and Charges for Gas Service**

Dear Ms. Westbrook-Sedgwick:

Enclosed for filing in the above-referenced proceeding, pursuant to the procedural schedule outlined by the Commission, please find the public copy of the *Office of the People's Counsel for the District of Columbia's Direct Testimony of OPC Witnesses, Exhibits OPC (A) – (E).* Below is a list of the Office's witnesses:

OPC Exhibit (A) – David E. Dismukes
OPC Exhibit (B) – Bion C. Ostrander
OPC Exhibit (C) – Henry T. Fitzhenry
OPC Exhibit (D) – Aaron L. Rothchild
OPC Exhibit (C) – Brian C. Andrews

Additionally, OPC Witness Bion C. Ostrander's confidential testimony and exhibits will be filed under a separate cover and the Witnesses' accompanying workpapers and native files will be transmitted separately.

If there are any questions regarding this matter, please contact Ade Adeniyi at 202.727.3071.

Sincerely,

*/s/ Sandra Mattavous-Frye*
Sandra Mattavous-Frye
People's Counsel

Enclosure

cc: Parties of Record

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

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

**DIRECT TESTIMONY**
**AND SUPPORTING EXHIBITS OF**
**DAVID E. DISMUKES, PH.D.**

**Exhibit OPC (A)**

**On Behalf of the**
**Office of the People's Counsel**
**for the District of Columbia**

**January 24, 2025**

## TABLE OF CONTENTS

**EXHIBIT LIST**

| | |
|---|---|
| Exhibit OPC (A)-1 | Academic Vitae' of David E. Dismukes, Ph.D. |
| Exhibit OPC (A)-2 | Comparison of Residential Non-Fuel Revenues (2011-2023) |
| Exhibit OPC (A)-3 | WNA Annual Revenue Impact (2019-2023) |
| Exhibit OPC (A)-4 | Company's Proposed Revenue Distribution |
| Exhibit OPC (A)-5 | Alternative Revenue Distribution |
| Exhibit OPC (A)-6 | Comparison of Current and Proposed Customer Charges |
| Exhibit OPC (A)-7 | Survey of Regional Customer Charges |
| Exhibit OPC (A)-8 | Energy Expenditure Data for the Middle Atlantic and Northeast Regions |
| Exhibit OPC (A)-9 | Typical Bill Comparison at Different Usage Levels |
| Exhibit OPC (A)-10 | Energy Affordability Index |
| Exhibit OPC (A)-11 | WGL Response to OPC Data Request No. 1-2A |
| Exhibit OPC (A)-12 | WGL Response to OPC Data Request No. 1-9 |
| Exhibit OPC (A)-13 | WGL Response to OPC Data Request No. 1-16 |
| Exhibit OPC (A)-14 | WGL Response to OPC Data Request No. 1-22 |
| Exhibit OPC (A)-15 | WGL Response to OPC Data Request No. 14-2 |
| Exhibit OPC (A)-16 | WGL Response to OPC Data Request No. 7-12 |
| Exhibit OPC (A)-17 | WGL Response to OPC Data Request No. 14-1 |
| Exhibit OPC (A)-18 | WGL Response to OPC Data Request No. 16-1 |
| Exhibit OPC (A)-19 | WGL Response to OPC Data Request No. 16-2 |
| Exhibit OPC (A)-20 | WGL Response to OPC Data Request No. 16-3 |
| Exhibit OPC (A)-21 | WGL Response to OPC Data Request No. 8-1 |
| Exhibit OPC (A)-22 | WGL Response to OPC Data Request Nos. 1-1A |
| Exhibit OPC (A)-23 | WGL Supplemental Response to OPC Data Request No. 8-1 |
| Exhibit OPC (A)-24 | WGL Response to OPC Data Request No. 1-1a |

## I. INTRODUCTION

**Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.**

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place, Suite 5-F, Baton Rouge, Louisiana, 70808. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and located in Baton Rouge, Louisiana.

**Q. DO YOU HOLD ANY ACADEMIC POSITIONS?**

A. Yes. I am a professor emeritus at Louisiana State University ("LSU"). Prior to my retirement in January 2023, I served as a full professor, executive director, and director of policy analysis at the LSU Center for Energy Studies and as a full tenured professor in the Department of Environmental Sciences and the director of the Coastal Marine Institute in the LSU College of the Coast and Environment. I also served as a senior fellow at the Institute of Public Utilities at Michigan State University, where I taught energy regulatory staff and other utility stakeholders about principles, trends, and issues in the electric and natural gas industries. I also serve as a distinguished fellow and senior economist with the Institute for Energy Research in Washington, D.C. Exhibit OPC (A)-1 provides my academic vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A. I am testifying on behalf of the Office of the People's Counsel for the District of Columbia ("OPC" or "Office") in this proceeding concerning the Application filed by the Washington Gas Light Company ("WGL" or "Company") with the District of Columbia Public Service Commission ("Commission" or "DC PSC") for authorization to increase its existing rates and charges for gas service.[1]

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE DC PSC?**

A. Yes, I have, and those formal cases are listed in my academic vitae, attached as Exhibit OPC (A)-1.

**Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR THOSE UNDER YOUR DIRECT SUPERVISION AND CONTROL?**

A. Yes, and my Exhibits contain my analysis and calculations and list the sources supporting my analysis and calculations. Although my associates at ACG have assisted me with my research and the presentation of my report, all opinions contained herein are mine alone.

**Q. PLEASE INTRODUCE OPC'S EXPERT WITNESSES AND SUMMARIZE THE TOPICS OF THEIR RESPECTIVE TESTIMONIES IN THIS PROCEEDING.**

A. In addition to my Direct Testimony, OPC is sponsoring the Direct Testimony of four additional witnesses in this proceeding, as follows:

- **Mr. Bion Ostrander,** President of Ostrander Consulting, who presents testimony in Exhibit OPC (B) concerning WGL's proposed revenue requirement in this proceeding, provides recommended adjustments to WGL's distribution rate base

---

1 *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* ("*Formal Case No. 1180*"), Washington Gas's Application, Direct Testimony and Supporting Exhibits, filed August 5, 2024 ("WGL Application"). As a general matter, for the remainder of my testimony, any references to WGL's "Application" include WGL's Supplemental Direct Testimony and Supporting Exhibits, Updated Supplemental Information, and Errata to Direct Testimony of Company Witnesses.

and distribution operations, and presents the overall revenue requirement impact of OPC's recommendations as set forth in his testimony and the testimony of other OPC witnesses who address issues impacting WGL's proposed distribution revenue requirements.

- **Mr. Colin T. Fitzhenry**, Senior Consultant at Brubaker & Associates, Inc., who presents testimony in Exhibit OPC (C) concerning the reliability, safety, reasonableness, and prudence of WGL's construction projects, PROJECT*pipes* program, intersections between this case and Formal Case No. 1179 (Strategic Pipe Replacement), and addresses associated costs for which the Company seeks rate base treatment in this proceeding.

- **Mr. Aaron L. Rothschild**, President of Rothschild Financial Consulting, who presents testimony in Exhibit OPC (D) concerning WGL's cost of capital, including cost of common equity, cost of debt, and capital structure.

- **Mr. Brian Andrews**, Partner at Brubaker & Associates, Inc., who presents testimony in Exhibit OPC (E) concerning WGL's proposed depreciation rates in this proceeding.

## II. <u>SCOPE AND SUMMARY OF TESTIMONY</u>

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. I have been retained by the Office to provide an expert opinion to the Commission on various economic and policy issues that have been raised in the proposed base rate increase request filed by WGL. My testimony addresses the Company's proposed Weather Normalization Adjustment ("WNA"), the Company's rate design and revenue distribution proposals, and energy affordability.

### *A. Summary of Recommendations*

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED WNA?**

A. I recommend the Commission reject the Company's WNA proposal. There is no recorded evidence showing that WGL is experiencing long-term financial harm without such a mechanism. The Company has also failed to provide sufficient evidence to support its claim that the mechanism would provide rate stability to customers. Additionally, the Company has not offered any reductions to its allowed return on equity ("ROE") in return for its reduced risk profile. The proposed WNA would inherently reduce the Company's financial risk and shift that risk onto ratepayers. Overall, the WNA would provide substantial benefits to WGL's shareholders by reducing its revenue recovery risks while providing no comparable benefits for ratepayers. Accordingly, the Commission should reject the WNA. However, if the Commission accepts the WNA, which I do not recommend, then the Commission should approve a downward adjustment in the Company's ROE, as also recommended by and discussed in OPC Witness Rothschild's testimony.

**Q. DO YOU AGREE WITH THE COMPANY'S REVENUE DISTRIBUTION PROPOSAL?**

A. No. The Company is proposing disproportionately high rate increases for several customer classes that in some instances, would be as much as 1.25 times the system average rate increase, which is inconsistent with the concept of rate gradualism. Instead, I recommend the Commission adopt a more reasonable revenue distribution that limits the rate increase to any single customer class to 1.15 times the overall system average increase. Using the Company's proposed system average increase of 30.3%, my recommendation would reduce the maximum total base revenue increase of any single rate class to 34.8%, compared to the Company's proposed maximum rate increase of 38.0%. I also recommend the Commission reject the Company's proposal to apply disproportionately high rate increases for residential heating and cooling customers, as well as small commercial and industrial heating and cooling customers, whose rate of return ("ROR") under the Company's class cost of service study ("CCOSS") is more aligned with the system average than any other rate class. Instead, these customers should receive the same increase applied to other customer classes whose ROR under the Company's CCOSS is near or above the system average.

**Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE DISTRIBUTION?**

A. Yes. My proposed alternative revenue distribution under the Company's system average increase of 30.3% is presented in Exhibit OPC (A)-5. My proposal would increase base rates for the primary residential class by 30.2%, compared to the Company's proposal which would increase such rates by 33.3%.

**Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?**

A. I recommend the Commission reject the Company's proposed increase in customer charges for several reasons. First, the Company's proposed $20.70 per month residential customer charge[2] would be 33% higher than the regional peer average. Second, the Company's proposal would negatively impact the public policy goals of promoting energy efficiency. Likewise, the proposal would burden low-use customers with a greater than average portion of any proposed increase in the case. Instead, I recommend the Company's customer charges remain unchanged.

[2] WGL Application at 7.

**Q. PLEASE SUMMARIZE YOUR POSITION ON THE COMPANY'S CREDIT AND DEBIT CARD PROCESSING FEE PROPOSAL.**

A. I do not oppose the Company's proposal to directly assign processing fees to customers who leverage credit or debit cards to pay their bills. However, I would recommend that the Company actively promote and market the availability of other electronic payment options that would allow customers to avoid vendor processing fees.

**Q. PLEASE SUMMARIZE YOUR AFFORDABILITY RECOMMENDATION.**

A. I recommend the Commission open a proceeding after the conclusion of the current rate case to examine low-income and affordability issues in a more holistic fashion given the increasing number of rate increase requests the District's ratepayers have been subjected to when such ratepayers are already facing difficulties in affording energy costs and where these difficulties are being masked by virtue of the fact that federal government transfer payments are recorded as "income" for such ratepayers, as discussed in my testimony. A more focused, stand-alone proceeding seems to be a better venue to develop an approach for consistent measurement and monitoring of energy affordability in the District.

## III. BACKGROUND ON WGL'S REQUEST AND RECENT REQUESTS

**Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST.**

A. The Company is requesting that the Commission allow the Company to (1) "increase charges for gas service", and (2) revise certain terms and conditions reflected in its tariff, as they pertain to gas service within the District.[3] The Company is seeking approval to collect approximately $45.6 million in total additional annual revenues ($33.9 million in

---

[3] *See* WGL Application at 1.

base rate revenues and a transfer of $11.7 million from the PROJECT*pipes* surcharge to base rates), representing an increase of approximately 11.9% over current rates.[4] The Company's Application includes the following proposed requests:

- New Depreciation Rates: The Company proposes new depreciation rates based on their 2024 Depreciation Rate Study. The Company uses the study to support a 0.54 percent increase in the primary account depreciation rates.[5]

- WNA: A mechanism that WGL refers to as "a billing adjustment factor" and that WGL claims will eliminate weather variability and stabilize customer bills.[6]

- Test Year Ratemaking Adjustments: The Company asserts that incremental revenues are needed based on: (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.[7]

- Tariff Modifications: The Company proposes to modify customer charges for all customer classes and the existing revenue distribution among the customer classes.[8]

- Credit Card Payments:[9] The Company proposes to eliminate its current program under which WGL pays the vendor processing fees for customers' use of credit/debit cards to pay bills, meaning, if approved, moving forward, customers who pay their bills with a credit or debit card will directly pay the vendors' proceeding fee.

- Discontinuance of Service and Service Initiation Charges:[10] The Company proposes to increase two charges in its General Service Provisions: (1) Discontinuance of Service; and (2) Service Initiation Charge.

---

4 WGL Application at 1.
5 *Id.* at 4.
6 *See id.* at 4.
7 *Id.* at 5.
8 *Id.* at 6-10.
9 Errata to Exhibit WG (O) (Lawson) at 19:19-23.
10 *Id.* at 23:17-21, 25:5-10, and 27:19–28:12.

**Q. HOW DOES WGL JUSTIFY ITS REQUESTED RATE INCREASE?**

A. According to WGL, an increase in base rates is needed 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."[11] WGL asserts that in addition to providing the necessary revenues to recover normal operating expenses and a fair rate of return for WGL shareholders (which WGL claims is a 10.50% return on common equity),[12] it needs additional revenues to make certain investments to "provid[e] support in attaining the District of Columbia's climate goals."[13] More specifically, WGL asserts that its current base rates, which were only recently established in Formal Case No. 1169, decided on December 22, 2023,[14] are now obsolete due to a number of factors currently facing WGL, including "(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; [] (7) cost increases in Operation and Maintenance expenses;" and (8) continued WGL support for the District's climate goals.[15]

**Q. HOW DO THE AMOUNTS REQUESTED IN WGL'S LAST RATE CASE COMPARE TO THE AMOUNTS REQUESTED IN THIS CASE?**

A. In its last rate case (Formal Case No. ("FC") 1169), the Company requested $53.0 million in total annual revenues (approximately $47.7 million in incremental base rate revenues

---

11 *See* WGL Application at 2.

12 *Id.* at 4.

13 *See id.* at 3.

14 *Formal Case No. 1169*, *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, rel. December 22, 2023.

15 *See* WGL Application at 3.

and approximately $5.3 million through a transfer of the PROJECT*pipes* surcharge to base rates), representing an increase of approximately 20.4% in revenue collection, and a return on common equity of 10.4%.[16] Ultimately, the Commission approved "a gross revenue increase of $24.6 million" in total revenues, "including $4.7 million PROJECT*pipes* surcharge revenue transfer to base rates", and a return on common equity of 9.65%.[17]

**Q. HOW DOES WGL'S CURRENT RATE REQUEST COMPARE TO REQUESTS DATING BACK TO 2005?**

A. Figure 1 below presents the incremental revenues requested by WGL and authorized by the Commission since 2005 on a dollar and percentage basis. During this time period, the Company's revenue requirements have more than doubled.

---

[16] *Formal Case No. 1169*, Washington Gas's Application, Direct Testimony and Supporting Exhibits, p. 1, 3, filed April 4, 2022.

[17] *Formal Case No. 1169*, Order No. 21939 ¶¶ 1-2.

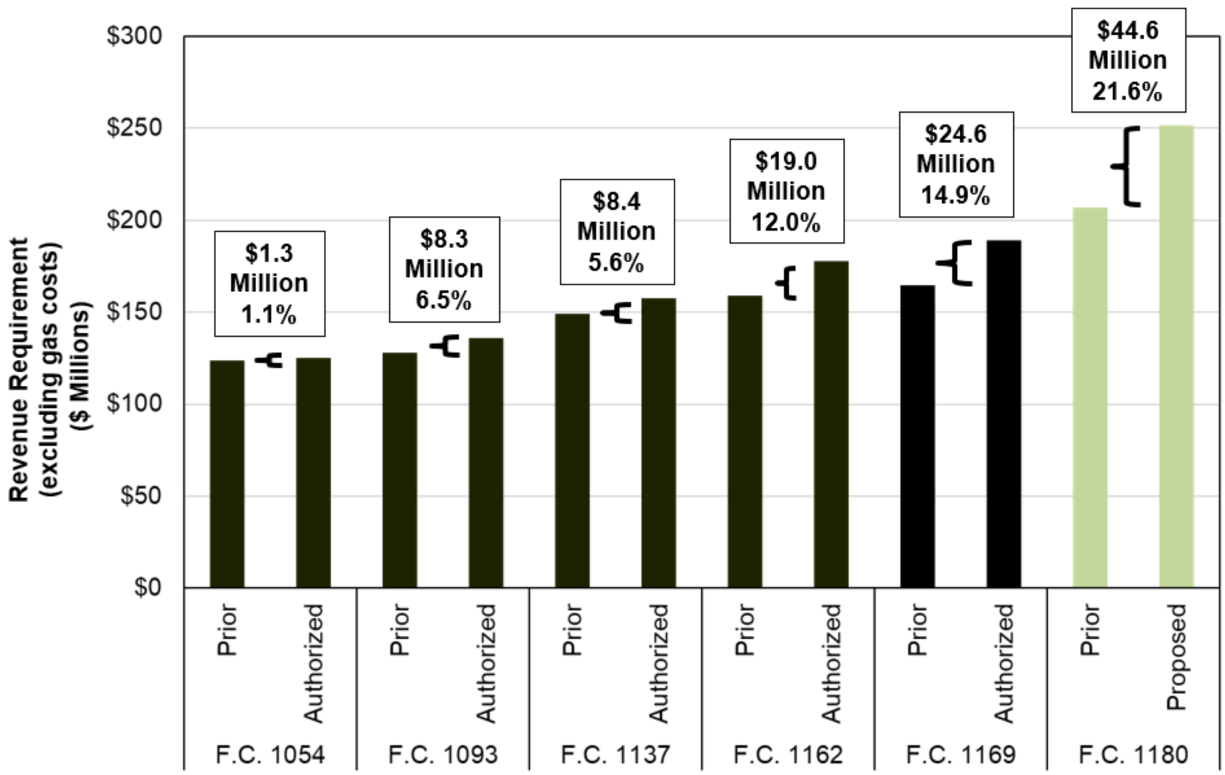



**Figure 1: Comparison of Prior WGL Increases**

**Q. HOW DOES WGL'S PROPOSED RATE INCREASE COMPARE TO THOSE PREVIOUSLY AUTHORIZED BY THE COMMISSION?**

A. Figure 1 shows that since 2005 the Commission has granted WGL average base rate increases of $12.3 million. In the current case, WGL is requesting approximately $44.6 million in incremental base rate revenues, or $45.6 million when additional other operating revenue increases are taken into account.[18] This represents a 21.6% increase over current rates. WGL's current rate request exceeds its most recently authorized rate increase in FC 1169 by approximately $20 million, or 81.5%. Additionally, the $44.6 million increase would be over three and a half times the average increases authorized since 2005.

---

[18] WGL Application at 1.

**Q. WHAT HAS BEEN THE AVERAGE PERCENTAGE REDUCTION BETWEEN WGL'S REQUESTED RATE INCREASES AND ITS AUTHORIZED RATE INCREASES?**

A. Figure 2 below shows that the Commission has recently approved rate increases that are, on average, approximately 45.8% of the Company's requested rate increases. This suggests that WGL has consistently overestimated the amount of incremental revenues required by a significant margin.

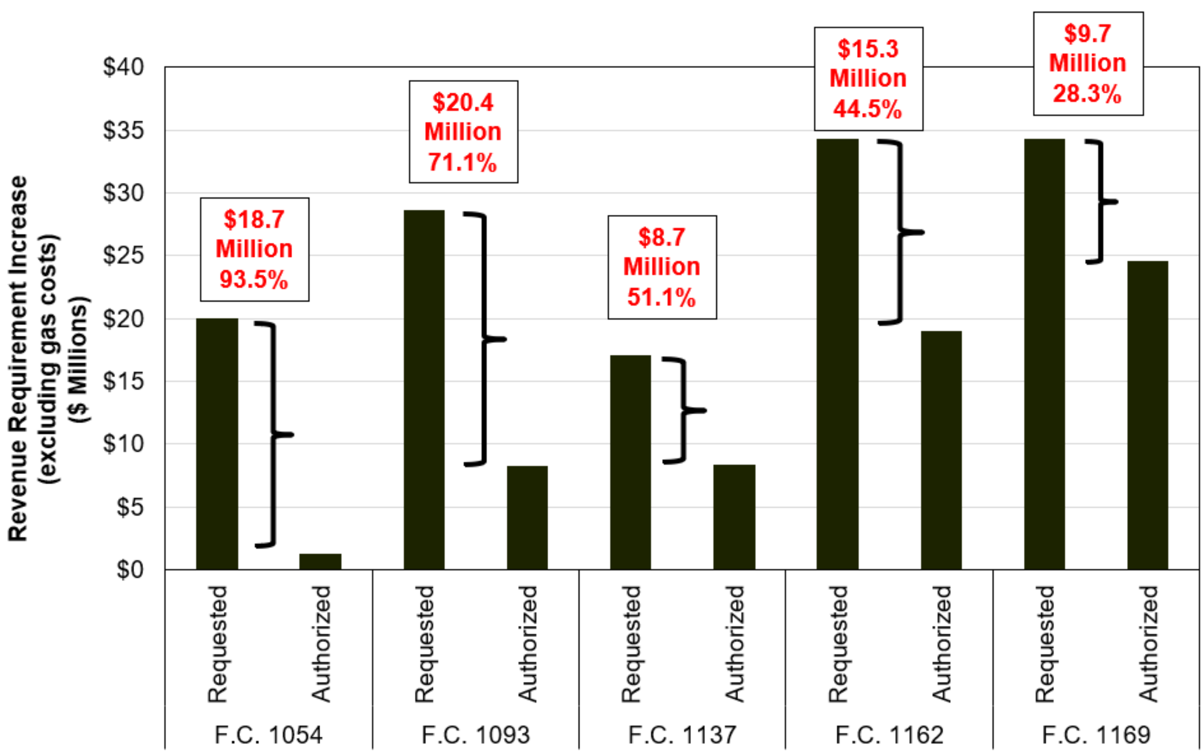



**Figure 2: WGL Historic Requested to Authorized Revenue Requirements**

**Q. HAS THE COMPANY PROVIDED ANY STUDIES OR ANALYSES THAT EXAMINE THE IMPACTS THAT ITS CURRENT RATE PROPOSAL WILL HAVE ON CUSTOMER AFFORDABILITY?**

A. No. The Company stated that it is not aware of any such studies in the Company's possession.[19] However, the Company did prepare an analysis showing the average monthly residential bills for the period of 2013 through 2023.[20]

**Q. PLEASE DISCUSS THE COMPANY'S ANALYSIS ON AVERAGE RESIDENTIAL MONTHLY BILLS.**

A. The Company's analysis includes the average monthly total bill for residential customers for the period of 2013 through 2023 and shows that there has been little to no growth in average residential monthly bills over the period.[21] In its initial filing, the Company did not provide any supporting details on which bill components were used to calculate these monthly bill totals, nor did it include the determinants and rates used in the calculations. Upon request for a breakdown of the determinants and rates by component to support their analysis, WGL responded that this information was "not readily available without the conduct of a specialized study."[22] Upon further request, the Company responded to this discovery request on December 20, 2024.[23] However, the Company's supplemental response still failed to include a breakdown of the determinants and rates for each bill component. Instead, WGL included broad data points such as revenue from "Other Charges" without any detail into what charges were included or excluded from their calculations or even the tariff rates that were applied.[24] In fact, the results on the

---

19 *See* WGL Response to OPC Data Request No. 1-2A(c) (Exhibit OPC (A)-11).

20 *See* Exhibit WG (A) (Steffes) at 12:3-25.

21 *See id.*

22 *See* WGL Response to OPC Data Request No. 8-1 (Exhibit OPC (A)-21). *See also* WGL Response to OPC Data Request No. 1-1A (Exhibit OPC (A)-22).

23 *See* WGL Supplemental Response to OPC Data Request No. 8-1 (Exhibit OPC (A)-23).

24 *See id.*

Company's updated response did not even match the results shown in the original filing. For instance, the updated response claims that the average bill for a residential customer in 2023 was $53.95, while the graph on the original filing reported the average bill to be $68.58, a 27 percent difference.[25] It is a fundamental expectation that any analysis presented in a regulatory proceeding be accompanied by sufficient detail to allow for independent verification. The Company's failure to provide reasonable supporting evidence undermines the ability to assess whether the assumptions in its analysis are accurate and reasonable. As a result, the Commission should disregard this analysis.

**Q. HAS THE COST OF NATURAL GAS FOR RESIDENTIAL CUSTOMERS REMAINED CONSTANT AS THE COMPANY'S ANALYSIS SUGGESTS?**

A. No. Figure 3 below depicts a definite upward trend in rate increases authorized for WGL since 2005, with a sharper increase over the last few years. Figure 3 also shows that the revenue WGL collects from customers has far outpaced the rate of inflation, as measured by the Consumer Price Index ("CPI").

---

[25] *See* WGL Supplemental Response to OPC Data Request No. 8-1 (Exhibit OPC (A)-23); *See* Exhibit WG (A) (Steffes) at 12:14-23.

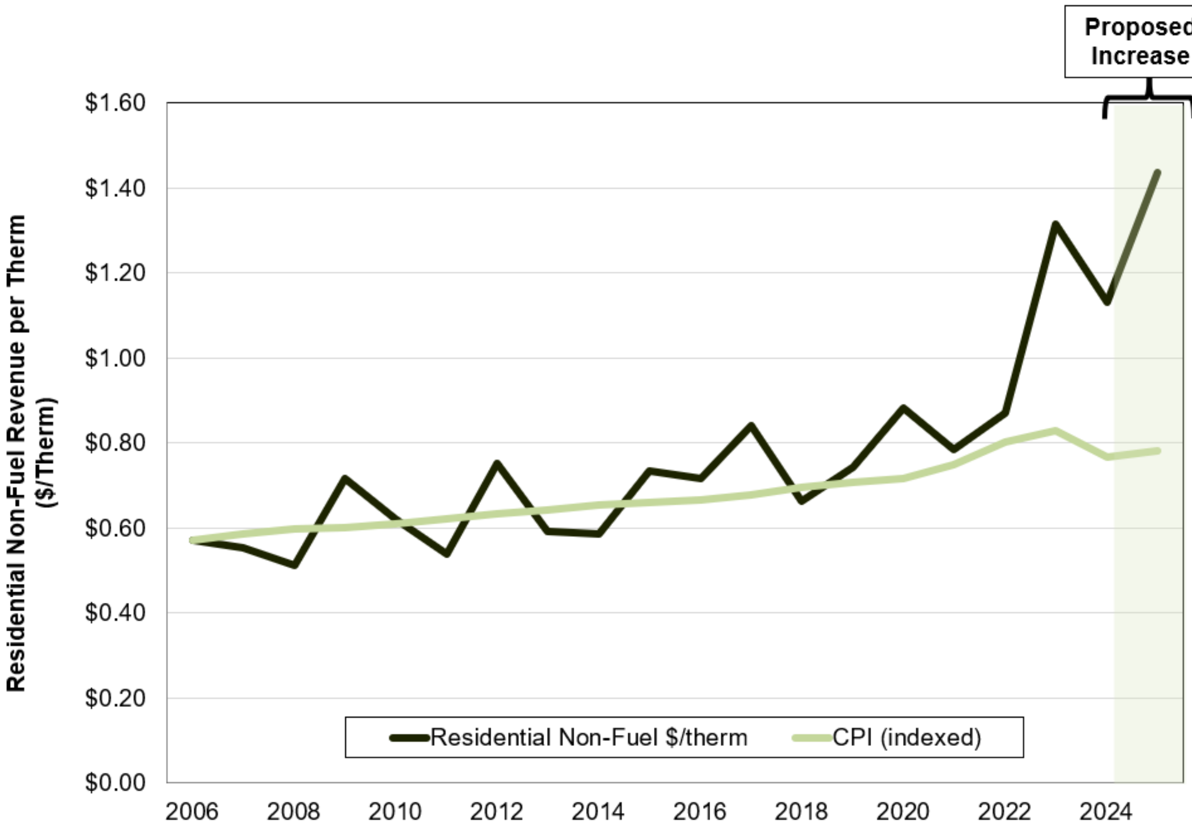



**Figure 3: Residential Revenue Growth to Inflation**

**Q. HOW DO WGL'S RESIDENTIAL RATES COMPARE TO ITS PEERS?**

A. Exhibit OPC (A)-2 presents a comparison of WGL's non-fuel residential revenues per Mcf to other local gas distribution companies located in the Mid-Atlantic region with a mostly urban customer base for the years 2011 through 2023. The exhibit shows that natural gas rates for residential customers located in the District have been consistently and significantly greater than the regional average. In fact, in 2023 the Company's average residential rates were $13.51 per Mcf, an amount that is 18% higher than the regional average of $11.44 per Mcf.[26]

[26] *See* Exhibit OPC (A)-2.

## IV. WNA PROPOSAL

**Q. PLEASE DESCRIBE THE COMPANY'S WNA PROPOSAL.**

A. The Company characterizes its proposed weather normalization adjustment as a "billing adjustment factor"[27] that calculates weather-related monthly revenue differences (*i.e.*, differences between actual revenues and a baseline set by regulation).[28] These weather-related revenue differences are applied to customer bills (as a credit or surcharge) during the period of October through May.[29] The Company claims the WNA will benefit customers by providing greater rate stability, without reducing the customers' incentive to conserve energy.[30] The Company notes that the WNA's purpose is to create stable revenue streams.[31]

**Q. HOW DOES THE COMPANY PROPOSE TO CALCULATE THESE WEATHER-RELATED DIFFERENCES IN REVENUES?**

A. The Company proposes to calculate class-specific monthly heating season revenue (October through May) differentials as the difference between those arising from actual heating degree days ("HDDs") and a normal level of HDDs set by the Commission in this case.[32] At the end of the month, if a net revenue excess is calculated, the Company would issue a refund for that month's excess revenue on a future bill.[33] If a revenue deficiency is calculated at the end of the month, the Company would accrue the deficiency into

---

27 *See* WGL Application at 4.
28 Errata to Exhibit WG (O) (Lawson) at 15:16-19.
29 *Id.* at 15:9-11.
30 Exhibit WG (D) (Tuoriniemi) at 22:9-17.
31 *Id.* at 22:18–23:8.
32 *Id.* at 28:1–29:3.
33 Errata to Exhibit WG (O) (Lawson) at 15:20-22.

subsequent months to offset any future revenue excess.[34] Net revenue deficiencies accruing at the end of the heating season would be deferred until the next heating season.[35] At that time, these weather-related revenue deficiencies would be recovered from ratepayers "over the following October to May period."[36] Carrying costs would be applied to the balance "at a rate equal to the Company's authorized Short-Term Debt rate on a monthly basis to any revenue excess or deficiency."[37]

**Q. HOW WOULD THE COMPANY HANDLE UNCLAIMED REFUNDS?**

A. It is unclear given the Company's silence on the issue. Rules surrounding refunds are especially problematic for WGL given the transient nature of the District's population. With a high proportion of renters, students, and temporary workers compared to most other utilities, customers are frequently moving in and out of the service territory. This creates a greater administrative burden to ensure refunds are distributed to their rightful owners. By not presenting a clear, fair, and administratively sound plan for managing this issue, WGL's proposal risks introducing new equity and fairness concerns.

**Q. IS THE COMPANY PROPOSING A CAP ON THE WNA RATE ADJUSTMENT?**

A. Yes. The Company proposes to limit the WNA rate adjustment "to no more than 15% of the rate class Distribution Charge per therm for either returning a revenue excess or collecting a revenue deficiency."[38]

---

[34] Errata to Exhibit WG (O) (Lawson) at 16:5-8.
[35] *Id.* at 16:9-11.
[36] *See id.* at 16:11-12.
[37] *See id.* at 16:12-14.
[38] *See id.* at 18:1-4.

**Q. WHAT IS THE BASIS FOR THE COMPANY'S WNA PROPOSAL?**

A. First, the Company states the WNA will ensure that actual sales do not deviate from Commission-established weather-normal sales.[39] Second, the Company argues that the WNA's more stable revenue streams would better align with the Company's costs, a majority of which are fixed.[40]

**Q. HAS THE COMPANY MADE SIMILAR ARGUMENTS IN PRIOR CASES?**

A. Yes. The Company made the same basic arguments when it requested a revenue decoupling mechanism in the form of a WNA in 2013,[41] a revenue normalization adjustment ("RNA") in 2016,[42] an RNA again in 2020,[43] and a Climate Progress Adjustment ("CPA") in 2023.[44] Each of these prior proposals included a revenue

---

[39] Exhibit WG (D) (Tuoriniemi) at 23:11-17.

[40] *Id.* at 23:18–24:3.

[41] *Formal Case No. 1110, In the Matter of the Application of Washington Gas Light Company for Approval of a Weather Normalization Adjustment*, Exhibit WG (A) (Buckley) at 4:15–5:6, filed November 8, 2013.

[42] *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*, Exhibit WG (K) (Raab) at 6:10–7:8, filed February 26, 2016.

[43] *Formal Case No. 1162, In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Natural Gas Service*, Exhibit WG (G) (Raab) at 18:10–19:6, filed January 13, 2020.

[44] *Formal Case No. 1169*, Exhibit WG (N) (Raab) at 28:7–29:9, filed April 4, 2022.

decoupling mechanism for weather,[45] and in each case, the revenue decoupling mechanism was either rejected by the Commission[46] or withdrawn in settlement.[47]

**Q. WHAT PRIOR OPINIONS HAS THE COMMISSION OFFERED IN REJECTING THESE REVENUE DECOUPLING PROPOSALS?**

A. The Commission noted, in rejecting WGL's most recent revenue decoupling proposal (*i.e.*, the CPA),[48] that it was "not convinced that WGL has adequately addressed the requirements prescribed by Order No. 18712"[49] that included:

1. The Company did not proffer any testimony or data on recent District-specific trends in average usage per customer. Consequently, WGL did not provide the Commission with sufficient recent evidence on the record to determine if the Company's claim of falling average customer usage is accurate and warrants an RNA mechanism to counter the resulting declining sales.
2. WGL offered no proof of financial pressures that it is incurring due to a lack of an RNA mechanism. Other than the assertion that the RNA would assist the Company

45 *Compare Formal Case No. 1110*, Exhibit WG (A) (Buckley) at 4:15–5:6 (proposing the WNA to ensure WGL's sales levels align with weather variations and to correct the mismatch between the Company's fixed cost and volumetric rate structures); *Formal Case No. 1137*, Exhibit WG (K) (Raab) at 6:10–7:8 (proposing an RNA so the Company's revenues are not rewarded or penalized based on weather variations and to align the Company's fixed cost and volumetric rate structures); *Formal Case No. 1162*, Exhibit WG (G) (Raab) at 18:10–19:6 (same); *Formal Case No. 1169*, Exhibit WG (N) (Raab) at 28:7–29:9 (same, but for CPA decoupling mechanism), *with Formal Case No. 1180*, Exhibit WG (D) (Tuoriniemi) at 21:17-18 (explaining the WNA "eliminates the variability of weather from the calculation of customer bills and revenues") and 22:18 (explaining the "WNA better aligns the Company's rate structure with its cost structure").

46 *Formal Case No. 1169*, Order No. 21939 ¶¶ 369-372 (rejecting the CPA because the Commission was "not convinced that WGL [] adequately addressed the requirements prescribed by Order No. 18712"); *Formal Case No. 1137*, Order No. 18712 ¶ 225, rel. March 3, 2017 (rejecting RNA because it the Commission was not persuaded that "the RNA promotes energy efficiency, better aligns rates and costs, and provides more stable and predictable bills"); *Formal Case No. 1110*, Order No. 17850 ¶ 38, rel. April 10, 2015 (rejecting the Company's WNA proposal because the Company proposed it "outside of a base rate case").

47 *Formal Case No. 1162*, Order No. 20705 ¶ 8, rel. February 24, 2021 ("WGL withdraws its proposed RNA without prejudice.").

48 The CPA differs from the WNA in that it related to changes in usage due to climate issues. In this case (FC 1180), it appears to be WGL's position that climate is not an issue given it did not propose specific climate programs in its application. *See* Exhibit WG (2A) (Steffes) at 5:13-15 (noting "this proceeding is a backward-looking rate case based upon a historic test year and is not the appropriate opportunity to address the District's climate goals"); WGL Response to OPC Data Request No. 14-1 (Exhibit OPC (A)-17) (objecting to data request regarding climate issues discussed in Witness Steffes' supplemental testimony). *See also* WGL Responses to OPC Data Request Nos. 16-1, 16-2, and 16-3 (Exhibit OPC (A)-18, Exhibit OPC (A)-19, Exhibit OPC (A)-20).

49 *See Formal Case No. 1169*, Order No. 21939 ¶ 370.

in meeting its approved revenue the Company failed to present any financial analysis explaining how the proposed RNA would impact the long-term financial health of the Company.

3. Month-to-month variations in the RNA will add month-to-month variations to customer bills.

4. The RNA does not signal the individual ratepayer that reduced consumption means a lower bill because the RNA surcharge is based on the usage behavior of the entire class, not the individual customer. Consequently, a customer who has conserved energy may not get the benefit of being energy efficient.[50]

**Q. DOES THE CURRENT WNA PROPOSAL SUFFER FROM ANY OF THE SAME DEFICIENCIES IDENTIFIED BY THE COMMISSION IN ITS 2017 ORDER?**

A. Yes. WGL still fails to present empirical evidence that financial pressures from the lack of any form of revenue decoupling (including a WNA) are impacting the long-term financial health of the Company. The Company simply provided a table that shows revenue deficiencies related to weather for four of the previous five years.[51] However, a simple listing of five-year revenue variances does not reflect a comprehensive financial analysis, nor does it show, in any way, any directly attributable reductions in earnings that are arising from these purported weather-related revenue variances.

**Q. DOES THE COMPANY ALREADY HAVE A CERTAIN LEVEL OF REVENUE STABILITY AS A RESULT OF ANY OTHER SURCHARGE RIDERS OR MECHANISMS?**

---

[50] *Formal Case No. 1137*, Order No. 18712 ¶¶ 225-227.

[51] Exhibit WG (D) (Tuoriniemi) at 14:1-17. In response to OPC's request for a quantification of "the impacts that weather variability, warming temperatures, ongoing conservation, and efficiency efforts of customers have had on the Company's financial performance," the Company provided no additional information, studies, or analyses and merely stated that the impacts "on the Company's financial performance are reflected in the Company's rate filing in this case." *See* WGL Response to OPC Data Request No. 1-22 (Exhibit OPC (A)-14). However, as discussed above, the information provided in the Company's rate filing fails to provide evidence that the Company is experiencing financial pressures from the lack of a decoupling mechanism.

A. Yes. The Company has other rider mechanisms that guarantee cost recovery and revenue stability between rate cases. For example, WGL recovers commodity costs through a Purchased Gas Charge ("PGC"), which the Company updates on a monthly basis to reflect fluctuations in commodity prices, and which allows this risk to pass through from the Company onto ratepayers.[52] As WGL notes, "the commodity, or gas cost, portion of the bill comprises the majority of the total bill . . . ."[53] Therefore, ratepayers are already bearing most of the price fluctuation risk. Additionally, WGL is allowed to recover a return on incremental infrastructure investments through its PROJECT*pipes* surcharge.[54] This surcharge helps to further insulate the Company from financial risk. By also requesting a WNA, WGL is seeking to transfer even more risk onto the District's ratepayers.

**Q. DOES THE COMPANY HAVE THE ABILITY TO MITIGATE THE IMPACT WEATHER PLAYS IN THE TIMING OF COST RECOVERY?**

A. Yes. WGL currently has plenty of tools at its disposal to mitigate such timing risks including the use of weather derivatives, hedging, and storage. WGL has previously acknowledged using such alternative measures, explaining it has "independently mitigated weather risk through the purchase of financial weather derivatives."[55] The Company provides no information or explanation in its Application or direct testimony on whether it has studied the use of such remedies or attempted to use such remedies prior to submitting its Application requesting approval of the WNA.

---

52 *Formal Case No. 1129*, Order No. 17826 ¶ 2, rel. March 12, 2015.

53 *See* Exhibit WG (D) (Tuoriniemi) at 22:15-17.

54 *Formal Case No. 1115*, Order No. 17789 ¶ 18, rel. January 29, 2015.

55 *See Formal Case No. 1110*, Exhibit WG (A) (Buckley) at 8:6-8.

**Q. HOW IS THE WNA EXPECTED TO IMPACT RATEPAYERS?**

A. Based on the Company's own estimates shown in Exhibit OPC (A)-3,[56] the WNA mechanism would have cost ratepayers $31.97 million over the past five years (2019 through 2023). It is therefore reasonable to assume that adoption of this mechanism would cause disproportionate harm to the District's ratepayers.

**Q. HAVE WNA MECHANISMS BEEN DETRIMENTAL TO RATEPAYERS IN OTHER GAS JURISDICTIONS?**

A. Yes. A proceeding before the Pennsylvania Public Utility Commission showed that the WNA mechanism adopted by Columbia Gas had cost its ratepayers a net total of $63.82 million over a similar five-year period (heating seasons 2019-2020 through 2023-2024).[57]

**Q. DO YOU AGREE WITH THE COMPANY'S CLAIM THAT THE WNA WILL BRING STABILITY TO CUSTOMER BILLS?**

A. No. This claim has proven to be baseless, as the Company failed to provide any individual customer impact study or other supporting empirical evidence. When requested to provide this supporting analysis, the Company simply pointed to their average monthly bill impact analysis,[58] which does not capture any of the WNA impacts that the Company has stated have a "virtually 100 percent"[59] chance of impacting customer bills. This is concerning given the fact that this mechanism could have the opposite impact by increasing customer

---

[56] Exhibit OPC (A)-3. *See also* WGL Response to OPC Data Request No. 1-1a (Exhibit OPC (A)-24).

[57] Docket No. R-2024-3046519, Direct Testimony of David E. Dismukes, PH.D. On behalf of the Pennsylvania Office of Consumer Advocate, Exhibit DED-10, filed June 14, 2024.

[58] *See* WGL Response to OPC Data Request No. 1-2A(a) (referring OPC to Exhibit WG (O)-2) (Exhibit OPC (A)-11).

[59] *See* Exhibit WG (D) (Tuoriniemi) at 23:12.

bill volatility in situations, for example, where a mild heating season is followed by an abnormally cold month the following winter. In this scenario, not only would a residential customer face significantly higher charges for the colder weather during the month they are being billed for, but they would also face additional costs to pay for the WNA's deferred balance from the prior season. Instead of providing customers with more rate stability, WNA's lagging adjustments would exacerbate it.

**Q. DOES THE COMPANY INCLUDE ANY PROPOSALS TO ADDRESS BILL STABILITY FOR CUSTOMERS?**

A. Yes. The Company proposes a 15% cap on the WNA rate adjustment to "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."[60]

**Q. IS THE COMPANY'S PROPOSED CAP ON THE WNA SUFFICIENT TO PROTECT RATEPAYERS FROM BILL VOLATILITY AND PROVIDE STABILITY?**

A. No. The 15% cap is too high to adequately protect ratepayers from excessive rate volatility and even rate shock, and moreover, does not limit the amount of revenues in excess of the cap that can be deferred for future recovery. Furthermore, the Company has failed to provide any individual customer impact study or other supporting empirical evidence to support the proposed cap. In fact, by proposing a cap, the Company has implicitly acknowledged that its proposed WNA has the potential to worsen customer bill

---

[60] *See* Errata to Exhibit WG (O) (Lawson) at 18:1-8.

fluctuations. A genuinely stabilizing mechanism would not require such a safeguard. Rather than a promoter of stability, the cap would serve to insufficiently limit the instability caused by the WNA in the first place.

**Q. HAS THE COMPANY PROPOSED ANY ROE REDUCTIONS TO ACCOUNT FOR THE REDUCED RISK ARISING FROM ITS PROPOSED WNA?**

A. No. The Company does not propose a reduction in ROE in conjunction with its WNA proposal. The proposed WNA would inherently reduce the Company's financial risk,[61] shifting these risks onto ratepayers. Other jurisdictions have recognized similar risk-shifting by reducing allowed ROEs, as discussed below, yet no such offer has been made by the Company in the current proceeding.

**Q. HAS THE D.C. PSC PREVIOUSLY RECOGNIZED THE RELATIONSHIP BETWEEN RISK REDUCTION AND A UTILITY'S AUTHORIZED ROE?**

A. Yes. In denying the RNA in FC 1137, the Commission noted its historic policy of reflecting decreases in utility risk through corresponding reductions in allowed ROE.[62] In Order No. 15556, the Commission noted that, because decoupling mechanisms provide benefits such as "reduced risk" for the utility, "it is imperative that on the other side of the ledger that the customers receive an offsetting benefit."[63] Such offsetting benefits could include "imposing [a] reduction in the utility's ROE, imposition of certain reporting

---

[61] Indeed, in response to OPC Data Request No. 7-12, WGL Witness D'Ascendis states that "[a]ll else being equal, a weather normalization mechanism, such as the Company's proposed WNA, will reduce some of the company-specific business risks related to the recovery of its authorized return." *See* WGL Response to OPC Data Request No. 7-12 (Exhibit OPC (A)-16).

[62] *Formal Case No. 1137*, Order No. 18712 ¶ 229.

[63] *See Formal Case No. 1053*, Order No. 15556 ¶ 26, rel. September 28, 2009.

requirements, establishment of specified energy efficiency performance requirements and benchmarking requirements, as well as the creation of reliability standards with attendant penalties for failure to meet said standards."[64] Accordingly, when approving Pepco's bill stabilization adjustment ("BSA") decoupling mechanism, the Commission approved a 50 basis point reduction in ROE "as part of the approval of the BSA [to] balance[] the ledger by providing a benefit to consumers in exchange for the benefit to the Company and shareholders of reaping lowered business risk."[65] While this decision was associated with a full revenue decoupling proposal, the principles related to a partial decoupling proposal in which the Company benefits from risk reduction, like a WNA, are the same.

**Q. HAVE OTHER REGULATORY COMMISSIONS PREVIOUSLY RECOGNIZED THE RELATIONSHIP BETWEEN RISK REDUCTION AND A UTILITY'S AUTHORIZED ROE?**

A. Yes. In the application of Aquarion Water Company of Connecticut ("Aquarion"), the Public Utilities Regulatory Authority ("Authority") of Connecticut addressed Aquarion's revenue adjustment mechanism, which reconciles in rates the difference "between actual revenues and allowed revenues."[66] The Authority found that there "must be a reduction in risk from the revenue adjustment mechanism"[67] and deducted 10 basis points from Aquarion's allowed ROE accordingly.[68] While this decision related to a full revenue

---

[64] *See Formal Case No. 1053*, Order No. 15556 ¶ 26.

[65] *See id.* ¶ 29.

[66] *See* State of Connecticut Public Utilities Regulatory Authority, *Docket No. 13-02-20, Application of Aquarion Water Company of Connecticut to Amend its Rates*, Decision, at 109, rel. September 24, 2013.

[67] *See id.* at 110.

[68] *See id.* at 115.

decoupling proposal, the over risk/reward principles outlined by the Authority remain the same: if risk is reduced, it should be reflected in the allowed rate of return.

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED WNA?**

A. I recommend the Commission reject the Company's WNA proposal. WGL has not provided evidence substantiating that WGL is experiencing long-term financial harm without such a mechanism. The Company has also failed to provide sufficient evidence to support its claim that the mechanism would provide rate stability to customers. Additionally, the Company has not offered any reductions to its allowed ROE in return for its reduced risk profile. The proposed WNA would inherently reduce the Company's financial risk and shift that risk onto ratepayers. Overall, the WNA would provide substantial benefits to WGL's shareholders by reducing its revenue recovery risks while providing no comparable benefits for ratepayers. Accordingly, the Commission should reject the WNA. However, if the Commission accepts the WNA, which I do not recommend, then the Commission should approve a downward adjustment in the Company's ROE, as also recommended by and discussed in OPC Witness Rothschild's testimony.

## V. REVENUE ALLOCATION

### *A. Revenue Allocation Objectives*

**Q. EXPLAIN THE PURPOSE OF THE REVENUE DISTRIBUTION PROCESS IN SETTING RATES.**

A. The revenue allocation process distributes a utility's overall revenue deficiency across customer classes which, in turn, is used to establish a new set of retail rates. The revenue allocation process often uses the results from the class cost of service study as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated rate of return, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their CCOSS-estimated class returns. The final class revenue responsibilities are then used, in conjunction with individual class billing determinants, to establish rates.

**Q. DOES THE REVENUE ALLOCATION PROCESS INCLUDE ANY POLICY CONSIDERATIONS?**

A. Yes. Allocating the overall system-wide revenue deficiency based entirely on the results of a CCOSS (or on a "full cost of service basis") can result in a very significant and adverse rate impact for certain under-earning classes. To avoid such a result, regulators often temper the revenue responsibilities assigned to various customer classes to meet a set of broad ratemaking policy goals.

**Q. WHAT ARE THOSE BROADER RATEMAKING POLICY GOALS?**

A. There are several generally accepted rate-making principles used in utility regulation, including the following:[69]

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.

[69] *See* CHARLES PHILLIPS JR., THE REGULATION OF PUBLIC UTILITIES 434-35 (Arlington: Public Utility Reports 1993) (citing JAMES C. BONBRIGHT, PRINCIPLES OF PUBLIC UTILITY RATES 291 (New York: Columbia University Press 1961)).

2) To the extent possible, gradualism should be used to protect customers from rate shock.

3) Rate continuity should be maintained.

4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.

5) Rates should be understandable to customers.

**Q. HOW ARE THE ABOVE PRINCIPLES APPLIED IN DEVELOPING RATES FOR A REGULATED UTILITY?**

A. Each of the above-enumerated principles are important, but any individual principle's relative weight can change depending upon the importance or prioritization of certain public policy goals. Rate design should strike a balance between policy goals and resulting rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates and, as a result, sound judgment is necessary to formulate a rate design that meets these objectives.

**Q. HAS THE COMMISSION RECOGNIZED THESE FACTORS IN SETTING RATES AND REVENUE RESPONSIBILITIES?**

A. Yes. The Commission has stated in the past that the appropriate determination of rates is "not a matter for the slide-rule, and "involves judgment regarding a myriad of facts."[70] "As part of its inquiry, the Commission considers cost factors and non-cost factors," such as efficiency and a customer's value of service.[71] Within this general framework, the

---

[70] *See Formal Case No. 1053*, Order No. 14712 ¶ 308, rel. January 30, 2008 (citing *Washington Gas Light Co. v. Pub. Serv. Comm'n. of D.C.*, 450 A.2d 1187, 1206 (D.C. 1982)).

[71] *See id.*

Commission has historically upheld a policy of gradualism in moving rates towards cost-causation.[72]

**Q. PLEASE EXPLAIN THE USE OF THE RELATIVE RATE OF RETURN ("RROR") IN REVENUE ALLOCATION.**

A. The RROR effectively standardizes the class-specific rate of return estimated by a CCOSS to the overall system average. In other words, it divides the estimated class ROR by the estimated system ROR. For instance, assume that the residential class is earning a class-specific eight percent ROR, and further assume that the system-wide average ROR estimated by the same CCOSS is also eight percent. The residential class, in this example, can be said to be earning a 1.0 RROR if the estimated ROR is the same as the overall system (*i.e.*, eight percent divided by eight percent equals 1.0). Put another way, any class earning a 1.0 RROR can be said to be making its full contribution to the system's overall ROR (*i.e.*, there is no cross-subsidy). A RROR that is greater than 1.0 indicates that an individual class is contributing more than the system average contribution to the Company's overall return. Likewise, a class that earns a RROR less than 1.0 but greater than zero can be said to be making a less-than-average contribution to the overall system.

**Q. DO YOU AGREE THAT A CLASS RROR LESS THAN 1.0 IS PROBLEMATIC OR INEQUITABLE?**

A. Not necessarily. As I noted earlier in my policy principles discussion, there may be policy reasons to support such a result that does not result in an inequitable cross-subsidization. For example, the presence and/or continuation of a RROR below 1.0 could be the result of

---

72 *Id.*

a prior agreed-upon rate freeze that prevents class rates from increasing to correct the revenue deficiency (relative to cost of service). In this example, the presence of a RROR below 1.0 is simply a function of a prior policy decision, not necessarily the result of some arbitrary or intentionally designed inequity.

***B. Company's Proposed Revenue Allocation***

**Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO DISTRIBUTE ITS CLASS REVENUE REQUIREMENTS.**

A. The Company's proposed revenue distribution is somewhat subjective and based upon a determination of whether any specific customer class is "at or above;" "below, but relatively near;" or "well below" the system average ROR.[73]

**Q. HOW ARE RATE INCREASES DETERMINED?**

A. The Company categorizes its rate increases into three different buckets. The first set of rate increases are applied to three customer classes[74] and set at 125% of the system average increase of 30.3% (or a 38% rate increase).[75] The second bucket of increases are assessed at 110% of the system average increase and results in a 33.3% increase for two different classes.[76] The third bucket applies a 26.3% increase to those classes with RRORs above parity.[77] The results are shown in Exhibit OPC (A)-4.

---

73 *See* Errata to Exhibit WG (O) (Lawson) at 3:22–4:20.

74 Residential non-heating and non-cooling other service, commercial and industrial combined heat and power service, and commercial and industrial natural gas vehicles service. *See id.* at 3:22–4:4.

75 *Id.* at 4:13-15.

76 *See id.* at 4:11-13. These classes include (a) residential heating and cooling service and (b) commercial and industrial heating and cooling small customer service. *Id.* at 4:1-4.

77 These classes include residential non-heating and non-cooling individually metered apartments service, commercial and industrial heating and cooling large customer service, commercial and industrial non-heating and non-cooling service, all three group metered apartment service classes, and interruptible service. *Id.* at 4:15-20.

### *C. Revenue Allocation Recommendations*

**Q. DO YOU AGREE WITH THE COMPANY'S REVENUE DISTRIBUTION PROPOSAL?**

A. No. The Company is proposing disproportionately high rate increases for several customer classes that in some instances, would be as much as 1.25 times the system average rate increase, which is inconsistent with the concept of rate gradualism. Instead, I recommend the Commission adopt a more reasonable revenue distribution that limits the rate increase to any single customer class to 1.15 times the overall system average increase. Using the Company's proposed system average increase of 30.3%, my recommendation would reduce the maximum total base revenue increase of any single rate class to 34.8%, compared to the Company's proposed maximum rate increase of 38.0%. I also recommend the Commission reject the Company's proposal to apply disproportionately high rate increases for residential heating and cooling customers, as well as small commercial and industrial heating and cooling customers whose RORs under the Company's CCOSS are described by the Company as "below, but relatively near, the system average."[78] Instead, these customers should receive the same increase given to other customer classes whose ROR under the Company's CCOSS is near or above the system average.

**Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE DISTRIBUTION?**

A. Yes. My proposed alternative revenue distribution under the Company's system average increase of 30.3% is presented in Exhibit OPC (A)-5. My proposal would increase base

---

78 *See* Errata to Exhibit WG (O) (Lawson) at 4:1-4.

rates for the primary residential class by 30.2%, compared to the Company's proposal which would increase such rates by 33.3%.

## VI. <u>RATE DESIGN</u>

### *A. Rate Design Objectives*

**Q. HOW SHOULD REGULATORY POLICY BALANCE COST ASSIGNMENTS BETWEEN CUSTOMER CHARGES AND VOLUMETRIC RATES?**

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by a form of pricing referred to as a "two-part tariff," sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

**Q. WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES FOR A TWO-PART TARIFF?**

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates in order for them to be set optimally (*i.e.*, fixed charges do not need to strictly equal fixed costs, variable rates need not strictly equal variable costs). Unfortunately, the "fixed charge-equals-fixed cost" philosophy gets repeated so often that it can often drown out meaningful discussions about other equally important considerations in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a two-part tariff typically has more to do with consumer demand than it does with cost.

***B. Customer Charge Proposals***

**Q. PLEASE DISCUSS THE COMPANY'S CUSTOMER CHARGE PROPOSALS.**

A. A summary of the Company's current and proposed customer charges has been provided in Exhibit OPC (A)-6. The Company proposes to increase all customer charges by approximately 25%.[79] According to the Company, its proposed customer charge increases are designed primarily to recover a greater percentage of its fixed costs through fixed revenues.[80] Indeed, Witness Lawson states "the Company *believes* recovery of a larger share of its fixed distribution costs through fixed charges promotes both bill stability and affordability for customers."[81] When asked whether the Company has prepared a study or analysis supporting this belief, the Company stated it "has not performed [such] a study."[82] Contrary to the Company's belief, the Company's customer charge proposal presents significant concerns because it would burden low-use customers with a greater than average portion of any proposed increase in the case, among other causes of concern.

**Q. HAVE YOU COMPARED THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES TO OTHER REGIONAL GAS UTILITIES?**

---

[79] Errata to Exhibit WG (O) (Lawson) at 4:24-5:2. *See also* WGL Response to OPC Data Request No. 1-16 (Exhibit OPC (A)-13) (showing the Company's customer charges and customer charge increases over the last six years).

[80] Errata to Exhibit WG (O) (Lawson) at 11:19-22.

[81] *See* Exhibit WG (2O) (Lawson) at 3:9-11 (emphasis added).

[82] *See* WGL Response to OPC Data Request No. 14-2 (Exhibit OPC (A)-15). While WGL claims no such study is "needed due to the obvious stability and affordability benefits of predictable bills that are spread more evenly over the entire year," the discussion in Section VII of my testimony refutes the Company's conclusory claims of affordability benefits. *See id.*

A. Yes, and this analysis[83] is presented in Exhibit OPC (A)-7, which surveys current residential and small commercial customer charges for major gas utility companies operating in the Mid-Atlantic region.[84] The Company's current residential customer charge of $16.55 per month is approximately a dollar higher than the average charge of $15.56 for other regional utilities. The survey also shows that only five out of the 24 gas distribution utilities in the region (or 21 percent) have residential customer charges greater than the Company's proposed charge of $20.70 per month. If the $20.70 per month proposal were approved, WGL's residential customer charge for the District would be 75 percent higher than WGL's Maryland jurisdiction and 67 percent higher than WGL's Virginia jurisdiction.

**Q. HAVE YOU COMPARED THE COMPANY'S COMMERCIAL CUSTOMER CHARGES TO OTHER REGIONAL GAS UTILITIES?**

A. Yes. The Company's current small commercial customer charge of $29.90 per month is comparable to the average charge of $30.46 for other regional utilities.[85] Only seven utilities in the survey (or 29%) have commercial customer charges greater than the Company's proposed charge of $37.40 per month. Furthermore, WGL's small commercial customer charge proposal for the District is 74% higher than WGL's customer charges in Maryland and 66% higher than WGL's customer charges in Virginia.

---

83 In contrast, when asked to "[p]rovide for the last three years all comparisons, analyses, and studies in the Company's possession, custody, or control that compare the customer charges of regulated gas companies," Witness Lawson stated he was "not aware of any such studies in the Company's possession." *See* WGL Response to OPC Data Request No. 1-9 (Exhibit OPC (A)-12).

84 The Mid-Atlantic region includes New York, Pennsylvania, New Jersey, Maryland, Delaware, District of Columbia, and Virginia.

85 *See* Exhibit OPC (A)-7.

**Q. IS THE COMPANY'S PROPOSAL TO INCREASE ITS RESIDENTIAL AND COMMERCIAL CUSTOMER CHARGES CONSISTENT WITH THE PROMOTION OF ENERGY EFFICIENCY AND CONSERVATION?**

A. No. The Company's rate design proposal is inconsistent with energy efficiency since it reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable.

**Q. HAVE OTHER REGULATORS RECOGNIZED THE NEGATIVE IMPACTS THAT CUSTOMER CHARGE INCREASES CAN HAVE FOR ENERGY EFFICIENCY?**

A. Yes. In rejecting a request by Baltimore Gas and Electric ("BGE") to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission ("MPSC") recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage:

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[86]

---

[86] *Maryland Public Service Commission Case No. 9299, In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates* (*"Case No. 9299*"), Order No. 85374, p. 99, rel. February 22, 2013.

**Q. CAN YOU POINT TO ANY OTHER REGULATORY EXAMPLES?**

A. Yes. The Montana Public Service Commission ("MT PSC") previously rejected a proposed straight fixed variable rate design for Energy West Montana citing several reasons, including the impact of the proposal on energy conservation efforts. In its decision, the MT PSC stated:

> The Commission agrees that most distribution costs are not avoidable, and that volumetric distribution charges may encourage conservation actions that, all other things being equal, reduce the utility's embedded cost recovery between rate cases and contribute to future rate increases.
>
> The Commission agrees that an [straight-fixed variable] SFV rate design is a clean and administratively inexpensive way to decouple revenue from volume. An often-cited public policy justification for revenue decoupling is to remove the volume disincentive for cost-effective conservation investment by a gas distribution company, which through SFV and other decoupling methods is rendered indifferent to the volume of gas consumed. Yet, SFV rates decouple revenue at the cost of decreasing returns to conservation investment by customers. For this reason the net conservation benefit of revenue decoupling via SFV rates is not clear and may be negative.[87]

**Q. ARE THE MPSC AND MT PSC ALONE IN THEIR BELIEF THAT HIGH FIXED CHARGES DISCOURAGE EFFICIENT USE OF ENERGY?**

A. No. A research document presented for consideration by the membership of the National Association for Regulatory Utility Commissioners ("NARUC") lists a straight-fixed variable ("SFV") rate design as an alternative to delink utility revenue from sales. An SFV places all fixed costs into fixed charges while relegating only variable costs to volumetric

---

87 *Montana Public Service Commission Docket No. D2010.9.90, In The Matter Of Energy West Montana, Application To Establish Increased Service Rates In Its Great Falls, Cascade, And West Yellowstone Service Areas* ("*Docket No. D2010.9.90*"), Order No. 7132c ¶¶ 119, 122, rel. November 18, 2011.

rates. The NARUC research noted this type of rate design was problematic because of its effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. <u>This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume</u>.[88]

**Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH SFV-TYPE RATE DESIGNS?**

A. Yes. The National Action Plan for Energy Efficiency ("NAPEE"), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that SFV had a detrimental effect on economic signals to encourage customers to change energy usage behavior and investments in energy efficiency devices, and specifically noted that such disincentives persist even when applied to individual components of a customer's utility bill, such as SFV for strictly distribution services:

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. <u>While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage</u>

[88] National Association of Regulatory Utility Commissioners, *Decoupling for Electric and Gas Utilities: Frequently Asked Questions (FAQ)*, at 4 (Sept. 2007), https://www.naesb.org/pdf3/dsmee_naruc_decoupling_faq.pdf (emphasis added).

> customers to change energy usage behavior or invest in efficiency technologies. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[89]

**Q. IN ADDITION TO CREATING DISINCENTIVES FOR ENERGY EFFICIENCY, CAN HIGH CUSTOMER CHARGES ALSO LEAD TO RATE EQUITY PROBLEMS?**

A. Yes. In addition to disincentivizing energy efficiency, increased customer charges also shift the rate burden within a customer class to lower-use customers. This results in equity concerns, as empirical research has shown that lower-use customers are consistently associated with lower income households. For instance, Exhibit OPC (A)-8 reflects U.S. Energy Information Administration ("EIA") energy expenditure data for the Middle Atlantic and Northeast census regions. The data indicates household income is positively correlated with energy consumption: as household income increases, energy consumption increases. For example, households earning between $10,000 and $20,000 a year consume 30.8 percent less energy per year than households earning between $100,000 and $150,000 a year.[90] This means that the customer charge is a higher proportion of a lower income household's total bill than a higher income household's energy bill. It therefore follows that the impact of increases in the customer charge create a disproportionately adverse impact on lower income households, thereby raising rate equity concerns.

---

89 U.S. Environmental Protection Agency, *Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design*, at 13-14, prepared by William Prindle, ICF International, Inc. (Sept. 2009), https://www.epa.gov/sites/default/files/2015-08/documents/rate_design.pdf (emphasis added).

90 Calculated as (95.0 – 65.7) / 95.0 = 0.308. *See* OPC Exhibit (A)-8.

**Q. HAVE YOU PREPARED A BILL ANALYSIS ASSOCIATED WITH THE COMPANY'S RATE DESIGN PROPOSALS?**

A. Yes. Exhibit OPC (A)-9 illustrates various total distribution bill changes for residential customers of varying monthly usage levels. Three types of customers, for illustrative purposes, are identified in this analysis. Customer 1 represents a customer taking service under the standard residential service class who uses an average of 52 therms per month. Customer 2 represents a smaller customer using an average of only 35 therms per month, approximately a third less than the hypothetical system average. Customer 3 represents a larger customer using an average of 70 therms per month, approximately a third more than the hypothetical system average. The schedule shows that residential customers using close to the system average would see an increase of 17.6% in their bill. Those customers with greater than average usage would incur a slightly smaller increase of 17.2%. Low-use residential customers would see their bill increase by 18.2%.

**Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?**

A. I recommend the Commission reject the Company's proposed increase in customer charges for several reasons. First, the Company's proposed $20.70 per month residential customer charge would be 33% higher than the regional peer average. Second, the Company's proposal would negatively impact the public policy goals of promoting energy efficiency. Likewise, the proposal would burden low-use customers with a greater than average portion of any proposed increase in the case. Instead, I recommend the Company's customer charges remain unchanged.

### *C. Credit and Debit Card Processing Fee Proposal*

**Q. PLEASE DISCUSS THE COMPANY'S CREDIT AND DEBIT CARD PROCESSING FEE PROPOSAL.**

A. WGL has proposed to modify General Service Provision No. 4 by charging each customer directly for any and all vendor charges related to the customer's credit or debit card used to pay their bill.[91] Currently, these credit and debit card fees, which amount to $411,796 in annual costs, are paid by the Company on behalf of the customers while the associated costs are collected from customers through an equivalent increase in base rate revenue requirements.[92] The Company argues "that directly assigning these costs to [] customers who leverage credit/debit cards to pay their bills is more appropriate" than forcing customers who do not use credit or debit cards to subsidize these processing fees.[93]

**Q. PLEASE SUMMARIZE YOUR POSITION ON THE COMPANY'S CREDIT AND DEBIT CARD PROCESSING FEE PROPOSAL.**

A. I do not oppose the Company's proposal to directly assign processing fees to customers who leverage credit or debit cards to pay their bills. However, I would recommend that the Company actively promote and market the availability of other electronic payment options that would allow customers to avoid vendor processing fees.

---

91 Errata to Exhibit WG (O) (Lawson) at 19:17-23.

92 Exhibit WG (D) (Tuoriniemi) at 80:2–81:11.

93 *See* Errata to Exhibit WG (O) (Lawson) at 22:8-12.

## VII. AFFORDABILITY

**Q. HOW DO YOU DEFINE ENERGY AFFORDABILITY?**

A. Energy affordability reflects a fundamental household value proposition: it defines how expensive energy is relative to a household's income. Affordability, more generally, can be utilized as an index number to measure, among other things, the ability of a specific type of household to pay for essential utility services such as water, electric, and/or natural gas.

**Q. ARE THERE ANY THRESHOLDS AT WHICH ENERGY SIMPLY BECOMES "UNAFFORDABLE" OR "BURDENSOME"?**

A. There is no universal definition of "unaffordability;" however, the most accepted and utilized threshold at which a customer's utility, and thus energy, bill reaches a level of significant burden is when the percentage of income spent on energy exceeds six percent.[94] This threshold comes from the Fisher, Sheehan, and Colton's Home Energy Affordability Gap Study from 2011.[95] The threshold is based on the premise that total shelter costs (including rent/mortgage and all utilities) should not exceed 30 percent of income, and that no more than 20 percent of shelter costs should be allocated to energy bills.[96] Thus, 20 percent of 30 percent yields a 6 percent affordable utility burden.[97]

---

94 *See* American Council for an Energy Efficiency Economy, *Understanding Energy Affordability*, at 1 (2015), https://www.aceee.org/sites/default/files/energy-affordability.pdf.

95 *See id.* at 1, n.2.

96 Roger D. Colton, *Home Energy Affordability in New York: The Affordability Gap (2008 – 2010)*, at 1, n.1 (June 2011), https://www.accessiblelaw.org/Documents/EnergyAffordabilityGap.pdf.

97 *Id.*

**Q. HOW DOES ACADEMIC LITERATURE EXAMINE UTILITY AFFORDABILITY?**

A. The academic literature examines energy affordability through various metrics, but predominantly through utility and energy burden rates. Utility burden rates measure the impact of a utility bill on household income. The American Council for an Energy Efficient Economy's ("ACEEE") *How High Are Household Energy Burdens?* report best encapsulates what the academic literature has studied. The ACEEE report determines four drivers of high energy burdens: (1) physical (*e.g.*, housing age and type, poor insulation, weather extremes, etc.); (2) socioeconomic (*e.g.*, chronic or sudden economic hardship, etc.); (3) behavioral (*e.g.*, lack of access to information for bill payment assistance); and (4) policy-related (*e.g.*, insufficient programs for bill assistance, high fixed customer charges, etc.).[98] It also examines utility burden rates throughout the United States, classifying any total utility burden above six percent as a household that experiences high energy burden.[99] In another report titled *City Energy Burdens*, ACEEE calculated energy burdens across the United States, concluding that "[h]ouseholds with high energy burdens are more likely to experience poor health and poverty," and that the average low-income household in the United States spent a median of 8.3 percent of their annual income on energy bills.[100]

---

98 Ariel Drehobl, Lauren Ross, and Roxana Ayala, *How High Are Household Energy Burdens? An assessment of National and Metropolitan Energy Burden across the United States*, at 4 (Sept. 2020), https://www.aceee.org/sites/default/files/pdfs/u2006.pdf

99 *Id.* at ii.

100 American Council for an Energy-Efficient Economy Policy Brief, *Data Update: City Energy Burdens*, at 1-2 (Sept. 2024), https://www.aceee.org/sites/default/files/pdfs/data_update_-_city_energy_burdens_0.pdf.

**Q HOW IS THE CONCEPT OF ENERGY AFFORDABILITY RECOGNIZED IN REGULATION AND PUBLIC POLICY?**

A. Energy affordability is increasingly becoming an important issue in regulatory policy with various states and local governments setting energy affordability targets. Recently, New York set a state-wide goal of achieving no more than a six percent energy burden for low-income households.[101] Three state agencies for the State of Oregon released a Ten-Year Plan to Reduce Energy Burden in Oregon Affordable Housing.[102] Adopting a three-phase process, the California Public Utilities Commission ("CPUC") developed the state's first energy affordability metric that tracks affordability for essential service level (electric, gas, water, and communications).[103] During the first phase, the CPUC defined affordability and established an affordability framework, setting residential household utility essential service levels and adopting the following three metrics to assess affordability of essential utility services: Affordability Ratio, Hours-at-Minimum-Wage, and Socioeconomic Vulnerability Index.[104] In phase two, the CPUC focuses on implementation of the affordability framework through various efforts including "rate cases, grants, and program

---

[101] NYC Mayor's Office of Sustainability and the Mayor's Office for Economic Opportunity, *Understanding and Alleviating Energy Cost Burden in New York City*, at 2 (Aug. 2019), https://www.nyc.gov/assets/sustainability/downloads/pdf/publications/EnergyCost.pdf.

[102] Oregon Housing and Community Services, Oregon Department of Energy, and Oregon Public Utility Commission, *Ten-Year Plan: Reducing the Energy Burden in Oregon Affordable Housing* (2019), https://www.oregon.gov/energy/Get-Involved/Documents/2018-BEEWG-Ten-Year-Plan-Energy-Burden.pdf

[103] *See* California Public Utilities Commission, Order Instituting Rulemaking to Develop Methods to Assess the Affordability Impacts of Utility Rate Requests and Commission Proceedings, Order 18-07-006, rel. July 12, 2018. *See also* California Public Utilities Commission, *Affordability Rulemaking*, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability.

[104] *See* California Public Utilities Commission, *Rulemaking 18-07-006*, Decision Adopting Metrics and Methodologies for Assessing the Relative Affordability of Utility Service, Decision D.20-07-032, at 8-18, rel. July 22, 2020.

assessments,"[105] while in the third phase of the order, the CPUC focuses on analyzing strategies to mitigate future rate increases based on the affordability metrics calculated.[106] On the other hand, the Pennsylvania Public Utility Commission ("PPUC") examined home energy burdens for low-income Pennsylvanians in its Home Energy Affordability 2019 report,[107] and subsequently issued a policy statement on March 21, 2020, establishing maximum energy burdens for customers.[108] The study found a "wide disparity in the average percent of household income spent on natural gas and electric services" by Customer Assistance Programs ("CAP") customers and non-CAP customers.[109] "CAP customers with gas heating and electric non-heating had a combined average energy burden of 12% to 14%," or "an average energy burden of 8 to 10%" for "CAP customers with electric heat."[110] In contrast, non-CAP customers "had an average energy burden of 4% for gas heating and electric non-heating or 4% for electric heating."[111] These examples demonstrate that examining energy affordability has become paramount in utility regulation across the country.

---

[105] *See* California Public Utilities Commission, *Affordability Rulemaking*, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability. *See also* California Public Utilities Commission, Docket R.18-07-006, *Affordability Metrics Implementation Staff Proposal*, rel. November 5, 2021.

[106] *See* California Public Utilities Commission, *Affordability Rulemaking*, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability. *See also* California Public Utilities Commission, Docket R.18-07-006, *Assigned Commissioner's Ruling Amending Ruling May 20, 2022 and Further Updating Proceeding Scheule for Phase 3 of Proceeding*, rel. June 9, 2022.

[107] Pennsylvania Public Utility Commission, *Home Energy Affordability for Low-Income Customers in Pennsylvania* (Jan. 2019) ("Pennsylvania Affordability Study"), https://www.puc.pa.gov/pcdocs/1602386.pdf.

[108] *See* Pennsylvania Public Utility Commission, *2019 Amendments to Policy Statement on Customer Assistance Program, 52 Pa. Code §§ 69.261—69.267 ; M-2019-3012599*, https://www.pacodeandbulletin.gov/Display/pabull?file=/secure/pabulletin/data/vol50/50-12/409.html.

[109] Pennsylvania Affordability Study at 109.

[110] *Id.*

[111] *Id.*

**Q. DOES THE COMMISSION CONSIDER AFFORDABILITY ISSUES IN REGULATING COMMISSION-JURISDICTIONAL UTILITIES.**

A. Yes. The Commission considers affordability and equity in its decision-making process under the MEDSIS Vision and Guiding Principles.[112]

**Q. WHERE DOES THE DISTRICT OF COLUMBIA RANK NATIONALLY IN TERMS OF INCOME INEQUALITY?**

A. Wealth and income gaps in the District remain stark, with income inequality in the District being amongst the highest in the nation.[113] Over the past decades, the District of Columbia has experienced economic growth, but this growth has been generally "uneven."[114] One contributing factor to wealth inequality is the stagnant wages for low-to-moderate income households, while costs such as housing and utilities have increased significantly.[115] According to the U.S. Bureau of Labor Statistics' Consumer Price Index, costs for transportation, food, and housing in the District of Columbia metro area have increased by 43 percent, 59 percent, and 70 percent respectively over the past 20 years.[116]

---

[112] *See Formal Case No. 1130*, Order No. 19275, Attachment A, rel. February 14, 2018.

[113] Statista Research Department, *Gini coefficient as a measure for household income distribution inequality in the United States 2023 by state* (Oct. 25, 2024), https://www.statista.com/statistics/227249/greatest-gap-between-rich-and-poor-by-us-state/.

[114] *See* Ariel Drehobl, Diana Hernández, Roxana Ayala, and Lauren Ross, *An Examination of District Residents' Experiences with Utility Burdens and Affordability Programs*, at 3 (March 2021), https://doee.dc.gov/sites/default/files/dc/sites/ddoe/service_content/attachments/Report_An%20Examination%20of%20District%20Residents%E2%80%99%20Experiences%20with%20Utility%20Burdens%20and%20Affordability%20Programs.pdf.

[115] *Id*. at 3-6.

[116] *Id*. at 4.

**Q. IS HOUSING AFFORDABILITY A GROWING CONCERN IN THE DISTRICT?**

A. Yes. Housing affordability is a critical issue facing the District of Columbia. "Over the last two decades, the number of affordable housing units . . . has decreased while the number of high-cost housing units has multiplied."[117] In 2002, 40% of housing in the District rented for less than $800 per month, falling to 20% by 2013 and to less than 15% by 2021.[118] Moreover, the District of Columbia has the nation's fourth highest "housing wage", that is, the hourly wage needed to afford housing.[119] The District of Columbia follows Hawaii, California, and Massachusetts in the "housing wage" ranking.[120] The increase in housing costs has made it difficult for low-income residents to afford basic necessities, resulting in such residents living in substandard housing and foregoing resources needed for a healthy lifestyle.[121]

**Q. HOW HAVE TRANSFER PAYMENTS TO LOWER-INCOME HOUSEHOLDS IMPACTED REPORTED INCOME GROWTH SINCE THE PANDEMIC ERA?**

A. Transfer payments have masked the flat, or declining disposal income (net of transfer payments) of lower income households because these payments are reported as

---

117 *See id*.

118 *Id*. *See also* Sophia Wedeen, *Low-Cost Rentals Have Decreased in Every State*, Joint Center for Housing Studies of Harvard University (July 6, 2023), https://www.jchs.harvard.edu/blog/low-cost-rentals-have-decreased-every-state.

119 Ariel Drehobl, Diana Hernández, Roxana Ayala, and Lauren Ross, *An Examination of District Residents' Experiences with Utility Burdens and Affordability Programs*, at 4 (March 2021), https://doee.dc.gov/sites/default/files/dc/sites/ddoe/service_content/attachments/Report_An%20Examination%20of%20District%20Residents%E2%80%99%20Experiences%20with%20Utility%20Burdens%20and%20Affordability%20Programs.pdf.

120 *Id*.

121 *Id.* at 5.

"income".[122] According to a recent report from the U.S. House Budget Committee, transfer payments have increased by 46% from 2019 to 2022, and more people are receiving welfare benefits today than at any point in United States history.[123] The COVID-19 pandemic significantly increased transfer payments, as "Congress spent trillions creating new transfer payment programs," like stimulus payments, expanded existing benefits, and relaxed eligibility for government assistance programs (*e.g.*, Medicaid, Earned Income Tax Credit, Supplemental Security Income, Food Stamps, etc.).[124] Due to rising costs, low-income households have sought cash assistance and in-kind benefits through available government assistance programs to afford their basic living expenses, including energy bills. For instance, the percent of the U.S. population enrolled in Medicaid has increased from 9.3% in 1975 to 24.3% in 2022 while enrollment in the Earned Income Tax Credit increased from 2.9% in 1975 to 9.3% in 2021.[125] These statistics underscore the meaningful increase in federal government transfer payments to lower income households, especially during the pandemic and continuing until the recent time. It is important to recognize the impact these transfer payments have had since they are reported as "income" and can mask what is otherwise flat, or declining disposable income (net of transfer payments). For instance, during the pandemic, income for 15th percentile low-income households increased by as much a 116% due to the unprecedently large amount of fiscal

---

[122] The U.S. House Budget Committee defines "transfer payments" as "Welfare, Medicaid, Medicare, Social Security, Disability Insurance, Unemployment Insurance, and other programs." *See* U.S. House Budget Committee, *A Growing Culture of Government Dependency* (April 4, 2023), https://budget.house.gov/resources/staff-working-papers/a-growing-culture-of-government-dependency.

[123] U.S. House Budget Committee, *A Growing Culture of Government Dependency* (April 4, 2023), https://budget.house.gov/resources/staff-working-papers/a-growing-culture-of-government-dependency.

[124] *Id.*

[125] *Id.*

stimulus that the government implemented in light of the pandemic economic disruption.[126] Three of these policies—the recovery rebate credit, expanded unemployment compensation, and expanded child tax credit—together increased income by an average of $6,800 per household in 2020.[127] As a result, government transfer payments from temporary, emergency policies had a significant impact on low-income households. Even after the pandemic was said to have ended, government transfer payments represent a significant majority of the annual income of low-income households in the District, raising concerns about the increasing inability of low- and moderate-income households to afford basic living expenses without cash or in-kind benefit assistance provided through government assistance programs as a result of rising costs. The figure below displays 15th percentile income in the District with and without government transfer payments, showing a stark increase in transfer payments during and after the pandemic.

[126] Congressional Budget Office, *The Distribution of Household Income in 2021*, at 4, https://www.cbo.gov/system/files/2024-09/60341-income.pdf.

[127] *Id*. at 3.

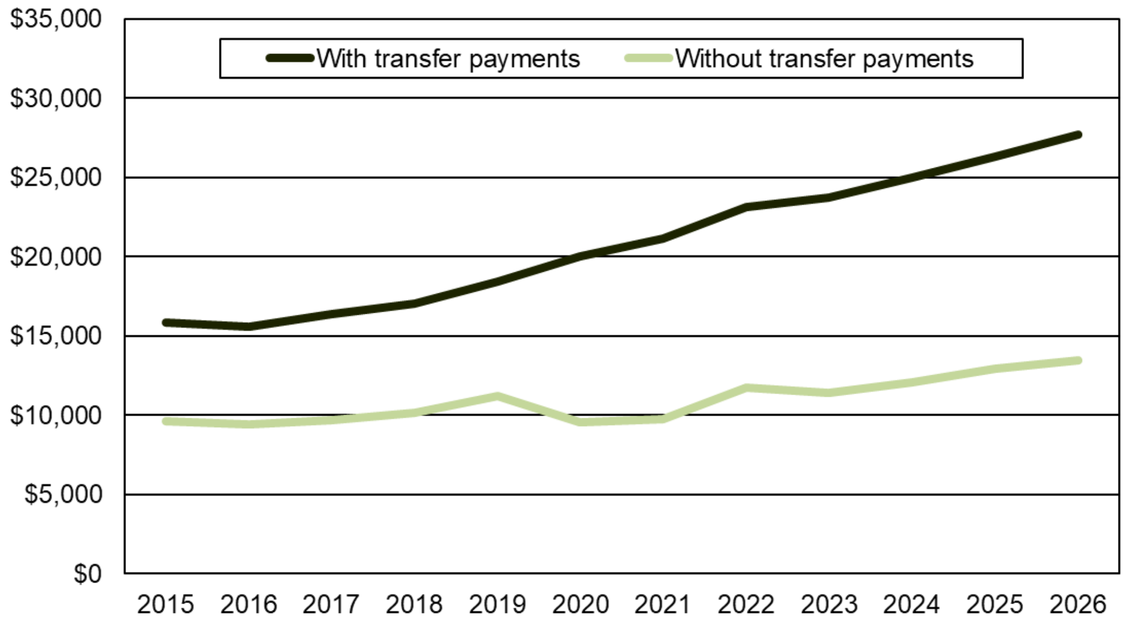



**Figure 4: 15th percentile income in the District**

**Q. HAVE YOU ESTIMATED THE EFFECT THE COMPANY'S PROPOSED RATE INCREASE WOULD HAVE ON THE AFFORDABILITY OF ENERGY IN THE DISTRICT?**

A. Yes. As shown in Exhibit OPC (A)-10, I calculated three different affordability indexes that offer a comprehensive assessment of energy affordability in the District. The first index does not take rent into account and was calculated for two low-income groups: 15th percentile income and 20th percentile income. The second index factors in the cost of rent on a household's ability to afford its monthly utility bill for 15th and 20th percentile income groups. The third index removes transfer payment and federal taxes from gross income to show what the energy burden looks like without the additional financial assistance provided through government assistance programs for 15th and 20th percentile incomes groups.

**Q. WHAT ARE THE RESULTS OF THE ENERGY AFFORDABILITY INDEX THAT MEASURES THE ENERGY BURDEN OF LOW-INCOME HOUSEHOLDS WITHOUT FACTORING IN RENT?**

A. In 2024, the energy affordability index for low-income households at 15th percentile income had an energy burden of 6.4% while 20th percentile income households had an energy burden of 4.2%. With the Company's proposed rate increase, the energy affordability index will increase to 6.5% in 2026 for 15th percentile income, and decrease to 4.0% in 2026 for 20th percentile income. The 15th percentile income energy burden in 2026 will remain above the six percent "unaffordable" threshold. This means that low-income households will experience increasingly unaffordable utility services, something the Commission needs to take into consideration when evaluating the Company's proposed rate increase.[128]

**Q. WHAT ARE THE RESULTS OF THE ENERGY AFFORDABILITY INDEX THAT MEASURES THE ENERGY BURDEN OF LOW-INCOME HOUSEHOLDS FACTORING IN RENT?**

A. The index with rent factored in for 15th percentile income residential households will increase from 13.1% in 2019 to 13.6% in 2026, representing a 4.1% increase, underscoring the increasingly unaffordable energy bills for the District's lowest income group. In comparison, the index with rent factored in for 20th percentile income residential households will decrease from 9.2% in 2019 to 6.4% in 2026. It is important to consider

---

[128] *See Formal Case No. 1130*, Order No. 19275, Attachment A (affordability listed as a Guiding Principle under the D.C. Public Service Commission's MEDSIS Vision Statement).

the impact of rising rent on energy affordability, and, evidently, the energy affordability index is significantly higher when rent is factored in.

**Q. WHAT ARE THE RESULTS OF THE ENERGY AFFORDABILITY INDEX THAT MEASURES THE ENERGY BURDEN OF LOW-INCOME HOUSEHOLDS, ADJUSTING FOR FEDERAL GOVERNMENT TRANSFER PAYMENTS?**

A. The energy affordability index with income before any transfer payments will increase from 12.4% in 2019 to 16.4% in 2026 for the 15th percentile income group. For the 20th percentile income group, the energy affordability index will increase from 9.1% in 2019 to 11.2% in 2026. The Commission must recognize that low-income customers are vulnerable to significant rate increases from the Company and are becoming increasingly reliant on government assistance to afford their basic living expenses. Higher and more burdensome natural gas rates will further contribute to unaffordability.

**Q. PLEASE SUMMARIZE YOUR AFFORDABILITY RECOMMENDATION.**

A. I recommend the Commission open a proceeding after the conclusion of the current rate case to examine low-income and affordability issues in a more holistic fashion given the increasing number of rate increase requests the District's ratepayers have been subjected to when such ratepayers are already facing difficulties in affording energy costs and where these difficulties are being masked by virtue of the fact that federal government transfer payments are recorded as "income" for such ratepayers, as discussed in my testimony. A more focused, stand-alone proceeding seems to be a better venue to develop an approach for consistent measurement and monitoring of energy affordability in the District.

## VIII. CONCLUSION AND RECOMMENDATIONS

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED WNA?**

A. I recommend the Commission reject the Company's WNA proposal. There is no record evidence showing that WGL is experiencing long-term financial harm without such a mechanism. The Company has also failed to provide sufficient evidence to support its claim that the mechanism would provide rate stability to customers. Additionally, the Company has not offered any reductions to its allowed ROE in return for its reduced risk profile. The proposed WNA would inherently reduce the Company's financial risk and shift that risk onto ratepayers. Overall, the WNA would provide substantial benefits to WGL's shareholders by reducing its revenue recovery risks while providing no comparable benefits for ratepayers. Accordingly, the Commission should reject the WNA. However, if the Commission accepts the WNA, which I do not recommend, then the Commission should approve a downward adjustment in the Company's ROE, as also recommended by and discussed in OPC Witness Rothschild's testimony.

**Q. DO YOU AGREE WITH THE COMPANY'S REVENUE DISTRIBUTION PROPOSAL?**

A. No. The Company is proposing disproportionately high rate increases for several customer classes that in some instances, would be as much as 1.25 times the system average rate increase, which is inconsistent with the concept of rate gradualism. Instead, I recommend the Commission adopt a more reasonable revenue distribution that limits the rate increase to any single customer class to 1.15 times the overall system average increase. Using the

Company's proposed system average increase of 30.3%, my recommendation would reduce the maximum total base revenue increase of any single rate class to 34.8%, compared to the Company's proposed maximum rate increase of 38.0%. I also recommend the Commission reject the Company's proposal to apply disproportionately high rate increases for residential heating and cooling customers, as well as small commercial and industrial heating and cooling customers whose ROR under the Company's CCOSS is more aligned with the system average than any other rate class. Instead, these customers should receive the same increase given to other customer classes whose ROR under the Company's CCOSS is near or above the system average.

**Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE DISTRIBUTION?**

A. Yes. My proposed alternative revenue distribution under the Company's system average increase of 30.3 percent is presented in Exhibit OPC (A)-5. My proposal would increase base rates for the primary residential class by 30.2%, compared to the Company's proposal which would increase such rates by 33.3%.

**Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?**

A. I recommend the Commission reject the Company's proposed increase in customer charges for several reasons. First, the Company's proposed $20.70 per month residential customer charge would be 33% higher than the regional peer average. Second, the Company's proposal would negatively impact the public policy goals of promoting energy efficiency. Likewise, the proposal would burden low-use customers with a greater than average portion of any proposed increase in the case. Instead, I recommend the Company's customer charges remain unchanged.

**Q. PLEASE SUMMARIZE YOUR POSITION ON THE COMPANY'S CREDIT AND DEBIT CARD PROCESSING FEE PROPOSAL.**

A. I do not oppose the Company's proposal to directly assign processing fees to customers who leverage credit or debit cards to pay their bills. However, I would recommend that the Company actively promote and market the availability of other electronic payment options that would allow customers to avoid vendor processing fees.

**Q. PLEASE SUMMARIZE YOUR AFFORDABILITY RECOMMENDATION.**

A. I recommend the Commission open a proceeding after the conclusion of the current rate case to examine low-income and affordability issues in a more holistic fashion given the increasing number of rate increase requests the District's ratepayers have been subjected to when such ratepayers are already facing difficulties in affording energy costs and where these difficulties are being masked by virtue of the fact that federal government transfer payments are recorded as "income" for such ratepayers, as discussed in my testimony. A more focused, stand-alone proceeding seems to be a better venue to develop an approach for consistent measurement and monitoring of energy affordability in the District.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Although my review of this matter is ongoing, this concludes my pre-filed direct testimony.

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

| | | |
|---|---|---|
| **In the Matter of** | § | |
| | § | |
| **THE APPLICATION OF** | § | |
| **WASHINGTON GAS LIGHT** | § | **Formal Case No. 1180** |
| **COMPANY FOR AUTHORITY** | § | |
| **TO INCREASE EXISTING RATES** | § | |
| **AND CHARGES FOR GAS** | § | |
| **SERVICE** | | |

**AFFIDAVIT**

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

david e. disukes

Date: 01.07.2025

Subscribed and sworn to before me

This 7 day of January, 2025.

State of Louisiana

Parish of East Baton Rouge

Notary Public

My Commission expires: for life

SHANNON O. BARNES
NOTARY PUBLIC ID #85415
STATE OF LOUISIANA
MY COMMISSION IS FOR LIFE

***DAVID E. DISMUKES, PH.D.***

***Professor Emeritus***
***Center for Energy Studies***
***Louisiana State University***
***Baton Rouge, LA 70803-0301***
***Phone: (225) 578-4343***
***dismukes@lsu.edu***

***URL: www.enrg.lsu.edu***

***Consulting Economist***
***Acadian Consulting Group, LLC 5800***
***One Perkins Place Drive***
***Suite 5-F***
***Baton Rouge, LA 70808***
***Phone: (225) 769-2603***
***daviddismukes@acadianconsulting.com***

***URL: www.acadianconsulting.com***

## EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

## ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

**Center for Energy Studies**

| | |
|---|---|
| 2023-Current | Professor Emeritus |
| 2014-2023 | Executive Director (Retired in 2023) |
| 2007-2023 | Director, Division of Policy Analysis |
| 2006-2023 | Professor |
| 2003-2014 | Associate Executive Director |
| 2001-2006 | Associate Professor |
| 1999-2001 | Research Fellow and Adjunct Assistant Professor |
| 1995-2000 | Assistant Professor |

**College of the Coast and the Environment (Department of Environmental Studies)**

| | |
|---|---|
| 2014-2023 | Professor (Joint Appointment with CES) |

| | |
|---|---|
| 2010-2023 | Director, Coastal Marine Institute |
| 2010-2014 | Adjunct Professor |

**E.J. Ourso College of Business Administration (Department of Economics)**

| | |
|---|---|
| 2006-2023 | Adjunct Professor |
| 2001-2006 | Adjunct Associate Professor |
| 1999-2000 | Adjunct Assistant Professor |

Michigan State University, East Lansing, Michigan

**Institute of Public Utilities**

2018-Current Senior Fellow

Florida State University, Tallahassee, Florida

**College of Social Sciences, Department of Economics**

1995 Instructor

## PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

| | |
|---|---|
| 2001-Current | Consulting Economist/Principal |
| 1995-1999 | Consulting Economist/Principal |

Econ One Research, Inc., Houston, Texas

1999-2001 Senior Economist

Florida Public Service Commission, Tallahassee, Florida

**Division of Communications, Policy Analysis Section**

1995 Planning & Research Economist

**Division of Auditing & Financial Analysis, Forecasting Section**

| | |
|---|---|
| 1993 | Planning & Research Economist |
| 1992-1993 | Economist |

Project for an Energy Efficient Florida/FlaSEIA, Tallahassee, Florida

1994 Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

| | |
|---|---|
| 1991-1992 | Research Associate |
| 1989-1991 | Senior Research Analyst |
| 1988-1989 | Research Analyst |

## GOVERNMENT & ADVISORY APPOINTMENTS

| | |
|---|---|
| 2023 – Current | Distinguished Fellow & Senior Economist<br>Institute For Energy Research<br>Washington, D.C. |
| 2017 -- Current | Member, National Petroleum Council.<br>U.S. Department of Energy. |
| 2020-2023 | Co-Chairperson, Energy Advisory Committee, World Trade Center New Orleans, Louisiana. |
| 2007-2023 | Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee. |
| 2007-2023 | Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research). |
| 2005 | Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322). |
| 2003-2005 | Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council |
| 2001-2003 | Member, Louisiana Comprehensive Energy Policy Commission. |

## PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Energy and Environment: The Grand Challenges of 21st Century.* (2022). With Chris F. D'Elia and Bryan F. Snyder. New York: Kendell Hunt Publishers. Pp. 153.
2. *Power System Operations and Planning in a Competitive Market*. (2002). With Fred I. Denny. New York: CRC Press. Pp. 133.
3. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy. Pp. 60.

## PUBLICATIONS: PEER REVIEWED ACADEMIC JOURNALS

1. "Anticipating and Adapting to the Future Impacts of Climate Change on the Health, Security, and Welfare of Low Elevation Coastal Zone (LECZ) Communities in Southeastern USA" (2021). With Thomas Allen, Joshua Behr, Anamaria Bukvic, Ryan S.D. Calder, Kiki Caruson, Charles Connor, Christopher D'Elia, Robin Ersing, Rima Franklin, Jesse Goldstein, Jonathon Goodall, Scott Hemmerling, Jennifer Irish, Steven Lazarus, Derek Loftis Mark Luther, Leigh McCallister, Karen McGlathery, Molly

Mitchell, William Moore, Carhles Reid Nichols, Karinna Nunez, Matthew Reidenbach, Julie Shortridge, Robert Weisberg, Robert Weiss, Lynn Donelson Wright, Meng Xia, Kehui Xu, Donald Young, Gary Zarillo, and Julie C. Zinnert. *Journal of Marine Science and Engineering.* 9 (11) 1196.

2. "The Potential Impact of the U.S. Carbon Capture and Storage Tax Credit Expansion on the Economic Feasibility of Industrial Carbon Capture and Storage" (2021). With Brittany Tarufelli and Brian Snyder. *Energy Policy*. Vol. 149.

3. "Current Trends and Issues in Reforming State-level Solar Net Energy Metering Policies." (2020). *Journal of Energy Law and Resources*. Vol. VIII: 419-451.

4. "A cash flow model of an integrated industrial CCS-EOR project in a petrochemical corridor: a case study in Louisiana. (2019). With Brian Snyder and Michael Layne. *International Journal of Greenhouse Gas Control*. 93(08).

5. "Understanding the challenges of industrial carbon capture and storage: An example in a U.S. petrochemical corridor." (2019). With Michael Layne and Brian Snyder. *International Journal of Sustainable Energy* 38(1):13-23.

6. "Understanding the Mississippi River Delta as a coupled natural-human system: research methods, challenges, and prospects. (2018). With Nina S.N. Lam, Y. Jun Xu, Kam-Biu Liu, Margaret Reams, R. Kelly Pace, Yi Qiang, Siddhartha Narra, Kenan Li, Thomas Blanchette, Heng Cei, Lei Zou, and Volodymyr Mihunov. *Water*. 10(8).

7. "Understanding the challenges of industrial carbon capture and storage: an example in a U.S. petrochemical corridor." (2018). With Brian Snyder and Michael Layne. *International Journal of Sustainable Energy*. 38(1):1-11

8. "Sea level rise and coastal inundation: a case study of the Gulf Coast energy infrastructure." (2018). With Siddhartha Narra. *Natural Resources*. 9: 150-174.

9. "The energy pillars of society: perverse interactions among human resource use, the economy and environmental degradation." (2018). With Adrian R.H. Wiegman, John W. Day, Christopher F. D'Elia, Jeffrey S. Rutherford, Charles Hall. *BioPhysical Economics and Resource Quality*. 3(2) 1-16.

10. "Modeling the impacts of sea-level rise, oil price, and management strategy on the costs of sustaining Mississippi delta marshes with hydraulic dredging." (2018). with Adrian R.H. Wiegman, John W. Day, Christopher F. D'Elia, Jeffrey S. Rutherford, James T. Morris, Eric D. Roy, Robert R. Lane, and Brian F. Snyder. *Science of the Total Environment* 618 (2018): 1547-1559.

11. "Identifying Vulnerabilities of Working Coasts Supporting Critical Energy Infrastructure." (2016). With Siddhartha Narra. *Water*. 8(1).

12. "Economies of Scale, Learning Effects and Offshore Wind Development Costs" (2015).

With Gregory B. Upton, Jr. *Renewable Energy*. 61-66.

13. "Economic impact of Gulf of Mexico ecosystem goods and services and integration into restoration decision-making." (2014) With Shepard, A.N., J.F. Valentine, C.F. D'Elia, D.W. Yoskowitz. *Gulf Science*.

14. "An Empirical Analysis of Differences in Interstate Oil and Natural Gas Drilling Activity." (2012). With Mark J. Kaiser and Christopher J. Peters. *Exploration & Production: Oil and Gas Review*. 30(1): 18-22.

15. "The Value of Lost Production from the 2004-2005 Hurricane Seasons in the Gulf of Mexico." (2009). With Mark J. Kaiser and Yunke Yu. *Journal of Business Valuation and Economic Loss Analysis*. 4(2).

16. "Estimating the Impact of Royalty Relief on Oil and Gas Production on Marginal State Leases in the US." (2006). With Jeffrey M. Burke and Dmitry V. Mesyanzhinov. *Energy Policy* 34(12): 1389-1398.

17. "Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds." (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation.* 2 (November): 69-85. (*Received 2005 Best Paper Award by NRRI*).

18. "Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes." (2004). With K.E. Hughes II. *International Energy Law and Taxation Review*. 10 (October): 206-212.

19. "Reflections on the U.S. Electric Power Production Industry: Precedent Decisions Vs. Market Pressures." (2003). With Robert F. Cope III and John W. Yeargain. *Journal of Legal, Ethical, and Regulatory Issues*. Volume 6, Number 1.

20. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001) *Public Resources Law Digest*. 38: 2.

21. "A Comment on the Integration of Price Cap and Yardstick Competition Schemes in Electrical Distribution Regulation." (2001). With Steven A. Ostrover. *IEEE Transactions on Power Systems.* 16 (4): 940 -942.

22. "Modeling Regional Power Markets and Market Power." (2001). With Robert F. Cope. *Managerial and Decision Economics.* 22:411-429.

23. "A Data Envelopment Analysis of Levels and Sources of Coal Fired Electric Power Generation Inefficiency" (2000). With Williams O. Olatubi. *Utilities Policy.* 9 (2): 47-59.

24. "Cogeneration and Electric Power Industry Restructuring" (1999). With Andrew N. Kleit. *Resource and Energy Economics*. 21:153-166.

25. "Capacity and Economies of Scale in Electric Power Transmission" (1999). With Robert F. Cope and Dmitry Mesyanzhinov. *Utilities Policy* 7: 155-162.

26. "Oil Spills, Workplace Safety, and Firm Size: Evidence from the U.S. Gulf of Mexico OCS." (1997). With O. O. Iledare, A. G. Pulsipher, and Dmitry Mesyanzhinov. *Energy Journal* 4: 73-90.

27. "A Comment on Cost Savings from Nuclear Regulatory Reform" (1997). *Southern Economic Journal*. 63:1108-1112.

28. "The Demand for Long Distance Telephone Communication: A Route-Specific Analysis of Short-Haul Service." (1996). *Studies in Economics and Finance* 17:33-45.

**PUBLICATIONS: PEER REVIEWED PROCEEDINGS**

1. "Hydraulic Fracturing: A Look at Efficiency and the Environmental Effects of Fracking" (2014). With Emily C. Jackson. *Environmental Science and Technology: Proceedings from the 7th International Conference on Environmental Science and Technology*. Volume1 of 2: edited by George A. Sorial and Jihua Hong. (Houston, TX: American Science Press, ISBN: 978-0976885368): 42-46.

2. "Economic and Policy Issues in Sustaining an Adequate Oil Spill Contingency Fund in the Aftermath of a Catastrophic Incident." (2014). With Stephen R. Barnes and Gregory B. Upton. *Proceedings of the Thirty-seventh AMOP Technical Seminar on Environmental contamination and Response.* June: 506-524.

3. "Technology Based Ethical Issues Surrounding the California Energy Crisis." (2002). With Robert F. Cope III and John Yeargain. *Proceedings of the Academy of Legal, Ethical, and Regulatory Issues*. September: 17-21.

4. "Electric Utility Restructuring and Strategies for the Future." (2001). With Scott W. Geiger. *Proceedings of the Southwest Academy of Management*. March.

5. "Applications for Distributed Energy Resources in Oil and Gas Production: Methods for Reducing Flare Gas Emissions and Increasing Generation Availability" (2000). With Ritchie D. Priddy. *Proceedings of the International Energy Foundation – ENERGEX 2000*. July.

6. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry" (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering*. June: 294-298.

7. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development*. October: 499-504.

8. "Safety Regulations, Firm Size, and the Risk of Accidents in E&P Operations on the Gulf of Mexico Outer Continental Shelf" (1996). With Allan Pulsipher, Omowumi Iledare, and Bob Baumann. *Proceedings of the American Society of Petroleum Engineers: Third International Conference on Health, Safety, and the Environment in Oil and Gas*

*Exploration and Production*, June.

9. "Comparing the Safety and Environmental Records of Firms Operating Offshore Platforms in the Gulf of Mexico." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the American Society of Mechanical Engineers: Offshore and Arctic Operations 1996*, January.

**PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS**

1. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements" (2005). *Proceedings of the 23rd Annual Information Technology Meetings*. U.S. Department of the Interior, Minerals Management Service, Gulf Coast Region, New Orleans, LA. January 12, 2005.
2. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) *Proceedings of the 51st Mineral Law Institute*, Louisiana State University, Baton Rouge, LA. April 2, 2004.
3. "Competitive Bidding in the Electric Power Industry." (2003). *Proceedings of the Association of Energy Engineers*. December 2003.
4. "The Role of ANS Gas on Southcentral Alaskan Development." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: Energy Markets in Turmoil: Making Sense of It All*. October.
5. "A New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities." (2002). With Vicki Zatarain. *Proceedings of the 2002 National IMPLAN Users Conference*: 241-258.
6. "Analysis of the Economic Impact Associated with Oil and Gas Activities on State Leases." (2002). With Dmitry Mesyanzhinov, Robert H. Baumann, and Allan G. Pulsipher. *Proceedings of the 2002 National IMPLAN Users Conference*: 149-155.
7. "Do Deepwater Activities Create Different Impacts to Communities Surrounding the Gulf OCS?" (2001). *Proceedings of the International Association for Energy Economics: 2001: An Energy Odyssey?* April.
8. "Modeling the Economic Impact of Offshore Activities on Onshore Communities." (2000). With Williams O. Olatubi. *Proceedings of the 20th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.
9. "Empirical Challenges in Estimating the Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico" (2000). With Williams O. Olatubi. *Proceedings of the International Association for Energy Economics: Transforming Energy Markets*. August.

10. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: The Only Constant is Change* August: 444-452.

11. "Modeling Electric Power Markets in a Restructured Environment" (1998). With Robert F. Cope and Dan Rinks. *Proceedings of the International Association for Energy Economics: Technology's Critical Role in Energy and Environmental Markets*. October: 48-56.

12. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Bob Baumann, and Dmitry Mesyanzhinov. *Proceedings of the 16th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana: 162-166.

13. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the 15th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.

**PUBLICATIONS: BOOK CHAPTERS**

1. "The Role of Distributed Energy Resources in a Restructured Power Industry." (2006). In *Electric Choices: Deregulation and the Future of Electric Power*. Edited by Andrew N. Kleit. Oakland, CA: The Independent Institute (Rowman & Littlefield Publishers, Inc.), 181-208.

2. "The Road Ahead: The Outlook for Louisiana Energy." (2006). In *Commemorating Louisiana Energy: 100 Years of Louisiana Natural Gas Development*. Houston, TX: Harts Energy Publications, 68-72.

3. "Competitive Power Procurement An Appropriate Strategy in a Quasi-Regulated World." (2004). In *Electric and Natural Gas Business: Using New Strategies, Understanding the Issues.* With Elizabeth A. Downer. Edited by Robert Willett. Houston, TX: Financial Communications Company, 91-104.

4. "Alaskan North Slope Natural Gas Development." (2003). In *Natural Gas and Electric Industries Analysis 2003*. With William E. Nebesky, Dmitry Mesyanzhinov, and Jeffrey M. Burke. Edited by Robert Willett. Houston, TX: Financial Communications Company, 185-205.

5. "Challenges and Opportunities for Distributed Energy Resources in the Natural Gas Industry." (2002). In *Natural Gas and Electric Industries Analysis 2001-2002*. Edited by

Robert Willett. With Martin J. Collette, Ritchie D. Priddy, and Jeffrey M. Burke. Houston, TX: Financial Communications Company, 114-131.

6. "The Hydropower Industry of the United States." (2000). With Dmitry Mesyanzhinov. In *Renewable Energy: Trends and Prospects*. Edited by E.W. Miller and A.I. Panah. Lafayette, PN: The Pennsylvania Academy of Science, 133-146.

7. "Electric Power Generation." (2000). In the *Macmillan Encyclopedia of Energy*. Edited by John Zumerchik. New York: Macmillan Reference.

**PUBLICATIONS: BOOK REVIEWS**

1. Review of ***Renewable Resources for Electric Power: Prospects and Challenges***. Raphael Edinger and Sanjay Kaul. (Westport, Connecticut: Quorum Books, 2000), pp 154. ISBN 1-56720-233-0. *Natural Resources Forum*. (*2000*).

2. Review of ***Electricity Transmission Pricing and Technology***, edited by Michael Einhorn and Riaz Siddiqi. (Boston: Kluwer Academic Publishers, 1996) pp. 282. ISBN 0-7923-9643-X. *Energy Journal* 18 (1997): 146-148.

3. Review of ***Electric Cooperatives on the Threshold of a New Era*** by Public Utilities Reports. (Vienna, Virginia: Public Utilities Reports, 1996) pp. 232. ISBN 0-910325-63-4. *Energy Journal* 17 (1996): 161-62.

**PUBLICATIONS: TRADE AND PROFESSIONAL JOURNALS**

1. "The Impact of Globalization, Decarbonization, and Politicization: Forecasting the outlook for the energy and energy transition along the Gulf Coast. *Landman* (2023, Forthcoming, Fall Edition).

2. "Opportunities for Carbon Capture, Utilization and Storage in Louisiana." (2020). *LOGA Industry Report*. Summer: 18-21.

3. "The Challenges of the Regulatory Review of Diversification Mergers." (2016). With Michael W. Deupree. *Electricity Journal*. 29 (2016): 9-14.

4. "Unconventional Natural Gas and the U.S. Manufacturing Renaissance" (2013). *BIC Magazine*. Vol. 30: No. 2, p. 76 (March).

5. "Louisiana's Tuscaloosa Marine Shale Development: Emerging Resource and Economic Potentials" (2012). *Spectrum*. January-April: 18-20.

6. "The Impact of Legacy Lawsuits on Louisiana's Conventional Drilling Activity" (2012). *LOGA Industry Report*. Spring 2012: 27-34.

7. "Value of Production Losses Tallied for 2004-2005 Storms." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.27: 32-26 (July 21) (part 3 of 3).

8. "Model Framework Can Aid Decision on Redevelopment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.26: 49-53 (July 14) (part 2 of 3).

9. "Field Redevelopment Economics and Storm Impact Assessment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.25: 42-50 (July 7) (part 1 of 3).

10. "The IRS' Latest Proposal on Tax Normalization: A Pyrrhic Victory for Ratepayers," (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 55(1): 217-236

11. "Executive Compensation in the Electric Power Industry: Is It Excessive?" (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(4): 913-940.

12. "Renewable Portfolio Standards in the Electric Power Industry." With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(3): 693-706.

13. "Regulating Mercury Emissions from Electric Utilities: Good Environmental Stewardship or Bad Public Policy? (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54 (2): 401-424.

14. "Using Industrial-Only Retail Choice as a Means of Moving Competition Forward in the Electric Power Industry." (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(1): 211-223.

15. "The Nuclear Power Plant Endgame: Decommissioning and Permanent Waste Storage. (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (4): 981-997.

16. "Can LNG Preserve the Gas-Power Convergence?" (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (3):783-796.

17. "Competitive Bidding as a Means of Securing Opportunities for Efficiency." (2004). With Elizabeth A. Downer. *Electricity and Natural Gas* 21 (4): 15-21.

18. "The Evolving Markets for Polluting Emissions: From Sulfur Dioxide to Carbon Dioxide." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53(2): 479-494.

19. "The Challenges Associated with a Nuclear Power Revival: Its Past." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (1): 193-211.

20. "Deregulation of Generating Assets and The Disposition of Excess Deferred Federal Income Taxes: A 'Catch-22' for Ratepayers." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 873-891.

21. "Will Competitive Bidding Make a Comeback?" (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 659-674.

22. "An Electric Utility's Exposure to Future Environmental Costs: Does It Matter? You Bet!" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 457-469.

23. "White Paper or White Flag: Do FERC's Concessions Represent A Withdrawal from Wholesale Power Market Reform?" (2003). With K.E. Hughes II. *Oil, Gas and Energy*

*Quarterly*. 52: 197-207.

24. "Clear Skies" or Storm Clouds Ahead? The Continuing Debate over Air Pollution and Climate Change" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 823-848.

25. "Economic Displacement Opportunities in Southeastern Power Markets." (2003). With Dmitry V. Mesyanzhinov. *USAEE Dialogue*. 11: 20-24.

26. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 635-652.

27. "Is There a Role for the TVA in Post-Restructured Electric Markets?" (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 433-454.

28. "The Role of Alaska North Slope Gas in the Southcentral Alaska Regional Energy Balance." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Natural Gas Journal*. 19: 10-15.

29. "Standardizing Wholesale Markets For Energy." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 51: 207-225.

30. "Do Economic Activities Create Different Economic Impacts to Communities Surrounding the Gulf OCS?" (2002). With Williams O. Olatubi. *IAEE Newsletter*. Second Quarter: 16-20.

31. "Will Electric Restructuring Ever Get Back on Track? Texas is not California." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 50: 943-960.

32. "An Assessment of the Role and Importance of Power Marketers." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly. 50: 713-731.*

33. "The EPA v. The TVA, et. al. Over New Source Review." (2001) With K.E. Hughes, II. *Oil, Gas and Energy Quarterly*. 50:531-543.

34. "Energy Policy by Crisis: Proposed Federal Changes for the Electric Power Industry." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50:235-249.

35. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49:947-973.

36. "California Dreaming: Are Competitive Markets Achievable?" (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 743-759.

37. "Distributed Energy Must Be Watched As Opportunity for Gas Companies." (2001). With Martin Collette, and Ritchie D. Priddy. *Natural Gas Journal*. January: 9-16.

38. "Clean Air, Kyoto, and the Boy Who Cried Wolf." (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. December: 529-540.

39. "Energy Conservation Programs and Electric Restructuring: Is There a Conflict?" (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. September: 211-224.
40. "The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry." (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 751-765.
41. "Issues and Opportunities for Small Scale Electricity Production in the Oil Patch." (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter*. 49: 78-82.
42. "Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry." (2000). With K.E. Hughes II *Oil, Gas and Energy Quarterly*. 48:593-602.
43. "Coming to a neighborhood near you: the merchant electric power plant." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48:433-441.
44. "Slow as molasses: the political economy of electric restructuring in the south." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48: 163-183.
45. "Stranded investment and non-utility generation." (1999). With Michael T. Maloney. *Electricity Journal*. 12: 50-61.
46. "Reliability or profit? Why Entergy quit the Southwest Power Pool." (1998). With Fred I. Denny. *Public Utilities Fortnightly*. February 1: 30-33.
47. "Electric utility mergers and acquisitions: a regulator's guide." (1996). With Kimberly H. Dismukes. *Public Utilities Fortnightly.* January 1.

**PUBLICATIONS: OPINION AND EDITORIAL ARTICLES**

1. "Disappointing offshore wind lease sale is first step, but development process will be long." *Baton Rouge Advocate*. Friday, September 8, 2023.
2. "Irreparable changes are coming to American oil and gas industry". (2020). *10/12 Industry Report. Baton Rouge Business Report, Q1.*
3. "An exceptionally uncertain time for energy markets." (2019). *10/12 Industry Report. Baton Rouge Business Report*, Q4.
4. "LNG's changing fortunes." (2019). *10/12 Industry Report. Baton Rouge Business Report*, Q3.
5. "A tenuous recovery." (2019). *10/12 Industry Report. Baton Rouge Business Report*, Q2.
6. "The 2019 Gulf Coast Energy Outlook." (2019). *10/12 Industry Report. Baton Rouge Business Report*, Q1.
7. "Why an offshore recovery may never happen." (2018). *10/12 Industry Report. Baton Rouge Business Report*, Q4.
8. "The dangers of trade protectionism for Louisiana energy development." (2018). *10/12*

*Industry Report. Baton Rouge Business Report*, Q3.

9. "The irrelevance of energy dominance." (2018). *10/12 Industry Report. Baton Rouge Business Report*, Q2.

10. "The whys and hows of maintaining the oil price rise." (2018). *10/12 Industry Report. Baton Rouge Business Report*, Q1.

11. "Taxing energy infrastructure." (2017). *10/12 Industry Report*. Baton Rouge Business Report. Q:4.

12. "A summer of discontent." (2017). *10/12 Industry Report*. Baton Rouge Business Report. Q:3.

13. "Low cost hydrocarbons continue to benefit the Gulf Coast." (2017). *10/12 Industry Report*. Baton Rouge Business Report. Q:2.

14. "Reading the tea leaves for 2017's crude oil markets." (2017). *10/12 Industry Report*. Baton Rouge Business Report. Q:1.

15. "The unappreciated role of energy infrastructure." (2016). *10/12 Industry Report*. Baton Rouge Business Report. Q:4.

16. "Other ways in which the energy world is changing." (2016). *10/12 Industry Report*. Baton Rouge Business Report. Q:3.

17. "Are oil prices bouncing back?" (2016). *Baton Rouge Business Report*, May 10 edition. (reprint of Industry Report article).

18. "Are we there yet? Have energy prices started to rebound?" (2016). *10/12 Industry Report*. Baton Rouge Business Report. Q:2.

19. Challenging Times for the South Louisiana Energy Economy. (2016). *10/12 Industry Report*. Baton Rouge Business Report. Q:1.

20. "Reading the Signs for the Energy Complex" (2015). *10/12 Industry Report*. Baton Rouge Business Report. Q:1.

21. "Louisiana's Export Opportunities." (2015). *10/12 Industry Report*. Baton Rouge Business Report. September, 15.

22. "Don't Kill Hydraulic Fracturing: It's the Golden Goose." (2015). *Mobile Press Register*. May 22. Also carried by Alabama Media Group and the following newspapers: *Birmingham News*, *Huntsville Times*, and *Birmingham Magazine*.

23. "The Least Effective Way to Invest in Green Energy." (2014). *Wall Street Journal*. Journal Reports: Energy. New York: Dow Jones & Company, October 2.

24. "Stop Picking Winners and Losers." (2013). *Wall Street Journal*. Journal Reports: Energy. New York: Dow Jones & Company, June 18.

**PUBLICATIONS: REPORTS AND OTHER MANUSCRIPTS**

1. *The economic implications of carbon capture and sequestration for the Gulf Coast economy: a case study of Gulf Coast Sequestration*. (2022). With Gregory B. Upton and Ron Minsk. Baton Rouge, LA: LSU Center for Energy Studies, July, 2022. Pp. 54. Report prepared on behalf of Gulf Coast Sequestration.
2. *Atlantic Fact Book update: onshore oil and gas infrastructure to support development in the Atlantic Outer Continental Shelf region*. (2022). New Orleans (LA): US Department of the Interior, Bureau of Ocean Energy Management. 528 p. Contract No.: 140M0119C0008. Report No.: BOEM 2022-076.
3. *The national importance of post-storm electricity restoration to critical energy infrastructure*. (2022). With Gregory B. Upton. Baton Rouge, LA: LSU Center for Energy Studies, March 31, 2022. Pp. 55. Report prepared on the behalf of Entergy Corporation.
4. *2022 Gulf Coast Energy Outlook*. (2021). With Gregory B. Upton. Baton Rouge, LA: LSU Center for Energy Studies, November 2021, 29 Pp.66.
5. *Louisiana 2021 Greenhouse Gas Inventory*. David Dismukes (2021). On Behalf of the Governor's Office of Coastal Activities; LSU Center for Energy Studies. October 2021. Pp. 404.
6. *The economic impacts of Koch Methanol St. James – M1* (2021). Report prepared on behalf of Koch Methanol St. James. With Gregory B. Upton. October 2021. Baton Rouge, LA: LSU Center for Energy Studies.
7. *The economic impacts of Koch Methanol St. James – M2*. (2021). Report prepared on behalf of Koch Methanol St. James. With Gregory B. Upton. October 2021. Baton Rouge LA: LSU Center for Energy Studies.
8. *Use and limits of ecosystem services valuations in the Gulf of Mexico.* With Brian Snyder, Valentine Gomez, and Sid Narra. (2020). New Orleans (LA): Department of the Interior, Bureau of Ocean Energy Management. Contract No.: M17AC00018, Report No.: OCS Study BOEM 2020-0xx. 80 Pp.
9. *2021 Gulf Coast Energy Outlook*. (2020). With Gregory B. Upton. Baton Rouge, LA: LSU Center for Energy Studies, November 2020, 29 Pp.66.
10. *2020 Gulf Coast Energy Outlook*. (2019). With Gregory B. Upton. Baton Rouge, LA: LSU Center for Energy Studies, Fall 2019, 29 Pp.
11. *The urgency of PURPA reform to assure ratepayer protection*. (2019). Institute of Energy Research, 24 Pp.
12. *Integrated carbon capture and storage in the Louisiana chemical corridor*. (2019). With Mehdi Zeidouni, Muhammad Zulqarnain, Richard G Hughes, Keith B Hall, Brian F.

Snyder, Michael Layne, Juan M Lorenzo, Chacko John, Brian Harder. National Energy Technology Laboratories/U.S. Department of Energy. 151 Pp.

13. *Actual Benefits of Distributed Generation in Mississippi.* (2019). Report prepared on the behalf of the Mississippi Public Service Commission. 191 Pp.

14. *2019 Gulf Coast Energy Outlook*. (2018). Baton Rouge, LA: LSU Center for Energy Studies, Fall 2018, 28 pp.

15. *MISO Grid 2033: Preparing for the Transmission Grid of the Future.* (2018). Baton Rouge, LA: LSU Center for Energy Studies, May 7, 87 pp.

16. *Opportunities and challenges in using industrial CHP as a resiliency measure in Louisiana*. (2017). Baton Rouge, LA: Louisiana Department of Natural Resources, December 17, 52 pp.

17. *Efficiency and emissions reduction opportunities at existing Louisiana combined heat and power applications*. (2017). Baton Rouge, LA: Louisiana Department of Natural Resources, December 17, 44 pp.

18. *Louisiana industrial combined heat and power applications: status and operations*. (2017). Baton Rouge, LA: Louisiana Department of Natural Resources, December 17, pp. 54.

19. *The potential economic impacts of the Washington Parish Energy Center*. (2017). With Gregory B. Upton, Jr. Report prepared on behalf of Calpine Corporation. 5 pp.

20. *Economic impact and re-employment assessment of PES Philadelphia refining complex.* (2017). Report prepared on behalf of Philadelphia Energy Solutions. August 31, 43 pp.

21. *The potential economic impacts of the Bayou Bridge Project*. (2017). With Gregory B. Upton, Jr. Report prepared on behalf of Energy Transfer, LLC. 23 pp.

22. *Gulf Coast energy outlook (2017)*. With Christopher Coombs, Dek Terrell, and Gregory B. Upton. Center for Energy Studies/Applied Economics Group, 18 pp.

23. *Potential economic impacts of the Lake Charles methanol projec*t. (2017). Report prepared on behalf of the Lake Charles Methanol Project, LLC. 68 pp.

24. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers. (2015). Louisiana Public Service Commission, In re: Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana, Docket No. X-33192. Notice of Issuance of Final Report dated September 11, 2015,* 187 pp.

25. *Beyond the Energy Roadmap: Starting Mississippi's Energy-Based Economic Development Venture.* (2014). Report prepared on behalf of the Mississippi Energy Institute, 310 pp.

26. *Combined Heat and Power in Louisiana: Status, Potentials, and Policies*. Phase 4 Report:

*Policy and Market Opportunities and Challenges for CHP Development*. (2013). Louisiana Department of Natural Resources, Baton Rouge, Louisiana. 17 pp.

27. *Combined Heat and Power in Louisiana: Status, Potentials, and Policies. Phase 3 Report: Empirical Results, Technical and Cost-Effectiveness Potentials*. (2013). Louisiana Department of Natural Resources, Baton Rouge, Louisiana. 65 pp.

28. *Combined Heat and Power in Louisiana: Status, Potentials, and Policies. Phase 2 Report: Technical and Cost Effectiveness Methodologies*. (2013). Louisiana Department of Natural Resources, Baton Rouge, Louisiana. 39 pp.

29. *Combined Heat and Power in Louisiana: Status, Potentials, and Policies. Phase 1 Report: Resource Characterization and Database*. (2013). Louisiana Department of Natural Resources, Baton Rouge, Louisiana. 62 pp.

30. *Onshore Oil and Gas Infrastructure to Support Development in the Mid-Atlantic OCS Region. (2014).* U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study BOEM 2014-657. 360 pp.

31. *Unconventional Resources and Louisiana's Manufacturing Development Renaissance* (2013). Baton Rouge, LA: LSU Center for Energy Studies, 93 pp.

32. *Removing Big Wind's "Training Wheels:" The Case for Ending the Production Tax Credit* (2012). Washington, DC: American Energy Alliance, 19 pp.

33. *The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana*. (2012). Baton Rouge, LA: LSU Center for Energy Studies, 62 pp.

34. *Diversifying Energy Industry Risk in the GOM: Post-2004 Changes in Offshore Oil and Gas Insurance Markets*. (2011) With Christopher P. Peters. U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, New Orleans, LA. OCS Study BOEM 2011-054. 95pp.

35. *OCS-Related Infrastructure Fact Book. Volume I: Post-Hurricane Impact Assessment*. (2011). U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, New Orleans, LA. OCS Study BOEM 2011-043. 372 pp.

36. *Fact Book: Offshore Oil and Gas Industry Support Sectors*. (2010). U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, New Orleans, LA. OCS Study BOEM 2010-042. 138pp.

37. *The Impacts of Greenhouse Gas Regulation on the Louisiana Economy*. (2011). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, and Lauren L. Stuart. Louisiana Greenhouse Gas Inventory Project, Task 3 and 4 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 134 pp.

38. *Overview of States' Climate Action and/or Alternative Energy Policy Measures*. (2010).

With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, and Lauren L. Stuart. Louisiana Greenhouse Gas Inventory Project, Task 2 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 30 pp.

39. *Louisiana Greenhouse Gas Inventory*. (2010). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, Lauren L. Stuart, and Jordan L. Gilmore. Louisiana Greenhouse Gas Inventory Project, Task 1 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 114 pp.

40. *Opportunities for Geo-pressured Thermal Energy in Southwestern Louisiana*. (2010). Report prepared on behalf of Louisiana Geothermal, L.L.C, 41 pp.

41. *Economic and Energy Market Benefits of the Proposed Cavern Expansions at the Jefferson Island Storage and Hub Facility*. (2009). Report prepared on behalf of Jefferson Island Storage and Hub, LLC, 28 pp.

42. *The Benefits of Continued and Expanded Investments in the Port of Venice*. (2009). With Christopher Peters and Kathryn Perry. Baton Rouge, LA: LSU Center for Energy Studies. 83 pp.

43. *Examination of the Development of Liquefied Natural Gas on the Gulf of Mexico*. (2008). U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA OCS Study MMS 2008-017. 106 pp.

44. *Gulf of Mexico OCS Oil and Gas Scenario Examination: Onshore Waste Disposal*. (2007). With Michelle Barnett, Derek Vitrano, and Kristen Strellec. OCS Report, MMS 2007-051. New Orleans, LA: U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico Region.

45. *Economic Impact Analysis of the Proposed Lake Charles Gasification Project*. (2007). Report Prepared on Behalf of Leucadia Corporation.

46. *The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard.* (2005) Report Prepared on Behalf of the New Jersey Division of Ratepayer Advocate.

47. *The Importance of Energy Production and Infrastructure in Plaquemines Parish*. (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.

48. *Louisiana's Oil and Gas Industry: A Study of the Recent Deterioration in-State Drilling Activity*. (2005). With Kristi A.R. Darby, Jeffrey M. Burke, and Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources.

49. *Comparison of Methods for Estimating the $NO_x$ Emission Impacts of Energy Efficiency and Renewable Energy Projects Shreveport, Louisiana Case Study*. (2005). With Adam Chambers, David Kline, Laura Vimmerstedt, Art Diem, and Dmitry Mesyanzhinov. Golden, Colorado: National Renewable Energy Laboratory.

50. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.

51. *Economic Opportunities for LNG Development in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana Department of Economic Development and Greater New Orleans, Inc.

52. *Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production*. (2004). With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

53. *Deepwater Program: OCS-Related Infrastructure in the Gulf of Mexico Fact Book.* (2004). With Louis Berger Associates, University of New Orleans National Ports and Waterways Institute, and Research and Planning Associates. MMS Study No. 1435-01-99-CT-30955. U.S. Department of the Interior, Minerals Management Service.

54. *The Power of Generation: The Ongoing Benefits of Independent Power Development in Louisiana.* With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, and Elizabeth A. Downer. Baton Rouge, LA: LSU Center for Energy Studies, 2003.

55. *Modeling the Economic Impact of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Application.* (2003). With Williams O. Olatubi, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Prepared by the Center for Energy Studies, Louisiana State University, Baton Rouge, LA. OCS Study MMS2000-0XX. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.

56. *An Analysis of the Economic Impacts Associated with Oil and Gas Activities on State Leases*. (2002) With Robert H. Baumann, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

57. *Alaska In-State Natural Gas Demand Study*. (2002). With Dmitry Mesyanzhinov, et.al. Anchorage, Alaska: Alaska Department of Natural Resources, Division of Oil and Gas.

58. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana*. (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

59. *The Economic Impacts of Merchant Power Plant Development in Mississippi.* (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.

60. *Energy Conservation and Electric Restructuring in Louisiana*. (2000). With Dmitry Mesyanzhinov, Ritchie D. Priddy, Robert F. Cope III, and Vera Tabakova. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

61. *Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS.* (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

62. *Restructuring the Electric Utility Industry: Implications for Louisiana.* (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

## GRANT RESEARCH

1. *Co-Principal Investigator* (2022). With Gregory B. Upton, Jr. Estimating the benefits of electricity restoration to critical energy infrastructure. Funded by Entergy Corporation. Total Funding: $56,088. Status: Completed.

2. *Co-Principal Investigator*. (2021). With Gregory B. Upton Jr. Estimating the benefits of underground carbon dioxide storage investments. Funded by Gulf Coast Sequestration. Total Funding: $124,835. Status: In Progress.

3. *Principal Investigator*. (2021). Louisiana Greenhouse Gas Inventory Update and Report. Governor's Office of Coastal Affairs. Total Funding $65,830. Status: Completed.

4. *Principal Investigator*. (2021). Estimating Louisiana's power generation greenhouse gas emissions. The Nature Conservancy. Total Funding: $9,994. Status: Completed.

5. *Co-Principal Investigator*. (2021). With Gregory B. Upton. Estimating the economic impacts of methanol investments in St. James Parish. Koch Industries. Total Funding: $37,457. Status: Completed.

6. *Co-Principal Investigator*. (2019). With Gregory B. Upton Estimating the economic impact of TransCanada pipeline investments. TransCanada Pipelines. Total Funding: $40,798. Status: Completed.

7. *Co-Principal Investigator*. (2018). With Gregory B. Upton. Estimating the economic impact of Enable Pipeline Investments. Total Funding: $49,798. Status: Completed.

8. *Co-investigator*. Estimating offshore Gulf of Mexico carbon capture, sequestration, and utilization opportunities. (2018). With Southern States Energy Board, Advanced Resources International, Argonne Laboratories, University of Alabama, University of South Carolina, and Oklahoma State University. U.S. Department of Energy, National Energy Technology Laboratory. Total funding: $731,031 (LSU share of $4.0 million project, three years, in progress).

9. *Co-Principal Investigator*. Planning Grant: Engineering Research Center for Resiliency Enhancement and Disaster-Impact Interception ("READII") in the Manufacturing Sector. (2018). With Mahmoud El-Halwagi, Mark Stadtherr, Heshmat Aglan, Efstratos Postikopoulus. National Science Foundation (#1840512). Total Funding: $100,000 (one

year). Status: Completed.

10. *Principal Investigator*. Understanding MISO long term infrastructure needs and stakeholder positions. (2017). Midcontinent Independent System Operator. Total Project: $9,500, six months. Status: Completed.

11. *Principal Investigator*. Offshore oil and gas activity impacts on ecosystem services in the Gulf of Mexico. (2017). With Brian F, Snyder. U.S. Department of the Interior, Bureau of Ocean Energy Management. Total Project: $240,982, two years. Status: Completed.

12. *Principal Investigator*. Economic Impacts of the Bayou Bridge pipeline. (2017). With Gregory B, Upton, Jr., Energy Transfer Corporation. $9,900. Status: Completed.

13. *Principal Investigator*. Integrated carbon capture, storage and utilization in the Louisiana chemical corridor. (2017). U.S, Department of Energy/National Energy Technology Laboratory. Total funding: $1,300,000 (18 months). Status: Completed.

14. *Co-Principal Investigator*. Gulf coast energy outlook and analysis. (2016). With Gregory B. Upton and Mallory Vachon. Regions Bank. Total funding: $20,000, one year. Status: Completed.

15. *Principal Investigator*. GOM energy infrastructure trends and factbook update. (2016). With Gregory B. Upton and Mallory Vachon. U.S. Department of the Interior, Bureau of Ocean Energy Management ("BOEM"). Total funding: $224,995, two years. Status: In progress.

16. *Principal Investigator*. Examining Louisiana's Industrial Carbon Sequestration Potential. Phase 2: Follow-up and estimation. (2016). With Brian F. Snyder. Southern States Energy Board. Total Project: $69,990, three months. Status: Completed.

17. *Principal Investigator*. Examining Louisiana's Industrial Carbon Sequestration Potential. Phase 1: Scoping and Identification. (2016). With Brian F. Snyder. Southern States Energy Board. Total Project: $29,919, three months. Status: Completed.

18. *Principal Investigator*. Energy efficiency building codes for Louisiana. (2016). With Brian F. Snyder. Louisiana Department of Natural Resources. Total Project: $50,000, one year. Status: Completed.

19. *Principal Investigator*. An update of Louisiana's combined heat and power potentials, current utilizations, and barriers to improved operating efficiencies. (2016). Louisiana Department of Natural Resources. Total Project: $90,000, one year. Status: Completed.

20. *Principal Investigator*. Combined Heat and Power Stakeholder Meeting. (2016). Southeastern Energy Efficiency Council. Total Project $9,160, two months. Status: Completed.

21. *Co-Investigator*. "Expanding Ecosystem Service Provisioning from Coastal Restoration to Minimize Environmental and Energy Constraints" (2015). With John Day and Chris

D'Elia. Gulf Research Program. Total Project: $147,937. Status: Completed.

22. *Principal Investigator*. "Coastal Marine Institute Administrative Grant" (2104). U.S. Department of the Interior. Total Project $45,000. Status: Completed.

23. *Principal Investigator*. "Analysis of the Potential for Combined Heat and Power (CHP) in Louisiana." (2013). Louisiana Department of Natural Resources. Total Project: $90,000. Status: Completed.

24. *Co-Investigator*. "CNH: A Tale of Two Louisianas: Coupled Natural-Human Dynamics in a Vulnerable Coastal System" (2013) With Nina Lam, Margaret Reams, Kam-Biu Liu, Victor Rivera, Yi-Jun Xu and Kelley Pace. National Science Foundation. Total Project: $1.5 million. Status: Completed (Sept 2012-Feb 2017).

25. *Principal Investigator*. "Examination of Unconventional Natural Gas and Industrial Economic Development" (2012). America's Natural Gas Alliance. Total Project: $48,210. Status: Completed.

26. *Principal Investigator*. "Investigation of the Potential Economic Impacts Associated with Shell's Proposed Gas-To-Liquids Project" (2012). Shell Oil Company, North America. Total Project: $76,708. Status: Completed.

27. *Principal Investigator*. "Analysis of the Federal Wind Energy Production Tax Credit." American Energy Alliance. Total Project: $20,000. Status: Completed.

28. *Principal Investigator*. "Energy Sector Impacts Associated with the Deepwater Horizon Oil Spill." Louisiana Department of Economic Development. Total Project: approximately $50,000. Status: Completed.

29. *Principal Investigator*. "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: $20,000. Status: Completed.

30. *Principal Investigator.* "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $150,000. Status: Completed.

31. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: Completed.

32. *Principal Investigator*. "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Completed.

33. *Principal Investigator*. "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Completed.

34. *Principal Investigator*. "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Completed.

35. *Principal Investigator*. "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, Completed.

36. *Principal Investigator*. "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

37. *Principal Investigator*. "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, Completed.

38. *Principal Investigator*. "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: Completed.

39. *Principal Investigator*. "Ultra-Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

40. *Principal Investigator*. "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

41. *Principal Investigator*. " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

42. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

43. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

44. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

45. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

46. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

47. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

48. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

49. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

50. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

51. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

## ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "The changing nature of Gulf of Mexico energy infrastructure." (2017). Session 3B: New Directions in Social Science Research. 27th Gulf of Mexico Region Information

Technology Meetings. U.S. Department of the Interior, Bureau of Ocean Energy Management, Environmental Studies Program. New Orleans, LA. August 24.

2. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). U.S. Department of Energy, 2017 Industrial Energy Technology Conference, New Orleans, LA June 21.

3. "Vulnerability assessment of the central Gulf of Mexico coast using a multi-dimensional approach." (2016). With Siddhartha Narra. Eighth International Conference on Environmental Science and Technology. June 6-10, Houston, TX.

4. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). With Gregory Upton. Southern Economic Association Meeting 2015. New Orleans, Louisiana. November 23.

5. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks" (2015). With Gregory Upton. 38th IAEE International Conference, Antalya, Turkey. May 26.

6. "Modifying Renewables Policies to Sustain Positive Economic and Environmental Change" (2015). IEEE Annual Green Technologies ("Greentech") Conference. April 17.

7. "The Gulf Coast Industrial Investment Renaissance and New CHP Development Opportunities." (2014). Industrial Energy and Technology Conference, New Orleans, Louisiana. May 20.

8. "Estimating Critical Energy Infrastructure Value at Risk from Coastal Erosion" (2014). With Siddhartha Narra. American's Estuaries: 7th Annual Summit on Coastal and Estuarine Habitat Restoration. Washington, D.C., November 3-6.

9. "Economies of Scale, Learning Curves, and Offshore Wind Development Costs" (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17.

10. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7.

11. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

12. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

13. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7.

14. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19.

15. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16.

16. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

17. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). U.S. Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

18. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

19. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

20. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

21. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

22. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

23. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

24. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

25. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

26. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

27. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

28. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

29. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

30. "Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach." (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

31. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

32. "Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation." (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

33. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

34. "Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

35. "Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana" (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

36. "Empirical Issues in Electric Power Transmission and Distribution Cost Modeling." (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

37. "Modeling Electric Power Markets in a Restructured Environment." (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

38. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

39. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

40. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

41. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

42. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

43. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

44. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

45. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

46. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

47. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.
48. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.
49. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.
50. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.
51. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.
52. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

## ACADEMIC SEMINARS AND PRESENTATIONS

1. Panelist. "Fuel Security, Resource Adequacy & Value of Transmission." (2019). 6th Annual Electricity Dialogue at Northwestern University: Energy and Capacity: Transitions? Northwestern University Center of Law, Regulation, and Economic Growth.
2. "Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation." Lecture before School of the Coast & Environment. November 5, 2011.
3. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.
4. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.
5. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.
6. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.
7. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge,

LA. April 2, 2004.

8. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.
9. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.
10. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.
11. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

**PROFESSIONAL AND CIVIC PRESENTATIONS**

1. "Electricity in transition: are we up to the challenge? An oil and gas perspective." (2024). Energy Council 2024 Global Energy and Environmental Issues Conference, Salt Lake City, Utah. December 6, 2024.
2. "Santee Cooper 2024 Electric System Cost of Service and Rate Design Review" (2024). Prepared on behalf of South Carolina Department of Consumer Affairs. September 13, 2024.
3. "Ratepayer perspectives on alternative regulation." (2024). *"Inside Look At Alternative Regulation: Regulation of the Future?"* NARUC Staff Subcommittee on Accounting and Finance Meeting. August 9 (online webinar).
4. "The role and outlook for CCS in Louisiana energy manufacturing development." (2024). GINP-CCS International Network. February 20, 2024.
5. "Louisiana energy manufacturing development outlook and the energy transition." (2024). Greater Baton Rouge Industry Alliance. February 1, 2024.
6. "Gulf Coast Energy Outlook 2024." (2023). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2023.
7. "Louisiana clean, green industry: reconciling industrial decarbonization, capital formation, and growth." (2023). Louisiana State Bar Association, Public Utility Section. December 1, 2023.
8. "Expert witness training: considerations for preparation and effective execution during public utility regulatory hearings and proceedings." (2023). On the Behalf of the National

Association of State Utility Consumer Advocates, Accounting and Finance Subcommittee. September 21, 2023.

9. "Gulf cost energy outlook: traditional resources and the energy transition." (2023). AAPL/Gulf Coast Land Institute Meetings. April 26, 2023.
10. "Ratepayer considerations in the promotion of clean energy." (2023). Public Utility Law Section Roundtable Discussion. April 21, 2023.
11. "Gulf coast energy outlook: traditional resources and the energy transition." (2023). Louisiana Engineering Society. April 19, 2023.
12. "Carbon capture & storage: three thoughts and considerations." (2023). Gulf Coast Power Association. 9th Annual MISO/SPP Conference. March 9, 2023.
13. "Natural gas markets: prices; trends; and ratepayer impacts." (2023). Maryland Energy Advocates Virtual Monthly Meeting. February 17, 2023.
14. "Hydrogen overview and its role in Louisiana decarbonization." (2022). Louisiana Public Service Commission Monthly Business & Executive Meeting. November 17, 2022.
15. "High winter natural gas prices and ratepayer impacts." (2022). National Association of State Utility Consumer Advocates ("NASUCA") Annual Conference. November 14, 2022.
16. "Facing the future together: the Louisiana energy transition, industrial decarbonization, and capital formation trends." (2022). Louisiana Chemical Association: Annual Meeting 2022. October 27, 2022.
17. "Louisiana and the energy transition: reconciling industrial decarbonization, capital formation, and growth." (2022). Louisiana Air and Waste Management 2022 Annual Meeting. October 26, 2022.
18. "The Louisiana energy transition, industrial decarbonization, and industrial capital formation trends." (2022). Postlethwaite & Netterville: 2022 Governmental Update. August 4, 2022.
19. "Identifying and mapping regulatory requirements for CCUS projects." (2022). SECARB Offshore GOM Gulf Regulator Workshop. New Orleans LA. May 16, 2022.
20. "Louisiana industrial decarbonization opportunities." (2022). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Meeting. May 11, 2022. Baton Rouge, LA.
21. "Natural Gas outlook, 2022: supply, demand, and geopolitical considerations." (2022). National Association of State Utility Consumer Advocates ("NASUCA") Monthly Natural Gas Committee Webinar. March 30, 2022.

22. "Louisiana industrial decarbonization opportunities." (2022). LSU Law School, Journal of Energy Law and Resources Symposium on Energy Transitions. February 4, 2022. Baton Rouge, LA.

23. Panelist. Grid Resiliency in the Era of Extreme Weather. Gulf Coast Power Association 8th Annual MISO/SPP Regional Meeting. February 9, 2022. New Orleans, LA.

24. Panelist. Natural Gas Industry Update. (2022). National Association of State Utility Consumer Advocates Annual Meeting. (virtual). November 8, 2021.

25. "Overview of Louisiana's greenhouse gas emissions and trends." (2021). Louisiana Energy Users Group ("LEUG") Meeting. November 11, 2021.

26. "State of energy in Louisiana: a preview of the 2021 Gulf Coast Energy Outlook." (2021). Financial Planning Association of Baton Rouge. November 10, 2021.

27. "Replacing natural gas and industrial decarbonization: utility and ratemaking issues." (2021). Virtual Joint Annual Meeting: Virginia Committee for Fair Utility Rates, Old Dominion Committee for Fair Utility Rates, and Virginia Industrial Gas Users Group Workshop. September 8, 2021.

28. "Louisiana 2021 GHG Inventory: Update and summary of preliminary findings." (2021). Presentation before the Climate Initiative Task Force. July 29, 2021.

29. "Opportunities for the development of a hydrogen economy in Louisiana." (2021). Louisiana Energy Climate Solutions Workshop. June 15, 2021.

30. "Natural gas: Building gas system resilience. Overview of the 2021 polar vortex and its implications for gas resiliency." (2021). National Association of State Utility Consumer Advocates ("NASUCA"). Virtual mid-year meeting. June 14, 2021.

31. "Status and briefing on the Louisiana greenhouse gas inventory and emissions analysis." (2021). Scientific Advisory Group ("SAG") Meeting, Governor's Climate Initiative Task Force. March 29, 2021.

32. "Louisiana carbon capture: sinks; sources; and the role of transportation in industrial applications." (2021). LSU Journal of Energy Law & Resources Symposium on Carbon Capture and Solutions. February 5, 2021.

33. "Natural gas outlook, 2021: production, demand, pandemic and policy." (2021). National Association of State Utility Consumer Advocates ("NASUCA") Monthly Natural Gas Committee Webinar. January 20, 2021.

34. "Consumer Perspectives on the Rate Design of the Future." (2020). National Association of State Utility Consumer Advocates ("NASUCA"). Annual Conference, November 10.

35. "Evaluation of Louisiana's Depleted Gas Reservoirs for Geological Carbon Sequestration." (2020). Louisiana Mid-Continent Oil and Gas Association ("LMOGA") Carbon Capture and Underground Storage ("CCUS") Committee Meeting. August 25.

36. "The 2020 Gulf Coast Energy Outlook: COVID-19 update." (2020). Baton Rouge Area Chamber of Commerce Business Webinar. COVID-19 and Global Supply Impacts on the Capital Region and Louisiana Economies. Baton Rouge, LA. June 3.

37. "Ratepayer benefits of reforming PURPA". (2020). Harvard Electricity Policy Group Webinar. PURPA: A time to reform or reduce its role? March 26.

38. "Pipeline industry: economic trends and outlook". (2020). Joint Industry Association Annual Meeting. Louisiana Mid-Continent Oil and Gas Association ("LMOGA") and the Louisiana Oil and Gas Association ("LOGA"). Lake Charles, LA March 5.

39. "The outlook for natural gas: storm clouds ahead?" (2020). National Association of State Utility Consumer Advocates ("NASUCA"). Natural Gas Committee Webinar, February 26.

40. "The 2020 Gulf Coast Energy Outlook". (2020). University of Louisiana Lafayette, Southern Unconventional Resources Center for Excellence. Lafayette, LA February 16.

41. "Opportunities for carbon capture, utilization, and storage in the Louisiana chemical corridor". (2020). Air and Waste Management Association, Louisiana Section Luncheon. Gonzales, LA January 16.

42. Panelist. (2020). Baton Route Advocate, 2020 Economic Outlook Summit. Baton Rouge Advocate. January 8.

43. "2020 Louisiana business climate outlook: the view from the energy sector." (2019). American Council of Engineering Companies Fall Conference. November 21, 2019. Baton Rouge, LA

44. "The urgency of PURPA reform in protecting ratepayers." (2019). Americans for Tax Reform, Fall 2019 Coalition Leaders Summit, November 14, 2019. New Orleans, LA.

45. "Louisiana's coast and the energy industry." (2019). 2019 API Delta Chapter Joint Society Luncheon Meeting. November 12, 2019, New Orleans, LA.

46. "Reforming PURPA: implications for ratepayers." (2019). Thomas Jefferson Institute for Public Policy, Annual Energy Summit, State Policy Network Annual Meeting. Colorado Springs, CO, October 28.

47. "Natural gas outlook: supply, demand and prices." (2019). National Association of State Utility Consumer Advocates, Natural Gas Committee Monthly Meeting. July 30, 2019.

48. "The economic impacts and outlook for LNG development on the Gulf Coast." (2019). 73rd Annual Meeting of the Southern Legislative Conference of the Council of State Governments. New Orleans, LA, July 14. (prepared presentation, hurricane cancellation)

49. "Natural gas outlook: supply, demand, and prices." (2019). NASUCA Mid-Year Meeting. Portland, OR, June 20.

50. "Overview of Louisiana LNG issues and trends." (2019). Berlin: LNG, Energy Security, and Diversity Reporting Tour, LSU Center for Energy Studies. Baton Rouge, LA, May 9.
51. "Overview of Louisiana energy issues and outlook." (2019). Australian Media Visit, Greater New Orleans, Inc./Baton Rouge Area Foundation. Baton Rouge, LA, April 29.
52. "Gulf Coast Energy Outlook 2019: Regional trends and outlook." (2019). Women's Energy Network. Baton Rouge, LA, April 23.
53. "MISO Grid Vision 2033." (2019). 2019 Spring Regulator and Policymaker Forum. New Orleans, LA, April 15-16.
54. "Ratepayer benefits of reforming PURPA." (2019). LSU Center for Energy Studies Industry Advisory Council Meeting. March 27.
55. "Incentives, risk, and the changing nature of regulation." (2019). NASUCA Water Committee monthly meeting/webinar. March 13.
56. "Gulf Coast Energy Outlook 2019: Production, trade and infrastructure trends." (2019). 66th Annual Mineral Board Institute Meetings. Baton Rouge, LA, March 14.
57. "A golden age: energy outlook 2019." (2019). Engineering News Record Webinar. February 13.
58. Panelist. (2019). Baton Route Advocate, 2019 Economic Outlook Summit. Baton Rouge Advocate. January 8.
59. "MISO Grid Vision 2033." (2018). 2018 Winter Regulatory and Policymaker Forum. New Orleans, LA, December 11.
60. "Gulf Coast Energy Outlook 2019." (2018). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2018.
61. "How LNG is transforming Louisiana's energy economy." (2018). Louisiana State Bar Association, Public Utility Section. Baton Rouge, LA, November 30.
62. "Overview of Louisiana LNG issues and trends." (2018). Kean Miller Law Firm: Energy and Environmental Practice Group. Baton Rouge, LA, November 28.
63. "Infrastructure and capacity: challenges for development." (2018). Society of Utility and Regulatory Financial Analysts (SURFA) Annual Meeting, New Orleans, LA, April 20.
64. "Louisiana industrial cogeneration trends." (2018). Annual Louisiana Solid Waste Association Conference, Lafayette, LA, March 16.
65. "Gulf Coast industrial development: overview of trends and issues." (2018). Gulf Coast Power Association Meetings, New Orleans, LA, February 8.

66. "Energy outlook – reflection on market trends and Louisiana implications." (2017). IberiaBank Corporation Bank Board of Directors Meeting, New Orleans, LA. November 15.

67. "Integrated carbon capture and storage in the Louisiana chemical corridor." (2017). Industry Associates Advisory Council Meeting, Baton Rouge, LA. November 7.

68. "The outlook for natural gas and energy development on the Gulf Coast." (2017). Louisiana Chemical Association, Annual Meeting, New Orleans, LA. October 26.

69. "Critical energy infrastructure: the big picture on resiliency research." (2017). National Academies of Science, Engineering, and Medicine. New Orleans, LA. September 18.

70. "The changing nature of Gulf of Mexico energy infrastructure." (2017). 27th Gulf of Mexico Region Information Technology Meetings, New Orleans, LA, August 24.

71. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). Industrial Energy Technology Conference, New Orleans, LA. June 21.

72. "Crude oil and natural gas outlook: Where are we and where are we going?" (2017). CCREDC Economic Trends Panel. Corpus Christi, TX, June 15.

73. "Navigating through the energy landscape." (2017). Baton Rouge Rotary Luncheon. Baton Rouge, LA, May 24.

74. "The 2017-2018 Louisiana energy outlook." (2017). Junior Achievement of Greater New Orleans, JA BizTown Speaker Series. New Orleans, LA, May 12.

75. "The Gulf Coast energy economy: trends and outlook." (2017). Society for Municipal Analysts. New Orleans, LA, April 21.

76. "Gulf coast energy outlook." (2017). E.J. Ourso College of Business, Dean's Advisory Council, Energy Committee Meeting. Baton Rouge, LA, March 31.

77. "Recent trends in energy: overview and impact for the banking community." (2017). Oil and Gas Industry Update, Louisiana Bankers Association. Baton Rouge, LA, March 24.

78. "How supply, demand and prices have influenced unconventional development." (2016). Energy Annual Meeting, CLEER-University Advisory Board Lecture. New Orleans, LA, September 17.

79. "The Basics of Natural Gas Production, Transportation, and Markets." (2016). Center for Energy Studies. Baton Rouge, LA, August 1.

80. "Gulf Coast industrial development: trends and outlook." (2016). Investor Relations Group Meeting, Edison Electric Institute. New Orleans, LA, June 23.

81. "The future of policy and regulation: Unlocking the Treasures of Utility Regulation." (2016). Annual Meeting, National Conference of Regulatory Attorneys. Tampa, FL, June 20.

82. "Utility mergers: where's the beef?". (2016). National Association of State Utility Consumer Advocates Mid-Year Meetings. New Orleans, LA, June 6.
83. "Overview of the Clean Power Plan and its application to Louisiana." (2016). Shell Oil Company Internal Meeting. April 12.
84. "Energy and economic development on the Gulf Coast: trends and emerging challenges." (2016). Gas Processors Association Meeting. New Orleans, LA, April 11.
85. "Unconventional Oil and Gas Drilling Trends and Issues." (2016). French Delegation Visit, LSU Center for Energy Studies. March 16.
86. "Gulf Coast Industrial Growth: Passing clouds or storms on the horizon?" (2016). Gulf Coast Power Association Meetings. New Orleans, LA, February 18.
87. "The Transition to Crisis: What do the recent changes in energy markets mean for Louisiana?" (2016). Louisiana Independent Study Group. February 2.
88. "Regulatory and Ratepayer Issues in the Analysis of Utility Natural Gas Reserves Purchases" (2016). National Association of State Utility Consumer Advocates Gas Consumer Monthly Meeting. January 25.
89. "Emerging Issues in Fuel Procurement: Opportunities & Challenges in Natural Gas Reserves Investment." (2015). National Association of State Utility Consumer Advocates Annual Meeting. Austin, Texas. November 9.
90. "Trends and Issues in Net Metering and Solar Generation." (2015). Louisiana Rural Electric Cooperative Meeting. November 5.
91. "Electric Power: Industry Overview, Organization, and Federal/State Distinctions." (2015). EUCI. October 16.
92. "Natural Gas 101: The Basics of Natural Gas Production, Transportation, and Markets." (2015). Council of State Governments Special Meeting on Gas Markets. New Orleans, LA. October 14.
93. "Update and General Business Matters." (2015). CES Industry Associates Meeting. Baton Rouge, Louisiana. Fall 2015.
94. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). 38th IAEE 2015 International Conference. Antalya, Turkey. May 26.
95. "Industry on the Move – What's Next?" (2015). Event Sponsored by Regional Bank and 1012 Industry Report. May 5.
96. "The State of the Energy Industry and Other Emerging Issues." (2015). Lex Mundi Energy & Natural Resources Practice Group Global Meeting. May 5.
97. "Energy, Louisiana, and LSU." (2015). LSU Science Café. Baton Rouge, Louisiana. April 28.

98. "Energy Market Changes and Impacts for Louisiana." (2015). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 22.

99. "Incentives, Risk and the Changing Nature of Utility Regulation." (2015). NARUC Staff Subcommittee on Accounting and Finance Meetings, New Orleans, Louisiana. April 22.

100. "Modifying Renewables Policies to Sustain Positive and Economic Change." (2015). IEEE Annual Green Technologies ("Greentech Conference"). April 17.

101. "Louisiana's Changing Energy Environment." (2015). John P. Laborde Energy Law Center Advisory Board Spring Meeting, Baton Rouge, Louisiana. March 27.

102. "The Latest and the Long on Energy: Outlooks and Implications for Louisiana." (2015). Iberia Bank Advisory Board Meeting, Baton Rouge, Louisiana. February 23.

103. "A Survey of Recent Energy Market Changes and their Potential Implications for Louisiana." (2015). Vistage Group, New Orleans, Louisiana. February 4.

104. "Energy Prices and the Outlook for the Tuscaloosa Marine Shale." (2015). Baton Rouge Rotary Club, Baton Rouge, Louisiana. January 28.

105. "Trends in Energy & Energy-Related Economic Development." (2014). Miller and Thompson Presentation, Baton Rouge, Louisiana. December 30.

106. "Overview EPA's Proposed Rule Under Section 111(d) of the Clean Air Act: Impacts for Louisiana." (2014). Louisiana State Bar: Utility Section CLE Annual Meeting, Baton Rouge, Louisiana. November 7.

107. "Overview EPA's Proposed Clean Power Plan and Impacts for Louisiana." (2014). Clean Cities Coalition Meeting, Baton Rouge, Louisiana. November 5.

108. "Impacts on Louisiana from EPA's Proposed Clean Power Plan." (2014). Air & Waste Management Annual Environmental Conference (Louisiana Chapter), Baton Rouge, Louisiana. October 29, 2014.

109. "A Look at America's Growing Demand for Natural Gas." (2014). Louisiana Chemical Association Annual Meeting, New Orleans, Louisiana. October 23.

110. "Trends in Energy & Energy-Related Economic Development." (2014). 2014 Government Finance Officer Association Meetings, Baton Rouge, Louisiana. October 9.

111. "The Conventional Wisdom Associated with Unconventional Resource Development." (2014). National Association for Business Economics Annual Conference, Chicago, Illinois. September 28.

112. Unconventional Oil & Natural Gas: Overview of Resources, Economics & Policy Issues. (2014). Society of Environmental Journalists Annual Meeting. New Orleans, Louisiana. September 4.

113. "Natural Gas Leveraged Economic Development in the South." (2014). Southern

Governors Association Meeting, Little Rock, Arkansas. August 16.

114. "The Past, Present and Future of CHP Development in Louisiana." (2014). Louisiana Public Service Commission CHP Workshop, Baton Rouge, Louisiana. June 25.

115. "Regional Natural Gas Demand Growth: Industrial and Power Generation Trends." (2014). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 30.

116. "The Technical and Economic Potential for CHP in Louisiana and the Impact of the Industrial Investment Renaissance on New CHP Capacity Development." (2014). Electric Power 2014, New Orleans, Louisiana. April 1.

117. "Industry Investments and the Economic Development of Unconventional Development." (2014). Tuscaloosa Marine Shale Conference & Expo, Natchez, Mississippi. March 31.

118. Discussion Panelist. Energy Outlook 2035: The Global Energy Industry and Its Impact on Louisiana, (2014). Grow Louisiana Coalition, Baton Rouge, Louisiana. March 18.

119. "Natural Gas and the Polar Vortex: Has Recent Weather Led to a Structural Change in Natural Gas Markets?" (2014). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. February 19.

120. "Some Unconventional Thoughts on Regional Unconventional Gas and Power Generation Requirements." (2014). Gulf Coast Power Association Special Briefing, New Orleans, Louisiana. February 6.

121. "Leveraging Energy for Industrial Development." (2013). 2013 Governor's Energy Summit, Jackson, Mississippi. December 5.

122. "Natural Gas Line Extension Policies: Ratepayer Issues and Considerations." (2013). National Association of State Utility Consumer Advocates Annual Meeting, Orlando, Florida. November 19.

123. "Replacement, Reliability & Resiliency: Infrastructure & Ratemaking Issues in the Power & Natural Gas Distribution Industries." (2013). Louisiana State Bar, Public Utility Section Meetings. November 15.

124. "Natural Gas Markets: Leveraging the Production Revolution into an Industrial Renaissance." (2013). International Technical Conference, Houston, TX. October 11.

125. "Natural Gas, Coal & Power Generation Issues and Trends." (2013). Southeast Labor and Management Public Affairs Committee Conference, Chattanooga, Tennessee. September 27.

126. "Recent Trends in Pipeline Replacement Trackers." (2013). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. September 19.

127. Discussion Panelist (2013). Think About Energy Summit, America's Natural Gas Alliance, Columbus Ohio. September 16-17.

128. "Future Test Years: Issues to Consider." (2013). National Regulatory Research Institute, Teleseminar on Future Test Years. August 28.

129. "Industrial Development Outlook for Louisiana." (2013). Louisiana Water Synergy Project Meetings, Jones Walker Law Firm, Baton Rouge, Louisiana. July 30.

130. "Natural Gas & Electric Power Coordination Issues and Challenges." (2013). Utilities State Government Organization Conference, Pointe Clear, Alabama. July 9.

131. "Natural Gas Market Issues & Trends." (2013). Western Conference of Public Service Commissioners, Santa Fe, New Mexico. June 3.

132. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Annual Legislative Conference, Baton Rouge, Louisiana. May 8.

133. "Infrastructure Cost Recovery Mechanism: Overview of Issues." (2013). Energy Bar Association Annual Meeting, Washington, D.C. May 1.

134. "GOM Offshore Oil and Gas." (2013). Energy Executive Roundtable, New Orleans, Louisiana. March 27.

135. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Risk Management Association Luncheon, March 21.

136. "Natural Gas Market Update and Emerging Issues." (2013). NASUCA Gas Committee Conference Call/Webinar, March 12.

137. "Unconventional Resources and Louisiana's Manufacturing Development Renaissance." (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.

138. "New Industrial Operations Leveraged by Unconventional Natural Gas." (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.

139. "What's Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff." (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.

140. "Trends, Issues, and Market Changes for Crude Oil and Natural Gas." (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.

141. "Game Changers in Crude and Natural Gas Markets." (2012). Chevron Community Advisory Panel Meeting. Belle Chase, LA, September 17.

142. "The Outlook for Renewables in a Changing Power and Natural Gas Market." (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.

143. "The Changing Dynamics of Crude and Natural Gas Markets." (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.

144. "The Really Big Game Changer: Crude Oil Production from Shale Resources and the Tuscaloosa Marine Shale." (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.

145. "The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency." (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.

146. "Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

147. "Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

148. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.

149. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27, 2012.

150. "Louisiana's Unconventional Plays: Economic Opportunities, Policy Challenges. Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New Orleans, Louisiana. January 26, 2012.

151. "EPA's Recently Proposed Cross State Air Pollution Rule ("CSAPR") and Its Impacts on Louisiana." (2011). Bossier Chamber of Commerce. November 18, 2011.

152. "Facilitating the Growth of America's Natural Gas Advantage." (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.

153. "CSAPR and EPA Regulations Impacting Louisiana Power Generation." (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.

154. "Natural Gas Trends and Impact on Industrial Development." (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL. September 22, 2011.

155. "Energy Market Changes and Policy Challenges." (2011). Southeast Manpower Tripartite Alliance ("SEMTA") Summer Conference. Nashville, TN September 2, 2011.

156. "EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers." (2011). Workshop: "A Smarter Approach to Improving Our Environment." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.

157. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th

Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 4, 2011.

158. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council, Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.

159. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.

160. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

161. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

162. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

163. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

164. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

165. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

166. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

167. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

168. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

169. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

170. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual

Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

171. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

172. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

173. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

174. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

175. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

176. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

177. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

178. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

179. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

180. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

181. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

182. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

183. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

184. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

185. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

186. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

187. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

188. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

189. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

190. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economics (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

191. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

192. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

193. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

194. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

195. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

196. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

197. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

198. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

199. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

200. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

201. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

202. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

203. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

204. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

205. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

206. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

207. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

208. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

209. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

210. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

211. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

212. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

213. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

214. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

215. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

216. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

217. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

218. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

219. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

220. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

221. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

222. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

223. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

224. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

225. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

226. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

227. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

228. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

229. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

230. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

231. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

232. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

233. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

234. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

235. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

236. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

237. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

238. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

239. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

240. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

241. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

242. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

243. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

244. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

245. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

246. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

247. The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

248. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

249. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

250. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

251. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

252. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

253. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

254. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

255. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

256. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

257. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

258. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

259. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

260. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

261. "Merchant Power Plants and Deregulation: Issues and Impacts." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 18, 2002.

262. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

263. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

264. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

265. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

266. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

267. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

268. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

269. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

270. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

271. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

272. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

273. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

274. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

275. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

276. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

277. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

278. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

279. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

280. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

281. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

282. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

283. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

284. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

285. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

286. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

287. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

288. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

289. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

290. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

291. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

292. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

293. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

294. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

295. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

296. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

297. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

298. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

299. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

300. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

301. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

302. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

**EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS**

1. Expert Testimony. Docket No. 2024.08.088. (2024). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's, Energy West Montana, Inc.'s, and Cut Bank Gas Company's Joint Application for Approval of the Purchase and Sale of Assets and Associated Relief.* On Behalf of the Montana Consumer Counsel. Issues: acquisition standards, leak rates, pipe composition, rate analysis, acquisition commitments.

2. Expert Testimony. Case No. 24-0704-G-P. (2024). Before the Public Service Commission of West Virginia Charleston. *Hope Gas, Inc. Petition to convert farm-tap customers to propane, retain those customers as tariff customers, and for approval of related cost recovery proposals.* On Behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia. Issues: abandonment of gas wells, conversion of gas wells, propane customers.

3. Expert Testimony. Docket No. RPU-2024-0002. (2024). Before the Iowa Utilities Commission. In re: *Iowa-American Water Company Docket No. RPU-2024-0002.* On Behalf of the Office of Consumer Advocate. Issues: RDM proposal, tracker mechanisms, revenue adjustment and decoupling.

4. Expert Testimony. Docket No. UG-240008. (2024). Before the Washington Utilities & Transportation Commission. *Washington Utilities and Transportation Commission Complainant, v. Cascade Natural Gas Corporation, Respondent.* On Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Issues: revenue distribution, rate design, customer charges.

5. Expert Testimony. Docket No. UE-240004 and UE-240005. (2024). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission Complainant, v. Puget Sound Energy, Respondent.* On Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Issues: cost of service, revenue distribution, rate design.

6. Expert Testimony. Docket No. 46038. (2024). Before the Indiana Utility Regulatory Commission. *Verified Petition of Duke Energy Indiana, LLC pursuant to Ind. Code 8-1-2-42.7 and 8-1-2-61, for (1) Authority to modify its rates and charges for electric utility service through a multi-step rate implementation of new rates and charges using a forecasted test period; (2) approval of new schedules of rates and charges, general rules and regulations, and riders; (3) approval of revised electric depreciation rates applicable to its electric plant in service, and approval of regulatory asset treatment upon retirement of the company's last coal-fired steam generation plant; (4) approval of an adjustment to the company's FAC rider to track coal inventory balances; and (5) approval of necessary and appropriate accounting relief, including authority to: (A) defer to a regulatory asset*

*expenses associated with the Edwardsport carbon capture and sequestration study, (B) defer to a regulatory asset costs incurred to achieve organizational savings, and (C) defer to a regulatory asset or liability as applicable, all calculated income tax differences resulting from future changes in income tax rates.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: cost of service, revenue distribution, rate design, customer migration adjustment.

7. Expert Testimony. Docket No. UD-24-01. (2024). Before the Council of the City of New Orleans. *Delta States Utilities No, LLC and Entergy New Orleans, LLC, Ex Parte. In RE: Application for authority to operate as a local distribution company and incur indebtedness and joint application for approval of transfer and acquisition of local distribution company assets and related relief.* On Behalf of Delta Utilities No. LLC. Issues: revenue requirement, bill impact, transaction costs.

8. Expert Testimony. Docket No. UE-240006 and UG-240007. (2024). Before the Washington Utilities & Transportation Commission. *Complainant, v. Avista Corporation d/b/a Avista Utilities Respondent.* On Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Issues: rate design, customer charge.

9. Expert Testimony. Docket No. R-2024-3046519. (2024). Before the Pennsylvania Public Utility Commission. *Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.* On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: regulatory lag, decoupling, weather normalization. Direct and Surrebuttal.

10. Expert Testimony. Docket No. 20240025-EI. (2024). Before the Florida Public Service Commission. *In Re: Petition for rate increase by Duke Energy Florida, LLC.* On Behalf of The Citizens of the State of Florida. Issues: load forecasting, multi-year rate increase, energy affordability.

11. Expert Testimony. Docket No. 20240026. (2024). Before the Florida Public Service Commission. *In Re: Petition for rate increase by Tampa Electric Company.* On Behalf of The Citizens of the State of Florida. Issues: load forecasting, affordability.

12. Expert Testimony. Docket No. 2024-34-E. (2024). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Dominion Energy South Carolina, incorporated for authority to adjust and increase its retail electric rate schedules tariffs, and terms and conditions.* On Behalf of South Carolina Department of Consumer Affairs. Issues: GRID investment, cost of service, revenue allocation, rate design.

13. Expert Testimony. Cause No. 46011. (2024). Before the State of Indiana, Indiana Utility Regulatory Commission. *Petition of Ohio Valley Gas, Inc. for (1) authority to increase its rates and charges for gas utility service, (2) approval of new schedules of rates and charges, (3) approval of decoupling through a new sales reconciliation component rider, and (4) approval of necessary and appropriate accounting relief and other requests.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: decoupling, sales

reconciliation component rider.

14. Expert Testimony. Docket No. 2024-UA-42. (2024). Before the Mississippi Public Service Commission. *Joint Application of Centerpoint Energy Resources Corp. and Delta Utilities MS, LLC for all necessary authorizations and approvals for Delta Utilities MS, LLC to acquire the assets of Centerpoint Energy Resources Corp. and for approval of a certificate of public convenience and necessity for Delta Utilities MS, LLC, and for related relief.* On Behalf of Delta Utilities MS, LLC. Issues: economic benefits, ratemaking, other benefits.

15. Expert Testimony. Docket No. S-37187. (2024). Before the Louisiana Public Service Commission. *Delta Utilities No. LA, LLC, Delta Utilities S. LA., and Centerpoint Energy Resources Corp. Ex. Parte. In RE : Application for authority to operate as a local distribution company and incur indebtedness and joint application for approval for transfer and acquisition of local distribution company assets and related relief.* On Behalf of Delta Utilities No. LA, LLC. Issues: economic benefits, ratemaking, other benefits.

16. Expert Testimony. D.P.U. 23-150. (2024). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid Pursuant to G.L. c. 164 § 94 and 220 C.M.R. 5.00 for Approval of an Increase in Base Distribution Rates and Approval of a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Issues: capital tracker, Y-factor, IDRF, PBR, alternative regulation, benchmarking analysis.

17. Expert Testimony. Cause No. 45990. (2024). Before the Indiana Utility Regulatory Commission. *Verified Petition of Southern Indiana Gas and Electric Company D/B/A Centerpoint Energy Indiana South ("CEI South) for (1) Authority to modify its rates and charges for electric utility service through a phase in of rates (2) approval of new schedules of rates and charges and new and revised riders, including but not limited to a new tax adjustment rider and a new green power rider (3) approval of a critical peak pricing ("CPP") pilot program, (4) approval of revised depreciation rates applicable to electric and common plant in service, (5) approval of necessary and appropriate accounting relief, including authority to capitalize as rate base all cloud computing costs and defer to a regulatory asset amounts not already included in base rates that are incurred for third-party cloud computing arrangements, and (6) approval of an alternative regulatory plant granting CEI South a waiver from 170 IAC 4-1-16(f) to allow for remote disconnection for non-payment.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: proposed rate increases, cost of service study, minimum system study, revenue distribution, rate design, TOU-CPP pilot. Direct and Settlement.

18. Expert Testimony. Cause No. 45967. (2024). Before the Indiana Utility Regulatory Commission. *Petition of Northern Indiana Public Service Company LLC Pursuant to Ind. Code §§ 8-1-2-42, 8-1-2-42.7 and 8-1-2-61 for (1) authority to modify its retail rates and charges for gas utility service through a phase in of rates; (2) approval of new schedules*

*of rates and charges, general rule sand regulations, and riders (both existing and new): (3) approval of a new sales reconciliation adjustment mechanism; (4) approval of revised gas deprecation rates applicable to its gas plant in service; (5) approval of necessary and appropriate accounting relief, including but not limited to approval of certain deferral mechanisms for pensions, other post-retirement benefits and line locate expenses; and (6) to the extent necessary, approval of any of the relief requested herein pursuant to Ind. Code Ch. 8-1-2-5.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: sales reconciliation adjustment.

19. Expert Testimony. F.C. No. 1176. (2024). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia.* On Behalf of the Office of the People's Counsel for the District of Columbia. Issues: affordability, revenue distribution, rate design, multi-year rate planning, bill stabilization adjustment.

20. Expert Testimony. Case No. 23-0460-E-42T (2023). Before the Public Service Commission of West Virginia Charleston. *In the Matter of Monongahela Power Company and the Potomac Edison Company rule 42T tariff filing to increase rates and charges.* On Behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia. Issues: cost of service, zero intercept study, revenue allocation, rate design, net energy metering rider.

21. Expert Testimony. Docket No. DPU 23-81. (2023). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Gas Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Direct and Surrebuttal. Issues: alternative regulation performance-based ratemaking, cost of service, revenue distribution, rate design.

22. Expert Testimony. Docket No. DPU 23-80. (2023). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Electric Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Direct and Surrebuttal. Issues: alternative regulation performance-based ratemaking, cost of service, revenue distribution, rate design.

23. Expert Testimony. Case No. 23-03803-W-42T and 23-0384-S-42T (2023). Before the Public Service Commission of West Virginia Charleston. In the Matter of West Virginia-America Water Company rule 42T application to increase rates and charges. On Behalf of

the Consumer Advocate Division of the Public Service Commission of West Virginia. Issues: revenue distribution, rate design, affordability, service quality.

24. Expert Testimony. Cause No. 45933 (2023). Before the Indiana Utility Regulatory Commission. *Petition of Indiana Michigan Power Company an Indiana Corporation, for authority to increase rates and charges for electric utility service through a phase in rate adjustment; and for approval of related relief including: (1) revised depreciation rates, including cost of removal less salvage, and updated depreciation expense; (2) accounting relief, including deferrals and amortization; (3) inclusion of capital investment; (4) rate adjustment mechanism proposals, including new grant projects rider and modified tax rider; (5) a voluntary residential customer powerpay program; (6) waiver or declination of jurisdiction with respect to certain rules to facilitate implementation of the powerpay program; (7) cost recovery for cook plant subsequent license renewal evaluation project; and (8) new schedules of rates, rules and regulations.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: cost of service, rate design, revenue distribution, service fees.

25. Expert Report. (2023). *Alternative regulation deficiencies and potential ratepayer harms*. On Behalf of the Office of the Consumer Advocate of Iowa. October 3, 2023.

26. Expert Testimony. Docket No. 2023.06.057. (2023). Before the Public Service Commission of the State of Montana. *In the Matter of Energy West Montana's Application for Approval of Gas Cost Hedging Plan for West Yellowstone.* On Behalf of the Montana Consumer Counsel. Issues: gas hedging program.

27. Legislative Testimony. (2023). Ratepayer harms from alternative regulation in Oklahoma. Appearing on the Behalf of the Petroleum Alliance of Oklahoma. October 23, 2023.

28. Expert Testimony. Cause No. 45911. (2023). Before the State of Indiana Utility Regulatory Commission. *Petition of Indianapolis Power & Light Company D/B/A AES Indiana ("AES Indiana") for authority to increase rates and charges for electric utility service, and for approval of related relief, including (1) revised depreciation rates, (2) accounting relief, including deferrals and amortizations, (3) inclusion of capital investments, (4) rate adjustment mechanism proposals, including new economic development rider, (5) remote disconnect/reconnect process and (6) new schedules of rates, rules and regulations for service*. On Behalf of Indiana Office of Utility Consumer Counselor. Direct and Cross-Answering. Issues: allocated cost of service, revenue distribution, rate design, trackers.

29. Expert Testimony. Docket No. 23-06007. (2023). Before the Public Utilities Commission of Nevada. *In the Matter of the Application by Nevada Power Company D/B/A NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers.* On Behalf of the Nevada Bureau of Consumer Protection. Issues: marginal cost of service study, embedded cost of service study, revenue distribution, rate design.

30. Expert Testimony. Docket No. UE-230172. (2023). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission, Complainant v. Pacificorp dba Pacific Power & Light Company, Respondent.* On Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Issues: rate design, revenue distribution, cost of service.

31. Expert Testimony. Case No. U-21389. (2023). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for other Relief.* On Behalf of the Michigan Department of the Attorney General. Issues: capital expenditure adjustments, overview of proposal.

32. Expert Report. Case No. 22-1094-WW-AIR. (2023). *Audit of the Application to Increase Rates of Aqua Ohio, Inc. For the Period July 1, 2022 through June 30, 2023.* Prepared for the Public Utilities Commission of Ohio. Issues: cost of service, billing determinants, revenue distribution, rate design.

33. Expert Report. Case No. 22-1096-ST-AIR. (2023). *Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc. For the period July 1, 2022 through June 30, 2023.* Prepared for the Public Utilities Commission of Ohio. Issues: cost of service, billing determinants, revenue distribution, rate design.

34. Expert Report. *Analysis of the effectiveness and ratepayer impacts regarding the Natural Gas Rate Stabilization Act of 2005. (S.C. Code Ann. Section 58-5-410).* On Behalf of the South Carolina Department of Consumer Affairs. July 27, 2023.

35. Expert Testimony. Docket No. 2023-70-G. (2023). Before the Public Service Commission of South Carolina. *In the Matter of: Dominion Energy South Carolina, Inc's application for adjustments in its natural gas rate schedules and tariffs.* On Behalf of the South Carolina Department of Consumer Affairs. Issues: revenue credit, revenue distribution, rate design. Direct and Surrebuttal.

36. Expert Testimony. Docket No. E-01345A-22-0144. (2023). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of the Utilities Division Arizona Corporation Commission.* Issues: cost of service, revenue distribution, rate design. Direct, Surrebuttal, Rehearing Direct.

37. Expert Testimony. Docket No. 23-0068 (consol.) 23-0069. (2023). Before the Illinois Commerce Commission. *North Shore Gas Company, The Peoples Gas Light and Coke Company Proposed general increase in rates and revisions to service classifications, riders and terms and conditions of service.* On Behalf of the People of the State of Illinois. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

38. Expert Testimony. Docket No. 23-067. (2023). Before the Illinois Commerce Commission. *Ameren Illinois Company Proposed general increase in gas delivery service rates.* On Behalf of the Illinois Attorney General. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

39. Expert Testimony. Docket No. 23-066. (2023). Before the Illinois Commerce Commission. *Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed general increase in gas rates.* On Behalf of the People of the State of Illinois. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

40. Expert Testimony. Docket No. U-22-081. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study Designated as TA334-4 Filed by Enstar Natural Gas Company, A Division of SEMCO Energy, Inc.* On Behalf of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: cost of service, rate design, revenue distribution.

41. Expert Testimony. Docket No. U-22-078. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study and Tariff Filing Designated as TA510-1 Filed by Alaska Electric Light & Power Company.* On Behalf of the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: cost of service, rate design, seasonal rates, revenue allocation, customer charge.

42. Expert Testimony. Docket No. 2022.11.099. (2023). Before the Department of Public Service Regulation. *In the Matter of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electric Service.* On Behalf of the Montana Consumer Counsel. Direct and Cross-Answering. Issues: rate increase, cost of service study, marginal cost of service, revenue allocation, rate design.

43. Expert Testimony. Docket No. U-22-078. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study and Tariff Filing Designated as TA510-1 Filed by Alaska Electric Light & Power Company.* On Behalf of the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: rate design, cost of service, revenue allocation, seasonal rates.

44. Expert Testimony. Docket No. U-21193. (2023). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: Resource planning, coal retirements, asset amortization, financial compensation mechanism.

45. Expert Testimony. Docket No. RP22-1033. (2023). Before the Federal Energy Regulatory Commission. *Northern Natural Gas Company.* On Behalf of the Northern Municipal Distributors Group and the Midwest Region Gas Task Force Association. Issues: tariff provisions, rate analysis, discount adjustment.

46. Expert Testimony. Docket No. 22-061-U. (2023). Before the Arkansas Public Service

Commission. *In the Matter of an Investigation into Potential Cost Shifting Associated with Net Metering.* On Behalf of the Office of Tim Griffin, Attorney General of Arkansas. Issues: policy, net metering background.

47. Expert Testimony. Docket No. 22F-0263EG. (2023). Before the Public Utility Commission of the State of Colorado. *Olson's Greenhouses of Colorado, LLC. Complainant, v. Public Service Company of Colorado Respondent*. On Behalf of Olson's Greenhouses of Colorado, LLC. Issues: reliability, system upgrades, weather normalization.

48. Expert Testimony. Docket No. 2022.07.078. (2022). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Authority to Increase Retail Electric and Natural Gas Utility Rates and for Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design.* On Behalf of the Montana Consumer Counsel. Direct and Cross-Intervenor. Issues: riders, fixed cost recovery mechanism, power cost adjustment, cost of service, revenue distribution.

49. Expert Testimony. Docket No 2022-254-E. (2022). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges.* On Behalf of South Carolina Department of Consumer Affairs. Direct and Surrebuttal. Issues: Cost of service, revenue allocation, rate design.

50. Expert Testimony Docket No. 22-06014. (2022). *Before the Public Utilities Commission of Nevada. In the Matter of the Application by Sierra Pacific Power Company D/B/A NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers*. On Behalf of the Nevada Bureau of Consumer Protection. Issues: rate design, cost of services, marginal cost of service, revenue distribution.

51. Expert Testimony Docket No. 2022.06.067. (2022). *Before the Public Service Commission of the State of Montana. In RE NorthWestern Energy's Application for an Advanced Metering Opt-Out Tariff.* On Behalf of the Montana Consumer Counsel. Direct and Rebuttal. Issues: meter issues, opt-out fees, tariffs options.

52. Expert Testimony Docket No. 16-036-FR. (2022). *Before the Arkansas Public Service Commission. In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, INC., Pursuant to APSC Docket NO. 15-015-U. On Behalf of the Arkansas Attorney General Leslie Rutledge.* Issues: Rate design, netting adjustment, performance standards, projected year adjustments.

53. Expert Testimony Formal Case No. 1169. (2022). *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.* On Behalf of the People's Counsel for the District of Columbia. Direct and Rebuttal. Issues: Revenue

allocation, weather normalization, rate design.

54. Expert Testimony Case No. U-21224. (2022). *Before the Michigan Public Service Commission. In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, revenue distribution, policy overview.

55. Expert Report. Case No. 695287. (2022). Before the Nineteenth Judicial District Court, The Parish of East Baton Rouge, State of Louisiana. *Washington-St. Tammany Electric Cooperative, Inc. and Claiborne Electric Cooperative, Inc., Plaintiff v. Louisiana Generating, L.L.C., Defendant.* On Behalf of Louisiana Generating, L.L.C. Issues: environmental regulations, re-fueling, regulatory rules, collateral benefits.

56. Expert Report. Case No. 0:20-cv-60981-AMC. (2022). *Café, Gelato & Panini LLC, d/b/a Café Gelato Panini, on behalf of itself and all others similarly situated, Plaintiff v. Simon Property Group, Inc., Simon Property Group, L.P., M. S. Management Associates, Inc. And The Town Center at Boca Raton Trust, Defendant.* On Behalf of Simon Property Group, Inc.

57. Expert Testimony Case No. U-20836. (2022). *Before the Michigan Public Service Commission. In the Matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, revenue distribution, peer comparison.

58. Expert Testimony. D.P.U. 22-22. (2022*). Before the Department of Public Utilities of the Commonwealth of Massachusetts. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval of a Performance-Based Ratemaking Plan and Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, §94 and 220 C.M.R. §5.00.* On Behalf of Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate design, TFP analysis, rate increases, benchmark analysis, revenue distribution. Direct and Surrebuttal.

59. Expert Testimony. Docket No. 21-097-U. (2022). In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs. On Behalf of the Office of Arkansas Attorney General. Issues: cost of service, rate design, reliability, billing determinant adjustment.

60. Expert Testimony. Docket No. 2021-361-G. (2022). Before the Public Service Commission of South Carolina. *In the Matter of: Dominion Energy South Carolina, Inc.'s Request for Approval of New Natural Gas Energy Efficiency Programs*. On Behalf of South Carolina Department of Consumer Affairs. Issues: DSM Rider, energy efficiency, shared savings. Direct and Surrebuttal.

61. Expert Report. Case No. 21-596-ST-AIR. (2022). *Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc. For the Period January 1, 2021 through December 31, 2021*. Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

62. Expert Report. Case No. 21-595-WW-AIR. (2022). *Audit of the Application to Increase Rates of Aqua Ohio, Inc. For the Period January 1, 2021 through December 31, 2021.* Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

63. Expert Testimony. Docket No. 2021.09.112. (2022). *Before the Public Service Commission of the State of Montana. In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes.* On Behalf of the Montana Consumer Counsel. Issues: wholesale energy hedging, market exposure, overview of PCCAM filing, demand side management costs.

64. Expert Affidavit. Docket No. 2:21-cv-1074. (2021). In the United States District Court for the Western District of Louisiana. *The State of Louisiana by and through its Attorney General, Jeff Landry et al. Plantiffs, v. Joseph R. Biden, Jr., in his official capacity as President of the United States; et al., Defendants.* On Behalf of the Attorney General of Louisiana. Issues: social cost of carbon, carbon tax, environmental policy.

65. Expert Testimony. Case No. U21090. (2021). *Before the Michigan Public Service Commission. In the matter of the application of Consumers Energy Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, certain accounting approvals, and for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: IRP, coal plant retirements, acquisition premiums, financial compensation mechanism.

66. Expert Testimony. Docket No 16-036-FR. (2021). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: netting adjustments, rate increases, projected year adjustments, reliability.

67. Expert Report. Docket JCCP No. 4861. (2021). Before the Superior Court of the State of California County of Los Angeles, Central Civil West. *Coordination Proceeding Special Title [Rule 3.550] Southern California Gas Leak Cases.* On Behalf of Toll Brothers. Issues: gas leak, public service obligation, integrity management.

68. Expert Testimony. Docket No. U-35927. (2021). Before the Louisiana Public Service Commission. *In Re: Application of 1803 Electric Cooperative, Inc. for Approval of Power Purchase Agreements and for Cost Recovery.* Direct and Cross-Answering. On Behalf of Cleco Cajun LLC. Issues: tolling agreements, generation acquisition, risk factors.

69. Expert Testimony. Docket No. 21-060-U. (2021). Before the Arkansas Public Service

Commission. *In the Matter of Joint Application of Centerpoint Energy Resources Corp. and Summit Utilities Arkansas, Inc. For all Necessary Authorizations and Approvals for Summit Utilities Arkansas, Inc. To Acquire the Arkansas Assets of Centerpoint Energy Resources Corp. and for Approval of a Certificate of Public Convenience and necessity for Summit Utilities Arkansas, Inc.* Direct and Surrebuttal. On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: asset acquisition, ratepayer benefits, acquisition synergies, Rider FRP.

70. Expert Affidavit. Civil Action No. 2:21-cv-00778 (2021). Before the United States District Court for the Western District of Louisiana. *The State of Louisiana v. Joseph R. Biden, Jr.* Issues: leasing and drilling moratorium, state revenue, coastal restoration, economic activity.

71. Expert Testimony. Docket No. 21-044-U (2021). Before the Arkansas Public Service Commission. *In the Matter of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas' Request to Extend Rider FRP.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: ratepayer benefits, service quality, cost of service, FRP extension.

72. Expert Testimony. Docket No. 17-010-FR (2021). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: rate increase, investment and expense trends, revenue deficiency, leak performance.

73. Expert Testimony. Case No. U-20963 (2021). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, peak allocation, revenue distribution.

74. Expert Testimony. U-20-072, U-20-073, U-20-074. (2021). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement study and Tariff Filing designated as TA886-2 filed by Alaska Power Company, In the Matter of the Revenue Requirement study and Tariff filing designated as TA6-521 filed by Goat Lake Hydro, Inc., In the Matter of the Revenue Requirement study and Tariff filing designated as TA4-573 filed by BBL Hydro, Inc.* On Behalf of the Alaska Office of Attorney General. Issues: rate groups, cost of service.

75. Expert Testimony. Docket No. P20-001. (2021). Before the Louisiana Pilotage Fee Commission. *In Re: Request for Increase in Approved Pilot Complement; Increased Funding for necessary Additional Manpower; Upward Adjustment of Estimated Average Annual Pilot Compensation; and Related Relief Pursuant to LA R.S. 34:112.* On Behalf of the Louisiana Chemical Association (LCA) and Louisiana Mid-Continent Oil & Gas Association (LMOGA). Issues: unreasonable requests, fee structure, economic impact,

over earnings.

76. Expert Testimony. D.P.U. 20-120. (2021). Before the Commonwealth of Massachusetts Before the Department of Public Utilities. *Petition of Boston Gas Company d/b/a National Grid Pursuant to G.L. c. 164, 94 and 220 C.M.R. 5.00 for Approval of an Increase in Base Distribution Rates and Approval of a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate increase, accelerated depreciation, benchmarking analysis, performance incentive mechanism.

77. Expert Testimony. RPU-2020-0001. (2020). Before the Iowa Utilities Board. *In Re: Iowa-American Water Company.* On Behalf of the Office of Consumer Advocate. Issues: rate increase, test trackers, RSM accounting ratemaking construct.

78. Expert Testimony. BPU Docket Nos. QO19010040 and GO20090622. (2020). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Energy Efficiency Programs and the Associated Cost Recovery Mechanisms Pursuant to the Clean Energy Act, N.J.S.A. 48:3-87.8 et seq. and 48:3-98.1 et seq.* On behalf of the Division of Rate Counsel. Issues: CBA requirements, capacity benefits, volatility benefits.

79. Expert Testimony. Docket No. 2020-125-E. (2020). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Dominion Energy South Carolina, Incorporated for Adjustments of Rates and Charges (See Commission Order No. 2020-313).* On Behalf of the South Carolina department of Consumer Affairs. Issues: cost of service, revenue allocation, rate design.

80. Answering Testimony. Before the United States of America Federal Energy Regulatory Commission. Docket No. RP20-614-000 and RP20-618-000. (2020). *Transcontinental Gas Pile Line Company, LLC.* On Behalf of the North Carolina Utilities Commission. Issues: Tariff revisions, assessment of Transco claims.

81. Expert Testimony. Docket No. 16-036-FR. (2020). *Before the Arkansas Public Service Commission. In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U. Direct and Surrebuttal*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increases, investment and expenses trends, load forecast, historic year netting adjustment, reliability issues.

82. Expert Testimony. Docket No. 2019.12.101. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Approval of Capacity Resource Acquisition.* On the Behalf of the Montana Consumer Counsel. Issues: sale of capital asset, evaluation benefits, ratepayer cost exposure, reserve fund.

83. Expert Testimony. Formal Case No. 1162. (2020). 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*. On Behalf of the Office of the People's Counsel. Issues: rate increase, revenue adjustment, weather normalization, rate design, revenue distribution.

84. Expert Testimony. Docket No. E-01345A-19-0236. (2020). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for Ratemaking Purposes to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop such Return*. Direct and Surrebuttal. On Behalf of the Utilities Division of the Arizona Corporation Commission. Issues: Cost of Service, Revenue Distribution, Rate Design.

85. Expert Testimony. Docket No. 17-010-FR. (2020). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increase, leak replacement and reduction, netting adjustment, revenue deficiency, accounting policy changes.

86. Expert Testimony. Case No. U-20697. (2020). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*. On Behalf of the Michigan Department of Attorney General. Issues: cost of service, revenue distribution, rate design.

87. Expert Testimony. Docket No. 2019.09.058. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes*. On the Behalf of the Montana Consumer Counsel. Issues: purchase power expenses, cost sharing, PCAAM power cost.

88. Expert Testimony. Formal Case No. 1156. (2020). Before the Public Service Commission of the District of Columbia. *In the matter of Potomac Electric Power Company for authority to implement a multiyear rate plan for electric distribution service in the district of Columbia.* Direct, Rebuttal, Surrebuttal, Supplemental, and Second Supplemental. On Behalf of the Office of the People's Counsel. Issues: revenue distribution, rate design, customer charge, performance metric policies, performance metric incentives.

89. Expert Testimony. Case No. U-20561. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*. On Behalf of the Michigan Department of Attorney General. Issues: Cost of service, allocation of production plant, allocation of sub-transmission plant, revenue distribution.

90. Expert Testimony. Cause No. 45253. (2019). Before the Indiana Utility Regulatory

Commission. *Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code 8-1-2-42.7 and 8-1-2-61, for (1) Authority to Modify its Rates and Charges for Electric Utility Service through a Step-In of New Rates and Charges using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customers Classes*. On Behalf of the Indiana Office of Utility Consumer Counsel. Issues: Decoupling, revenue decoupling mechanism and design, commission policy, benchmarking analysis.

91. Expert Testimony. Docket 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues*:* Solar investment, risk assessment, proposed rider.

92. Expert Testimony. Docket No. 16-036-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

93. Expert Testimony. Docket No. 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: Solar project approval, ratepayer risk, cost allocation.

94. Expert Testimony. Docket No. 17-010-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: retail rates, leak analysis, revenue deficiency, investments.

95. Expert Testimony. Case No. U-20471. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.* On Behalf of the Michigan Department of Attorney General. Issues: load forecasting, least-cost system planning.

96. Expert Report. Docket No. 18-004422. (2019). Before the State of Florida Division of Administrative Hearings. *Peoples Gas System vs. South Sumter Gas Company, LLC and the City of Leesburg.* On Behalf of the City of Leesburg. Issues: retail rates, customer growth, sales trends and forecasts, policy, cost of service, socio-economic trends and forecasts.

97. Expert Testimony. Docket Nos. GO18101112 and EO18101113. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis.* On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, decoupling mechanisms.

98. Expert Testimony. Docket Nos. EO18060629 and GO18060630. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of the Second Energy Strong Program (Energy Strong II)*. On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, infrastructure replacement, cost recovery tracker mechanisms.

99. Expert Report. Docket No. 2011-AD-2. (2019). On Behalf of the Mississippi Public Service Commission. *Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards.* On Behalf of the Mississippi Public Utilities Staff. Issues: Net-metering, distributed generation.

100. Expert Testimony. Docket No. D2018.2.12. (2018). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.* On Behalf of the Montana Consumer Counsel. Issues: Net-metering, cost of service, revenue distribution, rate design.

101. Expert Testimony. Docket No. 19-SEPE-054-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc. for an Order Approving the Merger of Mid-Kansas Electric Company, Inc. into Sunflower Electric Power Corporation*. On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger impacts, rates, tariffs.

102. Expert Testimony. Docket No. 18-046-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Oklahoma Gas and Electric Company Pursuant to APSC Docket No. 16-052-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: formula rate plan, plant investment and expenses benchmarking analysis, reliability.

103. Expert Testimony. Docket No. 16-036-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

104. Expert Testimony. Docket No. 2017-AD-0112. (2018). Before the Mississippi Public Service Commission. *In Re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project.* On Behalf of the Mississippi Public Utilities Staff. Issues:

cost of service and rate design.

105. Expert Affidavit. Docket No. 87011-E. (2018). Before the 16th Judicial District Court Parish of St. Martin State of Louisiana. *Bayou Bridge Pipeline, LLC versus 38.00 Acres, More or Less, Located in St. Martin Parish; Barry Scott Carline, et al.* Issues: economic impacts.

106. Expert Testimony. Docket No. QO18080843. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Nautilus Offshore Wind, LLC for the Approval of the State Waters Wind Project and Authorizing Offshore Wind Renewable Energy Certificates.* On behalf of the Division of Rate Counsel. Issues: regulatory policy and cost-benefit analyses.

107. Expert Testimony. Docket No. ER18010029 and GR18010030. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief.* On behalf of the Division of Rate Counsel. Issues: rate proposal, revenue decoupling, regulatory policy, cost benchmarking.

108. Expert Testimony. Docket No. T-34695. (2018). Before the Louisiana Public Service Commission. *In re: Application for a rate increase on service originating at Grand isle and termination at St. James for Crude Petroleum as currently outlined in LPSC Tariff No. 75.2*. On Behalf of Energy XXI GOM, LLC. Issues: cost of service, rate design, and alternative regulation.

109. Expert Testimony. Docket No. 17-071-U. (2018). Before the Arkansas Public Service Commission*. In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, billing determinates.

110. Expert Testimony. Docket No. 17-010-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

111. Expert Testimony. Case No. PU-17-398. (2018). Before the North Dakota Public Service Commission. *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota*. On Behalf of the North Dakota Service Commission Advocacy Staff. Issues: cost of service, marginal cost of service, and rate design.

112. Expert Testimony. Docket No. 20170179-GU. (2018). Before the Florida Public Service

Commission. *In re: Petition for rate increase and approval of depreciation study by Florida City Gas.* On Behalf of the Citizens of the State of Florida. Issues: policy issues concerning long-term gas capacity procurement.

113. Expert Testimony. Docket No. 18-KCPE-095-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar, Inc. and Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

114. Expert Testimony. Docket No. GR17070776. (2018). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"). On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

115. Expert Affidavit. Case No. 18-489. (2018). Before the Civil District Court for the Parish of Orleans, State of Louisiana. *Bayou Bridge Pipeline, LLC versus The White Castle Lumber and Shingle Company Limited and Jeanerette Lumber & Shingle CO. L.L.C.* Issues: economic impact of crude oil pipeline development.

116. Expert Testimony. Docket No. 16-036-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: cost of service, rate design, alternative regulation, formula rate plan.

117. Expert Testimony. Docket No. 2017-AD-0112. (2017). Before the Mississippi Public Service Commission. *In re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project*. On Behalf of the Mississippi Public Utilities Staff. Issues: financial analysis, rates and cost trends, economic impacts of proposal.

118. Expert Testimony. Case No. 2017-00179. (2017). Before the Public Service Commission, Commonwealth of Kentucky. *Electronic Application of Kentucky power Company For (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish a Regulatory Asset or Liability Related to the Big Sandy 1 Operation Rider; and (5) An Order Granting All Other Required Approvals and Relief.* On Behalf of the Office of the Kentucky Attorney General. Issues: rate design, revenue allocation, economic development.

119. Expert Testimony. Docket No. 17-010-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy*

*Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

120. Expert Testimony. Formal Case No. 1142. (2017). Before the Public Service Commission of the District of Columbia. *In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.* On Behalf of the Office of the People's Counsel. Issues: merger/acquisition policy, financial risk, ring-fencing, and reliability.

121. Expert Testimony. D.P.U. 17-05. (2017). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00*. On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: performance-based ratemaking, multi-factor productivity estimation.

122. Deposition and Testimony. (2017) Before the Nebraska Section 70, Article 13 Arbitration Panel. *Northeast Nebraska Public Power District, City of South Sioux City Nebraska; City of Wayne, Nebraska; City of Valentine, Nebraska; City of Beatrice, Nebraska; City of Scribner, Nebraska; Village of Walthill, Nebraska, vs. Nebraska Public Power District.* On the Behalf of Baird Holm LLP for the Plaintiffs. Issues: rate discounts; cost of service; utility regulation, economic harm.

123. Expert Testimony. Docket No. 16-052-U. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Application of the Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges and Tariffs.* On the Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

124. Expert Testimony. Docket No. 16-KCPE-593-ACQ. (2016). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar, Inc. by Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

125. Expert Testimony. Formal Case No. 1139. (2016). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.* On the Behalf of the Office of the People's Counsel for the District of Columbia. Issues: cost of service, rate design, alternative regulation.

126. Expert Affidavit. Docket No. CP15-558-000 (2016). Before the United States of America Federal Energy Regulatory Commission. *PennEast Pipeline Company, LLC*. Affidavit and Reply Affidavit. On the Behalf of the New Jersey Division of Rate Counsel. Issues:

pipeline capacity, peak day requirements.

127. Expert Testimony. Docket No. RPU-2016-0002. (2016). Before the Iowa Utilities Board. *In re: Iowa American Water Company application for revision of rates.* On behalf of the Office of Consumer Advocate. Issue: revenue stabilization mechanism, revenue decoupling.

128. Expert Testimony. Docket No. 15-015-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: formula rate plan evaluation.

129. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: load forecasting.

130. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: off-system sales incentives.

131. Expert Testimony. Project No. 5-103. (2016). United States of America Federal Energy Regulatory Commission. *Confederated Salish and Kootenai Tribes Energy Keepers, Incorporated.* On behalf of the Flathead, Mission, and Jocko Valley Irrigation Districts and the Flathead Joint Board of Control of the Flathead, Mission, and Jocko Valley Irrigation Districts.

132. Expert Testimony. Docket No. 15-098-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas for a General Change or Modification in its Rates, Charges and Tariffs.* On behalf of the Office of the Arkansas Attorney General. Issues: formula rate plan, cost of service and rate design.

133. Expert Testimony. BPU Docket No. GM15101196. (2016). *In the Matter of the Merger of Southern Company and AGL Resources, Inc.* On behalf of the New Jersey Division of Rate Counsel. Issues: merger standards of review, customer dividend contributions, synergy savings and costs to achieve, ratemaking treatment of merger-related costs.

134. Expert Testimony. Docket No. 15-078-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Joint Application of SourceGas Inc., SourceGas LLC, SourceGas Holdings LLC and Black Hills Utility Holdings, Inc. for all Necessary Authorizations and Approvals for Black Hills Utility Holdings, Inc. to Acquire SourceGas Holdings LLC.* On behalf of the Office of the Arkansas Attorney General. Issues: public policy and regulatory policy associated with the acquisition.

135. Expert Testimony. Docket No. 15-031-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of SourceGas Arkansas Inc. for an Order Approving the Acquisition of Certain Storage Facilities and the Recovery of Investments and Expenses Associated Therewith.* On behalf of the Office of the Arkansas Attorney General. Issues: cost-benefit analysis, transmission cost analysis, and a due diligence analysis.

136. Expert Testimony. Docket No. 15-015-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.* On behalf of the Office of the Arkansas Attorney General. Issues: economic development riders and production plant cost allocation.

137. Expert Testimony. Docket No. 7970. (2015). Before the Vermont Public Service Board. *Petition of Vermont Gas Systems, Inc., for a certificate of public good pursuant to 30 V.S.A.§ 248, authorizing the construction of the "Addison Natural Gas Project" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 miles of new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont*. On behalf of AARP-Vermont. Issues: net economic benefits of proposed natural gas transmission project.

138. Expert Testimony. File No. ER-2014-0370 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of Kansas City Power & Light Company for Authority Implement A General Rate Increase for Electric Service*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, class cost of service, and policy and ratemaking considerations in connection with electric vehicle charging stations.

139. Expert Testimony. File No. ER-2014-0351 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of The Empire District Electric Company for Authority To File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, and class cost of service.

140. Expert Testimony. D.P.U. 14-130 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of the Company's 2015 Gas System Enhancement Program Plan, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015.* On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

141. Expert Testimony. D.P.U. 14-131 (2015). Before the Massachusetts Department of Public Utilities. *Petition of The Berkshire Gas Company for approval by the Department of Public*

*Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

142. Expert Testimony. D.P.U. 14-132 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for approval by the Department of Public Utilities of the Companies' Gas System Enhancement Program for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

143. Expert Testimony. D.P.U. 14-133 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Liberty Utilities for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

144. Expert Testimony. D.P.U. 14-134 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

145. Expert Testimony. D.P.U. 14-135 (2015). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

146. Expert Report. Docket No. X-33192 (2015). Before the Louisiana Public Service Commission. *Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana.* On behalf of the Louisiana Public Service Commission. Issues: cost-benefit, cost of service, rate impact.

147. Expert Testimony. F.C. 1119 (2014). Before the District of Columbia Public Service Commission. *In the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and new Special Purpose Entity, LLC*. On behalf of the Office of the People's Counsel. Issues: economic impact analysis, reliability, consumer investment fund, regulatory oversight, impacts to competitive electricity markets.

148. Expert Report. Civil Action 1:08-cv-0046 (2014). Before the U.S. District Court for the Southern District of Ohio. *Anthony Williams, et al., v. Duke Energy International, Inc., et*

*al.* On behalf of Markovits, Stock & DeMarco, Attorneys & Counselors at Law. Issues: public utility regulation, electric power markets, economic harm.

149. Expert Testimony. D.P.U. 14-64 (2014). Before the Massachusetts Department of Public Utilities. *NSTAR Gas Company/HOPCO Gas Services Agreement. On behalf of the Office of the Public Advocate*. Issues: certain ratemaking features associated with the proposed Gas Service Agreement.

150. Expert Testimony. Docket Nos. 14-0224 and 14-0225 (2014). Before the Illinois Commerce Commission. *In the Matter of the Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service (consolidated)*. On behalf of the People of the State of Illinois. Issues: test year expenses, cost benchmarking analysis, pipeline replacement, and leak rate comparisons.

151. Expert Testimony. Docket 8191 (2014). Before the Vermont Public Service Board. *In Re: Petition of Green Mountain Power Corporation for Approval of a Successor Alternative Regulation Plan.* On the behalf of AARP-Vermont. Issues: Alternative Regulation.

152. Expert Testimony. Docket No. 2013-00168 (2014). Before the Maine Public Utilities Commission. *In the Matter of the Request for Approval of an Alternative Rate Plan (ARP 2014) Pertaining to Central Maine Power Company*. On behalf of the Office of the Public Advocate. Issues: class cost of service study, marginal cost of service study, revenue distribution and rate design.

153. Expert Testimony. D.P.U. 13-90 (2013). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges and increase in base distribution rates for electric service.* On behalf of the Office of the Ratepayer Advocate. Issues: capital cost adjustment mechanism and performance-based regulation.

154. Expert Testimony. BPU Docket Nos. EO13020155 and GO13020156. (2013). Before the State of New Jersey Board of Public Utilities. *I/M/O The Petition of Public Service Electric & Gas Company for the Approval of the Energy Strong Program.* On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

155. Expert Testimony. D.P.U. 13-75 (2013). Before the Massachusetts Department of Public Utilities. *Investigation by the Department of Public Utilities on its Own Motion as to the Propriety of the Rates and Charges by Bay State Gas Company d/b/a Columbia Gas of Massachusetts set forth in Tariffs M.D.P.U. Nos. 140 through 173, and Approval of an Increase in Base Distribution Rates for Gas Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on April 16, 2013, to be effective May 1, 2013*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement, and leak rate

comparisons; environmental benefits analysis; O&M offset; and cost benchmarking analysis.

156. Expert Testimony. Docket No. 13-115 (2013). Before the Delaware Public Service Commission. *In the Matter of the Application of Delmarva Power & Light Company FOR an Increase in Electric Base Rates and Miscellaneous Tariff Changes* (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.

157. Expert Testimony. Formal Case No. 1103 (2013). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. On the Behalf of the Office of the People's Counsel of the District of Columbia. Issues: Pro forma adjustment for reliability investments.

158. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue distribution, and rate design

159. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.

160. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

161. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

162. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. *In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer*. On the Behalf of the Colorado Office of Consumer Counsel. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.

163. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program*. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.

164. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program.* On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.

165. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

166. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public Utilities. *In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.

167. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.

168. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. *In Re: Potomac Electric Power Company ("Pepco") General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

169. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. *In Re: the Delmarva Power and Light Company General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

170. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012).

Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms.

171. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

172. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. *In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase*. On the Behalf of the Public Advocate. January 31, 2012. Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization Adjustments, Class Cost of Service Study, Rate Design.

173. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

174. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's Counsel of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. Issues: Regulatory lag, ratemaking principles, reliability-related capital expenditure tracker proposals.

175. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson.* Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

176. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S. Environmental Protection Agency. *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on

electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

177. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. *On the Behalf of the Maryland Office of People's Counsel. In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and Revise its Terms and Conditions for Gas Service*. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

178. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

179. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. *In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company*. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)

180. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Capital Cost Rider, Revenue Decoupling.

181. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Pipeline Replacement Rider, Revenue Decoupling.

182. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

183. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

184. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

185. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

186. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

187. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

188. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

189. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

190. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

191. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept

analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

192. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

193. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

194. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

195. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380-A, ex parte, (2009). Before the Louisiana Public Service Commission. In re: Environmental Adjustment Clause and Environmental Certification for Electric Power Generation Resources. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets cost recovery treatment; other generation planning issues.

196. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

197. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

198. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of

Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

199. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

200. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

201. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

202. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

203. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

204. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

205. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the

Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

206. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

207. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

208. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

209. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

210. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

211. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

212. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

213. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

214. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

215. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

216. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

217. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

218. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

219. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

220. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

221. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the

Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

222. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

223. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

224. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

225. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

226. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

227. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

228. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

229. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

230. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

231. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

232. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

233. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

234. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al*. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

235. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

236. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

237. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

238. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

239. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission

of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

240. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

241. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

242. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

243. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

244. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

245. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

246. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

247. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

248. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On

behalf of a Consortium of Interstate Natural Gas Transportation Companies.

249. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

250. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

251. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

252. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

253. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

254. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

255. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

256. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

257. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and

Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

258. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

## REFEREE AND EDITORIAL APPOINTMENTS

Contributor, 2014-2018, *Wall Street Journal*, *Journal Reports*, Energy

Editorial Board Member, 2015-2017, *Utilities Policy*

Referee, 2014-Current, *Utilities Policy*

Referee, 2010-Current, *Economics of Energy & Environmental Policy*

Referee, 1995-Current*, Energy Journal*

Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*

Referee, 2005, *Energy Policy*

Referee, 2004, *Southern Economic Journal*

Referee, 2002, *Resource & Energy Economics*

Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

## PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

## PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists ("IAEE"), United States Association of Energy Economics ("USAEE"), the National Association for Business Economics ("NABE"), and the Energy Bar Association (National and Louisiana Chapter; current Board member of LA chapter).

## HONORS AND AWARDS

*Baton Rouge Business Report*, Selected as one of the "Capital Region 500" (2023).

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

*Baton Rouge Business Report*, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current).

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

## TEACHING EXPERIENCE

Energy and the Environment (Survey Course)

Principles of Microeconomic Theory

Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept. of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

"Natural Gas Issues and Recent Market Trends." Michigan State University Institute of Public Utilities, GridSchool Regulatory Studies Program, East Lansing, Mich., March 29, 2017.

"Gas Supply Planning and Procurement: Regulatory Overview and issues." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Natural Gas Supply Issues and Challenges." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Incentives, Risk and Changes in the Nature of Regulation." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 18, 2017.

"Traditional and Alternative Forms of Regulation: Background and Overview." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Utility and policy motivations for risk and change." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Incentives and Formula Based Methods." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

**THESIS/DISSERTATIONS COMMITTEES**

Active:
1 Thesis Committee Memberships (Environmental Studies)
2 Ph.D. Dissertation Committee (Economics)
Completed:
8 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

**LSU SERVICE AND COMMITTEE MEMBERSHIPS**

Committee Member, Energy Education Curriculum Committee. E.J. Ourso College of Business. LSU (2016-Current).

Chairman, LSU Energy Initiative/LSU Energy Council (2014-Current).

Co-Director & Steering Committee Member, LSU Coastal Marine Institute (2009-2014).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-2014); Full Member (2014-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

## PROFESSIONAL SERVICE

Board Member (2018). Energy Bar Association, Louisiana Chapter.

Program Committee Member (2017). Gulf Coast Power Association Conference. New Orleans.

Program Committee Member (2016). Gulf Coast Power Association Conference. New Orleans.

Program Committee Member (2015). Gulf Coast Power Association Workshop/Special Briefing. "Gulf Coast Disaster Readiness: A Past, Present and Future Look at Power and Industry Readiness in MISO South."

Advisor (2008). National Association of Regulatory Utility Commissioners. Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Exhibit OPC (A)-2
Formal Case No. 1180
Direct Testimony of David E. Dismukes


# Comparison of Residential Non-Fuel Revenues (2011-2023)

| State | Company | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ($/Mcf) | | | | | | | | | | | | |
| **DC** | **Washington Gas Light** | **$ 5.51** | **$ 7.71** | **$ 6.08** | **$ 6.02** | **$ 7.54** | **$ 7.34** | **$ 8.62** | **$ 6.80** | **$ 7.63** | **$ 9.05** | **$ 8.06** | **$ 8.95** | **$ 13.51** |
| MD | Baltimore Gas and Electric Co. | 5.63 | 6.19 | 6.52 | 5.35 | 7.30 | 8.14 | 8.98 | 8.05 | 8.99 | 10.50 | 10.96 | 10.31 | 13.26 |
| MD | Washington Gas Light - MD | 5.14 | 8.27 | 5.08 | 4.87 | 6.60 | 7.14 | 7.52 | 5.69 | 6.57 | 8.03 | 6.84 | 7.29 | 11.81 |
| NJ | Public Service Electric & Gas Co. | 7.07 | 7.37 | 5.91 | 5.51 | 5.02 | 5.76 | 5.42 | 4.86 | 5.60 | 5.72 | 5.74 | 6.78 | 7.93 |
| NJ | New Jersey Natural Gas | 8.59 | 8.63 | 8.03 | 7.15 | 8.43 | 7.82 | 8.11 | 7.28 | 8.67 | 9.84 | 9.29 | 10.24 | 13.05 |
| NJ | South Jersey Gas Co. | 6.20 | 7.72 | 6.06 | 5.90 | 8.27 | 8.08 | 8.64 | 8.09 | 9.67 | 11.63 | 10.73 | 10.17 | 14.34 |
| NY | The Brooklyn Union Gas Co. | 6.87 | 8.81 | 6.96 | 7.47 | 7.34 | 8.07 | 8.78 | 8.87 | 10.23 | 11.40 | 10.49 | 10.22 | 14.94 |
| NY | Consolidated Edison Company of New York, Inc. | 7.39 | 11.51 | 10.05 | 8.97 | 8.82 | 8.99 | 8.71 | 8.62 | 9.26 | 11.57 | 15.51 | 16.35 | 16.51 |
| NY | Keyspan Energy Dba National Grid NY | 7.63 | 9.67 | 8.44 | 7.60 | 8.73 | 7.81 | 8.77 | 8.95 | 9.49 | 10.30 | 9.47 | 9.07 | 13.12 |
| NY | Niagara Mohawk Power Company | 4.58 | 6.23 | 5.24 | 4.60 | 5.11 | 5.67 | 5.10 | 4.74 | 5.00 | 5.82 | 5.77 | 5.20 | 8.15 |
| NY | National Fuel Gas Distribution Corporation | 5.82 | 6.93 | 6.12 | 5.31 | 5.54 | 6.19 | 5.85 | 5.22 | 5.45 | 6.16 | 6.22 | 5.98 | 6.23 |
| PA | UGI Utilities, Inc. | 1.61 | 3.56 | 3.11 | 2.47 | 3.46 | 4.18 | 3.68 | 3.75 | 4.32 | 5.14 | 4.18 | 3.82 | 7.61 |
| PA | PECO Energy Co. | 5.74 | 6.47 | 5.55 | 5.43 | 5.91 | 5.65 | 5.52 | 5.40 | 6.17 | 6.28 | 6.02 | 6.27 | 9.29 |
| VA | Washington Gas Light - VA | 4.26 | 6.75 | 4.25 | 4.45 | 6.34 | 6.18 | 7.44 | 5.76 | 6.56 | 8.02 | 6.27 | 6.98 | 12.52 |
| | **Peer Group Average** | **$ 5.89** | **$ 7.55** | **$ 6.26** | **$ 5.78** | **$ 6.68** | **$ 6.90** | **$ 7.12** | **$ 6.56** | **$ 7.38** | **$ 8.49** | **$ 8.27** | **$ 8.36** | **$11.44** |

| | Company | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (Rank) | | | | | | | | | | | | |
| **DC** | **Washington Gas Light** | **5** | **8** | **8** | **10** | **10** | **8** | **9** | **8** | **8** | **8** | **8** | **8** | **11** |
| MD | Baltimore Gas and Electric Co. | 6 | 2 | 10 | 6 | 8 | 13 | 14 | 10 | 10 | 11 | 13 | 13 | 10 |
| MD | Washington Gas Light - MD | 4 | 10 | 3 | 4 | 7 | 7 | 7 | 6 | 7 | 7 | 7 | 7 | 6 |
| NJ | Public Service Electric & Gas Co. | 11 | 7 | 6 | 8 | 2 | 4 | 3 | 3 | 4 | 2 | 2 | 5 | 3 |
| NJ | New Jersey Natural Gas | 14 | 11 | 12 | 11 | 12 | 10 | 8 | 9 | 9 | 9 | 9 | 12 | 8 |
| NJ | South Jersey Gas Co. | 9 | 9 | 7 | 9 | 11 | 12 | 10 | 11 | 13 | 14 | 12 | 10 | 12 |
| NY | The Brooklyn Union Gas Co. | 10 | 12 | 11 | 12 | 9 | 11 | 13 | 13 | 14 | 12 | 11 | 11 | 13 |
| NY | Consolidated Edison Company of New York, Inc. | 12 | 14 | 14 | 14 | 14 | 14 | 11 | 12 | 11 | 13 | 14 | 14 | 14 |
| NY | Keyspan Energy Dba National Grid NY | 13 | 13 | 13 | 13 | 13 | 9 | 12 | 14 | 12 | 10 | 10 | 9 | 9 |
| NY | Niagara Mohawk Power Company | 3 | 3 | 4 | 3 | 3 | 3 | 2 | 2 | 2 | 3 | 3 | 2 | 4 |
| NY | National Fuel Gas Distribution Corporation | 8 | 6 | 9 | 5 | 4 | 6 | 5 | 4 | 3 | 4 | 5 | 3 | 1 |
| PA | UGI Utilities, Inc. | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 2 |
| PA | PECO Energy Co. | 7 | 4 | 5 | 7 | 5 | 2 | 4 | 5 | 5 | 5 | 4 | 4 | 5 |
| VA | Washington Gas Light - VA | 2 | 5 | 2 | 2 | 6 | 5 | 6 | 7 | 6 | 6 | 6 | 6 | 7 |

**Note**: (1) PSE&G includes residential transport revenues.
**Source**: (1) Annual Gas Reports.

# WNA Annual Revenue Impact (2019-2023)



| Year | WNA Revenue Impact | Total Revenue | Percentage of Total |
|---|---|---|---|
| 2019 | 4,393,000 | 223,865,494 | 1.96% |
| 2020 | 12,619,000 | 204,436,290 | 6.17% |
| 2021 | 6,288,000 | 233,688,484 | 2.69% |
| 2022 | (1,900,000) | 280,401,760 | -0.68% |
| 2023 | 10,565,000 | 264,361,894 | 4.00% |
| **Total** | **$ 31,965,000** | **$ 1,206,753,922** | **2.65%** |
| **Average** | **$ 6,393,000** | **$ 241,350,784** | **2.65%** |

Source:
(1) Direct Testimony of Robert E. Tuoriniemi at 14:1-11.

Exhibit OPC (A)-4
Formal Case No. 1180
Direct Testimony of David E. Dismukes

# Company's Proposed Revenue Distribution



| | Revenue Distribution | | | | |
|---|---|---|---|---|---|
| Customer Class[1] | Current Revenues | Proposed Increase | Proposed Revenues | Percent Increase | Relative ROR |
| Residential: Heating/Cooling | $ 74,739,509 | $ 24,899,361 | $ 99,638,870 | 33.3% | 1.10 |
| Residential: Non-Heating/Non-Cooling Individually Metered Apartments | 2,020,915 | 531,690 | 2,552,605 | 26.3% | 0.87 |
| Residential: Non-Heating/Non-Cooling Other | 1,668,417 | 632,029 | 2,300,446 | 37.9% | 1.25 |
| Commercial & Industrial: Heating/Cooling < 3,075 | 4,964,847 | 1,654,484 | 6,619,331 | 33.3% | 1.10 |
| Commercial & Industrial: Heating/Cooling > 3,075 | 38,280,214 | 10,070,644 | 48,350,858 | 26.3% | 0.87 |
| Commercial & Industrial: Combined Heat & Power | 525,659 | 199,638 | 725,297 | 38.0% | 1.25 |
| Commercial & Industrial: Non-Heating/Non-Cooling | 4,781,855 | 1,258,386 | 6,040,241 | 26.3% | 0.87 |
| Commercial & Industrial: Natural Gas Vehicles | 238,205 | 90,557 | 328,762 | 38.0% | 1.26 |
| Group Metered Apartments: Heating/Cooling < 3,075 | 726,885 | 191,204 | 918,089 | 26.3% | 0.87 |
| Group Metered Apartments: Heating/Cooling > 3,075 | 16,931,317 | 4,452,982 | 21,384,299 | 26.3% | 0.87 |
| Group Metered Apartments: Non-Heating/Non-Cooling | 2,334,514 | 614,152 | 2,948,666 | 26.3% | 0.87 |
| Interruptible Service[2] | 160,567 | 40,142 | 200,709 | 25.0% | 0.83 |
| **Net Revenue for Rate Schedules** | **$ 147,372,904** | **$ 44,635,270** | **$ 192,008,174** | **30.3%** | **1.00** |

Note:
(1) This exhibit does not include the Special Contracts class.
(2) Interruptible Service Distribution Charge revenue is not included in net revenues. See Schedule C, Page 4 where the 26.3 percent increase was applied.
Source:
(1) Exhibit WG (O)-1 Errata, Schedule B, Pages 2-4.

Exhibit OPC (A)-5
Formal Case No. 1180
Direct Testimony of David E. Dismukes

# Alternative Revenue Distribution



| | Revenue Distribution | | | | |
|---|---|---|---|---|---|
| **Customer Class[1]** | **Current Revenues** | **Proposed Increase** | **Proposed Revenues** | **Percent Increase** | **Relative ROR** |
| Residential: Heating/Cooling | $ 74,739,509 | $ 22,581,341 | $ 97,320,850 | 30.2% | 0.997 |
| Residential: Non-Heating/Non-Cooling Individually Metered Apartments | 2,020,915 | 610,587 | 2,631,502 | 30.2% | 0.997 |
| Residential: Non-Heating/Non-Cooling Other | 1,668,417 | 581,161 | 2,249,578 | 34.8% | 1.150 |
| Commercial & Industrial: Heating/Cooling < 3,075 | 4,964,847 | 1,500,049 | 6,464,896 | 30.2% | 0.997 |
| Commercial & Industrial: Heating/Cooling > 3,075 | 38,280,214 | 11,565,751 | 49,845,965 | 30.2% | 0.997 |
| Commercial & Industrial: Combined Heat & Power | 525,659 | 183,103 | 708,762 | 34.8% | 1.150 |
| Commercial & Industrial: Non-Heating/Non-Cooling | 4,781,855 | 1,444,761 | 6,226,616 | 30.2% | 0.997 |
| Commercial & Industrial: Natural Gas Vehicles | 238,205 | 82,974 | 321,179 | 34.8% | 1.150 |
| Group Metered Apartments: Heating/Cooling < 3,075 | 726,885 | 219,617 | 946,502 | 30.2% | 0.997 |
| Group Metered Apartments: Heating/Cooling > 3,075 | 16,931,317 | 5,115,525 | 22,046,842 | 30.2% | 0.997 |
| Group Metered Apartments: Non-Heating/Non-Cooling | 2,334,514 | 705,336 | 3,039,850 | 30.2% | 0.997 |
| Interruptible Service | 160,567 | 48,513 | 209,080 | 30.2% | 0.997 |
| **Net Revenue for Rate Schedules** | **$ 147,372,904** | **$ 44,638,718** | **$ 192,011,622** | **30.3%** | **1.00** |

Note:
(1) This exhibit does not include the Special Contracts class.
Source:
(1) Exhibit WG (O)-1 Errata, Schedule B, Pages 2-4.

Exhibit OPC (A)-6
Formal Case No. 1180
Direct Testimony of David E. Dismukes

# Comparison of Current and Proposed Customer Charges



| Rate Schedule | Current | Proposed | Percentage Difference |
|---|---|---|---|
| **Residential Service** | | | |
| Heating and/or Cooling | $ 16.55 | $ 20.70 | 25.1% |
| Non-Heating and Non-Cooling - Individually Metered Apartments | $ 12.00 | $ 15.00 | 25.0% |
| Non-Heating and Non-Cooling - Other | $ 13.55 | $ 16.95 | 25.1% |
| **Commercial and Industrial Service** | | | |
| Heating and/or Cooling (< 3,075 therms) | $ 29.90 | $ 37.40 | 25.1% |
| Heating and/or Cooling (>= 3,075 therms) | $ 70.05 | $ 87.55 | 25.0% |
| Non-Heating and Non-Cooling | $ 28.50 | $ 35.65 | 25.1% |
| **Group Metered Apartment Service** | | | |
| Heating and/or Cooling (< 3,075 therms) | $ 28.50 | $ 35.65 | 25.1% |
| Heating and/or Cooling (>= 3,075 therms) | $ 70.05 | $ 87.60 | 25.1% |
| Non-Heating and Non-Cooling | $ 28.50 | $ 35.65 | 25.1% |
| **Interruptible Service** | | | |
| Developmental Natural Gas Vehicles | $ 49.67 | $ 62.10 | 25.0% |
| Delivery Service | $ 121.00 | $ 151.25 | 25.0% |
| Combined Heat and Power/Distributed Generation Facilities | $ 343.75 | $ 429.70 | 25.0% |

Source:
(1) Exhibit WG (O)-1 Errata, Schedule A.

Exhibit OPC (A)-7
Formal Case No. 1180
Direct Testimony of David E. Dismukes

# Survey of Regional Customer Charges



| State | Company | Customer Charge ($/month) Residential | Customer Charge ($/month) Small Commercial |
|---|---|---|---|
| **DC** | **Washington Gas and Light Co[1]** | **$ 16.55** | **$ 29.90** |
| DE | Delmarva Power & Light Company | 15.00 | 55.59 |
| MD | Baltimore Gas and Electric Company | 9.30 | 14.55 |
| MD | Chesapeake Utilities Corporation | 8.75 | 17.25 |
| MD | Columbia Gas of Maryland Inc | 16.25 | 64.81 |
| MD | Washington Gas and Light Co | 11.85 | 21.50 |
| NJ | Elizabethtown Gas Co | 10.50 | 36.79 |
| NJ | New Jersey Natural Gas Co | 11.00 | 42.00 |
| NJ | Public Service Electric & Gas Co[2] | 8.62 | 20.23 |
| NJ | South Jersey Gas Co | 10.50 | 40.50 |
| NY | Central Hudson Gas & Electric Corp | 26.25 | 41.00 |
| NY | Consolidated Edison Co of New York | 31.67 | 43.00 |
| NY | Keyspan Energy Delivery - Long Island[1] | 21.75 | 41.50 |
| NY | National Fuel Gas Distribution Corp[3] | 15.54 | 17.86 |
| NY | Niagara Mohawk Power Corp | 21.40 | 26.00 |
| NY | Orange & Rockland Utility Inc | 22.00 | 33.00 |
| NY | Rochester Gas & Electric Corp | 20.30 | 20.30 |
| PA | PECO Energy Co | 10.54 | 18.99 |
| PA | Peoples Natural Gas Company LLC | 14.50 | 20.00 |
| PA | UGI Utilities, Inc | 15.00 | 27.38 |
| VA | Atmos Energy Corporation | 13.24 | 20.52 |
| VA | Columbia Gas of Virginia Inc | 18.00 | 30.31 |
| VA | Roanoke Gas Co | 17.00 | 29.00 |
| VA | Virginia Natural Gas | 12.18 | 26.54 |
| VA | Washington Gas and Light Co | 12.40 | 22.50 |
| | **Average** | **15.56** | **30.46** |

**Note**: (1) Residential charge is for heating and/or cooling residential services. (2) Residential charge is $8.62 and commercial charge is $19.18 when including New Jersey Sales and Use Tax (SUT). (3) Charges are for customers that receive a bill from the Supplier. If received by the Company, residential and small commercial charges are $16.58 and $18.90, respectively.
**Source**: (1) Company tariff sheets.

Exhibit OPC (A)-8
Formal Case No. 1180
Direct Testimony of David E. Dismukes

# Energy Expenditure Data for the Middle Atlantic and Northeast Regions



Data release date: March 2023
Revised data release date: March 2024

**Table CE1.2 Summary annual household site consumption and expenditures in the Northeast—totals and intensities, 2020**

| | Number of housing units (million) | Site energy consumption[a] | | | | Energy expenditures[a] | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Northeast[b] | Total (trillion Btu) | Per household (million Btu) | Per household member (million Btu) | Per square foot (thousand Btu) | Total (billion dollars) | Per household (dollars) | Per household member (dollars) | Per square foot (dollars) |
| **All homes** | 21.92 | 1,956 | 89.2 | 36.8 | 48.8 | 49.60 | 2,263 | 932 | 1.24 |
| **Census division** | | | | | | | | | |
| New England | 5.88 | 528 | 89.9 | 36.4 | 46.6 | 14.92 | 2,539 | 1,028 | 1.32 |
| Middle Atlantic | 16.04 | 1,428 | 89.0 | 36.9 | 49.7 | 34.68 | 2,162 | 896 | 1.21 |
| **Census urban/rural classification[c]** | | | | | | | | | |
| Urban | 18.56 | 1,603 | 86.4 | 35.3 | 50.5 | 40.72 | 2,194 | 897 | 1.28 |
| Urbanized area | 17.30 | 1,483 | 85.7 | 34.8 | 50.4 | 38.12 | 2,203 | 893 | 1.30 |
| Urban cluster | 1.25 | 120 | 95.7 | 44.4 | 51.9 | 2.60 | 2,076 | 963 | 1.12 |
| Rural | 3.36 | 352 | 104.8 | 44.9 | 42.4 | 8.88 | 2,640 | 1,132 | 1.07 |
| **Climate region[d]** | | | | | | | | | |
| Very cold/Cold | 13.69 | 1,286 | 94.0 | 39.7 | 47.6 | 30.83 | 2,252 | 951 | 1.14 |
| Mixed-humid | 8.23 | 669 | 81.4 | 32.2 | 51.5 | 18.77 | 2,281 | 903 | 1.44 |
| Mixed-dry/Hot-dry | N | N | N | N | N | N | N | N | N |
| Hot-humid | N | N | N | N | N | N | N | N | N |
| Marine | N | N | N | N | N | N | N | N | N |
| **Housing unit type** | | | | | | | | | |
| Single-family detached | 11.23 | 1,355 | 120.7 | 45.6 | 47.9 | 31.13 | 2,773 | 1,049 | 1.10 |
| Single-family attached | 1.95 | 167 | 85.4 | 31.7 | 47.4 | 4.03 | 2,060 | 764 | 1.14 |
| Apartments in buildings with 2–4 units | 3.15 | 214 | 68.0 | 27.2 | 65.4 | 5.71 | 1,814 | 725 | 1.74 |
| Apartments in buildings with 5 or more units | 5.10 | 184 | 36.2 | 19.9 | 41.6 | 7.71 | 1,514 | 834 | 1.74 |
| Mobile homes | 0.50 | 36 | 72.1 | 31.4 | 66.7 | 1.02 | 2,054 | 894 | 1.90 |

Source:
(1) EIA, Table CE1.2 Summary annual household site consumption and expenditures in the Northeast – totals and intensities, 2020.

# Energy Expenditure Data for the Middle Atlantic and Northeast Regions



| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Ownership of housing unit** | | | | | | | | | |
| Owned | 13.77 | 1,526 | 110.8 | 43.0 | 47.9 | 36.22 | 2,631 | 1,021 | 1.14 |
| Single-family | 11.89 | 1,402 | 117.9 | 45.3 | 47.3 | 32.28 | 2,715 | 1,042 | 1.09 |
| Apartments | 1.50 | 96 | 64.0 | 26.7 | 54.6 | 3.16 | 2,104 | 878 | 1.80 |
| Mobile homes | 0.38 | 28 | 74.1 | 31.8 | 63.9 | 0.79 | 2,080 | 894 | 1.79 |
| Rented[e] | 8.15 | 430 | 52.7 | 24.2 | 52.5 | 13.38 | 1,641 | 753 | 1.63 |
| Single-family | 1.29 | 120 | 92.9 | 30.2 | 55.8 | 2.88 | 2,233 | 725 | 1.34 |
| Apartments | 6.74 | 302 | 44.8 | 22.3 | 50.8 | 10.26 | 1,522 | 759 | 1.73 |
| Mobile homes | 0.12 | 8 | 65.6 | 29.8 | 79.0 | 0.24 | 1,971 | 894 | 2.37 |
| **Year of construction** | | | | | | | | | |
| Before 1950 | 7.15 | 668 | 93.5 | 40.1 | 54.6 | 16.20 | 2,266 | 973 | 1.32 |
| 1950 to 1959 | 3.02 | 291 | 96.5 | 39.7 | 53.8 | 7.32 | 2,422 | 996 | 1.35 |
| 1960 to 1969 | 2.56 | 231 | 90.3 | 37.4 | 51.1 | 5.93 | 2,315 | 960 | 1.31 |
| 1970 to 1979 | 2.62 | 217 | 83.1 | 34.2 | 48.5 | 5.59 | 2,134 | 878 | 1.25 |
| 1980 to 1989 | 2.20 | 176 | 79.7 | 33.6 | 43.5 | 4.79 | 2,174 | 916 | 1.19 |
| 1990 to 1999 | 1.80 | 160 | 88.8 | 32.8 | 42.2 | 4.07 | 2,262 | 836 | 1.07 |
| 2000 to 2009 | 1.58 | 145 | 91.8 | 34.7 | 40.3 | 3.76 | 2,385 | 901 | 1.05 |
| 2010 to 2015 | 0.56 | 36 | 64.6 | 27.0 | 34.5 | 1.07 | 1,893 | 793 | 1.01 |
| 2016 to 2020 | 0.43 | 31 | 71.7 | 28.9 | 33.7 | 0.88 | 2,049 | 825 | 0.96 |
| **Total square footage[f]** | | | | | | | | | |
| Less than 1,000 | 6.04 | 273 | 45.2 | 23.6 | 61.8 | 9.33 | 1,545 | 807 | 2.11 |
| 1,000 to 1,499 | 4.39 | 319 | 72.7 | 30.1 | 61.0 | 8.65 | 1,970 | 816 | 1.65 |

Source:
(1) EIA, Table CE1.2 Summary annual household site consumption and expenditures in the Northeast – totals and intensities, 2020.

# Energy Expenditure Data for the Middle Atlantic and Northeast Regions



**Table CE1.2 Summary annual household site consumption and expenditures in the Northeast—totals and intensities, 2020**

| | Number of housing units (million) | Site energy consumption[a] | | | | Energy expenditures[a] | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Northeast[b] | Total (trillion Btu) | Per household (million Btu) | Per household member (million Btu) | Per square foot (thousand Btu) | Total (billion dollars) | Per household (dollars) | Per household member (dollars) | Per square foot (dollars) |
| All homes | 21.92 | 1,956 | 89.2 | 36.8 | 48.8 | 49.60 | 2,263 | 932 | 1.24 |
| 1,500 to 1,999 | 3.56 | 351 | 98.6 | 37.9 | 57.4 | 8.29 | 2,330 | 896 | 1.36 |
| 2,000 to 2,499 | 2.71 | 291 | 107.3 | 40.9 | 48.1 | 6.80 | 2,509 | 956 | 1.12 |
| 2,500 to 2,999 | 1.90 | 230 | 121.4 | 43.9 | 44.9 | 5.23 | 2,753 | 995 | 1.02 |
| 3,000 or more | 3.33 | 492 | 147.8 | 52.1 | 37.5 | 11.31 | 3,400 | 1,197 | 0.86 |
| Number of household members | | | | | | | | | |
| 1 member | 6.02 | 364 | 60.4 | 60.4 | 45.1 | 9.63 | 1,599 | 1,599 | 1.19 |
| 2 members | 7.96 | 713 | 89.6 | 44.8 | 46.3 | 17.76 | 2,232 | 1,116 | 1.15 |
| 3 members | 3.53 | 365 | 103.5 | 34.5 | 52.5 | 9.14 | 2,592 | 864 | 1.31 |
| 4 members | 2.76 | 311 | 112.8 | 28.2 | 51.8 | 7.85 | 2,846 | 711 | 1.31 |
| 5 members | 0.91 | 111 | 121.7 | 24.3 | 53.6 | 2.83 | 3,102 | 620 | 1.37 |
| 6 or more members | 0.75 | 92 | 123.0 | 17.9 | 60.1 | 2.40 | 3,212 | 468 | 1.57 |

Source:
(1) EIA, Table CE1.2 Summary annual household site consumption and expenditures in the Northeast – totals and intensities, 2020.

# Energy Expenditure Data for the Middle Atlantic and Northeast Regions



| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2020 annual household income** | | | | | | | | | |
| Less than $5,000 | 0.66 | 43 | 65.6 | 23.3 | 55.2 | 1.29 | 1,954 | 696 | 1.64 |
| $5,000 to $9,999 | 0.69 | 41 | 59.3 | 33.9 | 59.0 | 1.11 | 1,621 | 928 | 1.61 |
| $10,000 to $19,999 | 1.77 | 116 | 65.7 | 32.0 | 52.7 | 2.98 | 1,684 | 821 | 1.35 |
| $20,000 to $39,999 | 3.36 | 251 | 74.8 | 36.2 | 51.6 | 6.19 | 1,842 | 892 | 1.27 |
| $40,000 to $59,999 | 3.04 | 250 | 82.4 | 36.3 | 51.5 | 6.10 | 2,008 | 884 | 1.25 |
| $60,000 to $99,999 | 5.03 | 449 | 89.2 | 37.2 | 48.8 | 11.46 | 2,278 | 949 | 1.25 |
| $100,000 to $149,999 | 3.29 | 313 | 95.0 | 35.4 | 46.4 | 8.20 | 2,493 | 930 | 1.22 |
| $150,000 or more | 4.09 | 493 | 120.5 | 41.8 | 46.0 | 12.27 | 3,001 | 1,040 | 1.15 |
| **Payment method for energy bills** | | | | | | | | | |
| All paid by household | 18.00 | 1,767 | 98.1 | 39.0 | 48.8 | 43.03 | 2,390 | 949 | 1.19 |
| Some paid by household, some included in rent or condo fee | 2.54 | 123 | 48.5 | 22.8 | 50.3 | 4.38 | 1,726 | 812 | 1.79 |
| All included in rent or condo fee | 1.32 | 62 | 46.5 | 25.8 | 47.9 | 2.08 | 1,575 | 874 | 1.62 |
| Some other method | Q | Q | Q | Q | Q | Q | Q | Q | Q |
| **Main heating fuel** | | | | | | | | | |
| Natural gas | 12.24 | 1,217 | 99.5 | 40.0 | 54.6 | 26.77 | 2,187 | 879 | 1.20 |
| Electricity | 3.99 | 158 | 39.6 | 18.3 | 30.0 | 6.70 | 1,679 | 778 | 1.27 |
| Fuel oil or kerosene | 4.07 | 457 | 112.3 | 45.7 | 51.6 | 12.20 | 3,000 | 1,220 | 1.38 |
| Propane | 0.99 | 95 | 95.9 | 36.2 | 40.6 | 2.84 | 2,879 | 1,086 | 1.22 |
| Wood | 0.47 | 24 | 52.3 | 20.7 | 22.3 | 0.88 | 1,877 | 744 | 0.80 |
| Some other fuel[f] | Q | Q | Q | Q | Q | Q | Q | Q | Q |
| Does not use heating equipment | 0.12 | 3 | 23.8 | 10.8 | 24.2 | 0.15 | 1,223 | Q | 1.24 |

Source:
(1) EIA, Table CE1.2 Summary annual household site consumption and expenditures in the Northeast – totals and intensities, 2020.

# Energy Expenditure Data for the Middle Atlantic and Northeast Regions



**Table CE1.2 Summary annual household site consumption and expenditures in the Northeast—totals and intensities, 2020**

| | Number of housing units (million) | Site energy consumption[a] | | | | Energy expenditures[a] | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Northeast[b] | Total (trillion Btu) | Per household (million Btu) | Per household member (million Btu) | Per square foot (thousand Btu) | Total (billion dollars) | Per household (dollars) | Per household member (dollars) | Per square foot (dollars) |
| **All homes** | 21.92 | 1,956 | 89.2 | 36.8 | 48.8 | 49.60 | 2,263 | 932 | 1.24 |

Data source: U.S. Energy Information Administration, Office of Energy Demand and Integrated Statistics, Forms EIA-457A, D,E,F, & G of the *2020 Residential Energy Consumption Survey*

Notes: Because of rounding, data may not sum to totals. See RECS Terminology for definition of terms used in these tables.

Btu = British thermal units

[a] Consumption and expenditures for biomass (wood), coal, district steam, and solar thermal are excluded. Electricity consumption from on-site solar photovoltaic generation (that is, solar panels) is included.

[b] *Total Northeast* includes all primary occupied housing units in the Northeast Census Region. Vacant housing units, seasonal units, second homes, military houses, and group quarters are excluded.

[c] Housing units are classified using criteria created by the U.S. Census Bureau based on 2010 Census data. Urbanized areas are densely settled groupings of blocks or tracts with 50,000 or more people, while urban clusters have at least 2,500 but less than 50,000 people. All other areas are rural.

[d] The Building America program, sponsored by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE), created these climate regions. We combined climate regions for this publication. The subarctic region is included with data for *Very-cold/Cold* .

[e] *Rented* includes households that occupy their primary housing units without paying rent.

[f] *Total square footage* includes all basements, finished or conditioned (heated or cooled) areas of attics, and conditioned garage space that is attached to the home. Unconditioned and unfinished areas in attics and attached garages are excluded. The square footage of the home is based on respondent reports. Previous RECS cycles calculated square footage based on interviewer measurements. For households that did not report an exact square footage estimate, the square footage of the home was imputed based on a reported square footage range and/or characteristics of the home. See *2020 RECS Square Footage Methodology* for full details about data collection and processing.

[g] *Some other fuel* includes coal and district steam.

Q = Data withheld because either the relative standard error (RSE) was greater than 50% or fewer than 10 households in reporting sample.

N = No households in reporting sample.

Source:
(1) EIA, Table CE1.2 Summary annual household site consumption and expenditures in the Northeast – totals and intensities, 2020.

# Energy Expenditure Data for the Middle Atlantic and Northeast Regions



Data release date: March 2023
Revised data release date: March 2024

**Relative standard errors (RSEs) for Table CE1.2 Summary annual household site consumption and expenditures in the Northeast—totals and intensities, 2020**

| | RSEs for number of housing units | RSEs for site energy consumption[a] | | | | RSEs for energy expenditures[a] | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Northeast[b] | Total | Per household | Per household member | Per square foot | Total | Per household | Per household member | Per square foot |
| **All homes** | 0.00 | 0.78 | 0.78 | 0.93 | 0.84 | 0.88 | 0.88 | 1.13 | 0.99 |
| **Census division** | | | | | | | | | |
| New England | 0.00 | 1.34 | 1.34 | 1.61 | 1.44 | 1.25 | 1.25 | 1.63 | 1.32 |
| Middle Atlantic | 0.00 | 1.07 | 1.07 | 1.24 | 1.11 | 1.26 | 1.26 | 1.56 | 1.28 |
| **Census urban/rural classification[c]** | | | | | | | | | |
| Urban | 0.56 | 1.05 | 0.94 | 1.16 | 1.01 | 1.12 | 1.05 | 1.35 | 1.16 |
| Urbanized area | 0.59 | 1.21 | 1.08 | 1.24 | 1.09 | 1.35 | 1.16 | 1.44 | 1.25 |
| Urban cluster | 6.76 | 7.80 | 3.33 | 4.64 | 3.67 | 7.69 | 3.41 | 4.97 | 3.92 |
| Rural | 3.09 | 3.44 | 2.63 | 3.51 | 2.32 | 2.89 | 1.96 | 3.01 | 2.17 |
| **Climate region[d]** | | | | | | | | | |
| Very cold/Cold | 1.29 | 1.65 | 1.04 | 1.39 | 0.99 | 1.42 | 0.85 | 1.18 | 1.00 |
| Mixed-humid | 2.15 | 2.97 | 1.70 | 1.97 | 1.87 | 2.83 | 1.78 | 2.45 | 2.18 |
| Mixed-dry/Hot-dry | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Hot-humid | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Marine | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Source:
(1) EIA, Relative standard errors (RSEs) for Table CE1.2 Summary annual household site consumption and expenditures in the Northeast – totals and intensities, 2020.

# Energy Expenditure Data for the Middle Atlantic and Northeast Regions



| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Housing unit type** | | | | | | | | | |
| Single-family detached | 0.00 | 0.97 | 0.97 | 1.34 | 1.03 | 0.98 | 0.98 | 1.27 | 1.12 |
| Single-family attached | 0.00 | 2.68 | 2.68 | 3.96 | 3.61 | 2.58 | 2.58 | 3.84 | 3.19 |
| Apartments in buildings with 2–4 units | 0.00 | 3.64 | 3.64 | 4.72 | 3.88 | 3.30 | 3.30 | 4.13 | 3.86 |
| Apartments in buildings with 5 or more units | 0.00 | 2.22 | 2.22 | 2.61 | 2.33 | 2.81 | 2.81 | 3.28 | 2.94 |
| Mobile homes | 0.00 | 4.52 | 4.52 | 9.32 | 5.51 | 3.93 | 3.93 | 9.31 | 5.38 |
| **Ownership of housing unit** | | | | | | | | | |
| Owned | 1.01 | 1.31 | 0.94 | 1.20 | 1.08 | 1.49 | 0.98 | 1.25 | 1.28 |
| Single-family | 0.74 | 1.20 | 1.01 | 1.27 | 1.02 | 1.30 | 0.95 | 1.18 | 1.11 |
| Apartments | 8.09 | 11.39 | 7.15 | 6.40 | 7.01 | 10.89 | 6.83 | 6.45 | 6.60 |
| Mobile homes | 6.90 | 9.35 | 5.38 | 12.64 | 6.71 | 8.35 | 4.72 | 12.39 | 6.21 |
| Rented[e] | 1.70 | 3.28 | 2.35 | 2.39 | 1.93 | 2.75 | 1.84 | 2.06 | 1.80 |
| Single-family | 6.82 | 8.36 | 3.98 | 4.74 | 3.91 | 8.03 | 4.09 | 5.10 | 3.87 |
| Apartments | 1.80 | 3.26 | 2.49 | 2.76 | 2.38 | 2.98 | 2.09 | 2.51 | 2.33 |
| Mobile homes | 21.86 | 21.80 | 9.20 | 14.72 | 11.20 | 21.66 | 10.08 | 10.32 | 12.40 |
| **Year of construction** | | | | | | | | | |
| Before 1950 | 0.00 | 2.11 | 2.11 | 2.83 | 1.96 | 1.83 | 1.83 | 2.69 | 2.33 |
| 1950 to 1959 | 0.00 | 2.77 | 2.77 | 3.43 | 1.99 | 2.92 | 2.92 | 3.05 | 2.71 |
| 1960 to 1969 | 0.00 | 3.51 | 3.51 | 3.09 | 2.68 | 3.16 | 3.16 | 2.74 | 3.77 |
| 1970 to 1979 | 0.00 | 3.44 | 3.44 | 3.83 | 2.24 | 2.70 | 2.70 | 3.49 | 2.49 |
| 1980 to 1989 | 0.00 | 3.30 | 3.30 | 4.57 | 2.81 | 3.05 | 3.05 | 4.06 | 3.34 |
| 1990 to 1999 | 0.00 | 4.31 | 4.31 | 4.70 | 3.64 | 3.28 | 3.28 | 4.32 | 3.37 |
| 2000 to 2009 | 0.00 | 4.60 | 4.60 | 4.43 | 3.36 | 4.39 | 4.39 | 4.10 | 3.39 |
| 2010 to 2015 | 7.00 | 8.72 | 7.33 | 6.87 | 4.54 | 7.82 | 4.93 | 5.50 | 5.69 |
| 2016 to 2020 | 9.20 | 14.21 | 10.72 | 11.37 | 6.61 | 12.27 | 8.09 | 8.65 | 5.81 |
| **Total square footage[f]** | | | | | | | | | |
| Less than 1,000 | 2.12 | 3.40 | 2.35 | 2.61 | 2.23 | 3.17 | 2.23 | 2.76 | 2.38 |
| 1,000 to 1,499 | 3.75 | 4.38 | 2.39 | 2.93 | 2.39 | 4.06 | 2.21 | 2.60 | 2.29 |
| 1,500 to 1,999 | 3.87 | 3.85 | 1.75 | 2.91 | 1.76 | 3.67 | 1.75 | 2.84 | 1.74 |

Source:
(1) EIA, Relative standard errors (RSEs) for Table CE1.2 Summary annual household site consumption and expenditures in the Northeast – totals and intensities, 2020.

# Energy Expenditure Data for the Middle Atlantic and Northeast Regions

**Relative standard errors (RSEs) for Table CE1.2 Summary annual household site consumption and expenditures in the Northeast—totals and intensities, 2020**

| | RSEs for number of housing units | RSEs for site energy consumption[a] | | | | RSEs for energy expenditures[a] | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Northeast[b] | Total | Per household | Per household member | Per square foot | Total | Per household | Per household member | Per square foot |
| All homes | 0.00 | 0.78 | 0.78 | 0.93 | 0.84 | 0.88 | 0.88 | 1.13 | 0.99 |
| 2,000 to 2,499 | 4.21 | 4.55 | 1.86 | 3.05 | 1.81 | 4.35 | 1.72 | 2.69 | 1.67 |
| 2,500 to 2,999 | 5.59 | 5.82 | 2.31 | 3.53 | 2.38 | 5.84 | 2.20 | 2.85 | 2.26 |
| 3,000 or more | 3.86 | 4.24 | 2.47 | 3.17 | 2.05 | 3.92 | 1.88 | 2.50 | 1.62 |
| **Number of household members** | | | | | | | | | |
| 1 member | 2.99 | 4.01 | 2.39 | 2.39 | 1.54 | 4.03 | 2.05 | 2.05 | 2.40 |
| 2 members | 2.54 | 3.11 | 2.28 | 2.28 | 1.73 | 2.86 | 1.66 | 1.66 | 1.63 |
| 3 members | 3.66 | 4.03 | 2.20 | 2.20 | 2.63 | 4.20 | 2.05 | 2.05 | 2.82 |
| 4 members | 5.11 | 5.67 | 2.64 | 2.64 | 2.19 | 5.47 | 2.55 | 2.55 | 2.22 |
| 5 members | 8.00 | 8.43 | 3.92 | 3.92 | 3.86 | 8.11 | 3.99 | 3.99 | 4.15 |
| 6 or more members | 10.62 | 11.27 | 5.75 | 5.91 | 4.80 | 10.89 | 5.13 | 5.32 | 5.01 |

Source:
(1) EIA, Relative standard errors (RSEs) for Table CE1.2 Summary annual household site consumption and expenditures in the Northeast – totals and intensities, 2020.

# Energy Expenditure Data for the Middle Atlantic and Northeast Regions



| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **2020 annual household income** | | | | | | | | | |
| Less than $5,000 | 12.39 | 14.71 | 8.67 | 8.52 | 9.02 | 13.97 | 7.89 | 6.82 | 7.52 |
| $5,000 to $9,999 | 10.11 | 13.73 | 8.80 | 9.96 | 7.67 | 12.34 | 5.98 | 7.60 | 7.65 |
| $10,000 to $19,999 | 7.27 | 7.84 | 4.54 | 6.28 | 3.73 | 8.01 | 3.38 | 5.35 | 3.92 |
| $20,000 to $39,999 | 5.04 | 5.20 | 2.74 | 3.18 | 2.78 | 5.46 | 2.57 | 2.93 | 3.06 |
| $40,000 to $59,999 | 4.76 | 5.26 | 2.95 | 3.52 | 2.80 | 4.86 | 2.40 | 3.14 | 2.99 |
| $60,000 to $99,999 | 3.55 | 4.08 | 1.86 | 2.46 | 1.85 | 3.79 | 1.66 | 2.32 | 2.16 |
| $100,000 to $149,999 | 3.99 | 4.43 | 2.30 | 2.41 | 2.27 | 4.88 | 2.60 | 2.74 | 3.18 |
| $150,000 or more | 3.22 | 3.91 | 2.84 | 2.82 | 2.02 | 3.72 | 2.24 | 2.35 | 1.97 |
| **Payment method for energy bills** | | | | | | | | | |
| All paid by household | 0.77 | 0.99 | 0.94 | 1.02 | 0.91 | 1.01 | 0.88 | 1.07 | 1.06 |
| Some paid by household, some included in rent or condo fee | 5.15 | 6.56 | 3.51 | 4.67 | 3.16 | 6.59 | 4.16 | 5.34 | 4.00 |
| All included in rent or condo fee | 7.09 | 8.93 | 5.91 | 5.30 | 5.13 | 9.15 | 5.37 | 6.94 | 7.91 |
| Some other method | 37.55 | 42.42 | 27.13 | 27.25 | 6.19 | 37.13 | 14.68 | 14.75 | 18.61 |
| **Main heating fuel** | | | | | | | | | |
| Natural gas | 1.51 | 1.65 | 1.29 | 1.56 | 1.26 | 1.80 | 1.36 | 1.68 | 1.47 |
| Electricity | 4.25 | 5.88 | 3.54 | 3.07 | 2.74 | 5.41 | 2.79 | 2.78 | 2.52 |
| Fuel oil or kerosene | 3.90 | 3.74 | 1.67 | 2.54 | 1.86 | 3.67 | 1.55 | 2.38 | 2.04 |
| Propane | 8.29 | 9.57 | 3.53 | 6.16 | 3.64 | 8.82 | 3.51 | 5.83 | 3.57 |
| Wood | 10.55 | 12.44 | 5.45 | 7.43 | 7.39 | 11.84 | 5.21 | 6.56 | 8.04 |
| Some other fuel[a] | 39.10 | 43.99 | 27.75 | 29.54 | 35.15 | 40.17 | 15.35 | 18.11 | 31.11 |
| Does not use heating equipment | 27.39 | 28.87 | 14.18 | 33.14 | 19.49 | 31.50 | 15.20 | 51.95 | 21.16 |

Source:
(1) EIA, Relative standard errors (RSEs) for Table CE1.2 Summary annual household site consumption and expenditures in the Northeast – totals and intensities, 2020.

# Energy Expenditure Data for the Middle Atlantic and Northeast Regions



**Relative standard errors (RSEs) for Table CE1.2 Summary annual household site consumption and expenditures in the Northeast—totals and intensities, 2020**

| | RSEs for number of housing units | RSEs for site energy consumption[a] | | | | RSEs for energy expenditures[a] | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total Northeast[b] | Total | Per household | Per household member | Per square foot | Total | Per household | Per household member | Per square foot |
| All homes | 0.00 | 0.78 | 0.78 | 0.93 | 0.84 | 0.88 | 0.88 | 1.13 | 0.99 |

Data source: U.S. Energy Information Administration, Office of Energy Demand and Integrated Statistics, Forms EIA-457A, D, E, F, & G of the *2020 Residential Energy Consumption Survey*

Notes: See RECS Terminology for definition of terms used in these tables.

[a] Consumption and expenditures for biomass (wood), coal, district steam, and solar thermal are excluded. Electricity consumption from on-site solar photovoltaic generation (that is, solar panels) is included.

[b] *Total Northeast* includes all primary occupied housing units in the Northeast Census region. Vacant housing units, seasonal units, second homes, military houses, and group quarters are excluded.

[c] Housing units are classified using criteria created by the U.S. Census Bureau based on 2010 Census data. Urbanized areas are densely settled groupings of blocks or tracts with 50,000 or more people, while urban clusters have at least 2,500 but less than 50,000 people. All other areas are rural.

[d] The Building America program, sponsored by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE), created these climate regions. We combined climate regions for this publication. The subarctic region is included with data for *Very-cold/Cold* .

[e] *Rented* includes households that occupy their primary housing units without paying rent.

[f] *Total square footage* includes all basements, finished or conditioned (heated or cooled) areas of attics, and conditioned garage space that is attached to the home. Unconditioned and unfinished areas in attics and attached garages are excluded. The square footage of the home is based on respondent reports. Previous RECS cycles calculated square footage based on interviewer measurements. For households that did not report an exact square footage estimate, the square footage of the home was imputed based on a reported square footage range and/or characteristics of the home. See *2020 RECS Square Footage Methodology* for full details about data collection and processing.

[g] *Some other fuel* includes coal and district steam.

Source:

(1) EIA, Relative standard errors (RSEs) for Table CE1.2 Summary annual household site consumption and expenditures in the Northeast – totals and intensities, 2020.

Exhibit OPC (A)-9
Formal Case No. 1180
Direct Testimony of David E. Dismukes

# Typical Bill Comparison at Different Usage Levels

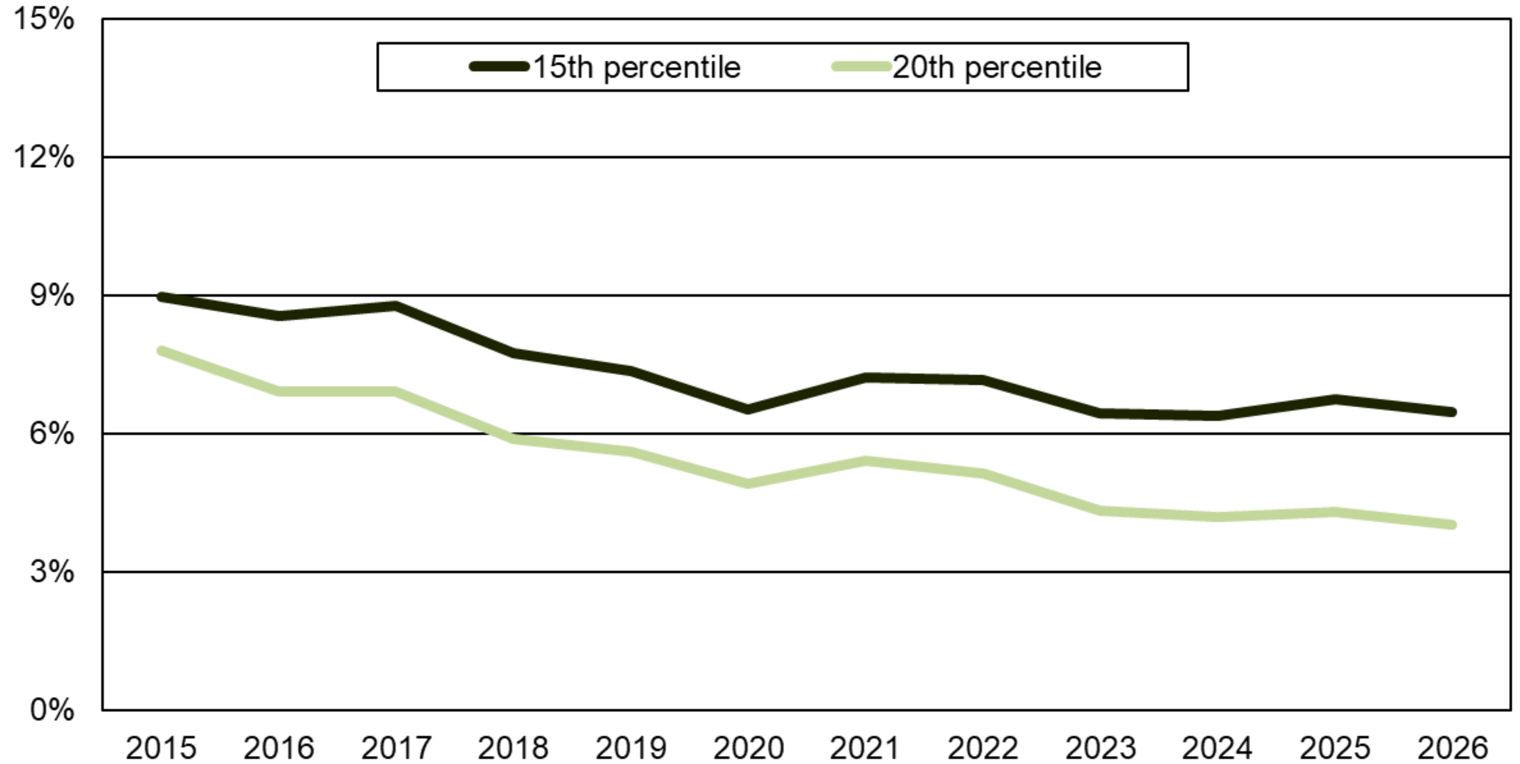
| | Customer 1 Hypothetical Typical User | | | | Customer 2 One-Third Less Than Typical User | | | | Customer 3 One-Third Greater Than System Average | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Average Usage per Month (therm) | 52 | | | | 35 | | | | 69 | | | |
| | | Rate | | Bill Amount | | Rate | | Bill Amount | | Rate | | Bill Amount |
| **Utility Charges - Current Rates** | | | | | | | | | | | | |
| Monthly Customer Charge | $ | 16.55 | $ | 16.55 | $ | 16.55 | $ | 16.55 | $ | 16.55 | $ | 16.55 |
| Distribution Charge | $ | 0.563800 | $ | 29.32 | $ | 0.563800 | $ | 19.55 | $ | 0.563800 | $ | 39.09 |
| ROW Fee | $ | 0.034900 | $ | 1.81 | $ | 0.034900 | $ | 1.21 | $ | 0.034900 | $ | 2.42 |
| Delivery Tax | $ | 0.070700 | $ | 3.68 | $ | 0.070700 | $ | 2.45 | $ | 0.070700 | $ | 4.90 |
| SETF & EATF | $ | 0.083486 | $ | 4.34 | $ | 0.083486 | $ | 2.89 | $ | 0.083486 | $ | 5.79 |
| Purchased Gas Charge | $ | 0.601800 | $ | 31.29 | $ | 0.601800 | $ | 20.86 | $ | 0.601800 | $ | 41.72 |
| **Average Monthly Utility Bill Under Existing Rates** | | | **$** | **86.99** | | | **$** | **63.51** | | | **$** | **110.47** |
| **Utility Charges - Proposed Rates** | | | | | | | | | | | | |
| Monthly Customer Charge | $ | 20.70 | $ | 20.70 | $ | 20.70 | $ | 20.70 | $ | 20.70 | $ | 20.70 |
| Distribution Charge | $ | 0.777800 | $ | 40.45 | $ | 0.777800 | $ | 26.96 | $ | 0.777800 | $ | 53.93 |
| ROW Fee | $ | 0.034900 | $ | 1.81 | $ | 0.034900 | $ | 1.21 | $ | 0.034900 | $ | 2.42 |
| Delivery Tax | $ | 0.070700 | $ | 3.68 | $ | 0.070700 | $ | 2.45 | $ | 0.070700 | $ | 4.90 |
| SETF & EATF | $ | 0.083486 | $ | 4.34 | $ | 0.083486 | $ | 2.89 | $ | 0.083486 | $ | 5.79 |
| Purchased Gas Charge | $ | 0.601800 | $ | 31.29 | $ | 0.601800 | $ | 20.86 | $ | 0.601800 | $ | 41.72 |
| **Average Monthly Utility Bill Under Proposed Rates** | | | **$** | **102.27** | | | **$** | **75.08** | | | **$** | **129.46** |
| **Percent Increase from Existing Rates to Proposed Rates** | | | | **17.6%** | | | | **18.2%** | | | | **17.2%** |

Note:
(1) This exhibit displays bill impacts for the Residential Heating and Cooling class.
Source:
(1) Direct Testimony of Andrew Lawson, Exhibit WG (O)-2.

Exhibit OPC (A)-10
Formal Case No. 1180
Direct Testimony of David E. Dismukes

# Energy Affordability Index (no rent)

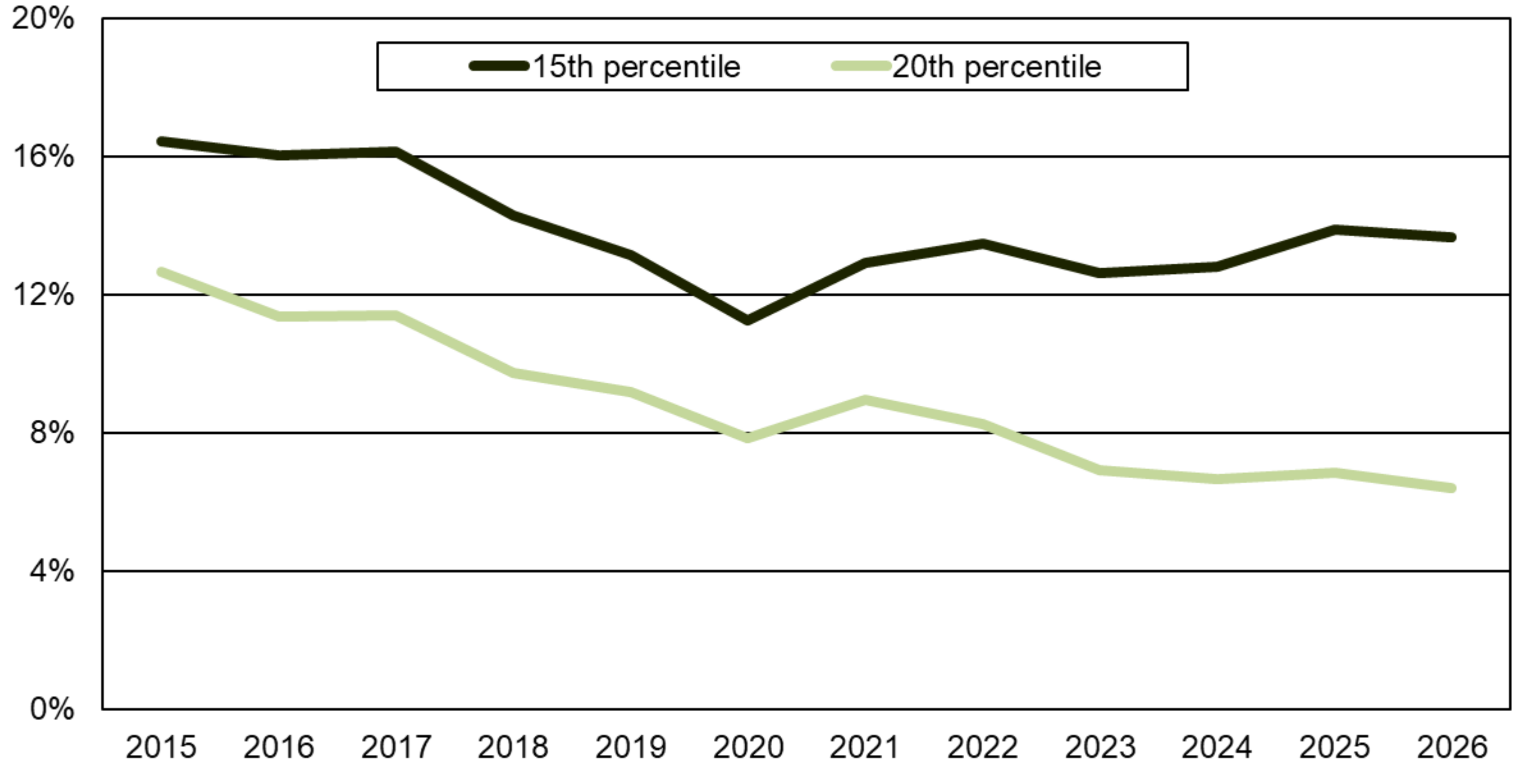





Source:
(1) U.S. Census, ACS 5-Year Estimates Subject Tables, 2015-2022.
(2) EIA, Residential Consumption Survey.
(3) PEPCO and WGL Tariffs.

# Energy Affordability Index (with rent)

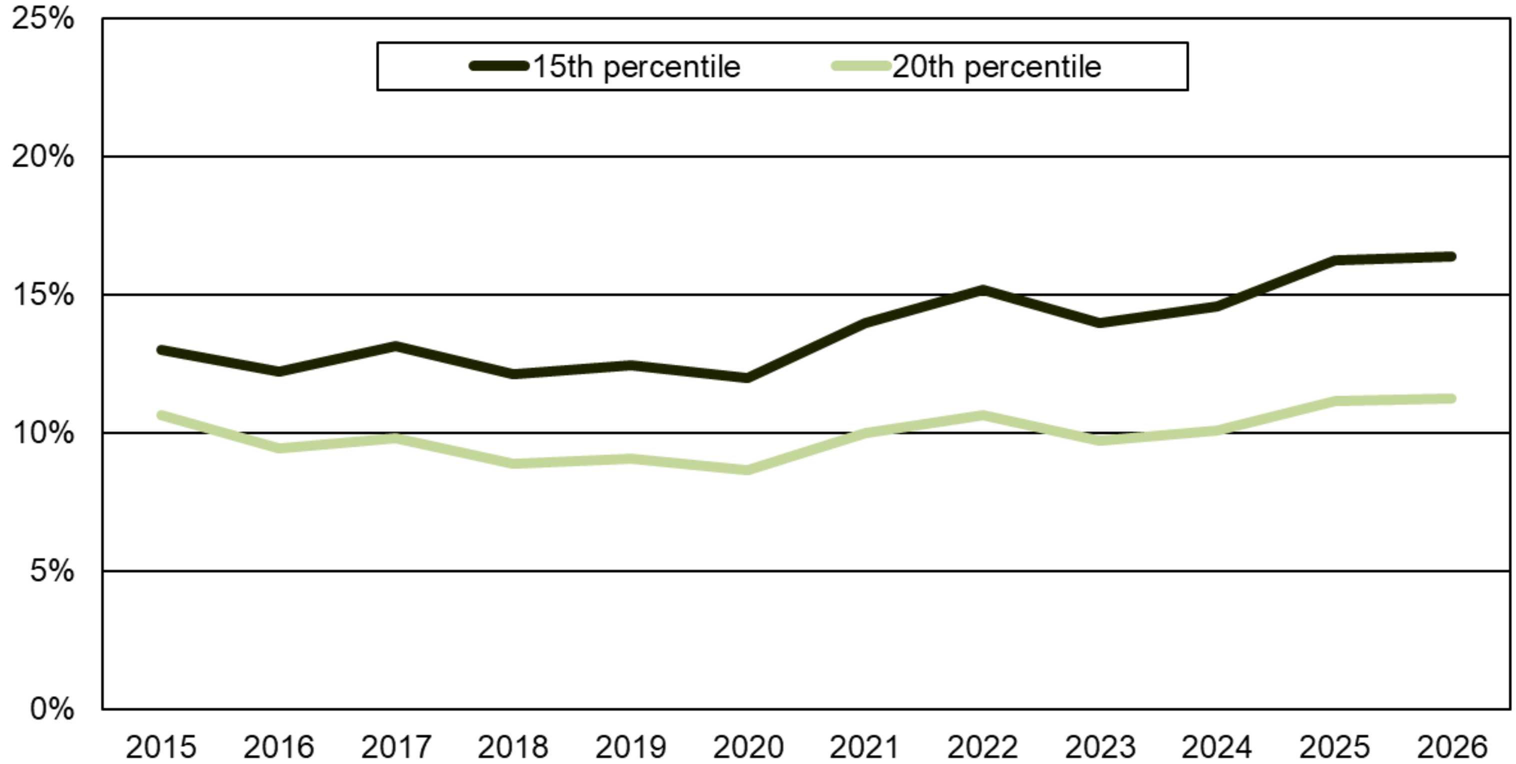





Source:
(1) U.S. Census, ACS 5-Year Estimates Subject Tables, 2015-2022.
(2) EIA, Residential Consumption Survey.
(3) PEPCO and WGL Tariffs.
(4) ACS, 5-Year Estimates Data Profiles, Housing Characteristics, 2015-2022.

# Energy Affordability Index (no rent or transfer payments)






Source:
(1) U.S. Census, ACS 5-Year Estimates Subject Tables, 2015-2022.
(2) EIA, Residential Consumption Survey.
(3) PEPCO and WGL Tariffs.
(4) Congressional Budget Office, Distribution of Household Income Reports.

Exhibit OPC (A)-11
Formal Case No. 1180
Direct Testimony of David E. Dismukes

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-2A

**Q.** **Rate Proposal**. Please respond to the following:

a. Provide all analyses conducted by or for the Company which demonstrates the impact the Company's rate proposals will have on customers' bills.

b. Provide all analyses prepared by or for the Company that compares its present or proposed rates to other gas distribution companies.

c. Provide all analyses prepared by or for the Company that examine the impacts that its rate proposal will have on customer affordability.

d. For each rate class, provide the percentage of an average customer bill (a) collected via surcharges, riders, and tracker mechanisms and (b) via fixed versus variable charges.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** a. Please see Exhibit WG (O)-2.

b. The witness is not aware of any such studies in the Company's possession; however, service rates are publicly available on most utility websites.

c. The witness is not aware of any such studies in the Company's possession.

d. See the response to OPC Data Request 1-2A (a).

SPONSOR: Andrew Lawson
Manager – Regulatory Affairs

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-9

**Q.** **Customer Charge.** Please respond to the following:

a. Explain how the Company's proposed customer charges comport with regulatory ratemaking policies of gradualism and rate continuity.

b. Provide for the last three years all comparisons, analyses, and studies in the Company's possession, custody, or control that compare the customer charges of regulated gas companies.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** a. Please see the Direct Testimony of Company Witness Lawson, Page 11, Line 16 through Page 13, Line 9.

b. The witness is not aware of any such studies in the Company's possession; however, utility rates are publicly available information that can be easily found on various utility websites.

SPONSOR: Andrew Lawson
Manager – Regulatory Affairs

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-16

**Q.** **Customer Charge**. Provide a summary of the customer charge and volume-based distribution charge by rate class over the last six years for the Company. Include the effective date for each change in the customer charge rate.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** Please see the attachment titled OPC Data Request 1-16.

SPONSOR: Andrew Lawson
Manager – Regulatory Affairs

Washington Gas-DC
Summary of Customer Charges
2019-2024

| Line No | Class | Customer Charge Amount | Customer Charge Effective Date | Customer Charge Case No. | Line No |
|---|---|---|---|---|---|
| 1 | RES HTG - SYS LEV 1 | $ 13.10 | Apr-2017 | FC1137 | 1 |
| 2 | RES HTG - SYS LEV 1 | $ 15.05 | Apr-2021 | FC1162 | 2 |
| 3 | RES HTG - SYS LEV 1 | $ 16.55 | Jan-2024 | FC1169 | 3 |
| 4 | RES NON-HTG NON-CLG - IND. MTR. APTS | $ 9.50 | Apr-2017 | FC1137 | 4 |
| 5 | RES NON-HTG NON-CLG - IND. MTR. APTS | $ 10.90 | Apr-2021 | FC1162 | 5 |
| 6 | RES NON-HTG NON-CLG - IND. MTR. APTS | $ 12.00 | Jan-2024 | FC1169 | 6 |
| 7 | RES NON-HTG NON-CLG - OTH | $ 10.70 | Apr-2017 | FC1137 | 7 |
| 8 | RES NON-HTG NON-CLG - OTH | $ 12.30 | Apr-2021 | FC1162 | 8 |
| 9 | RES NON-HTG NON-CLG - OTH | $ 13.55 | Jan-2024 | FC1169 | 9 |
| 10 | C&I HTG - SYS LEV 1 | $ 22.70 | Apr-2017 | FC1137 | 10 |
| 11 | C&I HTG - SYS LEV 1 | $ 27.20 | Apr-2021 | FC1162 | 11 |
| 12 | C&I HTG - SYS LEV 1 | $ 29.90 | Jan-2024 | FC1169 | 12 |
| 13 | C&I HTG - SYS LEV 2 | $ 55.80 | Apr-2017 | FC1137 | 13 |
| 14 | C&I HTG - SYS LEV 2 | $ 63.70 | Apr-2021 | FC1162 | 14 |
| 15 | C&I HTG - SYS LEV 2 | $ 70.05 | Jan-2024 | FC1169 | 15 |
| 16 | C&I NON-HTG NON-CLG | $ 22.70 | Apr-2017 | FC1137 | 16 |
| 17 | C&I NON-HTG NON-CLG | $ 25.90 | Apr-2021 | FC1162 | 17 |
| 18 | C&I NON-HTG NON-CLG | $ 28.50 | Jan-2024 | FC1169 | 18 |
| 19 | GMA HTG - SYS LEV 1 | $ 22.70 | Apr-2017 | FC1137 | 19 |
| 20 | GMA HTG - SYS LEV 1 | $ 25.90 | Apr-2021 | FC1162 | 20 |
| 21 | GMA HTG - SYS LEV 1 | $ 28.50 | Jan-2024 | FC1169 | 21 |
| 22 | GMA HTG - SYS LEV 2 | $ 55.80 | Apr-2017 | FC1137 | 22 |
| 23 | GMA HTG - SYS LEV 2 | $ 63.70 | Apr-2021 | FC1162 | 23 |
| 24 | GMA HTG - SYS LEV 2 | $ 70.05 | Jan-2024 | FC1169 | 24 |
| 25 | GMA NON-HTG NON-CLG | $ 22.70 | Apr-2017 | FC1137 | 25 |
| 26 | GMA NON-HTG NON-CLG | $ 25.90 | Apr-2021 | FC1162 | 26 |
| 27 | GMA NON-HTG NON-CLG | $ 28.50 | Jan-2024 | FC1169 | 27 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| RES HTG - SYS LEV 1 | Jan-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Feb-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Mar-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Apr-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | May-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Jun-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Jul-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Aug-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Sep-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Oct-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Nov-2019 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Dec-2019 | 13.10 | 0.3678 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jan-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Feb-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Mar-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Apr-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | May-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jun-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jul-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Aug-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Sep-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Oct-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Nov-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Dec-2019 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Jan-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Feb-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Mar-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Apr-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | May-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Jun-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Jul-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Aug-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Sep-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Oct-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Nov-2019 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Dec-2019 | 10.70 | 0.3663 |
| C&I HTG - SYS LEV 1 | Jan-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Feb-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Mar-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Apr-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | May-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Jun-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Jul-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Aug-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Sep-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Oct-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Nov-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Dec-2019 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 2 | Jan-2019 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Feb-2019 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Mar-2019 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Apr-2019 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | May-2019 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Jun-2019 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Jul-2019 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Aug-2019 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Sep-2019 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Oct-2019 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Nov-2019 | 55.80 | 0.3511 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| C&I HTG - SYS LEV 2 | Dec-2019 | 55.80 | 0.3511 |
| C&I NON-HTG NON-CLG | Jan-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Feb-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Mar-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Apr-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | May-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Jun-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Jul-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Aug-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Sep-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Oct-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Nov-2019 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Dec-2019 | 22.70 | 0.3498 |
| GMA HTG - SYS LEV 1 | Jan-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Feb-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Mar-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Apr-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | May-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Jun-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Jul-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Aug-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Sep-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Oct-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Nov-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Dec-2019 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 2 | Jan-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Feb-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Mar-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Apr-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | May-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Jun-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Jul-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Aug-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Sep-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Oct-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Nov-2019 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Dec-2019 | 55.80 | 0.3558 |
| GMA NON-HTG NON-CLG | Jan-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Feb-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Mar-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Apr-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | May-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Jun-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Jul-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Aug-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Sep-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Oct-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Nov-2019 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Dec-2019 | 22.70 | 0.3528 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| RES HTG - SYS LEV 1 | Jan-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Feb-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Mar-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Apr-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | May-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Jun-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Jul-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Aug-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Sep-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Oct-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Nov-2020 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Dec-2020 | 13.10 | 0.3678 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jan-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Feb-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Mar-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Apr-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | May-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jun-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jul-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Aug-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Sep-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Oct-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Nov-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Dec-2020 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Jan-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Feb-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Mar-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Apr-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | May-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Jun-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Jul-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Aug-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Sep-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Oct-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Nov-2020 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Dec-2020 | 10.70 | 0.3663 |
| C&I HTG - SYS LEV 1 | Jan-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Feb-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Mar-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Apr-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | May-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Jun-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Jul-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Aug-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Sep-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Oct-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Nov-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Dec-2020 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 2 | Jan-2020 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Feb-2020 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Mar-2020 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Apr-2020 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | May-2020 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Jun-2020 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Jul-2020 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Aug-2020 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Sep-2020 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Oct-2020 | 55.80 | 0.3511 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| C&I HTG - SYS LEV 2 | Nov-2020 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Dec-2020 | 55.80 | 0.3511 |
| C&I NON-HTG NON-CLG | Jan-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Feb-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Mar-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Apr-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | May-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Jun-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Jul-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Aug-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Sep-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Oct-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Nov-2020 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Dec-2020 | 22.70 | 0.3498 |
| GMA HTG - SYS LEV 1 | Jan-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Feb-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Mar-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Apr-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | May-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Jun-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Jul-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Aug-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Sep-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Oct-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Nov-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Dec-2020 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 2 | Jan-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Feb-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Mar-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Apr-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | May-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Jun-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Jul-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Aug-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Sep-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Oct-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Nov-2020 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Dec-2020 | 55.80 | 0.3558 |
| GMA NON-HTG NON-CLG | Jan-2020 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Feb-2020 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Mar-2020 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Apr-2020 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | May-2020 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Jun-2020 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Jul-2020 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Aug-2020 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Sep-2020 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Oct-2020 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Nov-2020 | 22.70 | 0.0700 |
| GMA NON-HTG NON-CLG | Dec-2020 | 22.70 | 0.3528 |

CUBE: tm1serv:PGC_Summary

PGC_Area DC

| System Charge | DC Distribution Charge |
|---|---|

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| RES HTG - SYS LEV 1 | Jan-2021 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Feb-2021 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Mar-2021 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | Apr-2021 | 13.10 | 0.3678 |
| RES HTG - SYS LEV 1 | May-2021 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Jun-2021 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Jul-2021 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Aug-2021 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Sep-2021 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Oct-2021 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Nov-2021 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Dec-2021 | 15.05 | 0.4542 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jan-2021 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Feb-2021 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Mar-2021 | 9.50 | 0.3663 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Apr-2021 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | May-2021 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jun-2021 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jul-2021 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Aug-2021 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Sep-2021 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Oct-2021 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Nov-2021 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Dec-2021 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - OTH | Jan-2021 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Feb-2021 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Mar-2021 | 10.70 | 0.3663 |
| RES NON-HTG NON-CLG - OTH | Apr-2021 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | May-2021 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Jun-2021 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Jul-2021 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Aug-2021 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Sep-2021 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Oct-2021 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Nov-2021 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Dec-2021 | 12.30 | 0.4511 |
| C&I HTG - SYS LEV 1 | Jan-2021 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Feb-2021 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Mar-2021 | 22.70 | 0.3459 |
| C&I HTG - SYS LEV 1 | Apr-2021 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | May-2021 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Jun-2021 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Jul-2021 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Aug-2021 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Sep-2021 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Oct-2021 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Nov-2021 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Dec-2021 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 2 | Jan-2021 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Feb-2021 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Mar-2021 | 55.80 | 0.3511 |
| C&I HTG - SYS LEV 2 | Apr-2021 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | May-2021 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Jun-2021 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Jul-2021 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Aug-2021 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Sep-2021 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Oct-2021 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Nov-2021 | 63.70 | 0.4006 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| C&I HTG - SYS LEV 2 | Dec-2021 | 63.70 | 0.4006 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| C&I NON-HTG NON-CLG | Jan-2021 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Feb-2021 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Mar-2021 | 22.70 | 0.3498 |
| C&I NON-HTG NON-CLG | Apr-2021 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | May-2021 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Jun-2021 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Jul-2021 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Aug-2021 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Sep-2021 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Oct-2021 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Nov-2021 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Dec-2021 | 25.90 | 0.3993 |
| GMA HTG - SYS LEV 1 | Jan-2021 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Feb-2021 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Mar-2021 | 22.70 | 0.3517 |
| GMA HTG - SYS LEV 1 | Apr-2021 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | May-2021 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Jun-2021 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Jul-2021 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Aug-2021 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Sep-2021 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Oct-2021 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Nov-2021 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Dec-2021 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 2 | Jan-2021 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Feb-2021 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Mar-2021 | 55.80 | 0.3558 |
| GMA HTG - SYS LEV 2 | Apr-2021 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | May-2021 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Jun-2021 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Jul-2021 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Aug-2021 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Sep-2021 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Oct-2021 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Nov-2021 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Dec-2021 | 63.70 | 0.4060 |
| GMA NON-HTG NON-CLG | Jan-2021 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Feb-2021 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Mar-2021 | 22.70 | 0.3528 |
| GMA NON-HTG NON-CLG | Apr-2021 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | May-2021 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Jun-2021 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Jul-2021 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Aug-2021 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Sep-2021 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Oct-2021 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Nov-2021 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Dec-2021 | 25.90 | 0.4027 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| RES HTG - SYS LEV 1 | Jan-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Feb-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Mar-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Apr-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | May-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Jun-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Jul-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Aug-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Sep-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Oct-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Nov-2022 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Dec-2022 | 15.05 | 0.4542 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jan-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Feb-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Mar-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Apr-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | May-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jun-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jul-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Aug-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Sep-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Oct-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Nov-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Dec-2022 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - OTH | Jan-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Feb-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Mar-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Apr-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | May-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Jun-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Jul-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Aug-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Sep-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Oct-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Nov-2022 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Dec-2022 | 12.30 | 0.4511 |
| C&I HTG - SYS LEV 1 | Jan-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Feb-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Mar-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Apr-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | May-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Jun-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Jul-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Aug-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Sep-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Oct-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Nov-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Dec-2022 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 2 | Jan-2022 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Feb-2022 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Mar-2022 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Apr-2022 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | May-2022 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Jun-2022 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Jul-2022 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Aug-2022 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Sep-2022 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Oct-2022 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Nov-2022 | 63.70 | 0.4006 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| C&I HTG - SYS LEV 2 | Dec-2022 | 63.70 | 0.4006 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| C&I NON-HTG NON-CLG | Jan-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Feb-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Mar-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Apr-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | May-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Jun-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Jul-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Aug-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Sep-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Oct-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Nov-2022 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Dec-2022 | 25.90 | 0.3993 |
| GMA HTG - SYS LEV 1 | Jan-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Feb-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Mar-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Apr-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | May-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Jun-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Jul-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Aug-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Sep-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Oct-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Nov-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Dec-2022 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 2 | Jan-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Feb-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Mar-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Apr-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | May-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Jun-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Jul-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Aug-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Sep-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Oct-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Nov-2022 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Dec-2022 | 63.70 | 0.4060 |
| GMA NON-HTG NON-CLG | Jan-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Feb-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Mar-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Apr-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | May-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Jun-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Jul-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Aug-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Sep-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Oct-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Nov-2022 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Dec-2022 | 25.90 | 0.4027 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| System Charge | DC Distribution Charge |
|---|---|

CUBE: tm1serv:PGC_Summary
PGC_Area DC

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| RES HTG - SYS LEV 1 | Jan-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Feb-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Mar-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Apr-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | May-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Jun-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Jul-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Aug-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Sep-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Oct-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Nov-2023 | 15.05 | 0.4542 |
| RES HTG - SYS LEV 1 | Dec-2023 | 15.05 | 0.4542 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jan-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Feb-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Mar-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Apr-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | May-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jun-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jul-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Aug-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Sep-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Oct-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Nov-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Dec-2023 | 10.90 | 0.4076 |
| RES NON-HTG NON-CLG - OTH | Jan-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Feb-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Mar-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Apr-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | May-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Jun-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Jul-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Aug-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Sep-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Oct-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Nov-2023 | 12.30 | 0.4511 |
| RES NON-HTG NON-CLG - OTH | Dec-2023 | 12.30 | 0.4511 |
| C&I HTG - SYS LEV 1 | Jan-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Feb-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Mar-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Apr-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | May-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Jun-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Jul-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Aug-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Sep-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Oct-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Nov-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 1 | Dec-2023 | 27.20 | 0.4135 |
| C&I HTG - SYS LEV 2 | Jan-2023 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Feb-2023 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Mar-2023 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Apr-2023 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | May-2023 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Jun-2023 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Jul-2023 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Aug-2023 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Sep-2023 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Oct-2023 | 63.70 | 0.4006 |
| C&I HTG - SYS LEV 2 | Nov-2023 | 63.70 | 0.4006 |

| | | | |
|---|---|---|---|
| C&I HTG - SYS LEV 2 | Dec-2023 | 63.70 | 0.4006 |
| C&I NON-HTG NON-CLG | Jan-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Feb-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Mar-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Apr-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | May-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Jun-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Jul-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Aug-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Sep-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Oct-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Nov-2023 | 25.90 | 0.3993 |
| C&I NON-HTG NON-CLG | Dec-2023 | 25.90 | 0.3993 |
| GMA HTG - SYS LEV 1 | Jan-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Feb-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Mar-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Apr-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | May-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Jun-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Jul-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Aug-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Sep-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Oct-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Nov-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 1 | Dec-2023 | 25.90 | 0.4014 |
| GMA HTG - SYS LEV 2 | Jan-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Feb-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Mar-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Apr-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | May-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Jun-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Jul-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Aug-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Sep-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Oct-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Nov-2023 | 63.70 | 0.4060 |
| GMA HTG - SYS LEV 2 | Dec-2023 | 63.70 | 0.4060 |
| GMA NON-HTG NON-CLG | Jan-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Feb-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Mar-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Apr-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | May-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Jun-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Jul-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Aug-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Sep-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Oct-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Nov-2023 | 25.90 | 0.4027 |
| GMA NON-HTG NON-CLG | Dec-2023 | 25.90 | 0.4027 |

CUBE: tm1serv:PGC_Summary
PGC_Area DC

**New Rates Effective January 16, 2024

| | | System Charge | DC Distribution Charge |
|---|---|---|---|
| RES HTG - SYS LEV 1 | Jan-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | Feb-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | Mar-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | Apr-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | May-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | Jun-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | Jul-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | Aug-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | Sep-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | Oct-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | Nov-2024 | 16.55 | 0.5638 |
| RES HTG - SYS LEV 1 | Dec-2024 | 16.55 | 0.5638 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jan-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Feb-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Mar-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Apr-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | May-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jun-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Jul-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Aug-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Sep-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Oct-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Nov-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - IND. MTR. APTS | Dec-2024 | 12.00 | 0.6610 |
| RES NON-HTG NON-CLG - OTH | Jan-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | Feb-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | Mar-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | Apr-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | May-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | Jun-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | Jul-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | Aug-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | Sep-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | Oct-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | Nov-2024 | 13.55 | 0.6390 |
| RES NON-HTG NON-CLG - OTH | Dec-2024 | 13.55 | 0.6390 |
| C&I HTG - SYS LEV 1 | Jan-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | Feb-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | Mar-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | Apr-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | May-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | Jun-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | Jul-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | Aug-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | Sep-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | Oct-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | Nov-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 1 | Dec-2024 | 29.90 | 0.5821 |
| C&I HTG - SYS LEV 2 | Jan-2024 | 70.05 | 0.4796 |
| C&I HTG - SYS LEV 2 | Feb-2024 | 70.05 | 0.4796 |
| C&I HTG - SYS LEV 2 | Mar-2024 | 70.05 | 0.4796 |
| C&I HTG - SYS LEV 2 | Apr-2024 | 70.05 | 0.4796 |
| C&I HTG - SYS LEV 2 | May-2024 | 70.05 | 0.4796 |
| C&I HTG - SYS LEV 2 | Jun-2024 | 70.05 | 0.4796 |
| C&I HTG - SYS LEV 2 | Jul-2024 | 70.05 | 0.4796 |
| C&I HTG - SYS LEV 2 | Aug-2024 | 70.05 | 0.4796 |
| C&I HTG - SYS LEV 2 | Sep-2024 | 70.05 | 0.4796 |
| C&I HTG - SYS LEV 2 | Oct-2024 | 70.05 | 0.4796 |
| C&I HTG - SYS LEV 2 | Nov-2024 | 70.05 | 0.4796 |

| | | | |
|---|---|---|---|
| C&I HTG - SYS LEV 2 | Dec-2024 | 70.05 | 0.4796 |
| C&I NON-HTG NON-CLG | Jan-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | Feb-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | Mar-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | Apr-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | May-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | Jun-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | Jul-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | Aug-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | Sep-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | Oct-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | Nov-2024 | 28.50 | 0.4811 |
| C&I NON-HTG NON-CLG | Dec-2024 | 28.50 | 0.4811 |
| GMA HTG - SYS LEV 1 | Jan-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | Feb-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | Mar-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | Apr-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | May-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | Jun-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | Jul-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | Aug-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | Sep-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | Oct-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | Nov-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 1 | Dec-2024 | 28.50 | 0.4930 |
| GMA HTG - SYS LEV 2 | Jan-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | Feb-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | Mar-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | Apr-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | May-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | Jun-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | Jul-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | Aug-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | Sep-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | Oct-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | Nov-2024 | 70.05 | 0.4863 |
| GMA HTG - SYS LEV 2 | Dec-2024 | 70.05 | 0.4863 |
| GMA NON-HTG NON-CLG | Jan-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | Feb-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | Mar-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | Apr-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | May-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | Jun-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | Jul-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | Aug-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | Sep-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | Oct-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | Nov-2024 | 28.50 | 0.4841 |
| GMA NON-HTG NON-CLG | Dec-2024 | 28.50 | 0.4841 |

Exhibit OPC (A)-14
Formal Case No. 1180
Direct Testimony of David E. Dismukes

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-22

**Q.** **Weather Variability Impact**. Please respond to the following:

a. Please quantify, individually, the impacts that weather variability, warming temperatures, ongoing conservation, and efficiency efforts of customers have had on the Company's financial performance.

b. Please quantify, individually, the impacts that weather variability, warming temperatures, ongoing conservation, and efficiency efforts of customers have had on the Company's customers' bills.

c. Using 120 months of usage and actual HDD data in lieu of the 60 months used in the Normal Weather Throughput Study, please calculate the impact of weather variability on the volume of natural gas usage (in therms) by rate class.

d. Please provide sales and average temperature data by rate class for ten years including the test year.

**WASHINGTON GAS'S PARTIAL OBJECTION** 09/20/2024

Washington Gas objects to subparts (b) and (c) of this request on grounds that they call for a special study which the Company has not performed.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.**

a. The impacts that weather variability, warming temperatures, ongoing conservation, and efficiency efforts of customers have had on the Company's financial performance are reflected in the Company's rate filing in this case.

b. Objection. This would require a special study that has not been done.

c. Objection. This would require a special study that has not been done.

d. See Attachment 1-22(d).

SPONSOR: Paul Raab
Consultant

| | | DCRH_USE | DCRHC_USE | DCRIMA_USE | DCROTH_USE | DCCH1_USE |
|---|---|---|---|---|---|---|
| Date | Actual HDDs | DCRH | DCRHC | DCRIMA | DCROTH | DCCH1 |
| Apr-14 | 466 | 11,086,569 | 2,267 | 80,297 | 173,375 | 1,398,242 |
| May-14 | 167 | 4,778,548 | 999 | 37,974 | 91,950 | 794,654 |
| Jun-14 | 21 | 2,307,942 | 374 | 40,093 | 53,857 | 381,214 |
| Jul-14 | 0 | 1,783,992 | 295 | 36,741 | 42,497 | 214,758 |
| Aug-14 | 0 | 1,656,469 | 276 | 35,109 | 39,611 | 421,028 |
| Sep-14 | 0 | 1,725,630 | 289 | 36,920 | 48,595 | 147,906 |
| Oct-14 | 21 | 2,213,009 | 424 | 39,311 | 51,993 | 154,117 |
| Nov-14 | 191 | 5,914,986 | 1,262 | 51,056 | 111,052 | 332,673 |
| Dec-14 | 605 | 14,999,855 | 3,178 | 89,926 | 248,011 | 952,283 |
| Jan-15 | 784 | 19,287,529 | 3,820 | 105,642 | 317,123 | 1,312,035 |
| Feb-15 | 906 | 22,057,162 | 4,274 | 111,311 | 361,777 | 1,562,102 |
| Mar-15 | 897 | 20,998,666 | 4,309 | 109,024 | 338,590 | 1,509,124 |
| Apr-15 | 394 | 10,213,324 | | 73,451 | 176,585 | 811,408 |
| May-15 | 115 | 4,137,298 | | 47,315 | 82,061 | 331,238 |
| Jun-15 | 14 | 2,136,510 | | 40,277 | 51,501 | 197,940 |
| Jul-15 | 2 | 1,726,859 | | 36,497 | 43,421 | 209,403 |
| Aug-15 | 0 | 1,592,761 | | 34,777 | 38,596 | 231,834 |
| Sep-15 | 0 | 1,627,213 | | 36,335 | 38,551 | 114,386 |
| Oct-15 | 51 | 2,510,177 | | 38,859 | 54,768 | 146,866 |
| Nov-15 | 207 | 5,029,269 | | 52,356 | 98,910 | 290,346 |
| Dec-15 | 445 | 9,687,218 | | 71,543 | 176,110 | 630,742 |
| Jan-16 | 580 | 13,369,201 | | 84,311 | 239,041 | 810,498 |
| Feb-16 | 862 | 19,237,108 | | 111,198 | 332,241 | 1,481,050 |
| Mar-16 | 629 | 13,673,347 | | 86,620 | 234,649 | 1,147,752 |
| Apr-16 | 314 | 7,326,753 | | 60,992 | 137,968 | 586,698 |
| May-16 | 199 | 4,757,969 | | 47,791 | 94,917 | 374,368 |
| Jun-16 | 74 | 2,879,769 | | 42,328 | 64,467 | 273,653 |
| Jul-16 | 0 | 1,729,730 | | 34,870 | 41,370 | 230,425 |
| Aug-16 | 0 | 1,496,022 | | 32,747 | 36,678 | 234,515 |
| Sep-16 | 0 | 1,537,749 | | 33,503 | 36,998 | 111,251 |
| Oct-16 | 13 | 1,905,518 | | 35,976 | 47,122 | 152,617 |
| Nov-16 | 155 | 4,338,782 | | 48,711 | 91,313 | 275,874 |
| Dec-16 | 513 | 11,239,684 | | 76,372 | 208,729 | 787,371 |
| Jan-17 | 715 | 18,455,649 | | 118,547 | 321,458 | 1,392,502 |
| Feb-17 | 687 | 14,918,384 | | 88,198 | 267,941 | 1,072,875 |
| Mar-17 | 508 | 12,881,159 | | 86,866 | 241,843 | 958,767 |
| Apr-17 | 368 | 8,017,604 | | 64,244 | 141,793 | 662,117 |
| May-17 | 101 | 3,241,625 | | 54,200 | 70,828 | 292,970 |
| Jun-17 | 37 | 2,491,738 | | 43,502 | 57,928 | 184,160 |
| Jul-17 | 0 | 1,659,837 | | 35,735 | 38,163 | 222,025 |
| Aug-17 | 0 | 1,560,947 | | 36,181 | 37,224 | 70,152 |
| Sep-17 | 4 | 1,667,553 | | 36,223 | 39,834 | 76,315 |

| | | | | | |
|---|---|---|---|---|---|
| Oct-17 | 19 | 2,148,164 | 29,747 | 50,714 | 97,248 |
| Nov-17 | 227 | 5,719,634 | 56,181 | 111,281 | 241,320 |
| Dec-17 | 567 | 12,297,194 | 84,083 | 226,902 | 576,280 |
| Jan-18 | 938 | 22,193,875 | 126,795 | 420,505 | 1,216,521 |
| Feb-18 | 764 | 16,025,076 | 98,032 | 287,162 | 1,038,334 |
| Mar-18 | 581 | 13,992,683 | 91,613 | 259,410 | 807,822 |
| Apr-18 | 499 | 12,254,971 | 82,292 | 223,122 | 672,599 |
| May-18 | 181 | 4,816,184 | 50,098 | 93,307 | 335,249 |
| Jun-18 | 5 | 2,092,298 | 41,144 | 50,566 | 167,094 |
| Jul-18 | 0 | 1,636,543 | 35,813 | 37,948 | 184,998 |
| Aug-18 | 0 | 1,586,332 | 37,241 | 36,502 | 147,285 |
| Sep-18 | 1 | 1,654,667 | 37,843 | 40,266 | 85,417 |
| Oct-18 | 32 | 2,250,863 | 42,038 | 52,878 | 106,774 |
| Nov-18 | 323 | 7,850,343 | 71,847 | 156,019 | 418,120 |
| Dec-18 | 648 | 14,648,591 | 108,749 | 276,947 | 824,337 |
| Jan-19 | 654 | 15,003,355 | 105,280 | 277,868 | 922,142 |
| Feb-19 | 864 | 19,690,660 | 126,832 | 367,147 | 1,196,345 |
| Mar-19 | 615 | 14,373,518 | 98,616 | 269,715 | 1,032,795 |
| Apr-19 | 386 | 8,906,715 | 67,511 | 164,093 | 561,591 |
| May-19 | 71 | 3,318,002 | 44,652 | 69,077 | 274,676 |
| Jun-19 | 16 | 2,218,590 | 30,228 | 52,539 | 140,174 |
| Jul-19 | 0 | 1,529,430 | 34,038 | 35,050 | 128,222 |
| Aug-19 | 0 | 1,526,482 | 34,249 | 34,631 | 156,588 |
| Sep-19 | 0 | 1,658,983 | 17,414 | 40,239 | 85,753 |
| Oct-19 | 15 | 1,821,152 | 8,205 | 43,221 | 108,480 |
| Nov-19 | 284 | 6,965,878 | 67,939 | 144,755 | 335,404 |
| Dec-19 | 611 | 13,365,473 | 88,870 | 258,488 | 741,750 |
| Jan-20 | 673 | 14,386,291 | 97,696 | 276,335 | 844,328 |
| Feb-20 | 681 | 14,959,175 | 129,748 | 288,439 | 878,766 |
| Mar-20 | 521 | 11,259,394 | 82,445 | 216,869 | 687,844 |
| Apr-20 | 317 | 7,379,741 | 71,917 | 147,012 | 397,982 |
| May-20 | 271 | 6,112,557 | 66,803 | 123,241 | 346,114 |
| Jun-20 | 58 | 2,905,104 | 46,229 | 66,920 | 144,032 |
| Jul-20 | 0 | 1,828,638 | 42,809 | 41,701 | 124,220 |
| Aug-20 | 0 | 1,548,348 | 114,555 | 35,051 | 146,333 |
| Sep-20 | 6 | 1,486,025 | 36,805 | 38,592 | 60,058 |
| Oct-20 | 55 | 2,384,449 | 45,163 | 55,150 | 95,301 |
| Nov-20 | 191 | 5,231,876 | 61,932 | 110,285 | 210,321 |
| Dec-20 | 465 | 10,219,382 | 78,766 | 202,218 | 461,327 |
| Jan-21 | 787 | 17,030,174 | 112,402 | 325,775 | 871,206 |
| Feb-21 | 784 | 17,864,740 | 112,000 | 337,579 | 1,042,149 |
| Mar-21 | 650 | 13,254,713 | 95,771 | 250,169 | 840,005 |
| Apr-21 | 341 | 7,981,143 | 67,525 | 155,927 | 511,348 |
| May-21 | 176 | 4,390,784 | 50,679 | 92,318 | 270,033 |

| | | | | | |
|---|---|---|---|---|---|
| Jun-21 | 44 | 2,244,596 | 16,260 | 49,288 | 288,713 |
| Jul-21 | 2 | 1,699,180 | 36,209 | 38,281 | 216,837 |
| Aug-21 | 0 | 1,484,458 | 32,627 | 32,036 | 148,258 |
| Sep-21 | 0 | 1,601,237 | 35,607 | 35,468 | 2,121 |
| Oct-21 | 5 | 1,701,417 | 19,481 | 41,757 | 148,993 |
| Nov-21 | 189 | 5,080,258 | 40,013 | 108,261 | 291,291 |
| Dec-21 | 531 | 11,250,949 | 78,015 | 212,352 | 601,130 |
| Jan-22 | 747 | 15,713,847 | 102,867 | 301,303 | 861,385 |
| Feb-22 | 787 | 17,778,523 | 103,871 | 334,758 | 1,070,622 |
| Mar-22 | 533 | 11,368,012 | 90,463 | 213,455 | 737,444 |
| Apr-22 | 408 | 8,994,064 | 83,080 | 170,305 | 680,005 |
| May-22 | 175 | 4,610,716 | 40,759 | 91,092 | 279,675 |
| Jun-22 | 25 | 2,205,599 | 34,925 | 45,763 | 99,565 |
| Jul-22 | 0 | 1,695,558 | 29,799 | 39,051 | 181,503 |
| Aug-22 | 0 | 1,288,857 | 26,024 | 28,234 | 98,275 |
| Sep-22 | 0 | 1,654,552 | 36,167 | 45,697 | 83,507 |
| Oct-22 | 89 | 3,057,388 | 40,949 | 66,489 | 121,930 |
| Nov-22 | 219 | 5,474,859 | 46,565 | 100,325 | 265,966 |
| Dec-22 | 517 | 10,235,733 | 72,806 | 190,830 | 560,648 |
| Jan-23 | 733 | 14,128,021 | 93,385 | 261,038 | 808,831 |
| Feb-23 | 619 | 14,230,641 | 84,416 | 280,439 | 774,596 |
| Mar-23 | 465 | 11,897,666 | 77,288 | 242,168 | 601,751 |
| Apr-23 | 367 | 7,856,288 | 65,163 | 151,399 | 512,891 |
| May-23 | 130 | 3,331,233 | 37,754 | 69,522 | 248,719 |
| Jun-23 | 21 | 2,296,757 | 37,552 | 54,630 | 207,835 |
| Jul-23 | 0 | 1,655,214 | 37,608 | 33,963 | 109,193 |
| Aug-23 | 0 | 1,316,376 | 27,299 | 27,960 | 133,302 |
| Sep-23 | 1 | 1,622,364 | 21,735 | 35,484 | 89,196 |
| Oct-23 | 39 | 1,968,056 | 30,619 | 43,928 | 111,430 |
| Nov-23 | 223 | 5,413,194 | 51,713 | 118,734 | 286,815 |
| Dec-23 | 536 | 10,890,742 | 60,138 | 215,376 | 616,887 |
| Jan-24 | 655 | 13,323,881 | 81,335 | 259,455 | 794,129 |
| Feb-24 | 699 | 14,520,541 | 103,348 | 279,296 | 922,229 |
| Mar-24 | 516 | 9,929,458 | 70,148 | 190,410 | 638,500 |

| DCCH2_USE | DCCHC1_USE | DCCHC2_USE | DCCNON_USE | CHP_USE | DCGMAH1_USE | DCGMAH2_USE |
|---|---|---|---|---|---|---|
| DCCH2 | DCCHC1 | DCCHC2 | DCCNON | CHP | DCGMAH1 | DCGMAH2 |
| 5,519,301 | 3,127 | 18,934 | 1,150,894 | | 117,215 | 2,998,761 |
| 3,598,044 | 2,149 | 14,379 | 939,156 | | 83,941 | 1,615,951 |
| 1,823,649 | 1,951 | 10,666 | 810,088 | | 86,423 | 833,777 |
| 1,652,115 | 2,175 | 11,161 | 786,034 | | 42,234 | 631,716 |
| 1,297,489 | 2,086 | 9,851 | 719,914 | | 37,601 | 595,073 |
| 1,752,483 | 2,136 | 11,490 | 753,978 | | 46,496 | 615,459 |
| 1,993,829 | 2,282 | 10,763 | 806,174 | | 40,367 | 1,729,351 |
| 3,820,249 | 2,551 | 15,602 | 973,278 | | 78,728 | 716,738 |
| 7,967,971 | 3,119 | 27,459 | 1,347,501 | | 221,253 | 3,789,245 |
| 9,805,597 | 3,093 | 31,888 | 1,463,477 | | 382,597 | 4,463,486 |
| 11,094,636 | 3,182 | 34,672 | 1,789,820 | | 350,064 | 4,868,940 |
| 10,303,689 | 2,826 | 18,659 | 1,623,525 | | 335,395 | 4,574,104 |
| 5,976,584 | | | 1,709,849 | | 192,900 | 2,916,372 |
| 2,928,127 | | | 1,201,433 | | 99,306 | 1,975,330 |
| 2,216,520 | | | 1,363,065 | | 62,110 | 187,593 |
| 1,643,990 | | | 872,487 | | 57,403 | 643,690 |
| 1,612,021 | | | 985,009 | | 44,144 | 593,747 |
| 1,703,603 | | | 896,637 | | 41,396 | 578,469 |
| 2,121,390 | | | 991,375 | | 48,359 | 761,472 |
| 4,107,330 | | | 1,071,302 | | 98,175 | 1,645,095 |
| 5,349,340 | | | 1,296,369 | | 158,838 | 2,832,458 |
| 6,750,784 | | | 1,367,194 | | 187,127 | 3,222,128 |
| 10,203,168 | | | 1,677,394 | | 263,189 | 4,615,813 |
| 8,139,861 | | | 1,362,656 | | 208,843 | 3,519,239 |
| 4,792,352 | | | 1,235,646 | | 177,397 | 2,293,604 |
| 3,190,264 | | | 998,814 | | 91,598 | 1,426,158 |
| 2,403,270 | | | 843,275 | | 104,786 | 780,169 |
| 1,788,232 | | | 808,937 | | 60,583 | 727,423 |
| 1,553,016 | | | 724,726 | | 46,802 | 524,874 |
| 1,708,675 | | | 739,459 | | 35,389 | 506,617 |
| 2,026,474 | | | 769,420 | | 50,370 | 661,482 |
| 3,146,255 | | | 916,709 | | 101,291 | 1,402,765 |
| 6,283,547 | | | 1,118,739 | | 187,040 | 3,012,968 |
| 10,136,757 | | | 1,685,052 | | 480,227 | 4,557,572 |
| 8,327,239 | | | 1,237,963 | | 498,965 | 3,882,680 |
| 7,413,578 | | | 1,327,277 | | 319,227 | 3,443,007 |
| 5,353,451 | | | 1,110,587 | | 213,852 | 2,440,796 |
| 2,581,937 | | | 825,564 | | 93,440 | 1,118,355 |
| 2,427,757 | | | 864,770 | | 85,846 | 867,901 |
| 1,703,927 | | | 699,150 | | 51,693 | 602,501 |
| 1,917,756 | | | 722,686 | | 6,505 | 625,488 |
| 2,128,647 | | | 733,850 | | 11,736 | 652,883 |

| | | | | |
|---|---|---|---|---|
| 2,332,461 | 838,488 | | 18,042 | 754,775 |
| 4,270,864 | 1,002,023 | | 3,604 | 1,970,587 |
| 7,621,208 | 1,317,574 | | 85,752 | 3,545,691 |
| 11,106,050 | 1,816,520 | | 180,724 | 5,163,477 |
| 8,266,313 | 1,263,152 | | 199,094 | 4,187,984 |
| 7,444,668 | 1,232,536 | | 240,343 | 3,925,909 |
| 7,254,526 | 1,101,031 | | 115,961 | 3,369,640 |
| 3,998,597 | 878,039 | | 93,633 | 1,734,653 |
| 2,622,404 | 784,948 | | 14,451 | 835,450 |
| 2,116,515 | 585,758 | | 30,942 | 730,243 |
| 1,990,633 | 772,421 | | 23,214 | 637,052 |
| 2,112,839 | 689,019 | | 21,996 | 681,785 |
| 2,620,443 | 754,385 | | 23,191 | 823,213 |
| 5,543,239 | 1,013,196 | | 59,239 | 2,450,338 |
| 8,600,026 | 1,247,631 | | 113,554 | 3,978,358 |
| 8,923,739 | 1,211,228 | | 78,376 | 4,234,219 |
| 11,018,643 | 1,460,598 | | 102,450 | 5,256,868 |
| 8,497,843 | 1,187,317 | | 80,031 | 3,817,374 |
| 6,076,153 | 996,413 | - | 61,941 | 2,951,335 |
| 3,347,209 | 755,838 | - | 37,654 | 1,406,154 |
| 2,502,342 | 747,186 | - | 28,835 | 900,543 |
| 1,929,560 | 618,254 | - | 21,490 | 643,311 |
| 1,964,544 | 582,123 | - | 22,100 | 625,049 |
| 2,167,622 | 660,271 | - | 26,293 | 703,141 |
| 2,245,099 | 675,538 | - | 26,313 | 693,633 |
| 5,238,323 | 1,023,185 | 100,748 | 57,694 | 2,408,194 |
| 8,219,633 | 1,235,966 | 324,314 | 109,214 | 3,797,110 |
| 8,947,122 | 1,212,220 | 352,899 | 127,402 | 4,046,864 |
| 7,841,316 | 1,298,226 | 334,671 | 133,815 | 4,191,042 |
| 8,582,723 | 991,685 | 302,785 | 107,816 | 3,429,093 |
| 4,561,480 | 619,389 | 293,992 | 107,652 | 2,632,751 |
| 3,931,228 | 479,833 | 82,054 | 98,834 | 2,282,808 |
| 2,224,159 | 350,235 | 78,109 | 47,089 | 953,929 |
| 1,710,467 | 377,437 | 72,186 | 31,241 | 706,617 |
| 1,496,687 | 345,722 | 83,373 | 28,532 | 634,512 |
| 1,832,906 | 376,418 | 128,611 | 20,973 | 649,601 |
| 2,446,959 | 425,514 | 137,094 | 37,790 | 875,232 |
| 3,767,922 | 595,648 | 172,672 | 48,217 | 1,831,503 |
| 6,222,723 | 729,478 | 251,725 | 81,199 | 3,052,288 |
| 9,689,070 | 1,039,056 | 393,404 | 147,367 | 4,670,591 |
| 10,651,651 | 1,104,625 | 292,132 | 162,145 | 4,853,013 |
| 7,631,403 | 853,869 | 257,712 | 136,179 | 3,788,189 |
| 5,476,891 | 643,635 | 256,017 | 125,773 | 2,602,306 |
| 3,574,466 | 546,232 | 105,822 | 73,698 | 1,758,825 |

| | | | | |
|---|---|---|---|---|
| 2,162,547 | 419,749 | 99,979 | 35,790 | 846,907 |
| 2,247,454 | 555,530 | 80,478 | 29,494 | 752,240 |
| 1,818,140 | 413,861 | 92,973 | 32,895 | 572,488 |
| 2,189,717 | 425,509 | 142,051 | 22,666 | 615,759 |
| 2,555,186 | 499,041 | 118,660 | 15,635 | 658,925 |
| 4,125,400 | 660,811 | 188,657 | 41,494 | 1,738,908 |
| 7,245,925 | 860,854 | 338,828 | 120,701 | 3,292,546 |
| 9,736,572 | 1,007,122 | 250,656 | 147,468 | 4,538,380 |
| 11,544,691 | 1,061,120 | 311,051 | 140,084 | 4,549,025 |
| 7,424,332 | 893,786 | 301,579 | 159,354 | 3,440,266 |
| 6,141,541 | 782,909 | 228,038 | 115,847 | 2,892,489 |
| 3,976,575 | 603,915 | 93,737 | 88,791 | 1,822,159 |
| 2,577,520 | 507,835 | 116,256 | 53,133 | 826,366 |
| 2,234,307 | 465,861 | 134,445 | 44,149 | 642,796 |
| 1,830,968 | 359,081 | 91,522 | 52,309 | 566,925 |
| 2,257,032 | 441,442 | 65,175 | 15,640 | 722,357 |
| 3,407,436 | 611,990 | 64,752 | 35,530 | 1,120,031 |
| 4,735,162 | 671,576 | 111,811 | 10,010 | 2,176,440 |
| 7,597,661 | 788,842 | 280,694 | 69,901 | 3,280,949 |
| 9,550,134 | 1,008,304 | 248,643 | 111,692 | 4,311,771 |
| 9,021,459 | 980,257 | 301,424 | 96,590 | 4,473,459 |
| 7,231,983 | 844,674 | 138,343 | 88,507 | 3,586,429 |
| 6,338,839 | 835,287 | 197,628 | 82,980 | 3,129,326 |
| 3,753,702 | 559,059 | 132,553 | 118,956 | 1,419,540 |
| 2,921,839 | 532,430 | 133,811 | 57,656 | 1,003,827 |
| 2,143,434 | 447,120 | 95,233 | 46,309 | 674,182 |
| 2,122,296 | 396,431 | 54,051 | 37,048 | 610,304 |
| 2,280,981 | 488,031 | 116,440 | 7,329 | 680,292 |
| 2,796,234 | 484,132 | 110,880 | 30,459 | 806,722 |
| 4,892,685 | 669,594 | 155,198 | 75,765 | 2,098,072 |
| 8,246,712 | 879,320 | 180,659 | 141,291 | 4,022,262 |
| 9,179,131 | 1,011,587 | 201,194 | 173,573 | 4,146,785 |
| 9,579,483 | 1,029,848 | 223,168 | 112,455 | 4,537,194 |
| 7,048,511 | 812,825 | 213,273 | 209,140 | 3,450,456 |

| DCGMAHC2_US | DCGMANON_USE |
|---|---|
| DCGMAHC2 | DCGMANON |
| 122 | 407,080 |
| 62 | 307,589 |
| 44 | 231,245 |
| 38 | 233,790 |
| 34 | 212,341 |
| 44 | 213,799 |
| 82 | 238,191 |
| 183 | 329,154 |
| 311 | 485,431 |
| 374 | 535,900 |
| 506 | 608,923 |
| 302 | 552,676 |
| | 405,750 |
| | 289,428 |
| | 230,284 |
| | 210,303 |
| | 193,531 |
| | 198,926 |
| | 239,859 |
| | 315,861 |
| | 406,258 |
| | 442,329 |
| | 547,626 |
| | 438,415 |
| | 248,823 |
| | 392,148 |
| | 261,941 |
| | 207,687 |
| | 186,666 |
| | 192,062 |
| | 222,360 |
| | 293,513 |
| | 391,502 |
| | 551,365 |
| | 489,373 |
| | 440,322 |
| | 348,200 |
| | 283,825 |
| | 258,112 |
| | 194,390 |
| | 190,620 |
| | 196,575 |

| |
|---|
| 225,119 |
| 312,716 |
| 422,515 |
| 580,416 |
| 489,567 |
| 458,970 |
| 426,058 |
| 292,524 |
| 242,398 |
| 197,156 |
| 202,010 |
| 205,363 |
| 235,111 |
| 361,745 |
| 458,166 |
| 465,025 |
| 572,573 |
| 453,518 |
| 367,841 |
| 308,438 |
| 268,790 |
| 204,032 |
| 206,567 |
| 204,976 |
| 219,006 |
| 368,225 |
| 449,742 |
| 437,968 |
| 500,211 |
| 398,663 |
| 350,621 |
| 348,890 |
| 228,452 |
| 207,666 |
| 177,756 |
| 183,436 |
| 215,652 |
| 299,468 |
| 376,132 |
| 509,970 |
| 520,998 |
| 464,300 |
| 338,384 |
| 281,212 |

| |
|---|
| 230,715 |
| 188,367 |
| 169,046 |
| 182,965 |
| 201,645 |
| 295,291 |
| 402,703 |
| 497,934 |
| 497,593 |
| 390,956 |
| 387,401 |
| 280,163 |
| 220,620 |
| 230,591 |
| 164,521 |
| 191,187 |
| 256,884 |
| 316,963 |
| 386,806 |
| 487,885 |
| 477,219 |
| 440,407 |
| 389,032 |
| 257,798 |
| 250,083 |
| 198,058 |
| 164,739 |
| 205,020 |
| 212,092 |
| 332,250 |
| 404,577 |
| 470,308 |
| 485,332 |
| 387,341 |

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 14

QUESTION NO. 14-2

**Q.** **Affordability.** Please refer to Witness Lawson's supplemental testimony (Exhibit WG (2O)) at page 3, lines 9-11, in which Witness Lawson states "the Company believes recovery of a larger share of its fixed distribution costs through fixed charges promotes both bill stability and affordability for customers." Has the Company conducted or prepared a study or analysis supporting the belief that recovery of fixed distribution costs through fixed charges promotes bill stability and affordability for customers? If yes, please provide such a study(ies) and/or analysis(es). If not, please state so.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.** The Company has not performed a study nor is one needed due to the obvious stability and affordability benefits of predictable bills that are spread more evenly over the entire year.

SPONSOR: Andrew Lawson
Manager – Regulatory Affairs

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 7

QUESTION NO. 7-12

**Q.** **Credit Impact of Proposed Weather Normalization Mechanism.** Reference Witness D'Ascendis' Direct Testimony at 48:23-25, which states that "As discussed in Company Witness James Steffes' direct testimony, Washington Gas is pursuing a weather normalization mechanism in this proceeding." Please address the following:

a. If the Company's proposed WNA is approved, would it reduce the Company's risks related to recovery of its authorized return? Please explain and provide all supporting documentation.

b. Would the Company's credit rating be impacted by the approval of WGL's proposed WNA? Please explain and provide all supporting documentation.

**WASHINGTON GAS'S RESPONSE** 11/19/2024

**A.** a. All else being equal, a weather normalization mechanism, such as the Company's proposed WNA, will reduce some of the company-specific business risks related to the recovery of its authorized return. As stated in Mr. D'Ascendis' Direct Testimony at 48:9-18, the estimation of the Company's ROE is a comparative exercise, and if a mechanism is common throughout the companies on which one bases their analyses, the comparative risk is zero. As every single one of the proxy companies has a form of partial decoupling, the acceptance of the Company's proposed WNA would reduce the comparative risk related to the WNA to zero.

b. Mr. D'Ascendis cannot speculate to the potential credit rating of WGL upon the potential approval of WGL's proposed WNA.

SPONSOR: Dylan D'Ascendis
Consultant, Scott Madden

Exhibit OPC (A)-17
Formal Case No. 1180
Direct Testimony of David E. Dismukes

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 14

QUESTION NO. 14-1

**Q.** **Climate.** Please refer to Witness Steffes' supplemental testimony (Exhibit WG (2A)) at page 5, lines 13-15, in which Witness Steffes states "[t]he Company reminds the Commission that this proceeding is a backward-looking rate case based upon a historic test year and is not the appropriate opportunity to address the District's climate goals." Is it the Company's position that § 34-808.02 of the D.C. Code, requiring the D.C. Public Service Commission to consider "the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments" in "supervising and regulating utility or energy companies", does not apply to this proceeding? If yes, please explain the basis for the response. If no, please reconcile the Company's position with the requirements of § 34-808.02 of the D.C. Code.

**WASHINGTON GAS'S OBJECTION** 11/14/2024

Washington Gas objects to this data request on the grounds that it calls for a legal conclusion, and the Company is not required to conduct legal research or provide legal opinions in discovery or testimony. Washington Gas further objects to this data request on the grounds that the Supplemental Testimony, which is the subject of OPC's inquiry, was provided subject to reconsideration of Order No. 22311.

Exhibit OPC (A)-18
Formal Case No. 1180
Direct Testimony of David E. Dismukes

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 16

QUESTION NO. 16-1

**Q.** With respect to witness Steffes' supplemental direct testimony, Exh. WG (2A) at 6:13, please identify with specificity the "District's climate policies" to which you refer.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.** At this time, the Company is unaware of any District climate policy that has an impact on the Company's planned capital investments, expected life assets, or depreciation rates.

SPONSOR: James D. Steffes
Senior VP, Regulatory Policy

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 16

QUESTION NO. 16-2

**Q.** With respect to witness Steffes' supplemental direct testimony, Exh. WG (2A) at 6:12 15, please provide all documents, including studies, analyses, or other assessments, that support or otherwise form the basis for the Company's position that the "District's climate policies" have "no impact to the Company's planned capital investments." If the Company's response is that there are no such documents, then please describe fully the bases for the Company's position.

**WASHINGTON GAS'S OBJECTION** 11/18/2024

Washington Gas objects to this request to the extent it seeks privileged information, a legal conclusion, or legal research. Subject to the foregoing, Washington Gas will provide a response to the data request.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.** At this time, the Company is unaware of any District climate policy that has an impact on the Company's planned capital investments and thus the Company does not have materials responsive to this request.

SPONSOR: James D. Steffes
Senior VP, Regulatory Affairs

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 16

QUESTION NO. 16-3

**Q.** With respect to witness Steffes' supplemental direct testimony, Exh. WG (2A) at 6:12 15, please provide all documents in your possession, including studies, analyses, or other assessments that address whether the "District's climate policies" will have an impact on the Company's capital investments.

**WASHINGTON GAS'S OBJECTION** 11/18/2024

Washington Gas objects to this request to the extent it seeks privileged information, a legal conclusion, or legal research. Subject to the foregoing, Washington Gas will provide a response to the data request.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.** At this time, the Company is unaware of any District climate policy that has an impact on the Company's planned capital investments and thus the Company does not have materials responsive to this request.

SPONSOR: James D. Steffes
Senior VP, Regulatory Affairs

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 8

QUESTION NO. 8-1

**Q.** **Application.** Please refer to the source documents provided by the Washington Gas Light Company in its response to OPC Data Request No. 1, Question 1-1A, subpart b. Please provide a breakdown of the determinants and rates by bill component used to calculate the average bill totals by month supporting 'Graph 1: Average Residential Heating/Cooling Customer Monthly Bill'.

**WASHINGTON GAS'S RESPONSE** 11/20/2024

**A.** Washington Gas' Average Bill data provided was extracted from the Company's bill calculation system and not a study. The information sought is not readily available without the conduct of a specialized study.

SPONSOR: James Steffes
Senior VP, Regulatory Affairs

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-1A

**Q.** **Application**. Please respond to the following:

a. Provide all copies of all supporting workpapers, documents, schedules, exhibits, tables, figures, and spreadsheets in electronic format with all formulae and links intact supporting the Company's application, testimony and exhibits.

b. Refer to the Direct Testimony of Company Witness Steffes, page 12. Provide all workpapers and source documents supporting 'Graph 1: Average Residential Heating/Cooling Customer Monthly Bill'.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** a. Response has already been provided with the Company's Application.

b. The source documents supporting Graph 1: Average residential heating/cooling Customer Monthly Bill are attached.

SPONSOR: James Steffes
Senior VP, Regulatory Affairs

***DC Avg Bill***

| | RATE CLASS DESC T | AVERAGE AMOUNT | |
|---|---|---|---|
| 2013 | RESIDENTIAL | $ | 67.44 |
| 2014 | RESIDENTIAL | $ | 75.93 |
| 2015 | RESIDENTIAL | $ | 68.28 |
| 2016 | RESIDENTIAL | $ | 51.46 |

```
--avg bill query legacy

SELECT A."RATE CLASS DESCRIPTION"
     ,SUM("WG CURRENT CHARGES") AS "TOTAL CHARGES"
                                                                                ,ROUND(S
FROM (SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
```

```
FROM CIS_DECOMM_TRSR_201401

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE

UNION ALL

SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
```

```
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201402

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE

UNION ALL

SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
```

```
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201403

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE

UNION ALL

SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
```

```
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201404

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE


UNION ALL

SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
```

```
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201405

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE

UNION ALL

SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
```

```
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201406

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE


UNION ALL

SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
```

```
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201407

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE

UNION ALL

SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
```

```
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201408

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE


UNION ALL
```

```
SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201409

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
```

```
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE


UNION ALL

SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
```

```
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201410

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE

UNION ALL

SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
```

```
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201411

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE


UNION ALL

SELECT RSR_ACCT AS "ACCOUNT"
,RSR_CLASS AS "RATE CLASS"
,CASE
 WHEN RSR_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
 ELSE 'COMMERCIAL/INDUSTRIAL'
 END AS "RATE CLASS DESCRIPTION"
,SUM(CAST(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_PEAK_USE_CHARGES AS DECIMAL(10,2)) +
CAST(RSR_ESM AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_CURR AS DECIMAL(10,2)) +
CAST(RSR_M_DC_WAY_RECONC AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
CAST(RSR_SE_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_TAX AS DECIMAL(10,2)) +
CAST(RSR_IRA_CHARGE AS DECIMAL(10,2)) +
CAST(RSR_EA_TRUST_FUND AS DECIMAL(10,2)) +
CAST(RSR_M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
CAST(RSR_SAVE AS DECIMAL(10,2)) +
CAST(RSR_WNA_ADJ AS DECIMAL(10,2)) +
CAST(RSR_PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_COMMODITY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DELIVERY_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_PGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RPGA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_ACA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_CCA_0 AS DECIMAL(10,2)) +
CAST(RSR_SURCHARGE_0 AS DECIMAL(10,2)) +
CAST(RSR_OTHER_CHG_0 AS DECIMAL(10,2)) +
```

```
CAST(RSR_UTILITY_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_SALES_TAX_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_ACA_0 AS DECIMAL(10,2)) +
CAST(RSR_GAC_CURR_0 AS DECIMAL(10,2)) +
CAST(RSR_DISCOUNT_0 AS DECIMAL(10,2)) +
CAST(RSR_PRA_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_RSM_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
CAST(RSR_GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
CAST(RSR_APRP_0 AS DECIMAL(10,2)) +
CAST(RSR_EMPWR AS DECIMAL(10,2)) +
CAST(RSR_NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
FROM CIS_DECOMM_TRSR_201412

WHERE RSR_DAYS_SERVED > 000
AND RSR_CLASS IN ('08','02','09','01','28','22','29','21',
'05','04','03','35','34','33','38','67')
AND RSR_ACCT BETWEEN '2000.000000' AND '2999.999999'
GROUP BY RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE

) AS A
GROUP BY "RATE CLASS DESCRIPTION"
```

```
--avg bill qu

SELECT A."I
    ,SUM("\

FROM (SELI
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "R/
,SUM(CAST
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_S
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_S
CAST(RSR_V
CAST(RSR_I
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_/
CAST(RSR_(
CAST(RSR_(
CAST(RSR_S
CAST(RSR_(
CAST(RSR_U
CAST(RSR_S
CAST(RSR_(
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_/
CAST(RSR_I
CAST(RSR_I
```

```
FROM CIS_

WHERE RSF
AND RSR_C
'05','04','03
AND RSR_/
GROUP BY

UNION ALL

SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "R/
,SUM(CAST
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_S
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_S
CAST(RSR_\
CAST(RSR_I
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_/
CAST(RSR_(
CAST(RSR_(
CAST(RSR_S
CAST(RSR_(
CAST(RSR_I
CAST(RSR_S
CAST(RSR_(
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
```

```
CAST(RSR_I
CAST(RSR_(
CAST(RSR_/
CAST(RSR_I
CAST(RSR_I
FROM CIS_

WHERE RSF
AND RSR_C
'05','04','03
AND RSR_A
GROUP BY

UNION ALL

SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "R/
,SUM(CAST
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_S
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_S
CAST(RSR_V
CAST(RSR_I
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_/
CAST(RSR_(
CAST(RSR_(
CAST(RSR_S
CAST(RSR_(
CAST(RSR_U
CAST(RSR_S
CAST(RSR_(
```

```
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_/
CAST(RSR_I
CAST(RSR_I
FROM CIS_

WHERE RSF
AND RSR_C
'05','04','03
AND RSR_A
GROUP BY

UNION ALL

SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "R/
,SUM(CAST
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_S
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_S
CAST(RSR_V
CAST(RSR_I
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_/
CAST(RSR_(
CAST(RSR_(
```

```
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
FROM CIS_

WHERE RSR
AND RSR_C
'05','04','03
AND RSR_A
GROUP BY


UNION ALL

SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "R
,SUM(CAST
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
```

```
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_/
CAST(RSR_(
CAST(RSR_(
CAST(RSR_S
CAST(RSR_(
CAST(RSR_I
CAST(RSR_S
CAST(RSR_(
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_/
CAST(RSR_I
CAST(RSR_I
FROM CIS_

WHERE RSI
AND RSR_C
'05','04','03
AND RSR_A
GROUP BY

UNION ALL

SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "R/
,SUM(CAST
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_S
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
```

```
CAST(RSR_I
CAST(RSR_S
CAST(RSR_V
CAST(RSR_I
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_A
CAST(RSR_(
CAST(RSR_(
CAST(RSR_S
CAST(RSR_(
CAST(RSR_U
CAST(RSR_S
CAST(RSR_(
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_A
CAST(RSR_I
CAST(RSR_I
FROM CIS_

WHERE RSR
AND RSR_C
'05','04','03
AND RSR_A
GROUP BY


UNION ALL

SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "RA
,SUM(CAST
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
```

```
CAST(RSR_I
CAST(RSR_(
CAST(RSR_S
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_S
CAST(RSR_V
CAST(RSR_I
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_A
CAST(RSR_(
CAST(RSR_(
CAST(RSR_S
CAST(RSR_(
CAST(RSR_U
CAST(RSR_S
CAST(RSR_(
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_A
CAST(RSR_I
CAST(RSR_I
FROM CIS_

WHERE RSF
AND RSR_C
'05','04','03
AND RSR_A
GROUP BY

UNION ALL

SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
```

```
END AS "R
,SUM(CAST
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
FROM CIS_

WHERE RS
AND RSR_C
'05','04','03
AND RSR_A
GROUP BY


UNION ALL
```

```
SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "R
,SUM(CAST
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
FROM CIS_

WHERE RSF
AND RSR_C
```

```
'05','04','03
AND RSR_A
GROUP BY


UNION ALL

SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "R
,SUM(CAST
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
```

```
CAST(RSR_I
CAST(RSR_I
FROM CIS_

WHERE RSF
AND RSR_C
'05','04','03
AND RSR_A
GROUP BY

UNION ALL

SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "R/
,SUM(CAST
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_S
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_S
CAST(RSR_V
CAST(RSR_I
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_A
CAST(RSR_(
CAST(RSR_(
CAST(RSR_S
CAST(RSR_(
CAST(RSR_U
CAST(RSR_S
CAST(RSR_(
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
```

```
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_/
CAST(RSR_I
CAST(RSR_I
FROM CIS_

WHERE RSI
AND RSR_C
'05','04','03
AND RSR_A
GROUP BY


UNION ALL

SELECT RSR
,RSR_CLASS
,CASE
 WHEN RSR
 ELSE 'COM
 END AS "R/
,SUM(CAST
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_(
CAST(RSR_S
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_S
CAST(RSR_V
CAST(RSR_I
CAST(RSR_(
CAST(RSR_I
CAST(RSR_I
CAST(RSR_I
CAST(RSR_/
CAST(RSR_(
CAST(RSR_(
CAST(RSR_S
CAST(RSR_(
```

```
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
CAST(RSR_
FROM CIS_

WHERE RSF
AND RSR_C
'05','04','03
AND RSR_A
GROUP BY

) AS A
GROUP BY
```

```
ıery legacy

ꝛATE CLASS DESCRIPTION"
ꟿG CURRENT CHARGES") AS "TOTAL CHARGES"
 ,ROUND(SUM("WG CURRENT CHARGES")/COUNT("ACCOUNT"),2) "AVERAGE AMOUNT"
ECT RSR_ACCT AS "ACCOUNT"
; AS "RATE CLASS"

_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
MERCIAL/INDUSTRIAL'
ATE CLASS DESCRIPTION"
(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
PEAK_USE_CHARGES AS DECIMAL(10,2)) +
ESM AS DECIMAL(10,2)) +
M_DC_WAY_CURR AS DECIMAL(10,2)) +
M_DC_WAY_RECONC AS DECIMAL(10,2)) +
GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
SE_TRUST_FUND AS DECIMAL(10,2)) +
DELIVERY_TAX AS DECIMAL(10,2)) +
IRA_CHARGE AS DECIMAL(10,2)) +
EA_TRUST_FUND AS DECIMAL(10,2)) +
M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
SAVE AS DECIMAL(10,2)) +
WNA_ADJ AS DECIMAL(10,2)) +
PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
COMMODITY_CHG_0 AS DECIMAL(10,2)) +
DELIVERY_CHG_0 AS DECIMAL(10,2)) +
PGA_CHG_0 AS DECIMAL(10,2)) +
RPGA_CHG_0 AS DECIMAL(10,2)) +
ACA_CHG_0 AS DECIMAL(10,2)) +
CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CCA_0 AS DECIMAL(10,2)) +
SURCHARGE_0 AS DECIMAL(10,2)) +
OTHER_CHG_0 AS DECIMAL(10,2)) +
UTILITY_TAX_0 AS DECIMAL(10,2)) +
SALES_TAX_0 AS DECIMAL(10,2)) +
GAC_ACA_0 AS DECIMAL(10,2)) +
GAC_CURR_0 AS DECIMAL(10,2)) +
DISCOUNT_0 AS DECIMAL(10,2)) +
PRA_CHG_0 AS DECIMAL(10,2)) +
RSM_CHG_0 AS DECIMAL(10,2)) +
DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
DSM_PREV_CHG_0 AS DECIMAL(10,2)) +
GROSS_RECPT_SRCHG_0 AS DECIMAL(10,2)) +
APRP_0 AS DECIMAL(10,2)) +
EMPWR AS DECIMAL(10,2)) +
NORMALIZED_CHG_0 AS DECIMAL(10,2))) AS "WG CURRENT CHARGES"
```

**DECOMM_TRSR_201401**

```
R_DAYS_SERVED > 000
LASS IN ('08','02','09','01','28','22','29','21',
','35','34','33','38','67')
```

**ACCT BETWEEN '0000.000000' AND '1999.999999'**

```
RSR_ACCT, RSR_CLASS, RSR_BILL_CYCLE


_ACCT AS "ACCOUNT"
 AS "RATE CLASS"

_CLASS IN ('02','09','01','08','28','22','29','21') THEN 'RESIDENTIAL'
MERCIAL/INDUSTRIAL'
ATE CLASS DESCRIPTION"
(RSR_FIXED_CHARGES AS DECIMAL(10,2)) +
PEAK_USE_CHARGES AS DECIMAL(10,2)) +
ESM AS DECIMAL(10,2)) +
M_DC_WAY_CURR AS DECIMAL(10,2)) +
M_DC_WAY_RECONC AS DECIMAL(10,2)) +
GROSS_RECPT_SRCHG02 AS DECIMAL(10,2)) +
SE_TRUST_FUND AS DECIMAL(10,2)) +
DELIVERY_TAX AS DECIMAL(10,2)) +
IRA_CHARGE AS DECIMAL(10,2)) +
EA_TRUST_FUND AS DECIMAL(10,2)) +
M_GAS_SUPPLY_REALIGN AS DECIMAL(10,2)) +
SAVE AS DECIMAL(10,2)) +
WNA_ADJ AS DECIMAL(10,2)) +
PURCH_GAS_CHG_0 AS DECIMAL(10,2)) +
COMMODITY_CHG_0 AS DECIMAL(10,2)) +
DELIVERY_CHG_0 AS DECIMAL(10,2)) +
PGA_CHG_0 AS DECIMAL(10,2)) +
RPGA_CHG_0 AS DECIMAL(10,2)) +
ACA_CHG_0 AS DECIMAL(10,2)) +
CCA_FCA_CHG_0 AS DECIMAL(10,2)) +
CCA_0 AS DECIMAL(10,2)) +
SURCHARGE_0 AS DECIMAL(10,2)) +
OTHER_CHG_0 AS DECIMAL(10,2)) +
UTILITY_TAX_0 AS DECIMAL(10,2)) +
SALES_TAX_0 AS DECIMAL(10,2)) +
GAC_ACA_0 AS DECIMAL(10,2)) +
GAC_CURR_0 AS DECIMAL(10,2)) +
DISCOUNT_0 AS DECIMAL(10,2)) +
PRA_CHG_0 AS DECIMAL(10,2)) +
RSM_CHG_0 AS DECIMAL(10,2)) +
DSM_CURR_CHG_0 AS DECIMAL(10,2)) +
```

| BILLING_PERIOD | Avg. TOTAL BILL |
|---|---|
| 2017/01 | 148.66 |
| 2017/02 | 107.37 |
| 2017/03 | 101.12 |
| 2017/04 | 65.91 |
| 2017/05 | 38.08 |
| 2017/06 | 32.01 |
| 2017/07 | 25.51 |
| 2017/08 | 24.98 |
| 2017/09 | 25.47 |
| 2017/10 | 26.97 |
| 2017/11 | 59.55 |
| 2017/12 | 97.66 |
| 2018/01 | 157.33 |
| 2018/02 | 123.33 |
| 2018/03 | 102.16 |
| 2018/04 | 81.53 |
| 2018/05 | 40.82 |
| 2018/06 | 25.71 |
| 2018/07 | 23.13 |
| 2018/08 | 22.45 |
| 2018/09 | 23.27 |
| 2018/10 | 28.62 |
| 2018/11 | 68.3 |
| 2018/12 | 97.97 |
| 2019/01 | 121.67 |
| 2019/02 | 144.95 |
| 2019/03 | 107.17 |
| 2019/04 | 69.18 |
| 2019/05 | 34.19 |
| 2019/06 | 27.53 |
| 2019/07 | 23.53 |
| 2019/08 | 22.84 |
| 2019/09 | 22.87 |
| 2019/10 | 25.47 |
| 2019/11 | 63.77 |
| 2019/12 | 103.96 |
| 2020/01 | 109.06 |
| 2020/02 | 105.93 |
| 2020/03 | 77.79 |
| 2020/04 | 60.02 |
| 2020/05 | 59.21 |
| 2020/06 | 33.25 |
| 2020/07 | 27 |
| 2020/08 | 24.99 |
| 2020/09 | 25.7 |
| 2020/10 | 29.89 |

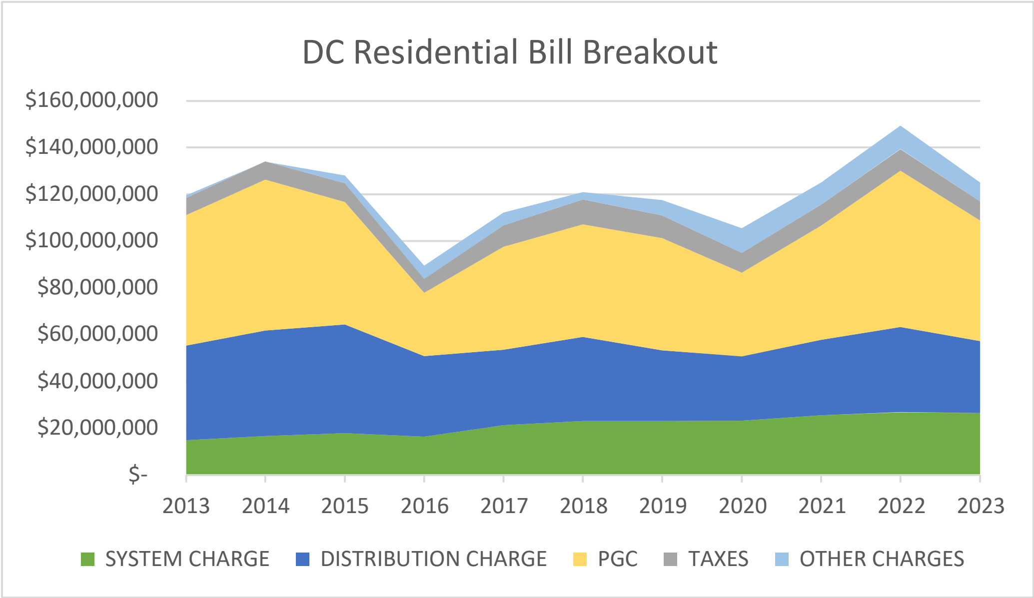
| | |
|---|---|
| 2020/11 | 52.3 |
| 2020/12 | 82.3 |
| 2021/01 | 123.02 |
| 2021/02 | 128.51 |
| 2021/03 | 117.96 |
| 2021/04 | 72.19 |
| 2021/05 | 51.14 |
| 2021/06 | 34.87 |
| 2021/07 | 30.07 |
| 2021/08 | 28.19 |
| 2021/09 | 28.51 |
| 2021/10 | 32.02 |
| 2021/11 | 68.77 |
| 2021/12 | 106.43 |
| 2022/01 | 146.86 |
| 2022/02 | 161.34 |
| 2022/03 | 112.8 |
| 2022/04 | 98.39 |
| 2022/05 | 60.04 |
| 2022/06 | 37.19 |
| 2022/07 | 32.83 |
| 2022/08 | 29.63 |
| 2022/09 | 32.45 |
| 2022/10 | 50.29 |
| 2022/11 | 68.49 |
| 2022/12 | 129.57 |
| 2023/01 | 166.32 |
| 2023/02 | 141.45 |
| 2023/03 | 90.33 |
| 2023/04 | 72.89 |
| 2023/05 | 41.29 |
| 2023/06 | 31.95 |
| 2023/07 | 27.31 |
| 2023/08 | 24.99 |
| 2023/09 | 27.51 |
| 2023/10 | 32.93 |
| 2023/11 | 64.22 |
| 2023/12 | 101.73 |

```
SELECT DISTINCT
VKONT AS "CONTRACT ACCOUNT",
BILLING_PERIOD,
BILLED_CON.BETRAG AS "TOTAL BILL"
FROM "_SYS_BIC"."wgl.production.models.BillingInvoice/CV_INVOICE_FROM_BILLING_QUERY"
('PLACEHOLDER' = ('$$IP_BILLING_PERIOD_DATE_RANGE$$', '*'),
'PLACEHOLDER' = ('$$IP_BILLING_PERIOD_RANGE$$','*'),
'PLACEHOLDER' = ('$$IP_END_BILLING_PERIOD_DATE_RANGE$$','20170101;20231231')) AS BILL
LEFT OUTER JOIN "_SYS_BIC"."wgl.production.models.base-table-view/DBERCHZ1_QUERY"  AS DBERCH
LEFT OUTER JOIN "_SYS_BIC"."wgl.production.models.base-table-view/ETTIFN_QUERY"  AS BILLED_CON
ON BILLED_CON.BELNR = BILL.BELNR AND BILLED_CON.OPERAND = 'BILLED_AMT'
WHERE STORNODAT = '00000000'
and AKLASSE = 'RES'
and SUBSTRING(VKONT,1,1) = '1'
```

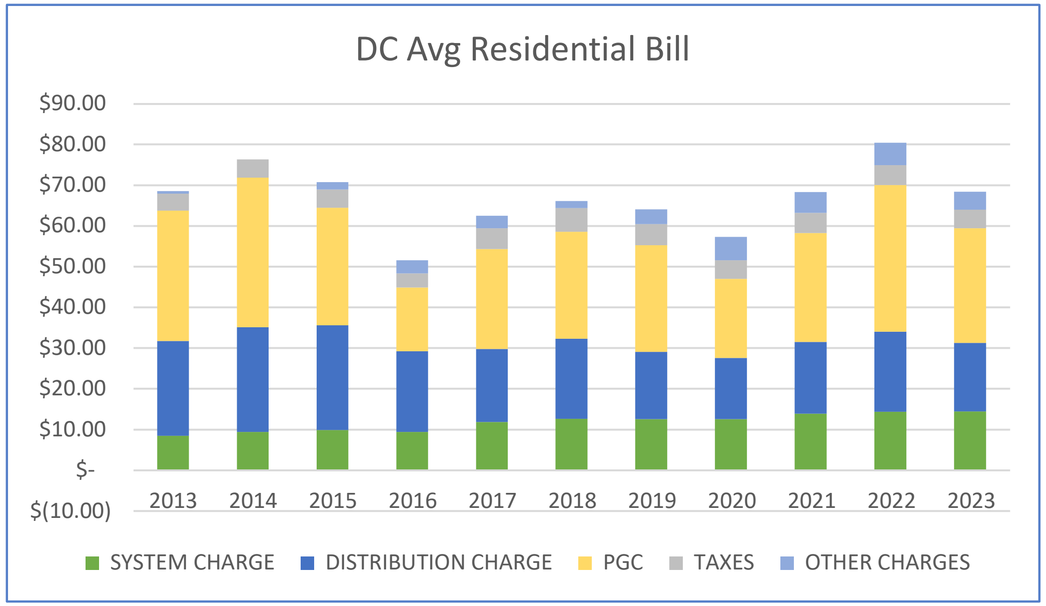
Z1 ON DBERCHZ1.BELNR = BILL.BELNR

***DC Residential Avg Bill***

| Year | RATE CLASS DESCRIPTION | Usage | COUNT | SYSTEM CHARGE | DISTRIBUTION CHARGE | PGC | TAXES | OTHER CHARGES | TOTAL CHARGES | AVERAGE BILL |
|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | RESIDENTIAL | 102,770,918 | 1,743,632 | $ 14,816,220 | $ 40,479,110 | $ 55,818,479 | $ 7,263,303 | $ 1,109,209 | $ 104,670,101 | $ 60.03 |
| 2014 | RESIDENTIAL | 110,847,653 | 1,755,374 | $ 16,502,092 | $ 45,142,408 | $ 64,544,095 | $ 7,831,004 | $ (154,867) | $ 117,362,640 | $ 66.86 |
| 2015 | RESIDENTIAL | 114,211,064 | 1,808,546 | $ 17,815,838 | $ 46,515,446 | $ 52,309,374 | $ 8,069,047 | $ 3,246,872 | $ 110,140,739 | $ 60.90 |
| 2016 | RESIDENTIAL | 84,621,857 | 1,734,709 | $ 16,265,183 | $ 34,472,899 | $ 27,102,457 | $ 5,978,915 | $ 5,659,537 | $ 73,213,808 | $ 42.21 |
| 2017 | RESIDENTIAL | 88,772,538 | 1,793,549 | $ 21,248,198 | $ 32,172,543 | $ 44,039,126 | $ 9,174,798 | $ 5,450,986 | $ 90,837,454 | $ 50.65 |
| 2018 | RESIDENTIAL | 103,157,320 | 1,829,286 | $ 23,041,206 | $ 35,975,875 | $ 48,099,902 | $ 10,623,305 | $ 3,201,261 | $ 97,900,343 | $ 53.52 |
| 2019 | RESIDENTIAL | 93,271,261 | 1,833,520 | $ 23,015,751 | $ 30,239,848 | $ 48,009,456 | $ 9,612,300 | $ 6,651,311 | $ 94,512,915 | $ 51.55 |
| 2020 | RESIDENTIAL | 82,132,803 | 1,840,274 | $ 23,137,839 | $ 27,577,929 | $ 35,719,080 | $ 8,483,611 | $ 10,516,167 | $ 82,296,787 | $ 44.72 |
| 2021 | RESIDENTIAL | 87,044,741 | 1,828,775 | $ 25,419,929 | $ 32,260,033 | $ 48,895,376 | $ 8,979,492 | $ 9,416,226 | $ 99,551,127 | $ 54.44 |
| 2022 | RESIDENTIAL | 88,333,473 | 1,858,588 | $ 26,756,017 | $ 36,483,193 | $ 66,881,522 | $ 9,187,380 | $ 10,122,622 | $ 122,674,716 | $ 66.00 |
| 2023 | RESIDENTIAL | 75,113,478 | 1,828,598 | $ 26,377,238 | $ 30,782,566 | $ 51,547,594 | $ 8,267,528 | $ 8,062,342 | $ 98,660,030 | $ 53.95 |


DC Residential Bill Breakout
$160,000,000
$140,000,000
$120,000,000
$100,000,000
$80,000,000
$60,000,000
$40,000,000
$20,000,000
$-
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
SYSTEM CHARGE
DISTRIBUTION CHARGE
PGC
TAXES
OTHER CHARGES

| ***Avg per Customer*** | | | ***Avg*** | ***Avg*** | ***Avg*** | ***Avg*** | ***Avg*** | ***Avg*** | ***Avg*** |
|---|---|---|---|---|---|---|---|---|---|
| ***Year*** | ***RATE CLASS DESCRIPTION*** | | ***Usage*** | ***SYSTEM CHARGE*** | ***DISTRIBUTION CHARGE*** | ***PGC*** | ***TAXES*** | ***OTHER CHARGES*** | ***TOTAL CHARGES*** |
| 2013 | RESIDENTIAL | | 59 | $ 8.50 | $ 23.22 | $ 32.01 | $ 4.17 | $ 0.64 | $ 60.03 |
| 2014 | RESIDENTIAL | | 63 | $ 9.40 | $ 25.72 | $ 36.77 | $ 4.46 | $ (0.09) | $ 66.86 |
| 2015 | RESIDENTIAL | | 63 | $ 9.85 | $ 25.72 | $ 28.92 | $ 4.46 | $ 1.80 | $ 60.90 |
| 2016 | RESIDENTIAL | | 49 | $ 9.38 | $ 19.87 | $ 15.62 | $ 3.45 | $ 3.26 | $ 42.21 |
| 2017 | RESIDENTIAL | | 49 | $ 11.85 | $ 17.94 | $ 24.55 | $ 5.12 | $ 3.04 | $ 50.65 |
| 2018 | RESIDENTIAL | | 56 | $ 12.60 | $ 19.67 | $ 26.29 | $ 5.81 | $ 1.75 | $ 53.52 |
| 2019 | RESIDENTIAL | | 51 | $ 12.55 | $ 16.49 | $ 26.18 | $ 5.24 | $ 3.63 | $ 51.55 |
| 2020 | RESIDENTIAL | | 45 | $ 12.57 | $ 14.99 | $ 19.41 | $ 4.61 | $ 5.71 | $ 44.72 |
| 2021 | RESIDENTIAL | | 48 | $ 13.90 | $ 17.64 | $ 26.74 | $ 4.91 | $ 5.15 | $ 54.44 |
| 2022 | RESIDENTIAL | | 48 | $ 14.40 | $ 19.63 | $ 35.99 | $ 4.94 | $ 5.45 | $ 66.00 |
| 2023 | RESIDENTIAL | | 41 | $ 14.42 | $ 16.83 | $ 28.19 | $ 4.52 | $ 4.41 | $ 53.95 |


DC Avg Residential Bill
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
$(10.00)
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
SYSTEM CHARGE
DISTRIBUTION CHARGE
PGC
TAXES
OTHER CHARGES

| ***Avg per Therm*** | | | | ***Avg*** | ***Avg*** | ***Avg*** | ***Avg*** | ***Avg*** | ***Avg*** |
|---|---|---|---|---|---|---|---|---|---|
| ***Year*** | ***RATE CLASS DESCRIPTION*** | | | ***SYSTEM CHARGE*** | ***DISTRIBUTION CHARGE*** | ***PGC*** | ***TAXES*** | ***OTHER CHARGES*** | ***TOTAL CHARGES*** |
| 2013 | RESIDENTIAL | | | $ 0.14 | $ 0.39 | $ 0.54 | $ 0.07 | $ 0.01 | $ 1.02 |
| 2014 | RESIDENTIAL | | | $ 0.15 | $ 0.41 | $ 0.58 | $ 0.07 | $ (0.00) | $ 1.06 |
| 2015 | RESIDENTIAL | | | $ 0.16 | $ 0.41 | $ 0.46 | $ 0.07 | $ 0.03 | $ 0.96 |
| 2016 | RESIDENTIAL | | | $ 0.19 | $ 0.41 | $ 0.32 | $ 0.07 | $ 0.07 | $ 0.87 |
| 2017 | RESIDENTIAL | | | $ 0.24 | $ 0.36 | $ 0.50 | $ 0.10 | $ 0.06 | $ 1.02 |
| 2018 | RESIDENTIAL | | | $ 0.22 | $ 0.35 | $ 0.47 | $ 0.10 | $ 0.03 | $ 0.95 |
| 2019 | RESIDENTIAL | | | $ 0.25 | $ 0.32 | $ 0.51 | $ 0.10 | $ 0.07 | $ 1.01 |
| 2020 | RESIDENTIAL | | | $ 0.28 | $ 0.34 | $ 0.43 | $ 0.10 | $ 0.13 | $ 1.00 |
| 2021 | RESIDENTIAL | | | $ 0.29 | $ 0.37 | $ 0.56 | $ 0.10 | $ 0.11 | $ 1.14 |
| 2022 | RESIDENTIAL | | | $ 0.30 | $ 0.41 | $ 0.76 | $ 0.10 | $ 0.11 | $ 1.39 |
| 2023 | RESIDENTIAL | | | $ 0.35 | $ 0.41 | $ 0.69 | $ 0.11 | $ 0.11 | $ 1.31 |

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-1

**Q.** **Revenue History**. Please respond to the following:

a. Provide (a) the base revenue, (b) other revenue (segregated by each surcharge, tracker, or rider), and (c) the total revenue by month for each current and proposed rate class for each of the years 2018 - 2023 and each month of 2024.

b. Describe each surcharge, tracker, or rider mechanism.

c. Itemize and explain the nature of the test year amounts recorded to "other revenue" (or similar) and explain what gave rise to the revenue.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** a. See the attachment titled OPC Data Request 1-1a.

b. Each tracker, surcharge or rider is described in the Company's tariff which is publicly available on the Washington Gas website.

c. Please refer to Exhibit WG (D)-5 Adjustment #1, pages 1 and 2.

SPONSOR: Andrew Lawson
Manager – Regulatory Affairs

CUBE: tm1serv:Rate Statistics DB
RS_ACTU/ DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Htg / HC Not assigned | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - IMA Not assigned | DC Res Non Htg - OTH 1 | DC Res Non Htg OTH Not assigned | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Htg / HC Not assigned | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC C&I Non Htg Not assigned | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | DC Interruptible Not assigned | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-2018 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 63,822 | 1,623 | - | 65,445 |
| Jan-2018 | PGC Rounding difference | (7) | (0) | (1) | (39) | (0) | (0) | (5) | (0) | (0) | 1 | - | (1) | (0) | (0) | (0) | (0) | (0) | 0 | - | - | - | (53) |
| Jan-2018 | ACA | (259,636) | (564) | (359) | (1,598) | (0) | (27) | (4,904) | (1) | (13,391) | (62,772) | - | (2,872) | (7,527) | (145) | (2,023) | (24,372) | (792) | (2,674) | - | - | - | (383,658) |
| Jan-2018 | DCA | (982,967) | (62) | (1,191) | (5,762) | (0) | (88) | (18,648) | (3) | (56,501) | (491,622) | (33,307) | (12,580) | (60,929) | (484) | (7,697) | (239,776) | (3,916) | (23,584) | - | - | - | (1,939,118) |
| Jan-2018 | GAC Current | 279,407 | (123) | 385 | 1,751 | 0 | 29 | 5,327 | 1 | 14,630 | 72,768 | - | 3,094 | 8,037 | 157 | 2,190 | 26,700 | 870 | 2,880 | - | - | - | 418,100 |
| Jan-2018 | Residential Essential Credit | (4,131) | (94) | (5) | (18) | - | (0) | (72) | (0) | (211) | (3,363) | - | (53) | (224) | (2) | (31) | (899) | (14) | (99) | (1,100) | (46) | (3) | (10,365) |
| Jan-2018 | RES Rider credit | (14,761) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (14,761) |
| Jan-2018 | Delivery Charge | 8,398,343 | (302) | 10,173 | 53,552 | 0 | 823 | 173,729 | 27 | 451,513 | 3,912,234 | 231,052 | 100,140 | 481,953 | 3,852 | 62,346 | 1,942,854 | 31,496 | 189,563 | 1,344,259 | 39,453 | 2,612 | 17,429,672 |
| Jan-2018 | Purchased Gas Charge | 7,699,738 | (6,979) | 10,608 | 48,037 | 0 | 787 | 146,699 | 26 | 403,596 | 2,015,381 | - | 85,275 | 220,879 | 4,314 | 60,358 | 736,830 | 24,021 | 79,356 | - | - | - | 11,528,926 |
| Jan-2018 | System Charge | 1,693,398 | 784 | 6,986 | 117,660 | 10 | 1,965 | 41,164 | 86 | 93,595 | 196,180 | - | 35,807 | 15,027 | 23 | 11,694 | 94,336 | 11,579 | 7,911 | 13,025 | 907 | 100 | 2,342,236 |
| Jan-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | 32,171 | 359,957 | - | 8,112 | 43,763 | 313 | 4,875 | 174,627 | 2,557 | 15,570 | - | - | - | 641,947 |
| Jan-2018 | DC Right of Way Tax | 671,140 | (24) | 813 | 3,924 | 0 | 60 | 12,735 | 2 | 38,597 | 334,424 | 22,741 | 8,590 | 41,616 | 330 | 5,256 | 163,795 | 2,676 | 16,102 | 299,506 | 7,443 | 499 | 1,630,225 |
| Jan-2018 | DC Right of Way Adjustment | 86,727 | (16) | 105 | 499 | - | 8 | 1,647 | 0 | 4,987 | 43,243 | 2,939 | 1,110 | 5,411 | 43 | 679 | 21,164 | 346 | 2,081 | 38,890 | 962 | 65 | 210,889 |
| Jan-2018 | SE Trust Fund | 309,923 | (11) | 376 | 1,828 | 0 | 28 | 5,897 | 1 | 17,873 | 154,864 | 10,531 | 3,977 | 19,287 | 153 | 2,434 | 75,849 | 1,239 | 7,457 | 138,677 | 3,447 | 231 | 754,061 |
| Jan-2018 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 182,382 | - | - | 182,382 |
| Jan-2018 | Delivery Tax | 1,459,957 | (52) | 1,769 | 8,546 | 0 | 131 | 27,702 | 4 | 92,357 | 800,249 | 54,418 | 20,554 | 99,693 | 791 | 11,434 | 356,316 | 5,820 | 35,029 | 705,946 | 17,436 | 1,195 | 3,699,293 |
| Jan-2018 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 3,042 | - | - | 3,042 |
| Jan-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 225 | - | - | 225 |
| Jan-2018 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 7,953 | - | - | 7,953 |
| Jan-2018 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 29 | - | - | 29 |
| Jan-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | 10,076 | - | - | - | - | - | - | - | 18,159 | 451 | 31 | 28,717 |
| Jan-2018 | STORAGE GAS CHRG | 143,335 | (76) | 198 | 898 | 0 | 15 | 2,733 | 0 | 7,503 | 37,331 | - | 1,587 | 4,145 | 80 | 1,123 | 13,691 | 446 | 1,477 | - | - | - | 214,487 |
| Jan-2018 | EA Trust Fund | 171,674 | 50 | 209 | 1,021 | 0 | 16 | 3,264 | 1 | 9,879 | 85,760 | 5,833 | 2,204 | 10,634 | 85 | 1,348 | 41,970 | 685 | 4,130 | 76,205 | 1,909 | 128 | 417,003 |
| Jan-2018 | PRA | 9 | (19) | (1) | - | - | - | 18 | - | 5 | 66 | - | 0 | 140 | - | - | (3) | 0 | - | 1,794 | - | - | 2,009 |
| Jan-2018 | APRP | 724,827 | 6 | 879 | 4,249 | 0 | 65 | 13,746 | 2 | 12,006 | 103,892 | 7,067 | 2,669 | 12,908 | 103 | 1,714 | 53,485 | 872 | 5,252 | 41,763 | 1,031 | 69 | 986,608 |
| | **TOTAL** | **20,376,975** | **(7,481)** | **30,943** | **234,548** | **10** | **3,810** | **411,031** | **147** | **1,108,608** | **7,558,594** | **311,350** | **257,614** | **894,814** | **9,611** | **155,701** | **3,436,566** | **77,884** | **340,451** | **2,934,576** | **74,615** | **4,927** | **38,215,294** |
| Feb-2018 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 84,416 | 2,751 | - | 87,168 |
| Feb-2018 | PGC Rounding difference | (19) | (0) | (0) | (17) | - | (0) | (0) | - | (0) | 0 | - | 0 | (0) | (0) | 0 | (0) | 0 | (0) | - | - | - | (37) |
| Feb-2018 | ACA | (217,360) | (336) | (347) | (1,394) | - | (41) | (3,755) | (1) | (12,366) | (51,110) | - | (2,235) | (6,174) | (97) | (3,197) | (22,904) | (732) | (2,476) | - | - | - | (324,522) |
| Feb-2018 | DCA | (822,975) | (1,382) | (1,183) | (5,109) | - | (135) | (14,328) | (3) | (51,364) | (426,062) | - | (9,953) | (75,218) | (322) | (10,497) | (207,565) | (3,593) | (19,366) | - | - | - | (1,649,054) |
| Feb-2018 | GAC Current | 234,002 | 362 | 383 | 1,533 | - | 44 | 4,046 | 1 | 13,317 | 55,201 | - | 2,410 | 6,657 | 104 | 3,101 | 25,045 | 788 | 2,667 | - | - | - | 349,660 |
| Feb-2018 | Residential Essential Credit | (3,293) | (6) | (4) | (15) | - | (1) | (58) | (0) | (216) | (1,735) | - | (39) | (161) | (1) | (80) | (829) | (15) | (87) | (2,212) | 44 | (3) | (8,710) |
| Feb-2018 | RES Rider credit | (200,674) | (31) | (51) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (200,756) |
| Feb-2018 | Delivery Charge | 7,031,413 | 11,806 | 10,117 | 47,444 | - | 1,259 | 133,449 | 30 | 410,250 | 3,403,547 | - | 79,245 | 600,482 | 2,564 | 84,643 | 1,681,438 | 28,875 | 155,601 | 1,506,719 | 43,830 | 2,631 | 15,235,342 |
| Feb-2018 | Purchased Gas Charge | 7,546,042 | 11,399 | 12,397 | 48,920 | - | 1,328 | 131,071 | 34 | 430,567 | 1,777,731 | - | 78,163 | 216,044 | 3,386 | 98,131 | 808,697 | 25,593 | 86,628 | - | - | - | 11,276,130 |
| Feb-2018 | System Charge | 1,791,195 | 893 | 7,536 | 116,977 | 10 | 1,958 | 41,222 | 72 | 91,776 | 171,251 | - | 35,112 | 17,524 | 39 | 11,490 | 92,313 | 11,427 | 7,583 | 14,600 | 1,400 | 100 | 2,414,477 |
| Feb-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | 36,302 | 342,226 | - | 8,865 | 41,647 | 327 | 7,689 | 171,850 | 2,553 | 14,583 | - | - | - | 626,043 |
| Feb-2018 | DC Right of Way Tax | 561,911 | 943 | 809 | 3,477 | - | 92 | 9,782 | 2 | 35,069 | 290,941 | - | 6,797 | 51,506 | 220 | 7,136 | 141,756 | 2,453 | 13,218 | 359,425 | 8,228 | 503 | 1,494,269 |
| Feb-2018 | DC Right of Way Adjustment | 72,616 | 122 | 105 | 438 | - | 12 | 1,264 | 0 | 4,532 | 37,614 | - | 879 | 6,656 | 28 | 922 | 18,319 | 317 | 1,708 | 46,449 | 1,063 | 65 | 193,110 |
| Feb-2018 | SE Trust Fund | 248,493 | 435 | 372 | 1,623 | - | 43 | 4,529 | 1 | 16,239 | 134,727 | - | 3,147 | 23,851 | 102 | 3,304 | 65,644 | 1,136 | 6,121 | 166,442 | 3,810 | 233 | 680,252 |
| Feb-2018 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (254,130) | - | - | (254,130) |
| Feb-2018 | Delivery Tax | 1,222,329 | 2,052 | 1,759 | 7,572 | - | 201 | 21,279 | 5 | 83,917 | 696,196 | - | 16,265 | 123,250 | 526 | 15,523 | 308,373 | 5,336 | 28,753 | 847,319 | 19,256 | 1,204 | 3,401,114 |
| Feb-2018 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,120,511 | 20,927 | 921 | 1,142,360 |
| Feb-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 225 | - | - | 225 |
| Feb-2018 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 326,374 | 5,203 | 208 | 331,785 |
| Feb-2018 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (10,461) | - | - | (10,461) |
| Feb-2018 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 4,455 | 339 | 40 | 4,834 |
| Feb-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 21,812 | 496 | 31 | 22,340 |
| Feb-2018 | STORAGE GAS CHRG | 120,038 | 186 | 197 | 785 | - | 22 | 2,076 | 1 | 6,832 | 28,325 | - | 1,236 | 3,415 | 53 | 1,592 | 12,847 | 404 | 1,368 | - | - | - | 179,377 |
| Feb-2018 | EA Trust Fund | 137,650 | 241 | 205 | 907 | - | 24 | 2,510 | 1 | 8,996 | 74,569 | - | 1,742 | 13,212 | 56 | 1,843 | 36,344 | 629 | 3,391 | 92,189 | 2,080 | 129 | 376,718 |
| Feb-2018 | PRA | (107,010) | (158) | (153) | (631) | - | (11) | (1,918) | (0) | (6,799) | (54,622) | - | (1,335) | (6,943) | (44) | (1,296) | (27,727) | (489) | (2,720) | (68,495) | (1,447) | (101) | (281,899) |
| Feb-2018 | APRP | 606,837 | 1,019 | 871 | 3,768 | - | 100 | 10,565 | 2 | 10,899 | 90,395 | - | 2,112 | 16,007 | 68 | 2,327 | 46,234 | 800 | 4,311 | 49,767 | 1,139 | 70 | 847,290 |
| | **TOTAL** | **18,221,196** | **27,546** | **33,012** | **226,277** | **10** | **4,895** | **341,735** | **144** | **1,077,950** | **6,569,196** | **-** | **222,411** | **1,031,756** | **7,010** | **222,632** | **3,149,834** | **75,483** | **301,281** | **4,305,406** | **109,121** | **6,031** | **35,932,926** |
| Mar-2018 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 48,839 | 2,403 | - | 51,242 |
| Mar-2018 | PGC Rounding difference | 2 | (0) | (0) | (38) | - | (0) | (0) | - | 1 | (0) | - | (0) | (0) | 0 | (0) | 0 | 0 | 0 | - | - | - | (36) |
| Mar-2018 | ACA | (162,008) | (313) | (267) | (1,137) | - | (33) | (3,035) | (1) | (9,373) | (40,284) | - | (2,113) | (5,453) | (82) | (1,835) | (18,588) | (609) | (2,158) | - | - | - | (247,290) |
| Mar-2018 | DCA | (641,337) | (1,339) | (929) | (4,252) | - | (114) | (11,983) | (3) | (38,180) | (351,862) | (63,308) | (9,445) | (48,244) | (285) | (11,422) | (185,209) | (3,061) | (18,591) | - | - | - | (1,389,563) |
| Mar-2018 | GAC Current | 181,929 | 351 | 300 | 1,284 | - | 37 | 3,409 | 1 | 10,536 | 40,268 | - | 2,373 | 6,129 | 92 | 2,056 | 20,885 | 687 | 2,426 | - | - | - | 272,762 |
| Mar-2018 | Residential Essential Credit | (2,643) | (6) | (4) | (13) | - | (0) | (48) | (0) | (153) | (2,047) | - | (39) | (248) | (1) | (48) | (778) | (13) | (78) | (1,361) | (38) | (3) | (7,521) |
| Mar-2018 | RES Rider credit | (83,500) | (20) | (20) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (83,541) |
| Mar-2018 | Delivery Charge | 5,479,871 | 11,440 | 7,935 | 39,457 | - | 1,064 | 111,622 | 27 | 305,022 | 2,806,213 | 439,165 | 75,183 | 383,686 | 2,267 | 92,503 | 1,499,960 | 24,603 | 149,436 | 1,209,806 | 33,101 | 2,165 | 12,674,524 |
| Mar-2018 | Purchased Gas Charge | 5,042,707 | 9,914 | 8,350 | 35,595 | - | 1,077 | 94,556 | 26 | 292,222 | 1,101,047 | - | 65,968 | 169,746 | 2,521 | 57,664 | 580,000 | 19,020 | 67,182 | - | - | - | 7,547,594 |
| Mar-2018 | System Charge | 1,728,280 | 923 | 8,280 | 117,189 | 10 | 2,067 | 41,021 | 64 | 92,736 | 191,597 | - | 35,233 | 17,017 | 42 | 11,469 | 92,276 | 11,889 | 7,627 | 13,400 | 1,200 | 100 | 2,372,419 |
| Mar-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | 36,519 | 325,219 | - | 7,918 | 39,908 | 304 | 6,612 | 175,408 | 2,657 | 15,035 | - | - | - | 609,579 |
| Mar-2018 | DC Right of Way Tax | 437,929 | 914 | 634 | 2,891 | - | 78 | 8,182 | 2 | 26,074 | 239,862 | 43,225 | 6,449 | 32,909 | 194 | 7,799 | 126,456 | 2,090 | 12,694 | 261,214 | 6,177 | 414 | 1,216,188 |
| Mar-2018 | DC Right of Way Adjustment | 56,589 | 118 | 82 | 362 | - | 10 | 1,057 | 0 | 3,369 | 30,877 | 5,586 | 833 | 4,245 | 25 | 1,008 | 16,342 | 270 | 1,640 | 33,757 | 798 | 53 | 157,023 |
| Mar-2018 | SE Trust Fund | 198,302 | 422 | 293 | 1,350 | - | 36 | 3,788 | 1 | 12,074 | 111,082 | 20,016 | 2,986 | 15,240 | 90 | 3,611 | 58,559 | 968 | 5,878 | 120,962 | 2,860 | 192 | 558,711 |
| Mar-2018 | Delivery Tax | 952,604 | 1,989 | 1,380 | 6,299 | - | 170 | 17,798 | 4 | 62,392 | 571,502 | 103,434 | 15,432 | 78,752 | 465 | 16,965 | 275,090 | 4,546 | 27,614 | 616,177 | 14,486 | 990 | 2,768,090 |
| Mar-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 4,625 | - | - | 4,625 |

CUBE: tm1serv:Rate Statistics DB
RS_ACTU/ DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Htg / HC Not assigned | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - IMA Not assigned | DC Res Non Htg - OTH 1 | DC Res Non Htg OTH Not assigned | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Htg / HC Not assigned | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC C&I Non Htg Not assigned | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | DC Interruptible Not assigned | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mar-2018 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (22,525) | - | - | **(22,525)** |
| Mar-2018 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 2 | - | - | **2** |
| Mar-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | 21,859 | - | - | - | - | - | - | - | 15,871 | 370 | 25 | **38,126** |
| Mar-2018 | STORAGE GAS CHRG | 100,395 | 192 | 166 | 712 | - | 20 | 1,881 | 1 | 5,812 | 22,332 | - | 1,308 | 3,383 | 51 | 1,129 | 11,519 | 379 | 1,339 | - | - | - | **150,617** |
| Mar-2018 | EA Trust Fund | 109,887 | 234 | 163 | 759 | - | 20 | 2,100 | 1 | 6,686 | 62,034 | 11,087 | 1,655 | 8,481 | 50 | 2,000 | 32,435 | 536 | 3,256 | 66,999 | 1,584 | 106 | **310,070** |
| Mar-2018 | PRA | (87,578) | (183) | (127) | (585) | - | (16) | (1,638) | (0) | (5,181) | (50,464) | (8,645) | (1,289) | (6,763) | (39) | (1,561) | (25,001) | (416) | (2,539) | (52,148) | (1,235) | (83) | **(245,490)** |
| Mar-2018 | APRP | 472,934 | 987 | 685 | 3,135 | - | 84 | 8,832 | 2 | 8,102 | 74,600 | 13,433 | 2,004 | 10,226 | 60 | 2,544 | 41,243 | 682 | 4,140 | 36,168 | 855 | 57 | **680,774** |
| | **TOTAL** | **13,784,364** | **25,622** | **26,920** | **203,008** | **10** | **4,499** | **277,541** | **124** | **808,658** | **5,131,975** | **585,853** | **204,456** | **709,015** | **5,756** | **190,493** | **2,700,597** | **64,226** | **274,900** | **2,351,786** | **62,562** | **4,018** | **27,416,381** |
| Apr-2018 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 82,145 | 2,701 | - | **84,847** |
| Apr-2018 | PGC Rounding difference | (80) | (0) | (1) | (40) | (0) | (0) | (3) | (0) | (1) | (0) | - | (0) | (0) | 0 | (0) | (0) | (0) | 0 | - | - | - | **(127)** |
| Apr-2018 | ACA | (140,547) | (213) | (271) | (1,028) | (0) | (15) | (2,446) | 0 | (8,004) | (38,401) | - | (1,981) | (4,885) | (52) | (1,344) | (17,203) | (594) | (1,916) | - | - | - | **(218,900)** |
| Apr-2018 | DCA | (557,444) | (948) | (945) | (4,003) | (0) | (51) | (9,726) | 0 | (33,939) | (344,630) | (33,244) | (8,650) | (45,875) | (181) | (5,260) | (152,685) | (3,009) | (16,145) | - | - | - | **(1,216,734)** |
| Apr-2018 | GAC Current | 157,981 | 240 | 306 | 1,179 | 0 | 17 | 2,752 | (0) | 8,985 | 42,733 | - | 2,186 | 5,491 | 59 | 1,511 | 19,842 | 669 | 2,154 | - | - | - | **246,105** |
| Apr-2018 | Residential Essential Credit | (2,202) | (4) | (4) | (11) | - | (0) | (41) | 0 | (144) | (1,445) | - | (40) | (147) | (1) | (22) | (641) | (13) | (68) | (1,812) | (45) | (3) | **(6,640)** |
| Apr-2018 | RES Rider credit | (174,419) | (23) | (23) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(174,465)** |
| Apr-2018 | Delivery Charge | 4,762,186 | 8,098 | 8,071 | 37,133 | 0 | 475 | 90,547 | (1) | 271,049 | 2,752,568 | 230,609 | 68,799 | 365,522 | 1,443 | 42,598 | 1,236,553 | 24,186 | 129,770 | 1,385,278 | 38,826 | 2,450 | **11,456,159** |
| Apr-2018 | Purchased Gas Charge | 4,380,757 | 6,639 | 8,460 | 32,368 | 0 | 456 | 76,202 | (1) | 249,100 | 1,184,948 | - | 60,591 | 152,083 | 1,624 | 41,858 | 553,131 | 18,521 | 59,646 | - | - | - | **6,826,384** |
| Apr-2018 | System Charge | 1,770,911 | 860 | 8,636 | 116,832 | 10 | 1,996 | 40,701 | 63 | 91,455 | 188,515 | - | 35,173 | 17,853 | 42 | 11,485 | 91,970 | 11,455 | 7,676 | 13,100 | 1,200 | 100 | **2,410,033** |
| Apr-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | 37,077 | 343,519 | - | 8,848 | 41,194 | 317 | 5,406 | 165,317 | 2,586 | 15,126 | - | - | - | **619,390** |
| Apr-2018 | DC Right of Way Tax | 375,971 | 640 | 637 | 2,687 | 0 | 34 | 6,555 | (0) | 22,894 | 232,712 | 22,418 | 5,831 | 30,983 | 122 | 3,547 | 102,961 | 2,029 | 10,889 | 314,052 | 7,163 | 463 | **1,142,589** |
| Apr-2018 | DC Right of Way Adjustment | 49,172 | 84 | 83 | 340 | - | 4 | 856 | (0) | 2,994 | 30,418 | 2,933 | 762 | 4,060 | 16 | 464 | 13,472 | 266 | 1,425 | 41,091 | 937 | 61 | **149,438** |
| Apr-2018 | SE Trust Fund | 166,554 | 298 | 297 | 1,273 | 0 | 16 | 3,073 | (0) | 10,729 | 108,959 | 10,511 | 2,732 | 14,519 | 57 | 1,663 | 48,275 | 951 | 5,105 | 147,242 | 3,359 | 217 | **525,831** |
| Apr-2018 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 12,810 | - | - | **12,810** |
| Apr-2018 | Delivery Tax | 827,850 | 1,408 | 1,403 | 5,928 | 0 | 76 | 14,438 | (0) | 55,443 | 563,039 | 54,314 | 14,121 | 75,024 | 296 | 7,812 | 226,782 | 4,469 | 23,980 | 750,862 | 16,993 | 1,121 | **2,645,359** |
| Apr-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,650 | - | - | **2,650** |
| Apr-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | 13,060 | - | - | - | - | - | - | - | 19,224 | 435 | 29 | **32,748** |
| Apr-2018 | STORAGE GAS CHRG | 87,138 | 132 | 169 | 657 | 0 | 9 | 1,519 | (0) | 4,957 | 23,610 | - | 1,206 | 3,031 | 32 | 834 | 10,926 | 369 | 1,189 | - | - | - | **135,778** |
| Apr-2018 | EA Trust Fund | 92,300 | 165 | 165 | 714 | 0 | 9 | 1,706 | (0) | 5,945 | 60,308 | 5,822 | 1,514 | 8,003 | 32 | 921 | 26,739 | 527 | 2,827 | 81,555 | 1,860 | 120 | **291,232** |
| Apr-2018 | PRA | (76,049) | (129) | (129) | (551) | (0) | (7) | (1,338) | 0 | (4,664) | (47,369) | (4,540) | (1,180) | (6,041) | (25) | (718) | (20,850) | (410) | (2,205) | (63,510) | (1,451) | (94) | **(231,256)** |
| Apr-2018 | APRP | 411,037 | 699 | 697 | 2,953 | 0 | 38 | 7,177 | (0) | 7,201 | 73,109 | 7,054 | 1,834 | 9,744 | 38 | 1,171 | 34,001 | 670 | 3,595 | 44,026 | 1,004 | 65 | **606,113** |
| | **TOTAL** | **12,131,116** | **17,945** | **27,552** | **196,431** | **10** | **3,057** | **231,973** | **61** | **721,077** | **5,172,593** | **308,938** | **191,747** | **670,559** | **3,820** | **111,927** | **2,338,589** | **62,673** | **243,049** | **2,828,715** | **72,984** | **4,528** | **25,339,343** |
| May-2018 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 31,765 | 1,223 | - | **32,988** |
| May-2018 | PGC Rounding difference | (74) | (0) | (1) | (33) | - | (0) | (3) | (0) | (2) | (0) | - | (1) | 0 | 0 | (0) | (0) | (0) | 0 | - | - | - | **(115)** |
| May-2018 | ACA | (58,179) | (88) | (92) | (622) | - | (426) | (1,125) | (0) | (5,087) | (22,667) | - | (1,148) | (3,703) | (9) | (1,695) | (8,943) | (584) | (1,407) | - | - | - | **(105,774)** |
| May-2018 | DCA | (232,742) | (394) | (323) | (2,345) | - | (1,450) | (4,577) | (1) | (19,934) | (182,251) | (31,955) | (4,804) | (35,732) | (33) | (1,889) | (79,958) | (2,766) | (11,637) | - | - | - | **(612,791)** |
| May-2018 | GAC Current | 65,398 | 99 | 104 | 718 | - | 469 | 1,285 | 0 | 5,696 | 25,067 | - | 1,078 | 4,419 | 11 | 1,891 | 10,052 | 657 | 1,581 | - | - | - | **118,525** |
| May-2018 | Residential Essential Credit | (891) | (2) | (1) | (5) | - | (6) | (14) | - | (83) | (777) | - | (49) | (118) | (0) | (8) | (334) | (12) | (49) | (1,266) | (30) | (2) | **(3,645)** |
| May-2018 | RES Rider credit | (406) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(406)** |
| May-2018 | Delivery Charge | 1,988,064 | 3,369 | 2,750 | 21,674 | - | 13,509 | 42,625 | 5 | 159,205 | 1,477,784 | 221,673 | 38,007 | 284,702 | 261 | 15,297 | 647,682 | 22,234 | 93,536 | 933,622 | 25,758 | 1,493 | **5,993,249** |
| May-2018 | Purchased Gas Charge | 1,810,925 | 2,744 | 2,867 | 19,549 | - | 13,985 | 35,645 | 4 | 158,739 | 706,618 | - | 29,108 | 122,928 | 294 | 53,649 | 278,394 | 18,188 | 43,798 | - | - | - | **3,297,434** |
| May-2018 | System Charge | 1,746,951 | 875 | 8,710 | 117,644 | 10 | 2,201 | 41,106 | 65 | 91,770 | 190,379 | - | 34,582 | 17,172 | 23 | 11,879 | 90,563 | 11,540 | 7,695 | 12,900 | 1,200 | 100 | **2,387,363** |
| May-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | 1,390 | 6,326 | - | (500) | (513) | - | 1,766 | 1,339 | 290 | 97 | - | - | - | **10,194** |
| May-2018 | DC Right of Way Tax | 156,913 | 266 | 217 | 1,566 | - | 987 | 3,086 | 0 | 13,459 | 123,063 | 21,550 | 3,211 | 24,122 | 22 | 1,249 | 53,923 | 1,867 | 7,848 | 213,977 | 4,788 | 282 | **632,395** |
| May-2018 | DC Right of Way Adjustment | 20,516 | 35 | 28 | 194 | - | 128 | 404 | 0 | 1,758 | 16,088 | 2,820 | 421 | 3,156 | 3 | 167 | 7,050 | 244 | 1,027 | 27,997 | 626 | 37 | **82,698** |
| May-2018 | SE Trust Fund | 70,391 | 124 | 102 | 751 | - | 459 | 1,448 | 0 | 6,303 | 57,645 | 10,103 | 1,510 | 11,308 | 10 | 597 | 25,284 | 875 | 3,679 | 100,322 | 2,245 | 132 | **293,289** |
| May-2018 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 9,036 | - | - | **9,036** |
| May-2018 | Delivery Tax | 345,668 | 586 | 479 | 3,461 | - | 2,154 | 6,800 | 1 | 32,566 | 297,898 | 52,209 | 7,801 | 58,435 | 54 | 2,806 | 118,779 | 4,109 | 17,284 | 512,520 | 11,374 | 683 | **1,475,665** |
| May-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,425 | - | - | **2,425** |
| May-2018 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (8,249) | - | - | **(8,249)** |
| May-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | 12,554 | - | - | - | - | - | - | - | 13,199 | 293 | 18 | **26,064** |
| May-2018 | STORAGE GAS CHRG | 36,111 | 55 | 58 | 394 | - | 250 | 709 | 0 | 3,128 | 13,637 | - | 607 | 2,436 | 6 | 1,030 | 5,548 | 362 | 873 | - | - | - | **65,205** |
| May-2018 | EA Trust Fund | 39,019 | 69 | 56 | 417 | - | 254 | 800 | 0 | 3,492 | 31,932 | 5,596 | 851 | 6,248 | 6 | 331 | 14,026 | 484 | 2,038 | 55,567 | 1,243 | 73 | **162,501** |
| May-2018 | PRA | (124) | 1 | 5 | 2 | - | (177) | 0 | - | (205) | (1,832) | - | 49 | 10 | - | 366 | 72 | (61) | (11) | (92) | - | - | **(1,997)** |
| May-2018 | APRP | 171,574 | 291 | 238 | 1,730 | - | 1,070 | 3,367 | 0 | 4,229 | 39,114 | 6,780 | 1,013 | 7,589 | 7 | 421 | 17,810 | 616 | 2,591 | 29,997 | 671 | 40 | **289,147** |
| | **TOTAL** | **6,159,112** | **8,029** | **15,197** | **165,096** | **10** | **33,406** | **131,556** | **75** | **456,424** | **2,778,023** | **301,330** | **111,737** | **502,458** | **654** | **87,856** | **1,181,287** | **58,043** | **168,945** | **1,933,720** | **49,391** | **2,856** | **14,145,202** |
| Jun-2018 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 8,439 | - | - | **8,439** |
| Jun-2018 | PGC Rounding difference | (87) | (0) | (1) | (29) | - | (0) | (3) | (0) | (2) | (1) | - | (1) | (0) | (0) | (0) | (0) | (0) | (0) | - | - | - | **(124)** |
| Jun-2018 | ACA | (24,973) | (57) | (53) | (567) | - | (24) | (604) | (0) | (3,246) | (22,758) | - | (1,054) | (3,555) | (74) | 256 | (4,139) | (370) | (1,111) | - | - | - | **(62,330)** |
| Jun-2018 | DCA | (100,346) | (226) | (186) | (2,147) | - | (85) | (2,424) | (1) | (12,005) | (196,444) | 31,955 | (5,108) | (56,083) | (257) | 975 | (41,882) | (1,877) | (10,496) | - | - | - | **(396,635)** |
| Jun-2018 | GAC Current | 28,153 | 64 | 60 | 661 | - | 27 | 683 | 0 | 3,593 | 27,142 | - | 1,185 | 3,996 | 83 | (608) | 4,725 | 416 | 1,249 | - | - | - | **71,430** |
| Jun-2018 | Residential Essential Credit | (225) | (1) | (0) | (3) | - | (0) | (5) | - | (55) | (409) | - | (21) | (236) | (1) | (34) | (155) | (8) | (27) | (107) | (17) | (0) | **(1,304)** |
| Jun-2018 | RES Rider credit | (1,133) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(1,133)** |
| Jun-2018 | Delivery Charge | 856,463 | 1,930 | 1,579 | 19,837 | - | 788 | 22,553 | 7 | 95,809 | 1,572,837 | (221,673) | 40,651 | 446,423 | 2,048 | (8,271) | 339,327 | 15,084 | 84,497 | 201,922 | 15,793 | - | **3,487,604** |
| Jun-2018 | Purchased Gas Charge | 749,088 | 1,708 | 1,592 | 17,463 | - | 730 | 18,160 | 6 | 96,995 | 755,036 | - | 31,568 | 106,460 | 2,218 | (18,321) | 126,383 | 11,091 | 33,276 | - | - | - | **1,933,452** |
| Jun-2018 | System Charge | 1,742,538 | 858 | 9,232 | 118,005 | 10 | 2,239 | 40,844 | 75 | 90,964 | 194,027 | - | 34,919 | 17,421 | 68 | 11,191 | 92,502 | 11,584 | 8,036 | 12,503 | 2,107 | 100 | **2,389,224** |
| Jun-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | (71) | 33,513 | - | - | 11,405 | - | (5,957) | 2,355 | - | 116 | - | - | - | **41,362** |
| Jun-2018 | DC Right of Way Tax | 67,554 | 152 | 124 | 1,432 | - | 57 | 1,631 | 0 | 8,085 | 133,206 | (21,550) | 3,444 | 37,958 | 174 | (714) | 28,287 | 1,266 | 7,097 | 6,380 | 3,250 | 38 | **277,872** |
| Jun-2018 | DC Right of Way Adjustment | 1,523 | 3 | 2 | 37 | - | 1 | 36 | 0 | 437 | 9,255 | (2,820) | 81 | 2,535 | 4 | (203) | 926 | 27 | 237 | (8,447) | 88 | 1 | **3,723** |
| Jun-2018 | SE Trust Fund | 30,215 | 71 | 58 | 690 | - | 27 | 769 | 0 | 3,794 | 62,260 | (10,103) | 1,615 | 17,732 | 81 | (323) | 13,248 | 593 | 3,324 | 2,991 | 1,523 | 18 | **128,586** |

CUBE: tm1serv:Rate Statistics DB
RS_ACTU/ DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Htg / HC Not assigned | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - IMA Not assigned | DC Res Non Htg - OTH 1 | DC Res Non Htg OTH Not assigned | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Htg / HC Not assigned | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC C&I Non Htg Not assigned | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | DC Interruptible Not assigned | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jun-2018 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 362 | - | **362** |
| Jun-2018 | Delivery Tax | 149,020 | 336 | 275 | 3,167 | - | 126 | 3,600 | 1 | 19,599 | 321,725 | (52,209) | 8,344 | 91,629 | 420 | (1,516) | 62,236 | 2,788 | 15,614 | 13,342 | 7,780 | 92 | **646,368** |
| Jun-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 16,790 | 20,700 | 225 | **37,715** |
| Jun-2018 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (422) | - | - | **(422)** |
| Jun-2018 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 43 | - | **43** |
| Jun-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | (12,554) | - | - | - | - | - | - | - | 361 | 202 | 2 | **(11,988)** |
| Jun-2018 | STORAGE GAS CHRG | 15,537 | 35 | 33 | 360 | - | 15 | 377 | 0 | 1,984 | 14,804 | - | 654 | 2,206 | 46 | (298) | 2,606 | 230 | 689 | - | - | - | **39,279** |
| Jun-2018 | EA Trust Fund | 16,733 | 40 | 32 | 381 | - | 15 | 425 | 0 | 2,102 | 34,290 | (5,596) | 895 | 9,822 | 45 | (165) | 7,317 | 329 | 1,826 | 1,657 | 843 | 10 | **71,000** |
| Jun-2018 | PRA | (50) | - | (0) | (25) | - | - | 0 | - | (78) | (6,238) | - | 0 | (2,938) | - | (5) | (366) | - | (55) | 92 | - | - | **(9,664)** |
| Jun-2018 | APRP | 66,676 | 150 | 123 | 1,436 | - | 56 | 1,610 | 0 | 2,864 | 45,961 | (6,780) | 1,273 | 13,141 | 64 | (179) | 10,520 | 477 | 2,637 | 3,016 | 532 | 6 | **143,585** |
| | **TOTAL** | **3,596,685** | **5,063** | **12,871** | **160,698** | **10** | **3,973** | **87,651** | **90** | **310,769** | **2,978,206** | **(301,330)** | **118,446** | **697,917** | **4,920** | **(24,173)** | **643,891** | **41,630** | **146,908** | **258,518** | **53,206** | **492** | **8,796,442** |
| Jul-2018 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 5,129 | - | - | **5,129** |
| Jul-2018 | PGC Rounding difference | (172) | (0) | (1) | (29) | - | (0) | (4) | - | (1) | (0) | - | (1) | (0) | - | (0) | (0) | (0) | 0 | - | - | - | **(209)** |
| Jul-2018 | ACA | (19,608) | (47) | (34) | (441) | - | (14) | (448) | (0) | (2,355) | (7,743) | - | (935) | (3,256) | (27) | (370) | (3,217) | (314) | (934) | - | - | - | **(39,744)** |
| Jul-2018 | DCA | (78,814) | (186) | (122) | (1,697) | - | (49) | (1,853) | (0) | (9,232) | (101,898) | (96,428) | (4,103) | 15,948 | (95) | (1,807) | (34,785) | (1,605) | (7,785) | - | - | - | **(324,512)** |
| Jul-2018 | GAC Current | 22,137 | 53 | 40 | 520 | - | 16 | 507 | 0 | 2,702 | 8,464 | - | 1,001 | 3,641 | 31 | 426 | 3,625 | 353 | 1,050 | - | - | - | **44,565** |
| Jul-2018 | Residential Essential Credit | (119) | (1) | (0) | (2) | - | (0) | (2) | - | (29) | (286) | - | (24) | (149) | (0) | (6) | (145) | (7) | (33) | (1,559) | (59) | (0) | **(2,421)** |
| Jul-2018 | RES Rider credit | (639) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(639)** |
| Jul-2018 | Delivery Charge | 672,326 | 1,588 | 1,035 | 15,629 | - | 451 | 17,227 | 1 | 73,786 | 815,096 | 668,919 | 32,601 | (129,061) | 753 | 14,639 | 281,724 | 12,904 | 62,572 | 831,826 | 49,740 | - | **3,423,756** |
| Jul-2018 | Purchased Gas Charge | 588,506 | 1,413 | 1,032 | 13,486 | - | 417 | 13,476 | 1 | 71,947 | 221,157 | - | 26,357 | 96,940 | 816 | 11,398 | 96,593 | 9,408 | 27,971 | - | - | - | **1,180,920** |
| Jul-2018 | System Charge | 1,743,216 | 864 | 9,487 | 117,762 | 10 | 2,270 | 40,797 | 75 | 92,060 | 189,640 | - | 34,521 | 17,053 | 45 | 11,687 | 92,156 | 11,464 | 7,718 | 13,400 | 2,100 | 100 | **2,386,424** |
| Jul-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | 133 | (2,765) | - | 3 | (10,138) | - | 27 | 2,590 | - | - | - | - | - | **(10,151)** |
| Jul-2018 | DC Right of Way Tax | 53,088 | 125 | 81 | 1,131 | - | 33 | 1,248 | 0 | 6,232 | 68,877 | 65,028 | 2,761 | (11,254) | 64 | 1,220 | 23,467 | 1,083 | 5,250 | 266,223 | 9,533 | 33 | **494,223** |
| Jul-2018 | DC Right of Way Adjustment | 1,167 | 3 | 0 | 11 | - | 1 | 30 | (0) | 57 | 2,332 | 3,768 | 48 | (3,485) | 1 | 38 | 820 | 24 | 114 | 14,490 | 881 | 1 | **20,301** |
| Jul-2018 | SE Trust Fund | 23,558 | 59 | 38 | 546 | - | 15 | 586 | 0 | 2,921 | 32,265 | 30,488 | 1,295 | (5,126) | 30 | 572 | 10,998 | 508 | 2,461 | 124,818 | 4,444 | 16 | **230,493** |
| Jul-2018 | Delivery Tax | 117,045 | 276 | 180 | 2,497 | - | 72 | 2,752 | 0 | 15,092 | 166,728 | 157,546 | 6,691 | (26,490) | 155 | 2,685 | 51,667 | 2,385 | 11,563 | 643,347 | 22,893 | 81 | **1,177,167** |
| Jul-2018 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 43,639 | - | **43,639** |
| Jul-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 29,200 | 3,100 | 225 | **32,525** |
| Jul-2018 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 6,117 | - | **6,117** |
| Jul-2018 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 161 | - | **161** |
| Jul-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | 37,882 | - | - | - | - | - | - | - | 16,565 | 591 | 2 | **55,040** |
| Jul-2018 | STORAGE GAS CHRG | 12,228 | 29 | 22 | 284 | - | 9 | 280 | 0 | 1,488 | 4,721 | - | 554 | 2,010 | 17 | 235 | 2,001 | 195 | 579 | - | - | - | **24,652** |
| Jul-2018 | EA Trust Fund | 13,101 | 33 | 21 | 302 | - | 9 | 326 | 0 | 1,613 | 17,769 | 16,887 | 723 | (2,822) | 17 | 316 | 6,092 | 281 | 1,363 | 69,134 | 2,462 | 9 | **127,635** |
| Jul-2018 | PRA | (13) | - | 2 | 6 | - | - | (2) | - | (14) | (412) | - | 1 | 2,628 | - | (1) | (336) | 0 | - | - | (695) | - | **1,162** |
| Jul-2018 | APRP | 52,267 | 123 | 79 | 1,114 | - | 32 | 1,231 | 0 | 2,348 | 25,086 | 22,899 | 1,030 | (2,384) | 24 | 455 | 8,711 | 408 | 1,979 | 41,971 | 1,411 | 6 | **158,789** |
| | **TOTAL** | **3,199,276** | **4,332** | **11,859** | **151,119** | **10** | **3,261** | **76,150** | **77** | **258,750** | **1,439,032** | **906,989** | **102,525** | **(55,945)** | **1,829** | **41,512** | **541,959** | **37,085** | **113,870** | **2,054,544** | **146,317** | **472** | **9,035,022** |
| Aug-2018 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 6,515 | - | - | **6,515** |
| Aug-2018 | PGC Rounding difference | (109) | (0) | (1) | (31) | - | (0) | (3) | 0 | (1) | (0) | (0) | (0) | 0 | - | 0 | 0 | (0) | (0) | - | - | - | **(146)** |
| Aug-2018 | ACA | (19,803) | (48) | (40) | (466) | - | (15) | (420) | (0) | (1,194) | (14,040) | 16 | (952) | (4,413) | (29) | (227) | (2,451) | (311) | (938) | - | - | - | **(45,331)** |
| Aug-2018 | DCA | (78,680) | (187) | (139) | (1,774) | - | (54) | (1,713) | (0) | (5,833) | (129,790) | (32,925) | (4,314) | (33,389) | (102) | (1,012) | (33,752) | (1,607) | (8,015) | - | - | - | **(333,287)** |
| Aug-2018 | GAC Current | 22,330 | 54 | 45 | 548 | - | 18 | 477 | 0 | 1,354 | 15,598 | 24 | 1,085 | 4,957 | 33 | 256 | 3,034 | 349 | 1,055 | - | - | - | **51,216** |
| Aug-2018 | Residential Essential Credit | (123) | (1) | (0) | (2) | - | (0) | (2) | - | (22) | (681) | 3 | (16) | (135) | (0) | (4) | (115) | (7) | (34) | (780) | (17) | (0) | **(1,936)** |
| Aug-2018 | RES Rider credit | (278) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(278)** |
| Aug-2018 | Delivery Charge | 640,547 | 1,498 | 1,120 | 14,477 | - | 430 | 14,350 | 3 | 43,821 | 1,006,716 | 228,496 | 33,085 | 255,359 | 747 | 7,822 | 265,133 | 12,562 | 61,789 | 472,061 | 13,298 | - | **3,073,315** |
| Aug-2018 | Purchased Gas Charge | 595,076 | 1,443 | 1,190 | 14,231 | - | 464 | 12,641 | 3 | 35,783 | 422,066 | 640 | 28,966 | 133,295 | 876 | 6,792 | 79,258 | 9,303 | 28,106 | - | - | - | **1,370,134** |
| Aug-2018 | System Charge | 1,739,267 | 865 | 10,023 | 117,602 | 10 | 2,241 | 40,814 | 76 | 92,372 | 189,894 | 214 | 35,884 | 17,782 | 54 | 11,610 | 92,309 | 11,489 | 7,704 | 12,500 | 1,400 | 100 | **2,384,210** |
| Aug-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | 695 | 33,818 | 52 | 52 | 6,800 | - | - | 58 | - | - | - | - | - | **41,475** |
| Aug-2018 | DC Right of Way Tax | 52,924 | 126 | 93 | 1,180 | - | 36 | 1,150 | 0 | 3,935 | 87,561 | 22,207 | 2,910 | 22,549 | 69 | 682 | 22,783 | 1,083 | 5,405 | 127,130 | 2,666 | 28 | **354,517** |
| Aug-2018 | DC Right of Way Adjustment | 1,398 | 3 | 2 | 15 | - | 1 | 22 | - | 101 | 3,993 | 491 | 69 | 745 | 1 | 12 | 511 | 24 | 118 | 2,744 | 58 | 1 | **10,307** |
| Aug-2018 | SE Trust Fund | 23,656 | 59 | 43 | 573 | - | 17 | 543 | 0 | 1,845 | 40,987 | 10,411 | 1,365 | 10,559 | 32 | 320 | 10,679 | 508 | 2,534 | 59,604 | 1,250 | 13 | **165,000** |
| Aug-2018 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 121 | - | - | **121** |
| Aug-2018 | Delivery Tax | 116,834 | 278 | 205 | 2,613 | - | 80 | 2,544 | 0 | 9,528 | 211,796 | 53,800 | 7,050 | 54,561 | 166 | 1,503 | 50,167 | 2,387 | 11,905 | 306,574 | 6,410 | 69 | **838,469** |
| Aug-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 34,275 | 3,100 | 225 | **37,600** |
| Aug-2018 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (7,777) | - | - | **(7,777)** |
| Aug-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | 12,910 | - | - | - | - | - | - | - | 7,893 | 166 | 2 | **20,970** |
| Aug-2018 | STORAGE GAS CHRG | 12,328 | 30 | 25 | 299 | - | 10 | 263 | 0 | 749 | 8,594 | 13 | 599 | 2,693 | 18 | 141 | 1,680 | 193 | 582 | - | - | - | **28,217** |
| Aug-2018 | EA Trust Fund | 13,102 | 33 | 24 | 316 | - | 10 | 301 | 0 | 1,021 | 22,770 | 5,762 | 754 | 5,847 | 18 | 177 | 5,887 | 281 | 1,404 | 33,014 | 692 | 7 | **91,421** |
| Aug-2018 | PRA | (401) | - | - | 0 | - | - | 4 | - | (16) | (4,014) | 16 | 1 | (9) | - | - | 182 | - | - | - | - | - | **(4,237)** |
| Aug-2018 | APRP | 52,436 | 124 | 92 | 1,171 | - | 36 | 1,134 | 0 | 1,450 | 31,363 | 8,232 | 1,076 | 8,218 | 25 | 259 | 8,613 | 408 | 2,037 | 20,997 | 440 | 5 | **138,117** |
| | **TOTAL** | **3,170,505** | **4,276** | **12,684** | **150,754** | **10** | **3,271** | **72,105** | **82** | **185,589** | **1,926,629** | **310,363** | **107,614** | **485,417** | **1,909** | **28,329** | **503,977** | **36,663** | **113,652** | **1,074,871** | **29,464** | **449** | **8,218,614** |
| Sep-2018 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 7,214 | - | - | **7,214** |
| Sep-2018 | PGC Rounding difference | (191) | (0) | (1) | (29) | (0) | (0) | (7) | (0) | (2) | (1) | - | (1) | (0) | - | (0) | (0) | (0) | (0) | - | - | - | **(233)** |
| Sep-2018 | ACA | (19,869) | (51) | (49) | (476) | (0) | (19) | (478) | (0) | (940) | (12,823) | - | (920) | (3,045) | (194) | (225) | (5,049) | (327) | (926) | - | - | - | **(45,392)** |
| Sep-2018 | DCA | (79,026) | (196) | (170) | (1,814) | (0) | (65) | (1,924) | (1) | (4,740) | (80,998) | (32,734) | (4,228) | (27,733) | (675) | (1,013) | (36,850) | (1,681) | (8,099) | - | - | - | **(281,947)** |
| Sep-2018 | GAC Current | 22,380 | 57 | 55 | 560 | 0 | 21 | 541 | 0 | 1,293 | 14,526 | - | 1,035 | 3,423 | 218 | 253 | 5,696 | 368 | 1,041 | - | - | - | **51,468** |
| Sep-2018 | Residential Essential Credit | (124) | (1) | (0) | (2) | - | (0) | (3) | - | 6 | (256) | - | (17) | (116) | (3) | (4) | (155) | (7) | (34) | (760) | (17) | (0) | **(1,493)** |
| Sep-2018 | RES Rider credit | (620) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(620)** |
| Sep-2018 | Delivery Charge | 609,926 | 1,512 | 1,308 | 13,883 | 0 | 498 | 14,785 | 7 | 35,117 | 588,727 | 227,072 | 31,064 | 203,628 | 4,960 | 7,484 | 279,236 | 12,457 | 60,026 | 447,064 | 13,176 | - | **2,551,930** |
| Sep-2018 | Purchased Gas Charge | 640,779 | 1,632 | 1,576 | 15,698 | 0 | 600 | 15,484 | 8 | 37,259 | 412,347 | - | 29,662 | 98,251 | 6,257 | 7,251 | 161,204 | 10,542 | 29,834 | - | - | - | **1,468,388** |

CUBE: tm1serv:Rate Statistics DB
RS_ACTU/ DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Htg / HC Not assigned | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - IMA Not assigned | DC Res Non Htg - OTH 1 | DC Res Non Htg OTH Not assigned | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Htg / HC Not assigned | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC C&I Non Htg Not assigned | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | DC Interruptible Not assigned | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sep-2018 | System Charge | 1,736,329 | 865 | 10,586 | 117,504 | 10 | 2,282 | 40,542 | 75 | 91,622 | 186,406 | - | 34,667 | 16,895 | 45 | 12,121 | 91,063 | 11,485 | 7,695 | 12,800 | 1,500 | 100 | **2,374,593** |
| Sep-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | (323) | (24,237) | - | - | 3 | - | (0) | 2,210 | (93) | - | - | - | - | **(22,440)** |
| Sep-2018 | DC Right of Way Tax | 53,122 | 132 | 114 | 1,208 | 0 | 44 | 1,293 | 1 | 3,218 | 54,575 | 22,075 | 2,850 | 18,703 | 455 | 683 | 24,861 | 1,133 | 5,462 | 123,955 | 2,749 | 29 | **316,660** |
| Sep-2018 | DC Right of Way Adjustment | 1,181 | 3 | 3 | 18 | - | 1 | 29 | 0 | 110 | 46 | 481 | 62 | 412 | 10 | 15 | 823 | 25 | 119 | 2,703 | 60 | 1 | **6,101** |
| Sep-2018 | SE Trust Fund | 23,671 | 62 | 53 | 584 | 0 | 21 | 610 | 0 | 1,509 | 25,639 | 10,350 | 1,337 | 8,769 | 213 | 320 | 11,651 | 532 | 2,561 | 58,116 | 1,289 | 14 | **147,300** |
| Sep-2018 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 9,445 | - | - | **9,445** |
| Sep-2018 | Delivery Tax | 117,364 | 291 | 251 | 2,673 | 0 | 96 | 2,858 | 1 | 7,791 | 132,487 | 53,481 | 6,907 | 45,312 | 1,103 | 1,505 | 54,733 | 2,496 | 12,029 | 298,844 | 6,587 | 70 | **746,878** |
| Sep-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 30,550 | 3,325 | 225 | **34,100** |
| Sep-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | 12,860 | - | - | - | - | - | - | - | 7,694 | 171 | 2 | **20,726** |
| Sep-2018 | STORAGE GAS CHRG | 10,705 | 27 | 27 | 274 | 0 | 10 | 260 | 0 | 624 | 7,105 | - | 491 | 1,616 | 104 | 120 | 2,821 | 174 | 494 | - | - | - | **24,852** |
| Sep-2018 | EA Trust Fund | 13,111 | 34 | 29 | 323 | 0 | 11 | 337 | 0 | 835 | 14,163 | 5,732 | 741 | 4,856 | 118 | 178 | 6,454 | 294 | 1,418 | 32,189 | 714 | 8 | **81,546** |
| Sep-2018 | PRA | (14) | - | (1) | (1) | - | - | - | - | (34) | 2,721 | - | 0 | (3) | - | - | (294) | - | - | - | - | - | **2,375** |
| Sep-2018 | APRP | 52,436 | 130 | 114 | 1,199 | 0 | 43 | 1,277 | 1 | 1,171 | 20,862 | 8,183 | 1,057 | 6,929 | 169 | 257 | 9,247 | 427 | 2,059 | 20,466 | 454 | 5 | **126,485** |
| | **TOTAL** | **3,181,159** | **4,498** | **13,896** | **151,602** | **10** | **3,543** | **75,603** | **93** | **174,516** | **1,341,290** | **307,500** | **104,707** | **377,900** | **12,781** | **28,944** | **607,651** | **37,827** | **113,679** | **1,050,279** | **30,006** | **452** | **7,617,937** |
| Oct-2018 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 6,503 | - | - | **6,503** |
| Oct-2018 | PGC Rounding difference | (185) | (0) | (1) | (29) | - | (0) | (9) | - | (2) | (0) | - | (0) | 0 | (0) | (0) | (0) | 0 | 0 | - | - | - | **(228)** |
| Oct-2018 | ACA | (26,744) | 6 | (55) | (539) | - | (29) | (637) | (0) | (1,255) | (18,014) | - | (800) | (3,561) | (38) | (271) | (4,423) | (341) | (1,041) | - | - | - | **(57,744)** |
| Oct-2018 | DCA | (106,328) | (239) | (198) | (2,031) | - | (103) | (2,551) | (1) | (5,288) | (140,216) | (31,770) | (3,497) | (32,273) | (134) | (1,175) | (41,311) | (1,770) | (9,904) | - | - | - | **(378,788)** |
| Oct-2018 | GAC Current | 30,307 | (7) | 63 | 629 | - | 33 | 723 | 0 | 1,412 | 20,549 | - | 655 | 4,003 | 43 | 305 | 4,498 | 384 | 1,171 | - | - | - | **64,767** |
| Oct-2018 | Residential Essential Credit | (255) | (1) | (0) | (3) | - | (0) | (6) | - | (20) | (540) | - | (41) | (136) | (1) | (5) | (198) | (7) | (42) | (784) | (17) | (0) | **(2,055)** |
| Oct-2018 | RES Rider credit | (496) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(496)** |
| Oct-2018 | Delivery Charge | 821,001 | 1,848 | 1,506 | 15,623 | - | 790 | 19,667 | 6 | 38,472 | 1,040,792 | 220,389 | 24,685 | 237,179 | 983 | 8,680 | 309,614 | 13,125 | 73,405 | 459,301 | 12,643 | - | **3,299,707** |
| Oct-2018 | Purchased Gas Charge | 868,185 | (96) | 1,799 | 17,624 | - | 951 | 20,684 | 7 | 40,435 | 586,678 | - | 18,856 | 114,666 | 1,240 | 8,715 | 128,176 | 10,991 | 33,547 | - | - | - | **1,852,457** |
| Oct-2018 | System Charge | 1,736,594 | 889 | 10,636 | 117,563 | 10 | 2,511 | 41,019 | 76 | 94,388 | 188,794 | - | 35,017 | 17,095 | 91 | 12,301 | 91,915 | 11,644 | 7,670 | 12,603 | 1,400 | 100 | **2,382,316** |
| Oct-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | 106 | 3,367 | - | (456) | (50) | - | 8 | 410 | 1 | - | - | - | - | **3,385** |
| Oct-2018 | DC Right of Way Tax | 71,564 | 161 | 133 | 1,354 | - | 69 | 1,716 | 1 | 3,564 | 94,625 | 21,425 | 2,329 | 21,764 | 90 | 792 | 27,846 | 1,194 | 6,679 | 127,150 | 2,679 | 31 | **385,163** |
| Oct-2018 | DC Right of Way Adjustment | 1,582 | 4 | 2 | 19 | - | 1 | 40 | 0 | 84 | 2,316 | 467 | (41) | 475 | 2 | 17 | 632 | 26 | 146 | 2,773 | 58 | 1 | **8,603** |
| Oct-2018 | SE Trust Fund | 32,323 | 76 | 62 | 653 | - | 33 | 809 | 0 | 1,673 | 44,354 | 10,045 | 1,097 | 10,204 | 42 | 372 | 13,072 | 560 | 3,131 | 59,614 | 1,256 | 14 | **179,390** |
| Oct-2018 | Delivery Tax | 157,916 | 355 | 293 | 2,995 | - | 152 | 3,787 | 1 | 8,638 | 229,194 | 51,907 | 5,667 | 52,728 | 218 | 1,745 | 61,440 | 2,630 | 14,710 | 306,501 | 6,422 | 75 | **907,374** |
| Oct-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 28,975 | 3,325 | 225 | **32,525** |
| Oct-2018 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (138,895) | - | - | **(138,895)** |
| Oct-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | 12,481 | - | - | - | - | - | - | - | 7,896 | 167 | 2 | **20,546** |
| Oct-2018 | STORAGE GAS CHRG | 14,461 | (7) | 30 | 309 | - | 16 | 346 | 0 | 670 | 9,906 | - | 284 | 1,899 | 21 | 144 | 2,144 | 182 | 555 | - | - | - | **30,960** |
| Oct-2018 | EA Trust Fund | 17,879 | 42 | 34 | 362 | - | 18 | 447 | 0 | 926 | 24,561 | 5,564 | 627 | 5,652 | 23 | 206 | 7,244 | 310 | 1,734 | 33,019 | 696 | 8 | **99,352** |
| Oct-2018 | PRA | 23 | - | 1 | 0 | - | - | (3) | - | (5) | (198) | - | (1) | - | - | - | (40) | 0 | - | - | - | - | **(224)** |
| Oct-2018 | APRP | 93,235 | 210 | 179 | 1,751 | - | 90 | 2,233 | 1 | 1,790 | 46,098 | 10,813 | 1,339 | 10,961 | 46 | 390 | 13,723 | 595 | 3,329 | 28,520 | 601 | 7 | **215,909** |
| | **TOTAL** | **3,711,061** | **3,241** | **14,483** | **156,280** | **10** | **4,533** | **88,264** | **90** | **185,588** | **2,132,264** | **301,320** | **85,720** | **440,605** | **2,626** | **32,224** | **614,741** | **39,524** | **135,090** | **933,174** | **29,230** | **462** | **8,910,528** |
| Nov-2018 | PGA - Retroactive | (2) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(2)** |
| Nov-2018 | PGC Rounding difference | (66) | (0) | (1) | (29) | - | (0) | (4) | (0) | (1) | 0 | - | (1) | (0) | (0) | (0) | (0) | (0) | 0 | - | - | - | **(104)** |
| Nov-2018 | ACA | (93,261) | (142) | (192) | (785) | - | (33) | (1,883) | (0) | (3,054) | (28,276) | - | (1,488) | (4,323) | (57) | (695) | (11,242) | (506) | (1,620) | - | - | - | **(147,557)** |
| Nov-2018 | DCA | (370,091) | (665) | (690) | (2,894) | - | (114) | (7,459) | (1) | (12,176) | (233,601) | (32,893) | (6,873) | (40,016) | (198) | (2,884) | (116,753) | (2,534) | (14,246) | - | - | - | **(844,089)** |
| Nov-2018 | GAC Current | 104,842 | 160 | 217 | 897 | - | 37 | 2,119 | 0 | 2,886 | 32,446 | - | 1,672 | 4,867 | 64 | 781 | 12,637 | 569 | 1,821 | - | - | - | **166,015** |
| Nov-2018 | Residential Essential Credit | (1,505) | (3) | (2) | (7) | - | (0) | (28) | - | (126) | (919) | - | (28) | (167) | (1) | (12) | (491) | (11) | (60) | (987) | (31) | (1) | **(4,379)** |
| Nov-2018 | RES Rider credit | 836 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **836** |
| Nov-2018 | Delivery Charge | 2,859,334 | 5,140 | 5,320 | 22,049 | - | 880 | 57,374 | 10 | 85,823 | 1,725,291 | 228,177 | 50,496 | 294,689 | 1,454 | 21,305 | 872,480 | 18,779 | 105,591 | 646,757 | 24,786 | 918 | **7,026,652** |
| Nov-2018 | Purchased Gas Charge | 3,232,253 | 4,922 | 6,688 | 27,306 | - | 1,140 | 65,302 | 13 | 90,246 | 998,079 | - | 51,578 | 150,402 | 1,975 | 24,086 | 390,448 | 17,536 | 56,136 | - | - | - | **5,118,108** |
| Nov-2018 | System Charge | 1,735,615 | 824 | 11,225 | 116,878 | 10 | 2,606 | 40,616 | 84 | 91,202 | 176,639 | - | 33,438 | 17,172 | 68 | 12,303 | 89,665 | 11,541 | 7,713 | 12,303 | 1,400 | 100 | **2,361,402** |
| Nov-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | 27,576 | 301,092 | - | 8,008 | 37,458 | 317 | 3,837 | 149,973 | 2,730 | 15,074 | - | - | - | **546,065** |
| Nov-2018 | DC Right of Way Tax | 249,526 | 449 | 464 | 1,937 | - | 77 | 5,028 | 1 | 8,138 | 157,596 | 22,182 | 4,634 | 26,991 | 133 | 1,945 | 78,734 | 1,709 | 9,607 | 167,264 | 4,989 | 184 | **741,589** |
| Nov-2018 | DC Right of Way Adjustment | 5,443 | 10 | 10 | 27 | - | 2 | 110 | 0 | (59) | 3,673 | 484 | 100 | 651 | 3 | 42 | 1,692 | 37 | 209 | 3,648 | 109 | 4 | **16,194** |
| Nov-2018 | SE Trust Fund | 117,008 | 210 | 218 | 922 | - | 36 | 2,357 | 0 | 3,827 | 73,877 | 10,400 | 2,173 | 12,653 | 63 | 912 | 36,914 | 801 | 4,504 | 78,421 | 2,339 | 86 | **347,721** |
| Nov-2018 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 104,175 | - | - | **104,175** |
| Nov-2018 | Delivery Tax | 549,628 | 988 | 1,023 | 4,277 | - | 170 | 11,075 | 2 | 19,777 | 381,757 | 53,741 | 11,228 | 65,381 | 323 | 4,283 | 173,413 | 3,763 | 21,160 | 400,987 | 11,915 | 446 | **1,715,338** |
| Nov-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 9,933 | 2,200 | - | **12,133** |
| Nov-2018 | Supplier Refunds (retro) | (2) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(2)** |
| Nov-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | 12,922 | - | - | - | - | - | - | - | 10,421 | 311 | 11 | **23,666** |
| Nov-2018 | STORAGE GAS CHRG | 49,722 | 76 | 103 | 433 | - | 18 | 1,005 | 0 | 1,310 | 15,445 | - | 792 | 2,302 | 30 | 370 | 5,976 | 270 | 863 | - | - | - | **78,715** |
| Nov-2018 | EA Trust Fund | 64,868 | 116 | 121 | 516 | - | 20 | 1,307 | 0 | 2,196 | 40,856 | 5,760 | 1,204 | 7,007 | 35 | 505 | 20,446 | 444 | 2,495 | 43,436 | 1,295 | 48 | **192,676** |
| Nov-2018 | PRA | 14 | - | - | 1 | - | - | - | - | (95) | 44 | - | 0 | (55) | - | - | 61 | - | - | - | - | - | **(29)** |
| Nov-2018 | APRP | 325,663 | 586 | 608 | 2,541 | - | 101 | 6,564 | 1 | 4,496 | 79,143 | 11,195 | 2,340 | 13,491 | 67 | 970 | 39,286 | 852 | 4,789 | 37,517 | 1,119 | 41 | **531,369** |
| | **TOTAL** | **8,829,825** | **12,671** | **25,113** | **174,069** | **10** | **4,938** | **183,483** | **110** | **321,964** | **3,723,140** | **311,968** | **159,273** | **588,502** | **4,277** | **67,748** | **1,743,239** | **55,980** | **214,036** | **1,513,877** | **50,432** | **1,838** | **17,986,491** |
| Dec-2018 | PGC Rounding difference | (9) | 0 | 0 | 12 | - | 0 | 1 | (0) | 1 | 0 | - | (0) | 0 | 0 | 0 | 0 | (0) | (0) | - | - | - | **5** |
| Dec-2018 | ACA | 15,745 | (12) | 55 | (8) | - | (9) | 318 | 0 | 701 | 3,132 | - | 324 | 440 | 5 | 196 | 1,815 | 68 | 259 | - | - | - | **23,030** |
| Dec-2018 | DCA | (668,589) | (1,196) | (1,536) | (4,685) | (0) | (311) | (12,651) | (1) | (31,749) | (359,662) | (30,836) | (10,175) | (45,751) | (183) | (5,073) | (183,111) | (3,370) | (17,705) | - | - | - | **(1,376,586)** |
| Dec-2018 | GAC Current | 197,778 | 260 | 505 | 1,481 | 0 | 104 | 3,725 | 0 | 8,497 | 53,843 | - | 2,624 | 5,949 | 62 | 1,469 | 22,085 | 810 | 2,328 | - | - | - | **301,518** |
| Dec-2018 | Residential Essential Credit | 52,145 | 78 | 124 | 322 | - | 20 | 997 | 0 | 2,475 | 26,371 | - | 809 | 3,408 | 14 | 400 | 14,294 | 265 | 1,392 | 28,639 | 938 | 43 | **132,736** |
| Dec-2018 | RES Rider credit | (543) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(543)** |
| Dec-2018 | Delivery Charge | 5,367,907 | 9,546 | 12,319 | 37,238 | 0 | 2,470 | 101,095 | 12 | 239,568 | 2,748,740 | 222,314 | 77,677 | 348,768 | 1,399 | 39,126 | 1,422,335 | 25,961 | 136,395 | 1,073,976 | 41,607 | 1,910 | **11,910,363** |
| Dec-2018 | Purchased Gas Charge | 6,223,638 | 8,161 | 15,921 | 46,244 | 0 | 3,257 | 117,299 | 15 | 267,496 | 1,698,830 | - | 82,961 | 187,162 | 1,939 | 45,642 | 694,961 | 25,482 | 73,295 | - | - | - | **9,492,303** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTU/** DC

| | | DC Res Htg / HC | DC Res Htg / HC | DC Res Htg / HC | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - OTH | DC Res Non Htg OTH | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Non Htg | DC C&I Non Htg | DC C&I Non Htg | DC GMA Htg / HC | DC GMA Htg / HC | DC GMA Non Htg | DC GMA Non Htg | DC Interruptible | DC Interruptible | DC Interruptible | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **1** | **2** | **Not assigned** | **1** | **2** | **Not assigned** | **1** | **Not assigned** | **1** | **2** | **Not assigned** | **1** | **2** | **Not assigned** | **1** | **2** | **1** | **2** | **1** | **2** | **Not assigned** | |
| Dec-2018 | System Charge | 1,741,638 | 814 | 11,767 | 117,743 | 10 | 2,607 | 40,228 | 86 | 90,546 | 187,934 | - | 34,150 | 16,643 | 68 | 13,845 | 90,350 | 11,622 | 7,736 | 12,750 | 1,400 | 100 | **2,382,036** |
| Dec-2018 | Peak Usage Charge | - | - | - | - | - | - | - | - | 32,135 | 346,330 | - | 8,596 | 40,394 | 380 | 4,466 | 158,468 | 2,842 | 15,141 | - | - | - | **608,752** |
| Dec-2018 | DC Right of Way Tax | 468,459 | 833 | 1,077 | 3,256 | 0 | 216 | 8,866 | 1 | 22,242 | 251,470 | 21,612 | 7,134 | 32,005 | 128 | 3,563 | 128,309 | 2,362 | 12,410 | 275,345 | 8,364 | 383 | **1,248,036** |
| Dec-2018 | DC Right of Way Adjustment | 10,238 | 18 | 21 | 62 | - | 5 | 189 | 0 | 473 | 5,487 | 471 | 151 | 698 | 3 | 97 | 2,812 | 52 | 271 | 6,004 | 182 | 8 | **27,243** |
| Dec-2018 | SE Trust Fund | 219,599 | 391 | 505 | 1,541 | 0 | 102 | 4,157 | 0 | 10,428 | 117,901 | 10,133 | 3,345 | 15,006 | 60 | 1,669 | 60,157 | 1,107 | 5,818 | 129,095 | 3,922 | 180 | **585,115** |
| Dec-2018 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (100,452) | - | - | **(100,452)** |
| Dec-2018 | Delivery Tax | 1,031,787 | 1,835 | 2,373 | 7,189 | 0 | 477 | 19,529 | 2 | 53,890 | 609,246 | 52,360 | 17,285 | 77,541 | 311 | 7,841 | 282,598 | 5,203 | 27,332 | 658,271 | 19,946 | 928 | **2,875,943** |
| Dec-2018 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 450 | 2,200 | - | **2,650** |
| Dec-2018 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | 10,705 | - | - | - | - | - | - | - | 17,155 | 521 | 24 | **28,405** |
| Dec-2018 | STORAGE GAS CHRG | 98,864 | 129 | 252 | 739 | 0 | 52 | 1,862 | 0 | 4,247 | 26,787 | - | 1,311 | 2,978 | 31 | 738 | 11,043 | 405 | 1,164 | - | - | - | **150,600** |
| Dec-2018 | EA Trust Fund | 121,652 | 216 | 280 | 862 | 0 | 56 | 2,305 | 0 | 5,785 | 65,303 | 5,612 | 1,852 | 8,311 | 33 | 911 | 33,318 | 613 | 3,222 | 71,503 | 2,172 | 99 | **324,109** |
| Dec-2018 | PRA | 31 | - | 2 | 0 | - | - | (1) | - | (4) | (10) | - | 7 | 0 | - | 57 | (9) | - | 18 | - | - | - | **91** |
| Dec-2018 | Distribution Charge Refund | (2,570,464) | (3,908) | (6,012) | (65,435) | (1) | (3,996) | (59,311) | (7) | (131,408) | (989,548) | - | (40,843) | (173,259) | (730) | (16,013) | (533,850) | (12,361) | (65,035) | (286,452) | (9,537) | (437) | **(4,968,607)** |
| Dec-2018 | APRP | 611,409 | 1,087 | 1,412 | 4,258 | 0 | 283 | 11,585 | 1 | 11,245 | 127,154 | 10,907 | 3,622 | 16,152 | 65 | 1,762 | 63,915 | 1,177 | 6,186 | 61,760 | 1,876 | 86 | **935,943** |
| | **TOTAL** | **12,921,285** | **18,253** | **39,065** | **150,821** | **10** | **5,331** | **240,193** | **111** | **586,568** | **4,919,309** | **303,279** | **190,828** | **536,445** | **3,586** | **100,695** | **2,269,489** | **62,238** | **210,226** | **1,948,044** | **73,592** | **3,324** | **24,582,692** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL_** DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Htg / HC Not assigned | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - IMA Not assigned | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-2019 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 3,859 | - | **3,859** |
| Jan-2019 | PGC Rounding difference | (5) | (0) | (0) | (14) | (0) | (0) | 0 | (0) | - | 0 | (0) | 0 | 0 | 0 | (0) | - | - | **(19)** |
| Jan-2019 | ACA | 17,248 | 24 | 15 | 120 | - | 1 | 320 | 831 | 4,553 | 269 | 552 | 133 | 1,901 | 69 | 109 | - | - | **26,146** |
| Jan-2019 | DCA | (687,773) | (1,241) | (527) | (4,789) | (0) | (48) | (12,871) | (82,271) | (463,450) | (11,992) | (48,027) | (5,403) | (193,133) | (3,279) | (17,981) | - | - | **(1,532,786)** |
| Jan-2019 | GAC Current | 203,237 | 283 | 174 | 1,516 | 0 | 16 | 3,807 | 10,166 | 56,508 | 3,152 | 5,641 | 1,553 | 22,526 | 771 | 2,525 | - | - | **311,877** |
| Jan-2019 | Residential Essential Credit | 54,072 | 98 | 42 | 371 | - | 4 | 1,012 | 3,406 | 34,987 | 943 | 3,817 | 425 | 15,023 | 259 | 1,414 | 31,397 | 1,039 | **148,308** |
| Jan-2019 | RES Rider credit | (31) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(31)** |
| Jan-2019 | Delivery Charge | 5,523,180 | 9,968 | 4,228 | 38,219 | 0 | 384 | 102,937 | 608,483 | 3,555,054 | 91,592 | 366,863 | 41,490 | 1,500,575 | 25,260 | 138,522 | 1,180,036 | 45,969 | **13,232,758** |
| Jan-2019 | Purchased Gas Charge | 7,074,105 | 9,720 | 6,063 | 51,820 | 1 | 562 | 132,467 | 353,218 | 1,961,054 | 109,829 | 197,014 | 54,031 | 784,667 | 26,917 | 87,258 | - | - | **10,848,727** |
| Jan-2019 | System Charge | 1,755,566 | 925 | 5,200 | 120,232 | 10 | 76 | 40,738 | 95,455 | 200,940 | 35,882 | 17,056 | 12,284 | 92,299 | 11,171 | 7,741 | 12,553 | 1,400 | **2,409,528** |
| Jan-2019 | Peak Usage Charge | - | - | - | - | - | - | - | 41,955 | 379,351 | 9,094 | 41,128 | 4,671 | 163,800 | 2,809 | 15,436 | - | - | **658,243** |
| Jan-2019 | DC Right of Way Tax | 482,027 | 870 | 369 | 3,342 | 0 | 34 | 9,020 | 57,489 | 324,461 | 8,405 | 33,674 | 3,787 | 135,319 | 2,298 | 12,602 | 306,252 | 9,263 | **1,389,212** |
| Jan-2019 | DC Right of Way Adjustment | 10,500 | 19 | 8 | 63 | - | 1 | 196 | 1,252 | 7,968 | 183 | 727 | 83 | 3,024 | 50 | 275 | 6,678 | 202 | **31,231** |
| Jan-2019 | SE Trust Fund | 226,001 | 408 | 173 | 1,582 | 0 | 16 | 4,230 | 26,953 | 152,075 | 3,941 | 15,788 | 1,775 | 63,441 | 1,078 | 5,909 | 143,586 | 4,343 | **651,299** |
| Jan-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 54,853 | - | **54,853** |
| Jan-2019 | Delivery Tax | 1,061,699 | 1,916 | 813 | 7,378 | 0 | 74 | 19,868 | 139,280 | 785,841 | 20,363 | 81,584 | 8,341 | 298,027 | 5,062 | 27,757 | 732,011 | 22,082 | **3,212,097** |
| Jan-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 225 | 2,200 | **2,425** |
| Jan-2019 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (16,379) | (1,088) | **(17,467)** |
| Jan-2019 | Balancing Charge | - | - | - | - | - | - | - | 11,126 | - | - | - | - | - | - | - | 19,067 | 577 | **30,770** |
| Jan-2019 | STORAGE GAS CHRG | 101,623 | 141 | 87 | 760 | 0 | 8 | 1,903 | 5,082 | 28,249 | 1,576 | 2,819 | 777 | 11,263 | 386 | 1,266 | - | - | **155,940** |
| Jan-2019 | EA Trust Fund | 125,208 | 226 | 96 | 884 | 0 | 9 | 2,344 | 14,930 | 84,228 | 2,183 | 8,745 | 983 | 35,139 | 597 | 3,273 | 79,529 | 2,406 | **360,779** |
| Jan-2019 | PRA | (5) | - | - | 0 | - | - | - | 4 | (1,953) | - | 10 | - | (55) | 0 | - | - | - | **(1,999)** |
| Jan-2019 | Distribution Charge Refund | (32,377) | (846) | 4 | (11,539) | - | - | (703) | (28,994) | (186,380) | (1,349) | (14,982) | (281) | (8,719) | 118 | 26 | (258) | - | **(286,279)** |
| Jan-2019 | APRP | 629,235 | 1,136 | 482 | 4,372 | 0 | 44 | 11,774 | 29,015 | 162,155 | 4,242 | 17,016 | 1,888 | 67,301 | 1,146 | 6,280 | 68,692 | 2,078 | **1,006,855** |
| | **TOTAL** | **16,543,511** | **23,647** | **17,227** | **214,318** | **11** | **1,179** | **317,042** | **1,287,378** | **7,085,642** | **278,313** | **729,424** | **126,537** | **2,992,401** | **74,713** | **292,411** | **2,622,102** | **90,471** | **32,696,327** |
| Feb-2019 | PGA - Retroactive | (2) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(2)** |
| Feb-2019 | PGC Rounding difference | (12) | - | - | (19) | - | - | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | - | - | **(33)** |
| Feb-2019 | ACA | 22,143 | 26 | - | 155 | - | - | 412 | 220 | 6,006 | 262 | 594 | 204 | 2,563 | 87 | 252 | - | - | **32,924** |
| Feb-2019 | DCA | (886,843) | (1,186) | - | (5,984) | - | - | (16,579) | (85,007) | (488,502) | (10,523) | (54,145) | (8,176) | (227,747) | (4,271) | (21,778) | - | - | **(1,810,742)** |
| Feb-2019 | GAC Current | 263,444 | 314 | - | 1,895 | - | - | 4,896 | 12,279 | 69,942 | 2,584 | 6,906 | 2,399 | 28,597 | 1,028 | 2,984 | - | - | **397,268** |
| Feb-2019 | Residential Essential Credit | 69,678 | 93 | - | 465 | - | - | 1,303 | 4,223 | 38,336 | 839 | 4,264 | 643 | 18,030 | 336 | 1,712 | 35,255 | 1,066 | **176,244** |
| Feb-2019 | RES Rider credit | (24) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(24)** |
| Feb-2019 | Delivery Charge | 7,122,283 | 9,524 | - | 47,771 | - | - | 132,593 | 627,662 | 3,744,909 | 80,333 | 413,532 | 62,790 | 1,770,439 | 32,897 | 167,758 | 1,357,671 | 47,088 | **15,617,250** |
| Feb-2019 | Purchased Gas Charge | 8,718,858 | 10,434 | - | 62,814 | - | - | 162,031 | 417,685 | 2,319,019 | 85,811 | 228,528 | 79,361 | 942,779 | 34,013 | 98,739 | - | - | **13,160,072** |
| Feb-2019 | System Charge | 1,752,614 | 885 | - | 120,126 | 10 | - | 40,701 | 90,934 | 184,018 | 34,036 | 16,312 | 12,554 | 89,321 | 11,486 | 7,491 | 12,300 | 1,300 | **2,374,087** |
| Feb-2019 | Peak Usage Charge | - | - | - | - | - | - | - | 36,528 | 358,549 | 8,161 | 39,813 | 5,730 | 159,402 | 2,820 | 14,883 | - | - | **625,885** |
| Feb-2019 | DC Right of Way Tax | 621,544 | 831 | - | 4,180 | - | - | 11,619 | 59,472 | 342,360 | 7,378 | 37,952 | 5,731 | 159,754 | 2,993 | 15,264 | 352,224 | 9,508 | **1,630,808** |
| Feb-2019 | DC Right of Way Adjustment | 13,581 | 18 | - | 81 | - | - | 253 | 918 | 7,506 | 152 | 826 | 125 | 3,793 | 65 | 333 | 7,681 | 207 | **35,540** |
| Feb-2019 | SE Trust Fund | 291,422 | 390 | - | 1,974 | - | - | 5,448 | 27,910 | 160,514 | 3,460 | 17,793 | 2,687 | 74,884 | 1,403 | 7,156 | 165,139 | 4,458 | **764,638** |
| Feb-2019 | Delivery Tax | 1,369,011 | 1,831 | - | 9,222 | - | - | 25,592 | 144,219 | 829,447 | 17,877 | 91,947 | 12,622 | 351,780 | 6,592 | 33,618 | 841,781 | 22,727 | **3,758,265** |
| Feb-2019 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 9,522 | - | **9,522** |
| Feb-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 225 | 2,200 | **2,425** |
| Feb-2019 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 14,110 | - | **14,110** |
| Feb-2019 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,909 | 1,088 | **2,997** |
| Feb-2019 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 232 | 5 | **237** |
| Feb-2019 | Balancing Charge | - | - | - | - | - | - | - | 11,126 | - | - | - | - | - | - | - | 21,945 | 592 | **33,664** |
| Feb-2019 | STORAGE GAS CHRG | 131,749 | 157 | - | 950 | - | - | 2,448 | 6,086 | 34,965 | 1,291 | 3,454 | 1,199 | 14,303 | 514 | 1,492 | - | - | **198,609** |
| Feb-2019 | EA Trust Fund | 161,415 | 216 | - | 1,102 | - | - | 3,019 | 15,715 | 88,906 | 1,917 | 9,856 | 1,488 | 41,307 | 777 | 3,964 | 91,467 | 2,469 | **423,618** |
| Feb-2019 | PRA | 45 | - | - | 4 | - | - | - | (1,068) | (55) | 15 | - | - | (41) | - | - | - | - | **(1,098)** |
| Feb-2019 | Distribution Charge Refund | (1,758) | (224) | - | (153) | (8) | - | 22 | 111 | 685 | 348 | 472 | (10) | (1,050) | - | - | - | - | **(1,565)** |
| Feb-2019 | APRP | 811,182 | 1,085 | - | 5,474 | - | - | 15,167 | 30,311 | 172,714 | 3,740 | 19,161 | 2,856 | 79,472 | 1,492 | 7,608 | 79,003 | 2,133 | **1,231,398** |
| | **TOTAL** | **20,460,333** | **24,393** | **-** | **250,058** | **1** | **-** | **388,924** | **1,399,322** | **7,869,318** | **237,678** | **837,265** | **182,201** | **3,507,587** | **92,233** | **341,476** | **2,990,465** | **94,841** | **38,676,096** |
| Mar-2019 | PGC Rounding difference | (40) | (0) | - | (64) | (0) | - | (2) | (1) | (0) | (1) | (0) | (0) | (0) | (0) | (0) | - | - | **(108)** |
| Mar-2019 | ACA | 67,008 | 68 | - | 441 | 0 | - | 1,269 | 3,711 | 19,487 | 1,053 | 1,896 | 618 | 7,426 | 284 | 820 | - | - | **104,080** |
| Mar-2019 | DCA | (663,559) | (1,297) | - | (4,472) | (0) | - | (12,562) | (75,007) | (435,706) | (13,458) | (44,332) | (6,311) | (181,726) | (3,368) | (17,361) | - | - | **(1,459,159)** |
| Mar-2019 | GAC Current | 196,492 | 273 | - | 1,443 | 0 | - | 3,717 | 10,258 | 55,165 | 3,688 | 5,487 | 1,814 | 22,562 | 811 | 2,337 | - | - | **304,047** |
| Mar-2019 | Residential Essential Credit | 51,928 | 102 | - | 343 | - | - | 988 | 3,727 | 33,128 | 1,061 | 3,485 | 496 | 14,280 | 265 | 1,365 | 30,567 | 1,045 | **142,778** |
| Mar-2019 | RES Rider credit | (14,900) | - | - | (6) | - | - | - | - | - | - | - | - | - | - | - | - | - | **(14,906)** |
| Mar-2019 | Delivery Charge | 5,326,998 | 10,412 | - | 35,717 | 0 | - | 100,471 | 669,171 | 3,345,272 | 102,793 | 338,588 | 48,462 | 1,411,733 | 25,946 | 133,734 | 1,131,210 | 46,231 | **12,726,740** |
| Mar-2019 | Purchased Gas Charge | 6,212,356 | 8,769 | - | 45,573 | 0 | - | 117,491 | 582,540 | 1,735,243 | 117,361 | 173,304 | 57,322 | 713,274 | 25,575 | 73,743 | - | - | **9,862,550** |
| Mar-2019 | System Charge | 1,731,494 | 855 | - | 119,089 | 10 | - | 40,482 | 103,082 | 190,494 | 34,047 | 16,605 | 12,225 | 90,067 | 11,339 | 7,653 | 12,843 | 1,500 | **2,371,784** |
| Mar-2019 | Peak Usage Charge | - | - | - | - | - | - | - | 44,378 | 412,920 | 10,310 | 40,373 | 6,053 | 164,031 | 2,833 | 14,915 | - | - | **695,813** |
| Mar-2019 | DC Right of Way Tax | 465,052 | 909 | - | 3,118 | 0 | - | 8,804 | 64,448 | 305,164 | 9,433 | 31,071 | 4,423 | 127,365 | 2,361 | 12,168 | 294,051 | 9,316 | **1,337,682** |
| Mar-2019 | DC Right of Way Adjustment | 10,137 | 20 | - | 60 | - | - | 192 | 1,136 | 7,743 | 205 | 678 | 97 | 2,777 | 51 | 265 | 6,412 | 203 | **29,976** |
| Mar-2019 | SE Trust Fund | 217,106 | 426 | - | 1,478 | 0 | - | 4,129 | 30,217 | 143,028 | 4,423 | 14,568 | 2,074 | 59,715 | 1,107 | 5,705 | 137,865 | 4,368 | **626,207** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL_** DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Htg / HC Not assigned | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - IMA Not assigned | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mar-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 65,724 | 43,715 | **109,439** |
| Mar-2019 | Delivery Tax | 1,024,319 | 2,002 | - | 6,887 | 0 | - | 19,392 | 156,146 | 739,085 | 22,855 | 75,277 | 9,742 | 280,522 | 5,199 | 26,800 | 703,017 | 22,120 | **3,093,362** |
| Mar-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 4,625 | 2,200 | **6,825** |
| Mar-2019 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,145 | 101 | **1,246** |
| Mar-2019 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 29 | 10 | **38** |
| Mar-2019 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,696 | 150 | **1,846** |
| Mar-2019 | Balancing Charge | - | - | - | - | - | - | - | 1,329 | - | - | - | - | - | - | - | 18,321 | 580 | **20,230** |
| Mar-2019 | STORAGE GAS CHRG | 103,181 | 141 | - | 762 | 0 | - | 1,953 | 5,396 | 28,970 | 1,919 | 2,884 | 952 | 11,836 | 426 | 1,229 | - | - | **159,650** |
| Mar-2019 | EA Trust Fund | 120,276 | 236 | - | 826 | 0 | - | 2,288 | 16,719 | 79,056 | 2,450 | 8,069 | 1,149 | 33,075 | 613 | 3,160 | 76,361 | 2,419 | **346,696** |
| Mar-2019 | PRA | 12 | - | - | 2 | - | - | - | 74 | (739) | - | - | (0) | - | - | - | - | - | **(650)** |
| Mar-2019 | Distribution Charge Refund | (250) | - | - | 30 | - | - | (19) | (1,978) | 167 | 47 | - | - | (155) | - | - | - | - | **(2,157)** |
| Mar-2019 | APRP | 482,961 | 1,066 | - | 3,330 | 0 | - | 9,130 | 25,931 | 145,769 | 4,570 | 14,919 | 2,098 | 60,423 | 1,118 | 5,763 | 62,343 | 1,884 | **821,305** |
| | **TOTAL** | **15,330,572** | **23,983** | **-** | **214,557** | **10** | **-** | **297,721** | **1,641,276** | **6,804,246** | **302,757** | **682,870** | **141,212** | **2,817,206** | **74,559** | **272,296** | **2,546,210** | **135,840** | **31,285,314** |
| Apr-2019 | PGA - Retroactive | 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **2** |
| Apr-2019 | PGC Rounding difference | (22) | 0 | - | (33) | - | - | (1) | (1) | 0 | (0) | (0) | (0) | (0) | 0 | 0 | - | - | **(56)** |
| Apr-2019 | ACA | 44,097 | 58 | - | 481 | - | - | 794 | 2,410 | 13,437 | 612 | 1,686 | 82 | 5,571 | 226 | 674 | - | - | **70,129** |
| Apr-2019 | DCA | (429,085) | (878) | - | (4,418) | - | - | (7,739) | (62,693) | (241,701) | (7,260) | (37,373) | (7,573) | (128,982) | (2,902) | (13,935) | - | - | **(944,539)** |
| Apr-2019 | GAC Current | 126,429 | 176 | - | 1,363 | - | - | 2,265 | 6,816 | 39,586 | 1,783 | 4,593 | 2,282 | 16,006 | 692 | 1,922 | - | - | **203,914** |
| Apr-2019 | Residential Essential Credit | 32,798 | 69 | - | 344 | - | - | 609 | 2,479 | 20,703 | 567 | 2,955 | 469 | 10,160 | 224 | 1,095 | 30,292 | 873 | **103,637** |
| Apr-2019 | RES Rider credit | (70,276) | - | - | (6) | - | - | - | - | - | - | - | - | - | - | - | - | - | **(70,282)** |
| Apr-2019 | Delivery Charge | 3,445,947 | 7,052 | - | 35,195 | - | - | 61,892 | 484,566 | 1,846,245 | 55,488 | 285,318 | 57,716 | 1,002,049 | 22,343 | 107,339 | 1,104,145 | 38,713 | **8,554,007** |
| Apr-2019 | Purchased Gas Charge | 4,433,296 | 5,978 | - | 46,602 | - | - | 79,608 | 272,669 | 1,382,699 | 62,770 | 162,536 | 76,249 | 563,868 | 24,383 | 67,828 | - | - | **7,178,486** |
| Apr-2019 | System Charge | 1,775,375 | 917 | - | 120,773 | 10 | - | 40,767 | 93,220 | 181,950 | 34,449 | 15,764 | 12,889 | 89,541 | 11,463 | 7,577 | 12,650 | 1,400 | **2,398,744** |
| Apr-2019 | Peak Usage Charge | - | - | - | - | - | - | - | 42,558 | 316,090 | 8,855 | 38,916 | 5,991 | 159,398 | 2,764 | 14,937 | - | - | **589,509** |
| Apr-2019 | DC Right of Way Tax | 305,154 | 620 | - | 3,119 | - | - | 5,505 | 46,993 | 172,501 | 5,166 | 26,598 | 5,316 | 91,791 | 2,065 | 9,916 | 295,946 | 7,910 | **978,599** |
| Apr-2019 | DC Right of Way Adjustment | 6,600 | 13 | - | 55 | - | - | 118 | 935 | 2,193 | 117 | 555 | 115 | 1,972 | 44 | 213 | 6,355 | 170 | **19,454** |
| Apr-2019 | SE Trust Fund | 137,168 | 289 | - | 1,461 | - | - | 2,543 | 21,563 | 79,679 | 2,385 | 12,283 | 2,470 | 42,387 | 953 | 4,579 | 136,640 | 3,652 | **448,050** |
| Apr-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (19,824) | - | **(19,824)** |
| Apr-2019 | Delivery Tax | 662,332 | 1,356 | - | 6,805 | - | - | 11,946 | 111,546 | 411,737 | 12,327 | 63,470 | 11,602 | 199,121 | 4,478 | 21,511 | 697,431 | 18,526 | **2,234,187** |
| Apr-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 4,625 | 2,200 | **6,825** |
| Apr-2019 | Balancing Charge | - | - | - | - | - | - | - | 1,467 | - | - | - | - | - | - | - | 18,158 | 485 | **20,110** |
| Apr-2019 | STORAGE GAS CHRG | 66,477 | 92 | - | 721 | - | - | 1,192 | 3,582 | 20,778 | 938 | 2,415 | 1,165 | 8,415 | 364 | 1,011 | - | - | **107,149** |
| Apr-2019 | EA Trust Fund | 75,990 | 160 | - | 817 | - | - | 1,410 | 11,828 | 44,132 | 1,320 | 6,806 | 1,368 | 23,477 | 528 | 2,536 | 75,682 | 2,023 | **248,079** |
| Apr-2019 | PRA | 44 | - | - | 2 | - | - | 0 | 5 | 2,810 | 2 | 9 | (0) | 16 | - | - | - | - | **2,888** |
| Apr-2019 | APRP | 309,994 | 640 | - | 3,231 | - | - | 5,580 | 21,766 | 83,913 | 2,433 | 12,599 | 2,423 | 42,812 | 962 | 4,624 | 62,259 | 1,674 | **554,910** |
| | **TOTAL** | **10,922,318** | **16,542** | **-** | **216,513** | **10** | **-** | **206,488** | **1,061,708** | **4,376,752** | **181,954** | **599,129** | **172,564** | **2,127,602** | **68,587** | **231,827** | **2,424,359** | **77,625** | **22,683,979** |
| May-2019 | PGC Rounding difference | (77) | 0 | - | (33) | (0) | - | (3) | (2) | 0 | (0) | 0 | (0) | (0) | (0) | (0) | - | - | **(117)** |
| May-2019 | ACA | 16,221 | 39 | - | 290 | 0 | - | 337 | 1,422 | 6,292 | 645 | 1,696 | 254 | 2,663 | 150 | 490 | - | - | **30,498** |
| May-2019 | DCA | (158,494) | (559) | - | (2,476) | (0) | - | (3,275) | (46,496) | (180,378) | (6,241) | (30,220) | (2,798) | (63,442) | (2,620) | (11,250) | - | - | **(508,247)** |
| May-2019 | GAC Current | 46,359 | 111 | - | 785 | 0 | - | 958 | 4,170 | 21,462 | 1,585 | 2,917 | 795 | 8,201 | 651 | 1,714 | - | - | **89,708** |
| May-2019 | Residential Essential Credit | 12,058 | 44 | - | 181 | - | - | 256 | 1,239 | 13,972 | 510 | 2,520 | 221 | 4,955 | 188 | 857 | 17,451 | 497 | **54,949** |
| May-2019 | RES Rider credit | (2,738) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(2,738)** |
| May-2019 | Delivery Charge | 1,272,867 | 4,487 | - | 19,628 | 0 | - | 26,178 | 340,520 | 1,383,406 | 47,550 | 230,046 | 21,476 | 493,172 | 20,288 | 86,921 | 641,602 | 21,974 | **4,610,115** |
| May-2019 | Purchased Gas Charge | 1,633,154 | 3,827 | - | 27,255 | 1 | - | 33,746 | 145,167 | 749,316 | 56,657 | 107,986 | 27,671 | 287,153 | 22,271 | 59,416 | - | - | **3,153,620** |
| May-2019 | System Charge | 1,771,945 | 956 | - | 120,257 | 10 | - | 40,388 | 95,184 | 183,416 | 32,708 | 14,917 | 11,901 | 92,791 | 12,593 | 8,254 | 12,600 | 1,300 | **2,399,220** |
| May-2019 | Peak Usage Charge | - | - | - | - | - | - | - | 9,368 | 45,238 | 105 | 134 | 570 | 4,591 | 256 | 388 | - | - | **60,651** |
| May-2019 | DC Right of Way Tax | 112,725 | 397 | - | 1,739 | 0 | - | 2,327 | 33,072 | 128,256 | 4,448 | 21,561 | 1,986 | 45,146 | 1,859 | 8,003 | 170,913 | 4,502 | **536,934** |
| May-2019 | DC Right of Way Adjustment | 2,439 | 9 | - | 28 | - | - | 50 | 701 | 2,874 | 75 | 339 | 42 | 1,017 | 59 | 209 | 3,670 | 97 | **11,607** |
| May-2019 | SE Trust Fund | 50,532 | 184 | - | 823 | 0 | - | 1,075 | 15,279 | 59,244 | 2,053 | 9,946 | 919 | 20,846 | 859 | 3,695 | 78,909 | 2,078 | **246,442** |
| May-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 14,492 | - | **14,492** |
| May-2019 | Delivery Tax | 244,661 | 863 | - | 3,800 | 0 | - | 5,054 | 78,953 | 306,142 | 10,609 | 51,394 | 4,319 | 97,928 | 4,035 | 17,358 | 404,149 | 10,607 | **1,239,873** |
| May-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 7,950 | 2,425 | **10,375** |
| May-2019 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 179 | - | **179** |
| May-2019 | Balancing Charge | - | - | - | - | - | - | - | 1,413 | - | - | - | - | - | - | - | 10,486 | 276 | **12,175** |
| May-2019 | STORAGE GAS CHRG | 24,412 | 58 | - | 419 | 0 | - | 504 | 2,187 | 11,279 | 834 | 1,539 | 415 | 4,311 | 342 | 902 | - | - | **47,204** |
| May-2019 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 120 | - | **120** |
| May-2019 | EA Trust Fund | 28,066 | 102 | - | 457 | 0 | - | 598 | 8,468 | 32,822 | 1,143 | 5,536 | 510 | 11,523 | 471 | 2,031 | 43,706 | 1,151 | **136,583** |
| May-2019 | PRA | 31 | - | - | (0) | - | - | - | (9) | (138) | (2) | 24 | 0 | 63 | 5 | 19 | - | - | **(7)** |
| May-2019 | APRP | 114,039 | 403 | - | 1,761 | 0 | - | 2,358 | 15,657 | 60,341 | 2,128 | 10,371 | 935 | 21,007 | 846 | 3,684 | 36,003 | 953 | **270,487** |
| | **TOTAL** | **5,168,201** | **10,920** | **-** | **174,915** | **11** | **-** | **110,554** | **706,292** | **2,823,544** | **154,807** | **430,704** | **69,216** | **1,031,925** | **62,254** | **182,690** | **1,442,229** | **45,861** | **12,414,121** |
| Jun-2019 | PGC Rounding difference | 23 | 0 | - | (22) | - | - | 1 | 0 | 1 | 0 | (0) | 0 | 0 | (0) | (0) | - | - | **3** |
| Jun-2019 | ACA | 10,464 | 14 | - | 295 | - | - | 246 | 620 | 3,940 | 409 | 1,225 | 191 | 1,477 | 133 | 418 | - | - | **19,431** |
| Jun-2019 | DCA | (103,317) | (260) | - | (1,305) | - | - | (2,411) | (40,313) | (98,778) | (4,673) | (34,158) | (2,137) | (40,080) | (2,208) | (10,355) | - | - | **(339,993)** |
| Jun-2019 | GAC Current | 30,290 | 40 | - | 415 | - | - | 699 | 2,577 | 12,368 | 1,129 | 3,561 | 606 | 5,631 | 438 | 1,506 | - | - | **59,260** |
| Jun-2019 | Residential Essential Credit | 8,080 | 20 | - | 114 | - | - | 188 | 637 | 7,691 | 368 | 2,668 | 165 | 3,076 | 170 | 785 | 14,381 | 384 | **38,728** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL_** DC

| | | DC Res Htg / HC | DC Res Htg / HC | DC Res Htg / HC | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - OTH | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Non Htg | DC C&I Non Htg | DC GMA Htg / HC | DC GMA Htg / HC | DC GMA Non Htg | DC GMA Non Htg | DC Interruptible | DC Interruptible | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **1** | **2** | **Not assigned** | **1** | **2** | **Not assigned** | **1** | **1** | **2** | **1** | **2** | **1** | **2** | **1** | **2** | **1** | **2** | |
| Jun-2019 | RES Rider credit | (521) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(521)** |
| Jun-2019 | Delivery Charge | 850,813 | 2,086 | - | 10,251 | - | - | 19,265 | 277,244 | 757,307 | 35,688 | 260,748 | 16,419 | 311,711 | 17,024 | 80,033 | 514,901 | 16,814 | **3,170,303** |
| Jun-2019 | Purchased Gas Charge | 1,099,153 | 1,383 | - | 14,626 | - | - | 24,152 | 65,727 | 425,520 | 39,173 | 123,616 | 20,747 | 192,674 | 15,042 | 50,763 | - | - | **2,072,575** |
| Jun-2019 | System Charge | 1,771,702 | 905 | - | 120,544 | 10 | - | 40,649 | 97,317 | 191,658 | 33,955 | 16,685 | 13,423 | 91,921 | 12,443 | 8,433 | 12,600 | 1,300 | **2,413,546** |
| Jun-2019 | Peak Usage Charge | - | - | - | - | - | - | - | (239) | 653 | (57) | 88 | 363 | 854 | 53 | 550 | - | - | **2,266** |
| Jun-2019 | DC Right of Way Tax | 75,601 | 185 | - | 927 | - | - | 1,714 | 26,902 | 70,273 | 3,327 | 24,300 | 1,517 | 28,489 | 1,570 | 7,363 | 138,882 | 3,479 | **384,529** |
| Jun-2019 | DC Right of Way Adjustment | (2,686) | (3) | - | (54) | - | - | (64) | (1,018) | (2,451) | (121) | (752) | (30) | (992) | (54) | (203) | (5,523) | (139) | **(14,089)** |
| Jun-2019 | SE Trust Fund | 33,940 | 85 | - | 446 | - | - | 795 | 12,595 | 32,448 | 1,536 | 11,220 | 702 | 13,165 | 725 | 3,401 | 64,118 | 1,606 | **176,781** |
| Jun-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 4,264 | - | **4,264** |
| Jun-2019 | Delivery Tax | 164,516 | 401 | - | 2,010 | - | - | 3,721 | 64,826 | 167,669 | 7,935 | 57,979 | 3,297 | 61,860 | 3,407 | 15,975 | 329,493 | 8,244 | **891,332** |
| Jun-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 28,075 | 2,650 | **30,725** |
| Jun-2019 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (15) | (0) | **(15)** |
| Jun-2019 | Balancing Charge | - | - | - | - | - | - | - | 1,448 | - | - | - | - | - | - | - | 8,521 | 213 | **10,182** |
| Jun-2019 | STORAGE GAS CHRG | 15,569 | 21 | - | 214 | - | - | 359 | 1,325 | 6,358 | 581 | 1,824 | 313 | 2,903 | 225 | 777 | - | - | **30,468** |
| Jun-2019 | EA Trust Fund | 18,725 | 47 | - | 247 | - | - | 440 | 7,099 | 17,974 | 851 | 6,229 | 388 | 7,293 | 402 | 1,867 | 35,514 | 890 | **97,966** |
| Jun-2019 | PRA | (75) | - | - | (1) | - | - | - | (25) | (51) | - | (60) | 1 | (52) | (3) | 33 | - | - | **(234)** |
| Jun-2019 | APRP | 74,395 | 187 | - | 873 | - | - | 1,736 | 12,915 | 33,147 | 1,570 | 11,485 | 708 | 13,231 | 729 | 3,389 | 29,344 | 736 | **184,443** |
| | **TOTAL** | **4,046,672** | **5,112** | **-** | **149,581** | **10** | **-** | **91,490** | **529,638** | **1,625,725** | **121,671** | **486,657** | **56,673** | **693,159** | **50,096** | **164,735** | **1,174,554** | **36,177** | **9,231,951** |
| Jul-2019 | PGC Rounding difference | 4 | 0 | - | (24) | (0) | - | (0) | 0 | 0 | (0) | (0) | 0 | (0) | 0 | 0 | - | - | **(20)** |
| Jul-2019 | ACA | 7,870 | 11 | - | 221 | 0 | - | 179 | 562 | 4,355 | 381 | 1,085 | 94 | 1,406 | 126 | 339 | - | - | **16,628** |
| Jul-2019 | DCA | (73,342) | (212) | - | (1,851) | (0) | - | (1,699) | (37,130) | (94,987) | (3,622) | (20,141) | (1,098) | (31,380) | (2,220) | (7,304) | - | - | **(274,985)** |
| Jul-2019 | GAC Current | 21,473 | 32 | - | 601 | 0 | - | 495 | 1,829 | 12,399 | 816 | 3,094 | 269 | 4,034 | 478 | 966 | - | - | **46,487** |
| Jul-2019 | Residential Essential Credit | 5,622 | 17 | - | 130 | - | - | 132 | 517 | 7,470 | 302 | 1,583 | 86 | 2,467 | 174 | 574 | 13,739 | 328 | **33,142** |
| Jul-2019 | RES Rider credit | (186) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(186)** |
| Jul-2019 | Delivery Charge | 588,570 | 1,703 | - | 14,685 | 0 | - | 13,572 | 269,539 | 728,172 | 27,613 | 153,825 | 8,430 | 243,775 | 17,098 | 56,262 | 451,581 | 14,151 | **2,588,976** |
| Jul-2019 | Purchased Gas Charge | 742,275 | 1,098 | - | 20,314 | 1 | - | 17,068 | 63,546 | 429,132 | 29,045 | 106,889 | 9,307 | 139,417 | 16,026 | 33,366 | - | - | **1,607,484** |
| Jul-2019 | System Charge | 1,773,760 | 904 | - | 120,777 | 10 | - | 40,647 | 95,685 | 191,106 | 34,251 | 16,287 | 12,482 | 92,286 | 11,556 | 7,733 | 12,500 | 1,300 | **2,411,282** |
| Jul-2019 | Peak Usage Charge | - | - | - | - | - | - | - | 402 | (1,019) | (225) | (21) | (68) | (32) | 1,524 | 0 | - | - | **561** |
| Jul-2019 | DC Right of Way Tax | 52,141 | 151 | - | 1,295 | 0 | - | 1,207 | 26,413 | 67,615 | 2,591 | 14,337 | 781 | 22,336 | 1,575 | 5,199 | 128,612 | 2,975 | **327,227** |
| Jul-2019 | DC Right of Way Adjustment | (2,096) | (6) | - | (45) | - | - | (49) | (1,091) | (2,728) | (154) | (779) | (31) | (884) | (43) | (207) | (5,118) | (119) | **(13,348)** |
| Jul-2019 | SE Trust Fund | 23,527 | 70 | - | 619 | 0 | - | 560 | 12,197 | 31,213 | 1,193 | 6,618 | 361 | 10,311 | 729 | 2,400 | 59,376 | 1,373 | **150,548** |
| Jul-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,934 | - | **2,934** |
| Jul-2019 | Delivery Tax | 113,300 | 327 | - | 2,833 | 0 | - | 2,623 | 63,018 | 161,293 | 6,163 | 34,200 | 1,695 | 48,440 | 3,427 | 11,275 | 305,299 | 7,053 | **760,947** |
| Jul-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 28,750 | 2,650 | **31,400** |
| Jul-2019 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,141) | - | **(1,141)** |
| Jul-2019 | Balancing Charge | - | - | - | - | - | - | - | 1,396 | - | - | - | - | - | - | - | 7,890 | 182 | **9,469** |
| Jul-2019 | STORAGE GAS CHRG | 10,983 | 16 | - | 306 | 0 | - | 253 | 938 | 6,355 | 415 | 1,587 | 138 | 2,069 | 243 | 495 | - | - | **23,799** |
| Jul-2019 | EA Trust Fund | 13,047 | 39 | - | 343 | 0 | - | 310 | 6,789 | 17,289 | 661 | 3,666 | 200 | 5,711 | 404 | 1,329 | 32,887 | 761 | **83,436** |
| Jul-2019 | PRA | 66 | - | - | 0 | - | - | - | (3) | 0 | 8 | - | - | - | - | - | - | - | **72** |
| Jul-2019 | APRP | 52,820 | 153 | - | 1,314 | 0 | - | 1,215 | 12,528 | 31,937 | 1,239 | 6,771 | 364 | 10,416 | 745 | 2,424 | 27,186 | 630 | **149,742** |
| | **TOTAL** | **3,329,834** | **4,301** | **-** | **161,519** | **11** | **-** | **76,515** | **517,135** | **1,589,604** | **100,678** | **329,002** | **33,012** | **550,373** | **51,842** | **114,851** | **1,064,496** | **31,285** | **7,954,456** |
| Aug-2019 | PGC Rounding difference | (168) | (0) | - | (28) | (0) | - | (5) | (2) | 0 | (1) | 0 | (0) | (0) | 0 | (0) | - | - | **(204)** |
| Aug-2019 | ACA | 7,481 | 12 | - | 222 | 0 | - | 164 | 900 | 4,156 | 430 | 1,528 | 218 | 1,192 | 127 | 306 | - | - | **16,735** |
| Aug-2019 | DCA | (71,272) | (169) | - | (1,852) | (0) | - | (1,585) | (40,268) | (104,629) | (4,806) | (25,436) | (2,193) | (28,384) | (1,527) | (7,982) | - | - | **(290,103)** |
| Aug-2019 | GAC Current | 21,072 | 35 | - | 602 | 0 | - | 462 | 2,557 | 11,748 | 1,212 | 3,649 | 655 | 3,398 | 328 | 1,244 | - | - | **46,964** |
| Aug-2019 | Residential Essential Credit | 5,404 | 13 | - | 130 | - | - | 123 | 674 | 8,226 | 379 | 2,105 | 170 | 2,231 | 125 | 594 | 12,928 | 281 | **33,384** |
| Aug-2019 | RES Rider credit | (369) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(369)** |
| Aug-2019 | Delivery Charge | 571,782 | 1,353 | - | 14,688 | 0 | - | 12,656 | 293,269 | 802,073 | 36,698 | 194,094 | 16,847 | 220,499 | 11,721 | 61,772 | 429,461 | 12,177 | **2,679,089** |
| Aug-2019 | Purchased Gas Charge | 726,417 | 1,219 | - | 20,360 | 1 | - | 15,908 | 88,301 | 405,556 | 41,880 | 127,476 | 22,561 | 117,272 | 11,384 | 41,662 | - | - | **1,619,998** |
| Aug-2019 | System Charge | 1,777,314 | 888 | - | 120,585 | 10 | - | 40,532 | 96,966 | 195,808 | 33,855 | 16,099 | 13,393 | 91,296 | 10,277 | 8,525 | 12,500 | 1,300 | **2,419,348** |
| Aug-2019 | Peak Usage Charge | - | - | - | - | - | - | - | 37 | 1,179 | (28) | (1,930) | 18 | (165) | (124) | 765 | - | - | **(247)** |
| Aug-2019 | DC Right of Way Tax | 50,613 | 120 | - | 1,294 | 0 | - | 1,124 | 28,660 | 74,468 | 3,421 | 18,161 | 1,560 | 20,203 | 1,088 | 5,673 | 122,558 | 2,544 | **331,488** |
| Aug-2019 | DC Right of Way Adjustment | (2,029) | (5) | - | (46) | - | - | (45) | (1,136) | (2,966) | (138) | (925) | (61) | (830) | (56) | (146) | (4,875) | (101) | **(13,359)** |
| Aug-2019 | SE Trust Fund | 22,756 | 55 | - | 619 | 0 | - | 521 | 13,232 | 34,381 | 1,579 | 8,372 | 720 | 9,327 | 502 | 2,620 | 56,581 | 1,174 | **152,440** |
| Aug-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 3,555 | - | **3,555** |
| Aug-2019 | Delivery Tax | 110,110 | 260 | - | 2,835 | 0 | - | 2,449 | 68,374 | 177,664 | 8,161 | 43,261 | 3,384 | 43,815 | 2,359 | 12,309 | 291,006 | 6,035 | **772,023** |
| Aug-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 29,425 | 2,650 | **32,075** |
| Aug-2019 | Balancing Charge | - | - | - | - | - | - | - | 1,453 | - | - | - | - | - | - | - | 7,519 | 156 | **9,128** |
| Aug-2019 | STORAGE GAS CHRG | 10,799 | 18 | - | 308 | 0 | - | 237 | 1,312 | 6,027 | 621 | 1,868 | 336 | 1,741 | 168 | 642 | - | - | **24,077** |
| Aug-2019 | EA Trust Fund | 12,694 | 31 | - | 342 | 0 | - | 290 | 7,329 | 19,044 | 875 | 4,653 | 399 | 5,166 | 280 | 1,436 | 31,339 | 651 | **84,528** |
| Aug-2019 | PRA | (5) | - | - | (0) | - | - | (0) | 4 | 0 | 1 | (10) | (2) | - | (2) | 28 | - | - | **14** |
| Aug-2019 | DC Tax Reform Credit | 294 | - | - | 12 | - | - | 3 | - | 359 | (7) | 1,703 | (18) | 36 | 39 | (182) | - | - | **2,238** |
| Aug-2019 | APRP | 51,243 | 121 | - | 1,313 | 0 | - | 1,139 | 13,538 | 35,185 | 1,619 | 8,646 | 726 | 9,420 | 514 | 2,596 | 25,897 | 538 | **152,496** |
| | **TOTAL** | **3,294,137** | **3,954** | **-** | **161,385** | **11** | **-** | **73,973** | **575,201** | **1,668,278** | **125,750** | **403,315** | **58,714** | **496,217** | **37,204** | **131,863** | **1,017,895** | **27,404** | **8,075,300** |
| Sep-2019 | PGC Rounding difference | (46) | - | - | (29) | 0 | - | (2) | (1) | (0) | (0) | 0 | 0 | (0) | 0 | (0) | - | - | **(79)** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL_** DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Htg / HC Not assigned | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - IMA Not assigned | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sep-2019 | ACA | 7,759 | 12 | - | 295 | 8 | - | 189 | 276 | 4,292 | 388 | 919 | 79 | 1,375 | 112 | 342 | - | - | **16,045** |
| Sep-2019 | DCA | (75,368) | (177) | - | (1,189) | 425 | - | (1,831) | (34,410) | (102,378) | (4,728) | (22,608) | (1,232) | (31,716) | (1,602) | (7,776) | - | - | **(284,590)** |
| Sep-2019 | GAC Current | 22,340 | 34 | - | 382 | (144) | - | 537 | 705 | 12,662 | 1,163 | 1,787 | 332 | 4,428 | 313 | 974 | - | - | **45,512** |
| Sep-2019 | Residential Essential Credit | 5,660 | 14 | - | 107 | (20) | - | 142 | 228 | 8,017 | 368 | 1,834 | 88 | 2,450 | 126 | 611 | 13,589 | 268 | **33,484** |
| Sep-2019 | RES Rider credit | 126 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **126** |
| Sep-2019 | Delivery Charge | 604,748 | 1,423 | - | 9,141 | (3,775) | - | 14,629 | 248,967 | 784,893 | 36,104 | 172,203 | 9,543 | 245,805 | 12,339 | 59,899 | 450,327 | 11,485 | **2,657,731** |
| Sep-2019 | Purchased Gas Charge | 554,091 | 843 | - | 8,130 | (4,483) | - | 13,288 | 13,337 | 316,177 | 29,096 | 31,367 | 8,683 | 112,259 | 7,777 | 24,292 | - | - | **1,114,855** |
| Sep-2019 | System Charge | 1,771,071 | 866 | - | 119,503 | (292) | - | 40,435 | 95,677 | 191,051 | 33,974 | 14,756 | 13,624 | 94,992 | 11,240 | 7,741 | 12,400 | 1,300 | **2,408,339** |
| Sep-2019 | Peak Usage Charge | - | - | - | - | - | - | - | (123) | 206 | 26 | (1,009) | 116 | 681 | (1) | - | - | - | **(105)** |
| Sep-2019 | DC Right of Way Tax | 53,556 | 126 | - | 839 | (299) | - | 1,301 | 24,494 | 72,860 | 3,363 | 16,109 | 874 | 22,578 | 1,140 | 5,535 | 127,058 | 2,423 | **331,956** |
| Sep-2019 | DC Right of Way Adjustment | (2,075) | (5) | - | (63) | (23) | - | (51) | (1,014) | (2,876) | (131) | (769) | (15) | (805) | (46) | (221) | (5,051) | (97) | **(13,241)** |
| Sep-2019 | SE Trust Fund | 24,026 | 58 | - | 407 | (139) | - | 604 | 11,309 | 33,638 | 1,554 | 7,433 | 404 | 10,423 | 526 | 2,555 | 58,659 | 1,119 | **152,576** |
| Sep-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 3,323 | - | **3,323** |
| Sep-2019 | Delivery Tax | 116,360 | 274 | - | 1,832 | (653) | - | 2,826 | 58,432 | 173,819 | 8,026 | 38,408 | 1,898 | 48,965 | 2,473 | 12,004 | 301,711 | 5,736 | **772,111** |
| Sep-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 29,200 | 3,550 | **32,750** |
| Sep-2019 | Balancing Charge | - | - | - | - | - | - | - | 1,448 | - | - | - | - | - | - | - | 7,795 | 149 | **9,392** |
| Sep-2019 | STORAGE GAS CHRG | 11,445 | 17 | - | 195 | (75) | - | 275 | 358 | 6,496 | 596 | 912 | 171 | 2,278 | 160 | 500 | - | - | **23,327** |
| Sep-2019 | EA Trust Fund | 13,300 | 32 | - | 225 | (69) | - | 334 | 6,268 | 18,632 | 861 | 4,142 | 219 | 5,740 | 291 | 1,415 | 32,490 | 620 | **84,501** |
| Sep-2019 | PRA | (1) | - | - | 11 | (9) | - | - | (9) | 5 | - | 25 | 6 | 84 | 1 | - | - | - | **112** |
| Sep-2019 | DC Tax Reform Credit | (67) | - | - | 791 | 315 | - | - | 18 | 43 | (75) | 309 | (37) | (173) | 3 | - | - | - | **1,126** |
| Sep-2019 | APRP | 54,276 | 128 | - | 795 | (320) | - | 1,317 | 11,584 | 34,394 | 1,589 | 7,700 | 394 | 10,449 | 531 | 2,581 | 26,838 | 513 | **152,768** |
| | **TOTAL** | **3,161,201** | **3,644** | **-** | **141,370** | **(9,552)** | **-** | **73,994** | **437,544** | **1,551,929** | **112,174** | **273,516** | **35,148** | **529,811** | **35,386** | **110,451** | **1,058,341** | **27,064** | **7,542,021** |
| Oct-2019 | PGC Rounding difference | (225) | (0) | - | (33) | - | - | (8) | (3) | (2) | (1) | (0) | (0) | (1) | (0) | (0) | - | - | **(273)** |
| Oct-2019 | ACA | 8,667 | 14 | - | 186 | - | - | 206 | 825 | 4,622 | 454 | 1,014 | 109 | 1,443 | 49 | 347 | - | - | **17,937** |
| Oct-2019 | DCA | (83,555) | (195) | - | 1,725 | - | - | (1,989) | (37,552) | (105,627) | (6,802) | (24,488) | (1,160) | (31,980) | (2,364) | (8,047) | - | - | **(302,035)** |
| Oct-2019 | GAC Current | 24,567 | 41 | - | (604) | - | - | 585 | 2,342 | 13,150 | 1,954 | 2,888 | 311 | 4,228 | 585 | 990 | - | - | **51,035** |
| Oct-2019 | Residential Essential Credit | 6,293 | 15 | - | (102) | - | - | 155 | 615 | 8,305 | 512 | 1,925 | 91 | 2,513 | 160 | 633 | 13,504 | 293 | **34,911** |
| Oct-2019 | RES Rider credit | 75 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **75** |
| Oct-2019 | Delivery Charge | 670,522 | 1,567 | - | (14,037) | - | - | 15,896 | 273,422 | 809,731 | 51,871 | 187,026 | 8,907 | 248,437 | 18,239 | 61,988 | 434,841 | 12,700 | **2,781,111** |
| Oct-2019 | Purchased Gas Charge | 683,998 | 1,152 | - | (22,556) | - | - | 16,317 | 65,358 | 366,614 | 58,585 | 80,322 | 8,690 | 118,940 | 17,254 | 27,626 | - | - | **1,422,300** |
| Oct-2019 | System Charge | 1,754,233 | 833 | - | 118,166 | 10 | - | 40,158 | 95,098 | 187,156 | 33,530 | 15,702 | 12,857 | 90,054 | 10,760 | 7,729 | 12,303 | 1,300 | **2,379,887** |
| Oct-2019 | Peak Usage Charge | - | - | - | - | - | - | - | 3 | 6 | 2,358 | (651) | 0 | (236) | 507 | - | - | - | **1,988** |
| Oct-2019 | DC Right of Way Tax | 59,397 | 139 | - | (1,204) | - | - | 1,413 | 26,728 | 75,185 | 4,813 | 17,436 | 826 | 22,766 | 1,668 | 5,728 | 122,278 | 2,653 | **339,824** |
| Oct-2019 | DC Right of Way Adjustment | (2,358) | (6) | - | (88) | - | - | (56) | (1,068) | (3,009) | (99) | (732) | (33) | (919) | (21) | (229) | (4,860) | (106) | **(13,582)** |
| Oct-2019 | SE Trust Fund | 80,113 | 193 | - | 526 | - | - | 1,966 | 37,018 | 104,359 | 5,124 | 24,868 | 1,141 | 31,582 | 1,808 | 7,925 | 169,357 | 3,674 | **469,653** |
| Oct-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 3,733 | - | **3,733** |
| Oct-2019 | Delivery Tax | 128,979 | 301 | - | (2,652) | - | - | 3,070 | 63,764 | 179,359 | 11,532 | 41,581 | 1,791 | 49,367 | 3,632 | 12,422 | 290,315 | 6,274 | **789,736** |
| Oct-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 28,983 | 3,100 | **32,083** |
| Oct-2019 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (131) | - | **(131)** |
| Oct-2019 | Balancing Charge | - | - | - | - | - | - | - | 1,362 | - | - | - | - | - | - | - | 7,502 | 163 | **9,027** |
| Oct-2019 | STORAGE GAS CHRG | 12,596 | 21 | - | (305) | - | - | 300 | 1,201 | 6,744 | 995 | 1,481 | 159 | 2,169 | 300 | 508 | - | - | **26,171** |
| Oct-2019 | EA Trust Fund | 14,717 | 36 | - | (303) | - | - | 363 | 6,835 | 19,225 | 1,235 | 4,457 | 211 | 5,821 | 428 | 1,465 | 31,268 | 678 | **86,436** |
| Oct-2019 | PRA | 2 | - | - | 21 | - | - | (0) | 0 | - | 1 | - | - | - | (21) | - | - | - | **3** |
| Oct-2019 | DC Tax Reform Credit | 62 | - | - | 11,242 | - | - | - | (24) | - | (2,536) | - | - | - | (388) | - | - | - | **8,357** |
| Oct-2019 | APRP | 60,130 | 141 | - | (1,658) | - | - | 1,431 | 12,626 | 35,520 | 2,311 | 8,228 | 385 | 10,609 | 770 | 2,671 | 25,826 | 561 | **159,552** |
| | **TOTAL** | **3,418,214** | **4,252** | **-** | **88,324** | **10** | **-** | **79,808** | **548,552** | **1,701,339** | **165,838** | **361,056** | **34,285** | **554,792** | **53,366** | **121,754** | **1,134,917** | **31,291** | **8,297,798** |
| Nov-2019 | PGC Rounding difference | (84) | (0) | - | (28) | - | - | (4) | (2) | (1) | (1) | (0) | (0) | (1) | (0) | (0) | - | - | **(121)** |
| Nov-2019 | ACA | 32,564 | 56 | - | 316 | - | - | 686 | 1,005 | 10,300 | 755 | 1,383 | 164 | 4,313 | 182 | 584 | - | - | **52,307** |
| Nov-2019 | DCA | (316,512) | (722) | - | (2,755) | - | - | (6,587) | (42,347) | (222,616) | (8,324) | (38,395) | (2,648) | (106,059) | (2,487) | (14,158) | - | - | **(763,608)** |
| Nov-2019 | GAC Current | 92,817 | 159 | - | 877 | - | - | 1,945 | 2,865 | 29,324 | 2,153 | 3,943 | 540 | 12,873 | 519 | 1,666 | - | - | **149,681** |
| Nov-2019 | Residential Essential Credit | 3 | 0 | - | 0 | - | - | (0) | (226) | (166) | (2) | 19 | (20) | (2) | 0 | - | 62 | 11 | **(322)** |
| Nov-2019 | Delivery Charge | 2,541,571 | 5,797 | - | 21,917 | - | - | 52,671 | 309,040 | 1,706,568 | 63,574 | 293,244 | 20,257 | 823,781 | 19,154 | 109,057 | 576,552 | 19,271 | **6,562,453** |
| Nov-2019 | Purchased Gas Charge | 2,591,303 | 4,435 | - | 24,170 | - | - | 54,252 | 80,022 | 818,547 | 60,120 | 110,142 | 14,660 | 359,662 | 14,479 | 46,531 | - | - | **4,178,324** |
| Nov-2019 | System Charge | 1,744,670 | 842 | - | 118,405 | 10 | - | 39,932 | 91,011 | 178,825 | 32,778 | 15,303 | 11,310 | 89,121 | 8,523 | 7,650 | 12,100 | 1,300 | **2,351,779** |
| Nov-2019 | Peak Usage Charge | - | - | - | - | - | - | - | 26,403 | 316,474 | 8,859 | 34,638 | 3,501 | 148,689 | 2,992 | 14,146 | - | - | **555,700** |
| Nov-2019 | DC Right of Way Tax | 225,247 | 514 | - | 1,939 | - | - | 4,687 | 30,141 | 158,460 | 5,925 | 27,329 | 1,886 | 75,474 | 1,770 | 10,077 | 153,504 | 3,950 | **700,901** |
| Nov-2019 | DC Right of Way Adjustment | (8,977) | (20) | - | (70) | - | - | (186) | (1,202) | (6,337) | (236) | (1,090) | (97) | (2,989) | (71) | (402) | (6,087) | (151) | **(27,918)** |
| Nov-2019 | SE Trust Fund | 311,985 | 711 | - | 2,707 | - | - | 6,499 | 41,765 | 219,877 | 8,214 | 37,878 | 2,835 | 104,226 | 2,449 | 13,957 | 212,610 | 5,473 | **971,186** |
| Nov-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 7,890 | 1,427 | **9,317** |
| Nov-2019 | Delivery Tax | 488,627 | 1,114 | - | 4,231 | - | - | 10,168 | 71,906 | 378,012 | 14,135 | 65,196 | 4,087 | 163,691 | 3,839 | 21,855 | 363,221 | 9,325 | **1,599,408** |
| Nov-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 15,450 | 2,425 | **17,875** |
| Nov-2019 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 131 | - | **131** |
| Nov-2019 | Balancing Charge | - | - | - | - | - | - | - | 1,441 | - | - | - | - | - | - | - | 9,418 | 242 | **11,102** |
| Nov-2019 | STORAGE GAS CHRG | 47,610 | 81 | - | 449 | - | - | 997 | 1,470 | 15,043 | 1,104 | 2,023 | 277 | 6,597 | 266 | 855 | - | - | **76,773** |
| Nov-2019 | EA Trust Fund | 57,638 | 131 | - | 507 | - | - | 1,200 | 7,708 | 40,518 | 1,515 | 6,988 | 485 | 19,300 | 453 | 2,577 | 39,254 | 1,010 | **179,285** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL_** DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Htg / HC Not assigned | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - IMA Not assigned | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nov-2019 | PRA | 2 | - | - | - | - | - | 0 | (0) | - | - | - | (6) | - | - | - | - | - | **(5)** |
| Nov-2019 | DC Tax Reform Credit | (40) | - | - | - | - | - | 2 | - | 14 | - | - | 20 | - | - | - | - | - | **(3)** |
| Nov-2019 | APRP | 231,477 | 528 | - | 1,990 | - | - | 4,816 | 14,042 | 73,871 | 2,762 | 12,743 | 898 | 35,662 | 836 | 4,760 | 38,003 | 957 | **423,346** |
| | **TOTAL** | **8,039,900** | **13,626** | **-** | **174,656** | **10** | **-** | **171,078** | **635,042** | **3,716,712** | **193,330** | **571,344** | **58,148** | **1,734,338** | **52,904** | **219,155** | **1,422,108** | **45,240** | **17,047,589** |
| Dec-2019 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 45 | - | **45** |
| Dec-2019 | PGC Rounding difference | (51) | (0) | - | (1) | - | - | (0) | (1) | (0) | (0) | (0) | 0 | (0) | (0) | 0 | - | - | **(56)** |
| Dec-2019 | ACA | 150,010 | 212 | - | 1,022 | 0 | - | 2,872 | 6,806 | 41,004 | 2,552 | 4,048 | 892 | 18,238 | 553 | 1,819 | - | - | **230,028** |
| Dec-2019 | DCA | (426,121) | (788) | - | (3,034) | (0) | - | (8,239) | (22,445) | (269,741) | (9,553) | (31,913) | (3,545) | (125,290) | (2,261) | (12,271) | - | - | **(915,200)** |
| Dec-2019 | GAC Current | 179,452 | 253 | - | 1,256 | 0 | - | 3,438 | 8,356 | 51,060 | 3,364 | 5,055 | 1,111 | 22,083 | 667 | 2,171 | - | - | **278,266** |
| Dec-2019 | Residential Essential Credit | 94,385 | 176 | - | 649 | 0 | - | 1,823 | 30,620 | 55,815 | 1,840 | 6,859 | 759 | 26,920 | 495 | 2,687 | 69,981 | 1,571 | **294,578** |
| Dec-2019 | RES Rider credit | (77) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(77)** |
| Dec-2019 | Delivery Charge | 4,844,390 | 8,974 | - | 33,812 | 0 | - | 93,225 | 236,239 | 2,868,399 | 97,859 | 341,962 | 38,118 | 1,363,761 | 24,547 | 133,327 | 331,066 | 35,611 | **10,451,290** |
| Dec-2019 | Purchased Gas Charge | 5,117,082 | 7,227 | - | 35,518 | 0 | - | 98,096 | 238,237 | 1,457,788 | 98,024 | 144,248 | 31,768 | 629,891 | 19,031 | 61,958 | - | - | **7,938,868** |
| Dec-2019 | System Charge | 1,742,870 | 837 | - | 118,205 | 10 | - | 39,947 | 94,578 | 191,811 | 34,052 | 15,748 | 13,609 | 90,778 | 10,452 | 7,695 | 12,007 | 1,300 | **2,373,899** |
| Dec-2019 | Peak Usage Charge | - | - | - | - | - | - | - | 178,411 | 348,543 | 11,742 | 35,857 | 4,390 | 155,773 | 3,045 | 14,605 | - | - | **752,365** |
| Dec-2019 | DC Right of Way Tax | 429,410 | 795 | - | 3,005 | 0 | - | 8,298 | 22,262 | 266,338 | 9,112 | 31,870 | 3,527 | 124,946 | 2,268 | 12,320 | 236,428 | 7,278 | **1,157,856** |
| Dec-2019 | DC Right of Way Adjustment | (17,162) | (32) | - | (112) | - | - | (331) | (883) | (10,548) | (307) | (1,271) | (126) | (4,936) | (90) | (491) | (9,351) | (270) | **(45,910)** |
| Dec-2019 | SE Trust Fund | 595,074 | 1,102 | - | 4,171 | 0 | - | 11,488 | 30,797 | 366,986 | 11,778 | 44,138 | 4,797 | 172,153 | 3,142 | 17,063 | 327,556 | 10,087 | **1,600,332** |
| Dec-2019 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19,027 | 4,976 | **24,003** |
| Dec-2019 | Delivery Tax | 931,200 | 1,725 | - | 6,528 | 0 | - | 17,994 | 53,111 | 635,386 | 21,757 | 76,027 | 7,650 | 270,990 | 4,919 | 26,718 | 555,698 | 17,093 | **2,626,797** |
| Dec-2019 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 225 | 2,200 | **2,425** |
| Dec-2019 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 14,506 | 447 | **14,953** |
| Dec-2019 | STORAGE GAS CHRG | 93,203 | 132 | - | 650 | 0 | - | 1,786 | 4,339 | 26,504 | 1,747 | 2,624 | 577 | 11,468 | 346 | 1,128 | - | - | **144,505** |
| Dec-2019 | EA Trust Fund | 109,836 | 203 | - | 785 | 0 | - | 2,123 | 5,693 | 68,105 | 2,333 | 8,149 | 898 | 31,951 | 580 | 3,150 | 60,460 | 1,862 | **296,129** |
| Dec-2019 | PRA | 7 | - | - | 0 | - | - | - | (1) | (0) | - | - | 10 | - | - | - | - | - | **16** |
| Dec-2019 | DC Tax Reform Credit | 60 | - | - | 2 | - | - | - | - | 360 | - | - | (23) | - | - | - | - | - | **398** |
| Dec-2019 | APRP | 441,187 | 817 | - | 3,073 | 0 | - | 8,525 | 10,376 | 124,198 | 4,263 | 14,859 | 1,657 | 59,031 | 1,071 | 5,820 | 58,430 | 1,725 | **735,033** |
| | **TOTAL** | **14,284,756** | **21,633** | **-** | **205,527** | **11** | **-** | **281,045** | **896,495** | **6,222,008** | **290,561** | **698,263** | **106,069** | **2,847,755** | **68,765** | **277,700** | **1,676,078** | **83,880** | **27,960,544** |

CUBE: tm1serv:Rate Statistics DB
RS_ACTUAL DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-2020 | PGC Rounding difference | (56) | (0) | (1) | - | (0) | (0) | (0) | (0) | - | (0) | 0 | (0) | (0) | - | - | **(59)** |
| Jan-2020 | ACA | 162,697 | 212 | 1,129 | 0 | 3,141 | 8,950 | 45,860 | 2,448 | 4,258 | 1,053 | 18,971 | 600 | 1,883 | - | - | **251,203** |
| Jan-2020 | DCA | (470,441) | (804) | (3,194) | (0) | (9,050) | (72,028) | (293,235) | (8,297) | (31,917) | (4,244) | (131,196) | (2,212) | (12,557) | - | - | **(1,039,176)** |
| Jan-2020 | GAC Current | 193,881 | 253 | 1,369 | 0 | 3,752 | 10,656 | 54,588 | 2,962 | 5,074 | 1,348 | 22,887 | 717 | 2,248 | - | - | **299,733** |
| Jan-2020 | Residential Essential Credit | 105,159 | 179 | 718 | 0 | 2,017 | 16,096 | 65,465 | 1,821 | 7,128 | 907 | 29,266 | 532 | 2,921 | 71,604 | 1,852 | **305,665** |
| Jan-2020 | RES Rider credit | 15 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **15** |
| Jan-2020 | Delivery Charge | 5,363,488 | 9,155 | 36,162 | 0 | 102,632 | 750,137 | 3,189,705 | 89,263 | 345,861 | 45,572 | 1,446,773 | 24,809 | 139,092 | 1,069,159 | 42,033 | **12,653,842** |
| Jan-2020 | Purchased Gas Charge | 5,532,899 | 7,222 | 38,733 | 0 | 107,035 | 302,978 | 1,556,725 | 84,673 | 144,783 | 38,589 | 652,478 | 20,445 | 64,149 | - | - | **8,550,708** |
| Jan-2020 | System Charge | 1,792,297 | 838 | 119,615 | 10 | 40,044 | 98,075 | 192,357 | 33,844 | 16,299 | 14,405 | 93,377 | 10,544 | 6,982 | 11,800 | 1,300 | **2,431,788** |
| Jan-2020 | Peak Usage Charge | - | - | - | - | - | 71,925 | 362,043 | 10,711 | 36,195 | 4,973 | 158,481 | 2,790 | 14,076 | - | - | **661,196** |
| Jan-2020 | DC Right of Way Tax | 475,394 | 811 | 3,212 | 0 | 9,135 | 72,731 | 296,162 | 8,319 | 32,233 | 4,217 | 132,541 | 2,299 | 12,876 | 319,406 | 8,582 | **1,377,917** |
| Jan-2020 | DC Right of Way Adjustment | (18,961) | (32) | (121) | - | (364) | (2,909) | (11,823) | (328) | (1,285) | (155) | (5,281) | (105) | (561) | (12,654) | (318) | **(54,897)** |
| Jan-2020 | SE Trust Fund | 659,191 | 1,124 | 4,458 | 0 | 12,649 | 100,579 | 410,557 | 11,420 | 44,642 | 5,715 | 183,986 | 3,309 | 18,226 | 442,396 | 11,894 | **1,910,146** |
| Jan-2020 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 30,690 | 5,899 | **36,589** |
| Jan-2020 | Delivery Tax | 1,030,977 | 1,760 | 6,980 | 0 | 19,809 | 173,502 | 706,518 | 19,846 | 76,894 | 9,149 | 287,439 | 4,983 | 27,919 | 752,289 | 20,140 | **3,138,205** |
| Jan-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 225 | 2,200 | **2,425** |
| Jan-2020 | Balancing Charge | - | - | - | - | - | 8,492 | - | - | - | - | - | - | - | 19,597 | 527 | **28,616** |
| Jan-2020 | STORAGE GAS CHRG | 100,689 | 131 | 708 | 0 | 1,948 | 5,535 | 28,358 | 1,538 | 2,636 | 700 | 11,893 | 372 | 1,168 | - | - | **155,677** |
| Jan-2020 | EA Trust Fund | 121,590 | 208 | 838 | 0 | 2,337 | 18,598 | 75,729 | 2,128 | 8,242 | 1,077 | 33,886 | 589 | 3,296 | 81,678 | 2,196 | **352,392** |
| Jan-2020 | PRA | 9 | - | - | - | 0 | - | - | - | 2 | 2 | (13) | (2) | 12 | - | - | **10** |
| Jan-2020 | DC Tax Reform Credit | 49 | - | 3 | - | - | 146 | - | (6) | - | (33) | (75) | 37 | 96 | - | - | **218** |
| Jan-2020 | APRP | 488,506 | 834 | 3,288 | 0 | 9,385 | 33,910 | 138,085 | 3,880 | 15,029 | 1,985 | 62,575 | 1,093 | 6,117 | 79,027 | 2,033 | **845,746** |
| | **TOTAL** | **15,537,383** | **21,891** | **213,897** | **11** | **304,471** | **1,597,373** | **6,817,095** | **264,222** | **706,072** | **125,261** | **2,997,988** | **70,800** | **287,941** | **2,865,216** | **98,338** | **31,907,960** |
| Feb-2020 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | 13,297 | - | **13,297** |
| Feb-2020 | PGC Rounding difference | (51) | (0) | (28) | (0) | (2) | (1) | 0 | (1) | (0) | (0) | (0) | (0) | 0 | - | - | **(82)** |
| Feb-2020 | ACA | 167,969 | 268 | 1,162 | 0 | 3,242 | 8,932 | 48,480 | 2,572 | 4,322 | 1,126 | 20,231 | 636 | 1,939 | - | - | **260,879** |
| Feb-2020 | DCA | (481,274) | (889) | (3,336) | (0) | (9,253) | (48,351) | (214,139) | (8,562) | (31,812) | (4,217) | (136,097) | (2,528) | (13,254) | - | - | **(953,712)** |
| Feb-2020 | GAC Current | 200,464 | 320 | 1,416 | 0 | 3,872 | 9,998 | 30,039 | 3,083 | 5,159 | 1,406 | 24,179 | 765 | 2,315 | - | - | **283,017** |
| Feb-2020 | Residential Essential Credit | 107,140 | 198 | 743 | 0 | 2,061 | 11,089 | 60,358 | 1,896 | 7,096 | 929 | 30,320 | 558 | 2,955 | 67,573 | 1,850 | **294,765** |
| Feb-2020 | RES Rider credit | (5,099) | - | - | - | (39) | - | - | - | - | - | - | - | - | - | - | **(5,138)** |
| Feb-2020 | Delivery Charge | 5,481,174 | 10,129 | 37,634 | 0 | 104,919 | 512,282 | 2,526,529 | 92,514 | 344,589 | 45,885 | 1,498,923 | 27,513 | 144,772 | 1,067,212 | 42,119 | **11,936,194** |
| Feb-2020 | Purchased Gas Charge | 4,895,246 | 7,814 | 34,420 | 0 | 94,698 | 240,341 | 613,507 | 75,611 | 126,218 | 34,334 | 591,350 | 18,747 | 56,543 | - | - | **6,788,830** |
| Feb-2020 | System Charge | 1,763,417 | 857 | 119,602 | 10 | 40,003 | 93,465 | 184,780 | 32,891 | 15,335 | 12,839 | 89,712 | 11,380 | 7,695 | 12,400 | 1,300 | **2,385,684** |
| Feb-2020 | Peak Usage Charge | - | - | - | - | - | 50,936 | 320,036 | 10,697 | 35,043 | 4,699 | 158,106 | 3,331 | 14,598 | - | - | **597,445** |
| Feb-2020 | DC Right of Way Tax | 485,836 | 898 | 3,345 | 0 | 9,338 | 49,373 | 237,029 | 8,622 | 32,114 | 4,250 | 137,336 | 2,542 | 13,378 | 306,677 | 8,598 | **1,299,336** |
| Feb-2020 | DC Right of Way Adjustment | (19,381) | (36) | (126) | - | (372) | (2,078) | (13,988) | (344) | (1,281) | (159) | (5,473) | (101) | (534) | (12,139) | (315) | **(56,326)** |
| Feb-2020 | SE Trust Fund | 671,999 | 1,243 | 4,639 | 0 | 12,924 | 69,495 | 368,481 | 11,941 | 44,477 | 5,843 | 190,201 | 3,521 | 18,527 | 424,770 | 11,917 | **1,839,980** |
| Feb-2020 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 18,930 | 5,836 | **24,766** |
| Feb-2020 | Delivery Tax | 1,053,620 | 1,947 | 7,265 | 0 | 20,251 | 117,746 | 564,721 | 20,569 | 76,611 | 9,216 | 297,847 | 5,514 | 29,012 | 721,512 | 20,188 | **2,946,019** |
| Feb-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 225 | 2,200 | **2,425** |
| Feb-2020 | Balancing Charge | - | - | - | - | - | 4,322 | - | - | - | - | - | - | - | 18,767 | 528 | **23,617** |
| Feb-2020 | STORAGE GAS CHRG | 104,110 | 166 | 733 | 0 | 2,011 | 5,192 | 15,608 | 1,601 | 2,680 | 732 | 12,560 | 397 | 1,203 | - | - | **146,995** |
| Feb-2020 | EA Trust Fund | 124,096 | 230 | 872 | 0 | 2,388 | 12,621 | 61,114 | 2,205 | 8,212 | 1,082 | 35,118 | 650 | 3,421 | 78,424 | 2,200 | **332,633** |
| Feb-2020 | PRA | 10 | - | - | - | - | 1 | 124 | - | - | 17 | - | - | - | - | - | **152** |
| Feb-2020 | DC Tax Reform Credit | 43 | - | (21) | - | 1 | 14 | 4,705 | - | - | - | (145) | - | - | - | - | **4,596** |
| Feb-2020 | APRP | 499,231 | 923 | 3,423 | 0 | 9,594 | 23,049 | 114,015 | 4,020 | 14,974 | 1,999 | 64,882 | 1,201 | 6,319 | 75,836 | 2,023 | **821,489** |
| | **TOTAL** | **15,048,551** | **24,068** | **211,744** | **10** | **295,636** | **1,158,427** | **4,921,400** | **259,315** | **683,736** | **119,981** | **3,009,048** | **74,126** | **288,889** | **2,793,484** | **98,444** | **28,986,861** |
| Mar-2020 | PGC Rounding difference | (64) | 0 | (5) | - | (3) | (1) | (1) | (1) | (0) | (0) | (0) | (0) | 0 | - | - | **(74)** |
| Mar-2020 | ACA | 142,327 | 202 | 1,402 | - | 2,809 | 8,428 | 36,887 | 2,214 | 3,844 | 1,119 | 18,392 | 752 | 1,887 | - | - | **220,264** |
| Mar-2020 | DCA | (364,682) | (607) | (3,418) | - | (7,147) | (44,143) | (316,811) | (6,853) | (29,462) | (3,580) | (108,734) | (2,391) | (10,446) | - | - | **(898,274)** |
| Mar-2020 | GAC Current | 151,294 | 215 | 1,563 | - | 2,989 | 9,021 | 67,265 | 2,361 | 4,066 | 1,205 | 19,556 | 802 | 2,006 | - | - | **262,343** |
| Mar-2020 | Residential Essential Credit | 77,176 | 135 | 787 | - | 1,592 | 9,840 | 58,050 | 1,492 | 6,576 | 795 | 24,147 | 531 | 2,329 | 61,300 | 1,614 | **246,364** |
| Mar-2020 | RES Rider credit | (154,410) | - | (15) | - | (15) | - | - | - | - | - | - | - | - | - | - | **(154,440)** |
| Mar-2020 | Delivery Charge | 4,152,323 | 6,913 | 38,997 | - | 81,040 | 462,515 | 3,245,530 | 73,475 | 319,205 | 38,971 | 1,195,717 | 26,089 | 114,100 | 990,666 | 36,608 | **10,782,148** |
| Mar-2020 | Purchased Gas Charge | 3,282,305 | 4,653 | 34,731 | - | 64,919 | 197,215 | 1,665,030 | 50,535 | 87,761 | 26,214 | 424,586 | 17,473 | 43,531 | - | - | **5,898,954** |
| Mar-2020 | System Charge | 1,762,136 | 836 | 118,302 | 10 | 40,145 | 97,847 | 195,714 | 32,879 | 16,151 | 12,493 | 90,971 | 11,967 | 7,779 | 12,400 | 1,300 | **2,400,929** |
| Mar-2020 | Peak Usage Charge | - | - | - | - | - | 54,384 | 387,221 | 10,576 | 39,200 | 4,901 | 156,757 | 3,611 | 15,049 | - | - | **671,700** |
| Mar-2020 | DC Right of Way Tax | 368,042 | 613 | 3,463 | - | 7,213 | 44,554 | 298,931 | 6,846 | 29,749 | 3,611 | 109,558 | 2,411 | 10,543 | 279,295 | 7,487 | **1,172,315** |
| Mar-2020 | DC Right of Way Adjustment | (14,666) | (24) | (129) | - | (287) | (1,776) | (7,368) | (265) | (1,186) | (141) | (4,373) | (96) | (421) | (10,924) | (276) | **(41,934)** |
| Mar-2020 | SE Trust Fund | 483,987 | 849 | 4,808 | - | 9,985 | 61,703 | 373,754 | 9,372 | 41,201 | 4,991 | 151,704 | 3,338 | 14,602 | 386,889 | 10,377 | **1,557,559** |
| Mar-2020 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 40,092 | 4,206 | **44,297** |
| Mar-2020 | Delivery Tax | 798,168 | 1,329 | 7,528 | - | 15,642 | 106,288 | 713,866 | 16,335 | 70,968 | 7,832 | 237,597 | 5,228 | 22,865 | 657,490 | 17,582 | **2,678,719** |
| Mar-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,200 | 2,200 | **4,400** |
| Mar-2020 | Balancing Charge | - | - | - | - | - | 6,580 | - | - | - | - | - | - | - | 17,138 | 460 | **24,177** |
| Mar-2020 | STORAGE GAS CHRG | 77,615 | 110 | 804 | - | 1,534 | 4,631 | 34,673 | 1,211 | 2,086 | 619 | 10,033 | 411 | 1,029 | - | - | **134,756** |

CUBE: tm1serv:Rate Statistics DB
RS_ACTUAL DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mar-2020 | EA Trust Fund | 89,411 | 157 | 901 | - | 1,845 | 11,394 | 75,933 | 1,752 | 7,607 | 922 | 28,014 | 617 | 2,696 | 71,430 | 1,916 | **294,594** |
| Mar-2020 | PRA | 5 | - | (1) | - | - | (0) | (123) | - | - | 4 | - | - | - | - | - | **(115)** |
| Mar-2020 | DC Tax Reform Credit | (73) | - | - | - | - | (38) | (4,355) | - | - | - | - | (0) | - | - | - | **(4,467)** |
| Mar-2020 | APRP | 325,533 | 541 | 3,179 | - | 6,391 | 16,681 | 114,531 | 2,565 | 11,089 | 1,369 | 41,468 | 915 | 3,951 | 60,241 | 1,552 | **590,004** |
| | **TOTAL** | **11,176,426** | **15,921** | **212,895** | **10** | **228,653** | **1,045,125** | **6,938,726** | **204,491** | **608,853** | **101,327** | **2,395,394** | **71,657** | **231,501** | **2,568,216** | **85,024** | **25,884,219** |
| Apr-2020 | PGC Rounding difference | 47 | 0 | (10) | (0) | 1 | 1 | (0) | 0 | 0 | 0 | 0 | 0 | 0 | - | - | **40** |
| Apr-2020 | ACA | 92,312 | 145 | 1,050 | 0 | 1,841 | 4,277 | 25,201 | 1,745 | 2,515 | 1,007 | 14,416 | 632 | 1,731 | - | - | **146,873** |
| Apr-2020 | DCA | (238,382) | (435) | (2,594) | (0) | (4,700) | (33,712) | (151,636) | (4,315) | (12,389) | (3,574) | (88,556) | (2,727) | (8,670) | - | - | **(551,691)** |
| Apr-2020 | GAC Current | 98,089 | 154 | 1,143 | 0 | 1,958 | 4,320 | 25,971 | 1,661 | 2,671 | 1,243 | 15,832 | 913 | 1,838 | - | - | **155,795** |
| Apr-2020 | Residential Essential Credit | 50,180 | 97 | 592 | 0 | 1,048 | 7,613 | 34,256 | 1,073 | 2,650 | 720 | 19,237 | 486 | 1,933 | 46,865 | 1,298 | **168,049** |
| Apr-2020 | RES Rider credit | (129,423) | - | (12) | - | (9) | - | - | - | - | - | - | - | - | - | - | **(129,444)** |
| Apr-2020 | Delivery Charge | 2,714,635 | 4,954 | 29,485 | 0 | 53,308 | 351,801 | 1,656,480 | 48,513 | 131,829 | 37,684 | 967,420 | 27,791 | 94,697 | 742,844 | 29,483 | **6,890,923** |
| Apr-2020 | Purchased Gas Charge | 2,716,856 | 4,260 | 31,427 | 0 | 54,267 | 119,829 | 711,731 | 45,629 | 74,152 | 34,978 | 438,808 | 25,759 | 50,944 | - | - | **4,308,641** |
| Apr-2020 | System Charge | 1,775,952 | 858 | 120,398 | 10 | 40,062 | 93,279 | 181,059 | 30,391 | 15,505 | 14,791 | 92,947 | 13,322 | 7,648 | 12,000 | 1,300 | **2,399,523** |
| Apr-2020 | Peak Usage Charge | - | - | - | - | - | 50,275 | 336,301 | 10,184 | 30,415 | 5,443 | 161,834 | 3,792 | 14,533 | - | - | **612,776** |
| Apr-2020 | DC Right of Way Tax | 241,340 | 440 | 2,622 | 0 | 4,758 | 34,305 | 154,340 | 4,561 | 12,328 | 3,488 | 88,830 | 2,550 | 8,780 | 211,416 | 6,039 | **775,796** |
| Apr-2020 | DC Right of Way Adjustment | (9,574) | (18) | (96) | - | (189) | (1,396) | (6,324) | (235) | (470) | (107) | (3,354) | (48) | (349) | (8,584) | (222) | **(30,965)** |
| Apr-2020 | SE Trust Fund | 314,444 | 608 | 3,635 | 0 | 6,566 | 47,680 | 214,764 | 6,684 | 16,606 | 4,543 | 121,553 | 3,113 | 12,119 | 291,833 | 8,346 | **1,052,495** |
| Apr-2020 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | (33,076) | 4,236 | **(28,840)** |
| Apr-2020 | Delivery Tax | 521,836 | 952 | 5,694 | 0 | 10,291 | 81,572 | 367,047 | 10,839 | 29,309 | 7,548 | 192,119 | 5,522 | 18,977 | 496,047 | 14,163 | **1,761,917** |
| Apr-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,200 | 2,200 | **4,400** |
| Apr-2020 | Balancing Charge | - | - | - | - | - | 7,000 | - | - | - | - | - | - | - | 12,927 | 370 | **20,297** |
| Apr-2020 | STORAGE GAS CHRG | 50,311 | 79 | 586 | 0 | 1,004 | 2,214 | 13,315 | 852 | 1,370 | 640 | 8,129 | 472 | 943 | - | - | **79,914** |
| Apr-2020 | EA Trust Fund | 58,128 | 112 | 680 | 0 | 1,215 | 8,748 | 39,376 | 1,175 | 3,141 | 885 | 22,618 | 639 | 2,237 | 53,880 | 1,541 | **194,376** |
| Apr-2020 | PRA | 29 | - | 0 | - | - | (5) | (86) | (18) | - | 5 | 86 | 18 | - | - | - | **30** |
| Apr-2020 | DC Tax Reform Credit | 10 | - | 1 | - | - | 126 | 620 | 120 | (187) | (80) | (415) | (92) | - | - | - | **102** |
| Apr-2020 | APRP | 212,544 | 388 | 2,324 | 0 | 4,193 | 12,619 | 56,852 | 1,689 | 4,633 | 1,324 | 33,715 | 982 | 3,232 | 46,537 | 1,248 | **382,279** |
| | **TOTAL** | **8,469,334** | **12,594** | **196,926** | **11** | **175,614** | **790,546** | **3,659,268** | **160,549** | **314,079** | **110,538** | **2,085,219** | **83,122** | **210,592** | **1,874,889** | **70,002** | **18,213,286** |
| May-2020 | PGC Rounding difference | 69 | (0) | (8) | - | 2 | 1 | (0) | 0 | 0 | (0) | (0) | 0 | 0 | - | - | **64** |
| May-2020 | ACA | 77,771 | 122 | 695 | 0 | 1,627 | 3,792 | 18,319 | 1,065 | 1,533 | 1,063 | 11,075 | 522 | 1,435 | - | - | **119,020** |
| May-2020 | DCA | (200,871) | (379) | (1,768) | (0) | (4,177) | (32,577) | (105,056) | (3,183) | (11,597) | (3,221) | (67,763) | (1,722) | (9,439) | - | - | **(441,757)** |
| May-2020 | GAC Current | 82,328 | 130 | 765 | 0 | 1,731 | 4,148 | 19,416 | 1,134 | 1,622 | 1,129 | 11,736 | 555 | 1,522 | - | - | **126,216** |
| May-2020 | Residential Essential Credit | 42,391 | 85 | 407 | 0 | 932 | 7,209 | 23,726 | 710 | 2,585 | 718 | 15,105 | 384 | 2,104 | 40,663 | 969 | **137,988** |
| May-2020 | RES Rider credit | (343) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(343)** |
| May-2020 | Delivery Charge | 2,288,383 | 4,320 | 20,102 | 1 | 47,372 | 337,414 | 1,148,400 | 34,479 | 125,595 | 35,079 | 746,447 | 18,812 | 103,098 | 666,664 | 21,351 | **5,597,518** |
| May-2020 | Purchased Gas Charge | 2,281,392 | 3,599 | 20,958 | 1 | 47,975 | 114,757 | 539,042 | 31,594 | 45,190 | 31,276 | 325,974 | 15,374 | 42,334 | - | - | **3,499,467** |
| May-2020 | System Charge | 1,764,197 | 838 | 119,918 | 10 | 39,912 | 94,124 | 164,964 | 31,917 | 12,987 | 12,100 | 86,771 | 11,237 | 7,378 | 12,397 | 1,300 | **2,360,050** |
| May-2020 | Peak Usage Charge | - | - | - | - | - | 2,321 | 23,996 | 262 | 3,100 | (20) | 3,256 | 13 | 63 | - | - | **32,989** |
| May-2020 | DC Right of Way Tax | 203,486 | 384 | 1,784 | 0 | 4,229 | 32,883 | 106,973 | 3,223 | 11,741 | 3,262 | 68,604 | 1,744 | 9,556 | 184,671 | 4,402 | **636,942** |
| May-2020 | DC Right of Way Adjustment | (8,148) | (15) | (63) | - | (168) | (1,295) | (4,297) | (128) | (467) | (130) | (2,727) | (69) | (380) | (7,342) | (175) | **(25,404)** |
| May-2020 | SE Trust Fund | 265,467 | 530 | 2,479 | 0 | 5,836 | 45,238 | 148,773 | 4,448 | 16,211 | 4,503 | 94,721 | 2,407 | 13,194 | 254,994 | 6,078 | **864,880** |
| May-2020 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,919 | 3,679 | **6,598** |
| May-2020 | Delivery Tax | 439,993 | 831 | 3,884 | 0 | 9,145 | 78,215 | 254,377 | 7,665 | 27,923 | 7,052 | 148,325 | 3,770 | 20,661 | 433,704 | 10,302 | **1,445,846** |
| May-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 12,590 | 4,625 | **17,215** |
| May-2020 | Balancing Charge | - | - | - | - | - | 6,754 | - | - | - | - | - | - | - | 11,295 | 269 | **18,319** |
| May-2020 | STORAGE GAS CHRG | 42,221 | 67 | 392 | 0 | 888 | 2,128 | 9,956 | 582 | 832 | 579 | 6,019 | 285 | 781 | - | - | **64,728** |
| May-2020 | EA Trust Fund | 49,017 | 98 | 467 | 0 | 1,080 | 8,385 | 27,266 | 822 | 2,993 | 832 | 17,488 | 445 | 2,436 | 47,079 | 1,122 | **159,529** |
| May-2020 | PRA | 9 | - | (0) | - | - | 0 | (0) | 1 | - | - | - | - | - | - | - | **10** |
| May-2020 | DC Tax Reform Credit | (3) | - | - | - | - | (144) | (441) | - | - | - | - | - | - | - | - | **(588)** |
| May-2020 | APRP | 1,220,937 | 2,301 | 12,418 | 0 | 25,149 | 34,239 | 111,581 | 3,551 | 12,315 | 5,917 | 124,552 | 3,163 | 17,399 | 94,190 | 2,154 | **1,669,867** |
| | **TOTAL** | **8,548,295** | **12,911** | **182,429** | **12** | **181,535** | **737,592** | **2,486,994** | **118,141** | **252,562** | **100,139** | **1,589,582** | **56,919** | **212,140** | **1,753,824** | **56,078** | **16,289,154** |
| Jun-2020 | PGC Rounding difference | 42 | 0 | (10) | (0) | 1 | 0 | (0) | 0 | 0 | (0) | (0) | 0 | (0) | - | - | **34** |
| Jun-2020 | ACA | 35,690 | 68 | 609 | 0 | 771 | 1,771 | 12,270 | 803 | 1,719 | 494 | 6,305 | 371 | 1,052 | - | - | **61,924** |
| Jun-2020 | DCA | (92,462) | (181) | (1,504) | (0) | (2,019) | (27,003) | (97,428) | (2,458) | (8,925) | (1,394) | (31,093) | (904) | (6,389) | - | - | **(271,760)** |
| Jun-2020 | GAC Current | 38,073 | 72 | 670 | 0 | 823 | 1,877 | 13,043 | 853 | 1,825 | 525 | 6,697 | 217 | 1,118 | - | - | **65,794** |
| Jun-2020 | Residential Essential Credit | 19,312 | 40 | 355 | 0 | 452 | 6,025 | 20,209 | 548 | 1,995 | 311 | 6,972 | 290 | 1,424 | 31,241 | 758 | **89,932** |
| Jun-2020 | RES Rider credit | (172) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(172)** |
| Jun-2020 | Delivery Charge | 1,053,343 | 2,062 | 17,213 | 0 | 22,928 | 278,475 | 1,026,063 | 26,624 | 96,738 | 15,176 | 343,102 | 11,286 | 69,779 | 518,287 | 16,766 | **3,497,843** |
| Jun-2020 | Purchased Gas Charge | 1,200,141 | 2,238 | 20,788 | 0 | 25,833 | 59,138 | 401,630 | 26,662 | 56,626 | 16,596 | 209,932 | 7,208 | 35,222 | - | - | **2,062,014** |
| Jun-2020 | System Charge | 1,771,738 | 878 | 120,521 | 10 | 40,008 | 97,692 | 197,268 | 33,247 | 16,138 | 13,005 | 91,501 | 10,462 | 7,837 | 12,000 | 1,300 | **2,413,604** |
| Jun-2020 | Peak Usage Charge | - | - | - | - | - | (51) | 23,079 | 69 | (92) | 7 | (2,610) | (752) | - | - | - | **19,651** |
| Jun-2020 | DC Right of Way Tax | 93,594 | 183 | 1,530 | 0 | 2,045 | 27,348 | 95,442 | 2,489 | 9,043 | 1,411 | 31,541 | 1,067 | 6,468 | 141,884 | 3,443 | **417,488** |
| Jun-2020 | DC Right of Way Adjustment | 7,008 | 11 | 117 | - | 147 | 2,059 | 3,893 | 164 | 534 | 109 | 2,372 | 69 | 448 | 10,847 | 263 | **28,043** |
| Jun-2020 | SE Trust Fund | 121,148 | 253 | 2,144 | 0 | 2,831 | 37,782 | 125,310 | 3,437 | 12,564 | 1,949 | 43,539 | 1,789 | 8,930 | 195,905 | 4,754 | **562,333** |
| Jun-2020 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,524 | **1,524** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL** DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jun-2020 | Delivery Tax | 202,599 | 397 | 3,326 | 0 | 4,429 | 65,044 | 227,260 | 5,919 | 21,508 | 3,051 | 68,177 | 2,301 | 13,983 | 334,237 | 8,081 | **960,311** |
| Jun-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 14,150 | 4,625 | **18,775** |
| Jun-2020 | Balancing Charge | - | - | - | - | - | 6,959 | - | - | - | - | - | - | - | 8,678 | 211 | **15,848** |
| Jun-2020 | STORAGE GAS CHRG | 17,585 | 34 | 304 | 0 | 381 | 867 | 6,167 | 397 | 853 | 242 | 3,110 | 90 | 517 | - | - | **30,546** |
| Jun-2020 | EA Trust Fund | 22,384 | 47 | 402 | 0 | 523 | 6,973 | 24,352 | 635 | 2,305 | 360 | 8,039 | 281 | 1,649 | 36,169 | 878 | **104,995** |
| Jun-2020 | PRA | 21 | - | (0) | - | - | - | 35 | - | - | - | - | (24) | - | - | - | **32** |
| Jun-2020 | DC Tax Reform Credit | 26 | - | - | - | - | - | - | - | - | - | - | 127 | - | - | - | **152** |
| Jun-2020 | APRP | 562,856 | 1,098 | 9,282 | 0 | 12,267 | 29,128 | 96,633 | 2,764 | 10,151 | 2,557 | 61,443 | 2,426 | 11,729 | 73,763 | 1,740 | **877,838** |
| | **TOTAL** | **5,052,929** | **7,200** | **175,749** | **11** | **111,420** | **594,084** | **2,175,225** | **102,155** | **222,982** | **54,399** | **849,027** | **36,303** | **153,766** | **1,377,161** | **44,342** | **10,956,752** |
| Jul-2020 | PGC Rounding difference | 5 | (0) | (12) | 0 | (0) | (1) | 0 | 0 | 0 | (0) | (0) | 0 | (0) | - | - | **(8)** |
| Jul-2020 | ACA | 21,052 | 98 | 478 | 0 | 502 | 933 | 6,469 | 867 | 1,866 | 250 | 3,565 | 294 | 879 | - | - | **37,254** |
| Jul-2020 | DCA | (54,692) | (918) | (1,202) | (0) | (1,316) | (24,186) | (49,280) | (2,448) | (9,420) | (943) | (21,654) | (1,131) | (5,259) | - | - | **(172,450)** |
| Jul-2020 | GAC Current | 22,520 | 344 | 542 | 0 | 539 | 975 | 6,726 | 921 | 1,820 | 266 | 3,808 | 313 | 933 | - | - | **39,707** |
| Jul-2020 | Residential Essential Credit | 11,423 | 88 | 284 | 0 | 295 | 5,404 | 11,045 | 546 | 2,174 | 210 | 4,785 | 252 | 1,172 | 28,676 | 478 | **66,833** |
| Jul-2020 | RES Rider credit | (444) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(444)** |
| Jul-2020 | Delivery Charge | 623,194 | 8,600 | 13,743 | 1 | 14,955 | 248,837 | 536,214 | 26,513 | 103,277 | 10,268 | 237,925 | 12,354 | 57,446 | 433,215 | 10,262 | **2,336,804** |
| Jul-2020 | Purchased Gas Charge | 711,100 | 10,249 | 16,755 | 1 | 17,007 | 30,933 | 213,949 | 29,206 | 58,427 | 8,401 | 118,826 | 9,881 | 29,489 | - | - | **1,254,223** |
| Jul-2020 | System Charge | 1,770,708 | 1,444 | 120,656 | 10 | 39,643 | 95,572 | 187,301 | 32,585 | 15,537 | 12,938 | 90,504 | 11,260 | 7,648 | 15,325 | 1,300 | **2,402,429** |
| Jul-2020 | Peak Usage Charge | - | - | - | - | - | (68) | 215 | (89) | (165) | - | 960 | - | - | - | - | **853** |
| Jul-2020 | DC Right of Way Tax | 55,377 | 731 | 1,217 | 0 | 1,334 | 24,510 | 49,986 | 2,478 | 9,664 | 955 | 21,864 | 1,145 | 5,325 | 130,236 | 2,170 | **306,992** |
| Jul-2020 | DC Right of Way Adjustment | 4,260 | 49 | 97 | 0 | 103 | 1,888 | 4,020 | 198 | 906 | 73 | 1,610 | 88 | 407 | 9,957 | 166 | **23,822** |
| Jul-2020 | SE Trust Fund | 71,528 | 609 | 1,702 | 0 | 1,848 | 33,888 | 69,319 | 3,423 | 13,557 | 1,319 | 30,192 | 1,581 | 7,352 | 179,821 | 2,997 | **419,136** |
| Jul-2020 | Delivery Tax | 119,917 | 1,589 | 2,652 | 0 | 2,890 | 58,294 | 118,883 | 5,895 | 22,974 | 2,064 | 47,277 | 2,476 | 11,512 | 308,249 | 5,095 | **709,766** |
| Jul-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 35,175 | 5,300 | **40,475** |
| Jul-2020 | Balancing Charge | - | - | - | - | - | 6,715 | - | - | - | - | - | - | - | 7,965 | 133 | **14,813** |
| Jul-2020 | STORAGE GAS CHRG | 10,385 | 176 | 244 | 0 | 249 | 446 | 3,056 | 424 | 823 | 123 | 1,773 | 144 | 430 | - | - | **18,274** |
| Jul-2020 | EA Trust Fund | 13,223 | 175 | 322 | 0 | 341 | 6,249 | 12,789 | 632 | 2,463 | 244 | 5,574 | 292 | 1,357 | 33,200 | 553 | **77,414** |
| Jul-2020 | PRA | 0 | 24 | - | - | - | - | (39) | - | 4 | - | - | - | - | - | - | **(11)** |
| Jul-2020 | DC Tax Reform Credit | (5) | (153) | - | - | - | (30) | 73 | - | 59 | - | - | - | - | - | - | **(56)** |
| Jul-2020 | APRP | 323,156 | 1,491 | 7,159 | 0 | 7,810 | 23,820 | 49,671 | 2,453 | 9,822 | 1,652 | 36,660 | 1,971 | 9,162 | 63,724 | 1,062 | **539,612** |
| | **TOTAL** | **3,702,707** | **24,593** | **164,638** | **12** | **86,200** | **514,179** | **1,220,395** | **103,603** | **233,788** | **37,819** | **583,671** | **40,921** | **127,852** | **1,245,543** | **29,516** | **8,115,438** |
| Aug-2020 | PGC Rounding difference | (57) | (0) | (18) | 0 | (2) | (1) | (0) | (0) | (0) | (0) | 0 | 0 | (0) | - | - | **(78)** |
| Aug-2020 | ACA | 19,733 | 46 | 1,540 | 0 | 436 | 4,237 | 7,645 | 715 | 1,773 | 290 | 3,095 | 254 | 719 | - | - | **40,483** |
| Aug-2020 | DCA | (49,817) | (117) | (4,481) | (0) | (1,137) | (10,925) | (58,445) | (97,589) | (9,638) | (994) | (27,838) | (999) | (4,784) | - | - | **(266,766)** |
| Aug-2020 | GAC Current | 20,795 | 49 | 1,954 | 0 | 468 | 4,828 | 8,113 | 473 | 1,882 | 309 | 3,287 | 270 | 764 | - | - | **43,192** |
| Aug-2020 | Residential Essential Credit | 10,535 | 26 | 840 | 0 | 254 | 2,251 | 13,030 | 35 | 2,099 | 222 | 5,635 | 223 | 1,067 | 28,351 | 415 | **64,983** |
| Aug-2020 | RES Rider credit | (257) | - | - | - | - | - | - | - | - | - | - | - | - | 1,294 | - | **1,037** |
| Aug-2020 | Delivery Charge | 569,411 | 1,327 | 47,351 | 1 | 12,914 | 114,387 | 635,343 | 178,309 | 103,613 | 10,829 | 296,657 | 10,917 | 52,256 | 453,598 | 8,911 | **2,495,824** |
| Aug-2020 | Purchased Gas Charge | 656,621 | 1,539 | 60,853 | 1 | 14,755 | 140,471 | 257,233 | 15,480 | 59,783 | 9,780 | 104,141 | 8,533 | 24,130 | - | - | **1,353,318** |
| Aug-2020 | System Charge | 1,776,370 | 867 | 121,969 | 10 | 39,657 | 95,998 | 188,808 | 34,315 | 15,412 | 13,124 | 90,868 | 11,238 | 7,657 | 12,880 | 1,200 | **2,410,373** |
| Aug-2020 | Peak Usage Charge | - | - | - | - | - | 5,233 | 1,147 | 145,597 | (80) | - | 2,072 | - | - | - | - | **153,970** |
| Aug-2020 | DC Right of Way Tax | 50,650 | 118 | 4,207 | 0 | 1,152 | 10,801 | 59,168 | 66,538 | 9,683 | 1,007 | 27,181 | 1,012 | 4,843 | 134,696 | 1,886 | **372,943** |
| Aug-2020 | DC Right of Way Adjustment | 3,892 | 9 | 230 | 0 | 90 | 176 | 4,190 | 1,630 | 761 | 79 | 1,396 | 77 | 370 | 9,633 | 144 | **22,678** |
| Aug-2020 | SE Trust Fund | 65,786 | 162 | 5,298 | 0 | 1,590 | 14,930 | 81,723 | 94,081 | 13,286 | 1,390 | 35,901 | 1,397 | 6,687 | 185,998 | 2,605 | **510,835** |
| Aug-2020 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 80,573 | - | **80,573** |
| Aug-2020 | Delivery Tax | 109,709 | 255 | 9,141 | 0 | 2,497 | 25,717 | 140,732 | 161,118 | 23,031 | 2,177 | 58,846 | 2,188 | 10,472 | 319,091 | 4,441 | **869,416** |
| Aug-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 35,228 | 5,075 | **40,303** |
| Aug-2020 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 8,239 | 115 | **8,355** |
| Aug-2020 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | (235) | (111) | **(345)** |
| Aug-2020 | STORAGE GAS CHRG | 9,554 | 22 | 919 | 0 | 215 | 2,372 | 3,734 | 194 | 865 | 142 | 1,512 | 125 | 352 | - | - | **20,007** |
| Aug-2020 | EA Trust Fund | 12,174 | 30 | 1,086 | 0 | 296 | 2,758 | 15,085 | 17,270 | 2,465 | 257 | 6,938 | 258 | 1,235 | 34,340 | 481 | **94,674** |
| Aug-2020 | PRA | 64 | - | - | - | - | - | 37 | - | 2 | - | (93) | - | - | - | - | **9** |
| Aug-2020 | DC Tax Reform Credit | 26 | - | (4,751) | - | - | - | 2,914 | 1,207 | (27) | - | (664) | - | - | - | - | **(1,295)** |
| Aug-2020 | APRP | 298,136 | 690 | 20,031 | 0 | 6,738 | 8,090 | 55,996 | 26,062 | 9,396 | 1,730 | 38,199 | 1,739 | 8,324 | 63,028 | 923 | **539,083** |
| | **TOTAL** | **3,553,326** | **5,024** | **266,170** | **12** | **79,924** | **421,324** | **1,416,454** | **645,435** | **234,307** | **40,340** | **647,135** | **37,230** | **114,092** | **1,366,713** | **26,087** | **8,853,572** |
| Sep-2020 | PGC Rounding difference | (7,124) | (21) | (161) | (0) | (160) | (356) | (3,069) | (286) | (594) | (78) | (1,123) | (84) | (246) | - | - | **(13,302)** |
| Sep-2020 | ACA | 21,494 | (257) | 521 | 0 | 475 | 1,561 | 8,949 | 949 | 1,674 | 231 | 3,524 | 263 | 739 | - | - | **40,124** |
| Sep-2020 | DCA | (47,407) | 773 | (1,297) | (0) | (1,238) | (47,689) | (61,939) | (8,806) | (10,251) | (745) | (20,813) | (1,089) | (5,107) | - | - | **(205,608)** |
| Sep-2020 | GAC Current | 20,257 | (342) | 589 | 0 | 510 | 1,304 | 10,796 | 1,008 | 1,779 | 246 | 3,807 | 279 | 785 | - | - | **41,017** |
| Sep-2020 | Residential Essential Credit | 11,040 | (130) | 306 | 0 | 278 | 10,743 | 13,717 | 573 | 2,285 | 166 | 4,598 | 243 | 1,138 | 32,007 | 471 | **77,433** |
| Sep-2020 | RES Rider credit | (110) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(110)** |
| Sep-2020 | Delivery Charge | 558,304 | (7,988) | 14,816 | 0 | 14,074 | 490,598 | 671,896 | 39,358 | 111,014 | 8,112 | 228,403 | 11,895 | 55,781 | 455,399 | 10,137 | **2,661,798** |
| Sep-2020 | Purchased Gas Charge | 571,797 | (9,445) | 16,480 | 0 | 14,358 | 36,807 | 311,073 | 28,872 | 50,037 | 6,951 | 107,463 | 7,944 | 22,246 | - | - | **1,164,585** |
| Sep-2020 | System Charge | 1,779,907 | 543 | 120,768 | 10 | 39,455 | 99,984 | 199,686 | 33,375 | 17,501 | 13,383 | 91,083 | 11,467 | 7,919 | 12,225 | 1,200 | **2,428,507** |
| Sep-2020 | Peak Usage Charge | - | - | - | - | - | (285) | (507) | 9,003 | - | - | 211 | - | - | - | - | **8,421** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL** DC

| | | DC Res Htg / HC | DC Res Htg / HC | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - OTH | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Non Htg | DC C&I Non Htg | DC GMA Htg / HC | DC GMA Htg / HC | DC GMA Non Htg | DC GMA Non Htg | DC Interruptible | DC Interruptible | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 1 | 2 | 1 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | |
| Sep-2020 | DC Right of Way Tax | 49,899 | (708) | 1,313 | 0 | 1,256 | 48,461 | 62,586 | 6,846 | 10,378 | 754 | 20,998 | 1,102 | 5,170 | 145,366 | 2,138 | **355,559** |
| Sep-2020 | DC Right of Way Adjustment | 4,033 | 33 | 104 | - | 98 | 3,704 | 5,054 | 298 | 904 | 58 | 1,559 | 84 | 395 | 11,114 | 164 | **27,602** |
| Sep-2020 | SE Trust Fund | 68,039 | (900) | 1,834 | 0 | 1,740 | 67,257 | 86,430 | 9,560 | 14,329 | 1,042 | 28,913 | 1,523 | 7,139 | 200,712 | 2,953 | **490,571** |
| Sep-2020 | Delivery Tax | 107,926 | (1,535) | 2,858 | 0 | 2,719 | 115,242 | 148,835 | 16,465 | 24,682 | 1,631 | 45,402 | 2,384 | 11,178 | 344,404 | 5,020 | **827,210** |
| Sep-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 34,600 | 5,075 | **39,675** |
| Sep-2020 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | (16,557) | (7,368) | **(23,926)** |
| Sep-2020 | Balancing Charge | - | - | - | - | - | 13,945 | - | - | - | - | - | - | - | 8,891 | 131 | **22,967** |
| Sep-2020 | STORAGE GAS CHRG | 8,694 | (179) | 257 | 0 | 224 | 562 | 4,815 | 447 | 783 | 109 | 1,702 | 124 | 347 | - | - | **17,884** |
| Sep-2020 | EA Trust Fund | 11,936 | (181) | 346 | 0 | 321 | 12,353 | 15,953 | 1,765 | 2,646 | 192 | 5,353 | 281 | 1,318 | 37,057 | 545 | **89,887** |
| Sep-2020 | PRA | 417 | 0 | 0 | - | 3 | 124 | - | - | - | - | - | - | - | - | - | **544** |
| Sep-2020 | DC Tax Reform Credit | 1,745 | - | - | - | - | 76 | - | - | - | - | - | - | - | - | - | **1,821** |
| Sep-2020 | APRP | 317,793 | (685) | 7,704 | 0 | 7,354 | 47,314 | 61,568 | 4,165 | 10,111 | 1,296 | 35,369 | 1,895 | 8,886 | 71,127 | 1,046 | **574,943** |
| | **TOTAL** | **3,478,640** | **(21,022)** | **166,439** | **11** | **81,466** | **901,703** | **1,535,843** | **143,592** | **237,280** | **33,347** | **556,448** | **38,311** | **117,690** | **1,336,345** | **21,511** | **8,627,604** |
| Oct-2020 | PGC Rounding difference | (10,018) | (29) | (186) | - | (231) | (467) | (4,024) | (378) | (683) | (149) | (1,566) | (101) | (291) | - | - | **(18,121)** |
| Oct-2020 | ACA | 30,134 | 42 | 551 | - | 689 | 1,201 | 12,262 | 1,238 | 2,015 | 476 | 4,704 | 298 | 860 | - | - | **54,470** |
| Oct-2020 | DCA | (77,582) | (26) | (1,378) | - | (1,788) | (24,557) | (81,164) | (7,958) | (10,115) | (1,255) | (27,747) | (1,220) | (5,610) | - | - | **(240,399)** |
| Oct-2020 | GAC Current | 32,287 | 15 | 620 | - | 737 | 1,228 | 15,846 | 1,333 | 2,140 | 507 | 5,006 | 317 | 913 | - | - | **60,948** |
| Oct-2020 | Residential Essential Credit | 16,327 | 24 | 323 | - | 400 | 5,511 | 17,010 | 1,767 | 2,321 | 280 | 6,182 | 272 | 1,251 | 30,411 | 560 | **82,638** |
| Oct-2020 | RES Rider credit | (68) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(68)** |
| Oct-2020 | Delivery Charge | 883,096 | 707 | 15,744 | - | 20,303 | 253,318 | 865,468 | 49,035 | 110,722 | 13,665 | 305,585 | 13,326 | 61,275 | 446,906 | 12,007 | **3,051,157** |
| Oct-2020 | Purchased Gas Charge | 911,787 | 266 | 17,199 | - | 20,814 | 34,328 | 447,546 | 37,520 | 60,510 | 14,235 | 141,340 | 8,951 | 25,817 | - | - | **1,720,311** |
| Oct-2020 | System Charge | 1,780,150 | 636 | 118,674 | 10 | 39,428 | 97,962 | 184,723 | 33,799 | 15,290 | 13,332 | 87,599 | 11,259 | 7,627 | 11,700 | 1,300 | **2,403,487** |
| Oct-2020 | Peak Usage Charge | - | - | - | - | - | (32) | 16,922 | 78 | - | 58 | - | - | - | - | - | **17,026** |
| Oct-2020 | DC Right of Way Tax | 78,481 | 64 | 1,396 | - | 1,811 | 24,937 | 80,375 | 8,041 | 10,351 | 1,270 | 28,086 | 1,235 | 5,679 | 138,118 | 2,543 | **382,387** |
| Oct-2020 | DC Right of Way Adjustment | 5,922 | 19 | 111 | - | 140 | 1,965 | 5,882 | 580 | 803 | 88 | 2,146 | 94 | 434 | 10,560 | 194 | **28,939** |
| Oct-2020 | SE Trust Fund | 102,443 | 160 | 1,950 | - | 2,508 | 34,582 | 107,706 | 11,084 | 14,402 | 1,755 | 38,780 | 1,706 | 7,842 | 190,704 | 3,511 | **519,132** |
| Oct-2020 | Delivery Tax | 169,895 | 136 | 3,038 | - | 3,922 | 59,308 | 191,286 | 19,126 | 24,616 | 2,747 | 60,725 | 2,671 | 12,279 | 326,998 | 5,965 | **882,712** |
| Oct-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 31,400 | 5,300 | **36,700** |
| Oct-2020 | Balancing Charge | - | - | - | - | - | 6,728 | - | - | - | - | - | - | - | 8,448 | 156 | **15,331** |
| Oct-2020 | STORAGE GAS CHRG | 14,268 | 1 | 269 | - | 324 | 525 | 7,261 | 599 | 945 | 227 | 2,218 | 140 | 403 | - | - | **27,179** |
| Oct-2020 | EA Trust Fund | 18,925 | 16 | 368 | - | 463 | 6,358 | 20,504 | 2,050 | 2,639 | 324 | 7,160 | 315 | 1,448 | 35,209 | 648 | **96,426** |
| Oct-2020 | PRA | 8 | - | - | - | - | (0) | (414) | - | - | - | - | - | - | - | - | **(406)** |
| Oct-2020 | DC Tax Reform Credit | (27) | 6 | - | - | - | 38 | (1,320) | - | - | - | - | - | - | - | - | **(1,302)** |
| Oct-2020 | APRP | 184,420 | 245 | 3,279 | - | 4,270 | 16,727 | 53,042 | 5,445 | 6,925 | 1,011 | 22,361 | 992 | 4,519 | 43,083 | 793 | **347,112** |
| | **TOTAL** | **4,140,448** | **2,282** | **161,957** | **10** | **93,789** | **519,659** | **1,938,909** | **163,360** | **242,882** | **48,571** | **682,579** | **40,254** | **124,447** | **1,273,536** | **32,978** | **9,465,659** |
| Nov-2020 | PGA - Retroactive | (22,155) | (48) | (277) | - | (457) | (806) | (6,340) | (455) | (926) | (185) | (3,024) | (142) | (438) | - | - | **(35,254)** |
| Nov-2020 | PGC Rounding difference | 138 | 1 | (4) | (0) | 3 | 60 | (40) | 13 | 7 | 1 | (34) | (0) | (0) | - | - | **144** |
| Nov-2020 | ACA | 65,152 | 141 | 824 | 0 | 1,344 | 2,218 | 18,842 | 1,322 | 2,735 | 545 | 9,013 | 419 | 1,297 | - | - | **103,850** |
| Nov-2020 | DCA | (167,333) | (397) | (1,967) | (0) | (3,464) | (28,372) | (111,246) | (9,568) | (12,979) | (1,514) | (53,594) | (1,539) | (8,116) | - | - | **(400,086)** |
| Nov-2020 | GAC Current | 69,298 | 149 | 892 | 0 | 1,431 | 2,365 | 20,011 | 1,429 | 2,924 | 579 | 9,572 | 445 | 1,377 | - | - | **110,474** |
| Nov-2020 | Residential Essential Credit | 36,737 | 87 | 439 | 0 | 762 | 6,218 | 24,464 | 2,078 | 2,839 | 333 | 11,782 | 338 | 1,784 | 32,811 | 783 | **121,454** |
| Nov-2020 | RES Rider credit | (1,938) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(1,938)** |
| Nov-2020 | Delivery Charge | 1,905,328 | 4,515 | 22,520 | 0 | 39,289 | 292,670 | 1,209,184 | 56,666 | 140,307 | 16,481 | 590,365 | 16,814 | 88,643 | 525,734 | 17,504 | **4,926,023** |
| Nov-2020 | Purchased Gas Charge | 1,959,590 | 4,221 | 24,893 | 0 | 40,444 | 66,773 | 565,867 | 40,407 | 82,622 | 16,374 | 271,038 | 12,586 | 38,944 | - | - | **3,123,760** |
| Nov-2020 | System Charge | 1,770,136 | 936 | 118,817 | 10 | 39,188 | 93,415 | 174,332 | 31,561 | 13,331 | 12,989 | 88,034 | 11,271 | 7,423 | 11,500 | 1,300 | **2,374,241** |
| Nov-2020 | Peak Usage Charge | - | - | - | - | - | 20,523 | 264,581 | 20,911 | 24,653 | 3,006 | 117,722 | 2,895 | 12,300 | - | - | **466,590** |
| Nov-2020 | DC Right of Way Tax | 169,390 | 401 | 2,001 | 0 | 3,507 | 28,689 | 112,622 | 9,652 | 13,116 | 1,532 | 54,258 | 1,558 | 8,216 | 151,116 | 3,604 | **559,663** |
| Nov-2020 | DC Right of Way Adjustment | 12,967 | 31 | 162 | - | 269 | 2,189 | 8,583 | 729 | 989 | 117 | 4,161 | 119 | 628 | 11,553 | 276 | **42,772** |
| Nov-2020 | SE Trust Fund | 233,591 | 554 | 2,806 | 0 | 4,844 | 39,573 | 155,502 | 13,327 | 18,104 | 2,116 | 74,915 | 2,152 | 11,344 | 208,651 | 4,976 | **772,454** |
| Nov-2020 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,222 | 1,497 | **2,718** |
| Nov-2020 | Delivery Tax | 366,319 | 868 | 4,349 | 0 | 7,585 | 68,232 | 267,849 | 22,956 | 31,194 | 3,313 | 117,310 | 3,370 | 17,764 | 356,277 | 8,439 | **1,275,826** |
| Nov-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 11,275 | 4,400 | **15,675** |
| Nov-2020 | Balancing Charge | - | - | - | - | - | 6,952 | - | - | - | - | - | - | - | 9,243 | 220 | **16,415** |
| Nov-2020 | STORAGE GAS CHRG | 30,601 | 66 | 391 | 0 | 632 | 1,045 | 8,835 | 634 | 1,295 | 256 | 4,223 | 197 | 608 | - | - | **48,782** |
| Nov-2020 | EA Trust Fund | 43,162 | 102 | 521 | 0 | 895 | 7,314 | 28,710 | 2,461 | 3,344 | 391 | 13,831 | 397 | 2,095 | 38,523 | 919 | **142,665** |
| Nov-2020 | PRA | (4) | - | - | - | - | 0 | - | - | - | - | - | - | - | - | - | **(4)** |
| Nov-2020 | DC Tax Reform Credit | (12) | - | 37 | - | - | 29 | - | - | - | - | - | - | - | - | - | **53** |
| Nov-2020 | APRP | 395,758 | 939 | 4,750 | 0 | 8,206 | 19,454 | 76,387 | 6,533 | 8,864 | 1,214 | 43,114 | 1,234 | 6,508 | 47,137 | 1,124 | **621,222** |
| | **TOTAL** | **6,866,723** | **12,567** | **181,152** | **11** | **144,477** | **628,544** | **2,818,143** | **200,656** | **332,418** | **57,547** | **1,352,686** | **52,115** | **190,377** | **1,405,042** | **45,041** | **14,287,499** |
| Dec-2020 | PGA - Retroactive | (43,643) | (59) | (327) | - | (886) | (2,054) | (11,831) | (752) | (1,078) | (327) | (5,482) | (191) | (538) | - | - | **(67,166)** |
| Dec-2020 | PGC Rounding difference | 17 | 0 | (2) | - | 1 | 2 | 17 | 8 | 22 | (2) | 47 | (0) | 0 | - | - | **111** |
| Dec-2020 | ACA | 235,501 | 248 | 1,778 | - | 4,749 | 11,034 | 63,154 | 3,941 | 5,555 | 1,763 | 29,068 | 1,033 | 2,906 | - | - | **360,731** |
| Dec-2020 | DCA | (293,296) | (168) | (2,174) | - | (5,903) | (34,876) | (192,089) | (12,964) | (16,763) | (2,331) | (94,205) | (1,713) | (9,164) | - | - | **(665,647)** |
| Dec-2020 | GAC Current | 137,093 | 61 | 1,049 | - | 2,781 | 6,488 | 37,567 | 2,339 | 3,189 | 1,034 | 17,076 | 599 | 1,690 | - | - | **210,965** |
| Dec-2020 | Residential Essential Credit | 72,148 | 73 | 531 | - | 1,457 | 8,619 | 47,025 | 3,201 | 4,121 | 576 | 23,141 | 424 | 2,261 | 42,471 | 1,109 | **207,157** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL** DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dec-2020 | RES Rider credit | (15,274) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(15,274)** |
| Dec-2020 | Delivery Charge | 3,756,349 | 3,099 | 27,489 | - | 75,280 | 409,341 | 2,326,277 | 89,778 | 203,217 | 28,506 | 1,159,709 | 21,067 | 112,375 | 694,162 | 23,689 | **8,930,339** |
| Dec-2020 | Purchased Gas Charge | 3,139,598 | 690 | 23,915 | - | 63,871 | 149,356 | 866,540 | 54,088 | 72,368 | 23,764 | 392,937 | 13,700 | 38,692 | - | - | **4,839,518** |
| Dec-2020 | System Charge | 1,780,624 | 585 | 119,002 | 10 | 38,912 | 102,720 | 194,964 | 33,009 | 16,740 | 12,558 | 91,882 | 11,303 | 7,922 | 11,400 | 1,300 | **2,422,931** |
| Dec-2020 | Peak Usage Charge | - | - | - | - | - | 46,917 | 322,838 | 27,125 | 41,779 | 3,460 | 140,872 | 2,908 | 13,187 | - | - | **599,087** |
| Dec-2020 | DC Right of Way Tax | 333,950 | 276 | 2,444 | - | 6,712 | 39,691 | 216,662 | 14,741 | 18,997 | 2,650 | 106,584 | 1,953 | 10,416 | 195,605 | 5,108 | **955,790** |
| Dec-2020 | DC Right of Way Adjustment | 25,551 | 50 | 190 | - | 514 | 3,029 | 16,584 | 1,127 | 1,464 | 203 | 8,149 | 149 | 796 | 14,955 | 391 | **73,152** |
| Dec-2020 | SE Trust Fund | 458,672 | 441 | 3,384 | - | 9,265 | 54,809 | 299,094 | 20,353 | 26,230 | 3,659 | 147,164 | 2,696 | 14,381 | 270,079 | 7,053 | **1,317,281** |
| Dec-2020 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,907 | (1,497) | **410** |
| Dec-2020 | Delivery Tax | 722,072 | 596 | 5,308 | - | 14,515 | 94,398 | 515,289 | 35,059 | 45,181 | 5,731 | 230,442 | 4,222 | 22,520 | 459,650 | 11,940 | **2,166,921** |
| Dec-2020 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 6,600 | 4,400 | **11,000** |
| Dec-2020 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | (12,387) | - | **(12,387)** |
| Dec-2020 | Balancing Charge | - | - | - | - | - | 8,702 | - | - | - | - | - | - | - | 11,964 | 312 | **20,978** |
| Dec-2020 | STORAGE GAS CHRG | 58,774 | 15 | 449 | - | 1,192 | 2,785 | 16,156 | 1,004 | 1,361 | 443 | 7,324 | 257 | 724 | - | - | **90,485** |
| Dec-2020 | EA Trust Fund | 84,748 | 70 | 634 | - | 1,712 | 10,120 | 55,232 | 3,758 | 4,843 | 676 | 27,170 | 498 | 2,655 | 49,864 | 1,302 | **243,283** |
| Dec-2020 | PRA | 6 | - | 0 | - | - | - | 24 | - | - | - | - | - | - | - | - | **31** |
| Dec-2020 | DC Tax Reform Credit | (11) | 19 | (4) | - | (3) | (15) | (20) | - | - | - | - | - | - | - | - | **(35)** |
| Dec-2020 | APRP | 781,114 | 883 | 5,738 | - | 15,699 | 26,956 | 146,784 | 10,008 | 12,540 | 2,100 | 84,398 | 1,547 | 8,250 | 61,015 | 1,593 | **1,158,625** |
| | **TOTAL** | **11,233,994** | **6,879** | **189,404** | **10** | **229,868** | **938,023** | **4,920,267** | **285,825** | **439,765** | **84,462** | **2,366,277** | **60,451** | **229,075** | **1,807,284** | **56,702** | **22,848,286** |

CUBE: tm1serv:Rate Statistics DB
RS_ACTUAL_AR DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-2021 | PGA - Retroactive | (72,622) | (114) | (485) | - | (1,391) | (3,123) | (18,837) | (926) | (1,360) | (583) | (7,926) | (255) | (755) | - | - | (108,376) |
| Jan-2021 | PGC Rounding difference | (40) | 1 | (40) | (0) | (1) | 1 | 30 | 1 | 1 | (0) | 0 | (0) | 0 | - | - | (48) |
| Jan-2021 | ACA | 392,663 | 584 | 2,647 | 0 | 7,514 | 16,828 | 101,802 | 5,004 | 7,400 | 3,153 | 42,859 | 1,381 | 4,085 | - | - | 585,920 |
| Jan-2021 | DCA | (485,517) | (478) | (3,222) | (0) | (9,293) | (41,760) | (264,616) | (18,552) | (22,488) | (4,345) | (130,347) | (2,363) | (12,250) | - | - | (995,231) |
| Jan-2021 | GAC Current | 228,262 | 212 | 1,543 | 0 | 4,367 | 9,696 | 59,163 | 2,903 | 4,273 | 1,832 | 24,909 | 803 | 2,374 | - | - | 340,335 |
| Jan-2021 | Residential Essential Credit | 118,833 | 180 | 791 | 0 | 2,297 | 10,370 | 65,409 | 4,591 | 5,569 | 1,072 | 32,242 | 585 | 3,030 | 65,357 | 1,678 | 312,005 |
| Jan-2021 | RES Rider credit | (45,208) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (45,208) |
| Jan-2021 | Delivery Charge | 6,221,428 | 7,560 | 41,010 | 0 | 118,582 | 493,445 | 3,236,287 | 120,018 | 274,377 | 53,117 | 1,615,736 | 29,048 | 150,581 | 1,022,207 | 37,636 | 13,421,032 |
| Jan-2021 | Purchased Gas Charge | 5,628,871 | 4,374 | 37,784 | 0 | 107,703 | 239,766 | 1,455,900 | 71,412 | 105,026 | 45,202 | 614,128 | 19,802 | 58,559 | - | - | 8,388,529 |
| Jan-2021 | System Charge | 1,777,893 | 272 | 117,163 | 10 | 39,059 | 97,294 | 183,584 | 32,316 | 14,892 | 12,564 | 89,129 | 10,203 | 7,582 | 11,400 | 1,300 | 2,394,660 |
| Jan-2021 | Peak Usage Charge | - | - | - | - | - | 45,112 | 301,395 | 36,880 | 34,368 | 4,564 | 135,644 | 2,948 | 12,835 | - | - | 573,746 |
| Jan-2021 | DC Right of Way Tax | 553,111 | 686 | 3,657 | 0 | 10,585 | 47,684 | 301,406 | 21,142 | 25,649 | 4,939 | 148,495 | 2,692 | 13,957 | 301,011 | 7,729 | 1,442,744 |
| Jan-2021 | DC Right of Way Adjustment | 42,305 | 59 | 282 | - | 811 | 3,669 | 23,040 | 1,617 | 1,961 | 378 | 11,353 | 206 | 1,067 | 23,013 | 591 | 110,352 |
| Jan-2021 | SE Trust Fund | 755,663 | 1,131 | 5,051 | 0 | 14,613 | 65,952 | 415,965 | 29,192 | 35,415 | 6,819 | 205,032 | 3,717 | 19,271 | 415,617 | 10,671 | 1,984,109 |
| Jan-2021 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 25,276 | - | 25,276 |
| Jan-2021 | Delivery Tax | 1,195,897 | 1,480 | 7,919 | 0 | 22,887 | 113,403 | 716,834 | 50,281 | 61,001 | 10,678 | 321,059 | 5,821 | 30,176 | 706,559 | 18,039 | 3,262,034 |
| Jan-2021 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,425 | 2,200 | 4,625 |
| Jan-2021 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | (18,220) | - | (18,220) |
| Jan-2021 | Balancing Charge | - | - | - | - | - | 9,036 | - | - | - | - | - | - | - | 18,411 | 473 | 27,919 |
| Jan-2021 | STORAGE GAS CHRG | 97,825 | 78 | 660 | 0 | 1,871 | 4,146 | 25,364 | 1,244 | 1,830 | 785 | 10,675 | 344 | 1,017 | - | - | 145,840 |
| Jan-2021 | EA Trust Fund | 139,552 | 180 | 948 | 0 | 2,700 | 12,156 | 76,830 | 5,390 | 6,539 | 1,259 | 37,854 | 686 | 3,558 | 76,734 | 1,970 | 366,355 |
| Jan-2021 | PRA | 1 | (10) | - | - | 0 | 1 | 10 | - | - | - | - | - | - | - | - | 3 |
| Jan-2021 | DC Tax Reform Credit | 20 | 45 | - | - | 5 | 56 | (50) | - | - | (1) | - | - | - | - | - | 75 |
| Jan-2021 | APRP | 726,523 | 962 | 4,989 | 0 | 13,852 | 19,769 | 130,482 | 9,090 | 11,105 | 2,402 | 69,585 | 1,243 | 6,445 | 77,324 | 1,985 | 1,075,758 |
| | **TOTAL** | **17,275,461** | **17,204** | **220,696** | **10** | **336,161** | **1,143,499** | **6,809,998** | **371,602** | **565,558** | **143,835** | **3,220,429** | **76,861** | **301,532** | **2,727,114** | **84,273** | **33,294,233** |
| Feb-2021 | PGA - Retroactive | (73,835) | (112) | (467) | - | (1,413) | (4,072) | (19,864) | (979) | (1,340) | (769) | (8,002) | (249) | (717) | - | - | (111,820) |
| Feb-2021 | PGC Rounding difference | (22) | (1) | (42) | (0) | (1) | (0) | (6) | 0 | 6 | (0) | 12 | (0) | 0 | - | - | (54) |
| Feb-2021 | ACA | 398,897 | 619 | 2,568 | 0 | 7,642 | 22,015 | 107,795 | 5,295 | 7,223 | 4,160 | 43,272 | 1,344 | 3,875 | - | - | 604,705 |
| Feb-2021 | DCA | (492,920) | (869) | (3,137) | (0) | (9,431) | (48,793) | (272,891) | (15,897) | (22,745) | (5,572) | (131,225) | (2,318) | (12,096) | - | - | (1,017,893) |
| Feb-2021 | GAC Current | 231,562 | 366 | 1,492 | 0 | 4,440 | 12,788 | 62,876 | 3,074 | 4,167 | 2,417 | 25,112 | 781 | 2,252 | - | - | 351,328 |
| Feb-2021 | Residential Essential Credit | 120,080 | 215 | 773 | 0 | 2,333 | 12,072 | 67,650 | 3,933 | 5,634 | 1,378 | 32,468 | 574 | 2,992 | 69,440 | 1,613 | 250,101 |
| Feb-2021 | RES Rider credit | (66,122) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (66,122) |
| Feb-2021 | Delivery Charge | 6,317,518 | 11,101 | 40,013 | 0 | 120,354 | 577,116 | 3,345,351 | 114,958 | 277,489 | 68,275 | 1,627,083 | 28,499 | 148,687 | 1,082,887 | 36,169 | 12,676,442 |
| Feb-2021 | Purchased Gas Charge | 5,955,110 | 9,326 | 38,160 | 0 | 114,208 | 328,500 | 1,614,355 | 78,872 | 107,048 | 61,983 | 645,478 | 20,081 | 57,939 | - | - | 9,031,061 |
| Feb-2021 | System Charge | 1,778,405 | 1,114 | 116,585 | 10 | 39,129 | 97,887 | 183,093 | 31,743 | 15,205 | 13,005 | 87,853 | 12,200 | 7,611 | 11,400 | 1,300 | 2,383,841 |
| Feb-2021 | Peak Usage Charge | - | - | - | - | - | 50,049 | 307,876 | 35,740 | 35,327 | 6,098 | 138,058 | 2,974 | 12,683 | - | - | 588,805 |
| Feb-2021 | DC Right of Way Tax | 561,675 | 987 | 3,567 | 0 | 10,744 | 55,595 | 311,585 | 18,114 | 25,941 | 6,348 | 149,538 | 2,641 | 13,781 | 319,815 | 7,430 | 1,160,517 |
| Feb-2021 | DC Right of Way Adjustment | 43,070 | 73 | 276 | - | 822 | 4,253 | 23,753 | 1,385 | 1,986 | 485 | 11,433 | 202 | 1,054 | 24,451 | 568 | 88,794 |
| Feb-2021 | SE Trust Fund | 763,634 | 1,364 | 4,929 | 0 | 14,833 | 76,761 | 430,219 | 25,012 | 35,831 | 8,765 | 206,472 | 3,647 | 19,028 | 441,580 | 10,258 | 1,590,495 |
| Feb-2021 | Delivery Tax | 1,214,377 | 2,134 | 7,723 | 0 | 23,230 | 132,220 | 741,044 | 43,082 | 61,694 | 13,725 | 323,313 | 5,711 | 29,796 | 750,179 | 17,295 | 2,598,049 |
| Feb-2021 | Balancing Charge | - | - | - | - | - | 9,079 | - | - | - | - | - | - | - | 19,561 | 454 | 9,079 |
| Feb-2021 | STORAGE GAS CHRG | 99,206 | 158 | 640 | 0 | 1,903 | 5,480 | 26,985 | 1,318 | 1,784 | 1,036 | 10,761 | 335 | 965 | - | - | 150,569 |
| Feb-2021 | EA Trust Fund | 141,021 | 252 | 925 | 0 | 2,740 | 14,173 | 79,430 | 4,618 | 6,613 | 1,618 | 38,120 | 673 | 3,513 | 81,528 | 1,894 | 293,696 |
| Feb-2021 | PRA | (3) | - | - | - | - | - | - | - | 1 | - | - | - | - | - | - | (2) |
| Feb-2021 | DC Tax Reform Credit | (21) | - | - | - | - | - | - | - | 13 | - | - | - | - | - | - | (7) |
| Feb-2021 | APRP | 734,923 | 1,321 | 4,657 | 0 | 14,062 | 23,796 | 132,648 | 7,744 | 11,006 | 2,931 | 68,890 | 1,219 | 6,362 | 82,154 | 1,909 | 1,009,557 |
| | **TOTAL** | **17,726,556** | **28,046** | **218,662** | **10** | **345,594** | **1,368,918** | **7,141,898** | **358,011** | **572,882** | **185,885** | **3,268,637** | **78,316** | **297,727** | **2,882,995** | **78,890** | **31,591,142** |
| Mar-2021 | PGA - Retroactive | (60,641) | (128) | (438) | - | (1,139) | (3,537) | (16,583) | (950) | (1,224) | (702) | (6,669) | (281) | (668) | - | - | (92,960) |
| Mar-2021 | PGC Rounding difference | (9) | 0 | (42) | - | (0) | 2 | (6) | (0) | (0) | 0 | (0) | (0) | (0) | - | - | (56) |
| Mar-2021 | ACA | 335,173 | 704 | 2,449 | - | 6,297 | 19,563 | 91,598 | 5,214 | 6,769 | 3,880 | 36,883 | 1,555 | 3,695 | - | - | 513,779 |
| Mar-2021 | DCA | (407,354) | (911) | (2,962) | - | (7,671) | (43,960) | (262,414) | (15,565) | (19,945) | (4,741) | (112,100) | (2,507) | (11,141) | - | - | (891,270) |
| Mar-2021 | GAC Current | 190,385 | 403 | 1,400 | - | 3,579 | 11,123 | 52,155 | 2,973 | 3,847 | 2,205 | 20,959 | 883 | 2,099 | - | - | 292,012 |
| Mar-2021 | Residential Essential Credit | 214,335 | 412 | 1,550 | - | 4,139 | 23,515 | 131,028 | 7,993 | 10,798 | 2,560 | 58,460 | 1,363 | 5,793 | 144,766 | 3,394 | 610,105 |
| Mar-2021 | RES Rider credit | (79,818) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (79,818) |
| Mar-2021 | Delivery Charge | 5,220,885 | 11,673 | 37,733 | - | 97,887 | 519,870 | 3,209,697 | 120,199 | 243,093 | 58,090 | 1,388,044 | 30,813 | 136,808 | 1,026,236 | 34,871 | 12,135,897 |
| Mar-2021 | Purchased Gas Charge | 7,266,389 | 13,577 | 52,445 | - | 136,699 | 422,767 | 1,961,941 | 104,937 | 146,923 | 84,303 | 801,816 | 33,877 | 80,679 | - | - | 11,106,351 |
| Mar-2021 | System Charge | 1,786,187 | 995 | 115,544 | 10 | 39,231 | 100,481 | 188,139 | 32,092 | 15,444 | 13,090 | 94,123 | 11,021 | 8,025 | 11,400 | 1,300 | 2,417,082 |
| Mar-2021 | Peak Usage Charge | - | - | - | - | - | 50,270 | 345,370 | 38,636 | 35,516 | 5,990 | 139,369 | 2,955 | 13,171 | - | - | 631,276 |
| Mar-2021 | DC Right of Way Tax | 464,161 | 1,038 | 3,360 | - | 8,738 | 50,082 | 298,939 | 17,736 | 22,725 | 5,401 | 127,569 | 2,856 | 12,680 | 305,409 | 7,159 | 1,327,854 |
| Mar-2021 | DC Right of Way Adjustment | 35,541 | 79 | 260 | - | 669 | 3,828 | 22,847 | 1,359 | 1,737 | 413 | 9,735 | 218 | 969 | 23,349 | 547 | 101,552 |
| Mar-2021 | SE Trust Fund | 626,820 | 1,433 | 4,651 | - | 12,064 | 69,146 | 412,775 | 24,489 | 31,377 | 7,457 | 176,139 | 3,943 | 17,508 | 421,688 | 9,885 | 1,819,377 |
| Mar-2021 | Delivery Tax | 1,003,586 | 2,244 | 7,284 | - | 18,894 | 119,111 | 710,964 | 42,182 | 54,046 | 11,677 | 275,815 | 6,175 | 27,416 | 716,716 | 16,681 | 3,012,790 |
| Mar-2021 | Balancing Charge | - | - | - | - | - | 8,200 | - | - | - | - | - | - | - | 18,679 | 438 | 27,318 |
| Mar-2021 | STORAGE GAS CHRG | 75,436 | 165 | 563 | - | 1,418 | 4,413 | 20,744 | 1,199 | 1,525 | 873 | 8,300 | 350 | 830 | - | - | 115,817 |
| Mar-2021 | EA Trust Fund | 115,745 | 265 | 869 | - | 2,229 | 12,768 | 76,214 | 4,522 | 5,793 | 1,377 | 32,520 | 728 | 3,233 | 77,855 | 1,825 | 335,942 |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL_AR** DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mar-2021 | PRA | 0 | - | - | - | - | (2) | (32) | - | - | - | - | - | - | - | - | **(34)** |
| Mar-2021 | APRP | 549,734 | 1,270 | 4,026 | - | 10,370 | 27,298 | 159,508 | 9,519 | 12,439 | 3,139 | 73,963 | 1,664 | 7,378 | 82,190 | 1,927 | **944,424** |
| | **TOTAL** | **17,336,556** | **33,216** | **228,692** | **10** | **333,402** | **1,394,939** | **7,402,885** | **396,535** | **570,864** | **195,014** | **3,124,924** | **95,612** | **308,475** | **2,828,288** | **78,027** | **31,421,123** |
| Apr-2021 | PGA - Retroactive | (33,318) | (51) | (310) | - | (627) | (2,057) | (9,916) | (544) | (861) | (574) | (4,936) | (181) | (601) | - | - | **(53,977)** |
| Apr-2021 | PGC Rounding difference | (15) | (0) | (25) | (0) | (1) | 3 | 1 | 0 | 0 | (0) | 0 | 0 | (1) | - | - | **(39)** |
| Apr-2021 | ACA | 184,100 | 284 | 1,750 | 0 | 3,463 | 11,384 | 54,938 | 2,990 | 4,760 | 3,181 | 27,308 | 998 | 3,318 | - | - | **298,474** |
| Apr-2021 | DCA | (224,569) | (343) | (2,080) | (0) | (4,255) | (34,317) | (153,890) | (10,791) | (13,590) | (3,835) | (77,734) | (1,799) | (8,646) | - | - | **(535,850)** |
| Apr-2021 | GAC Current | 109,364 | 168 | 1,041 | 0 | 2,059 | 6,772 | 32,138 | 1,741 | 2,829 | 1,894 | 16,214 | 593 | 1,975 | - | - | **176,788** |
| Apr-2021 | Residential Essential Credit | 117,901 | 185 | 1,140 | 0 | 2,300 | 18,457 | 84,089 | 5,931 | 7,218 | 2,058 | 42,067 | 972 | 4,670 | 113,354 | 2,780 | **403,121** |
| Apr-2021 | RES Rider credit | (126,915) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(126,915)** |
| Apr-2021 | Delivery Charge | 3,124,682 | 4,846 | 27,835 | 0 | 59,594 | 413,211 | 1,976,701 | 65,791 | 177,167 | 48,892 | 1,009,056 | 23,050 | 112,101 | 888,760 | 29,183 | **7,960,870** |
| Apr-2021 | Purchased Gas Charge | 4,283,385 | 6,568 | 40,738 | 1 | 80,655 | 263,968 | 1,284,178 | 69,815 | 110,996 | 73,881 | 636,903 | 23,232 | 76,098 | - | - | **6,950,416** |
| Apr-2021 | System Charge | 1,883,412 | 973 | 122,535 | 10 | 41,430 | 108,695 | 190,858 | 33,893 | 15,709 | 13,850 | 94,388 | 11,775 | 8,026 | 12,430 | 1,430 | **2,539,414** |
| Apr-2021 | Peak Usage Charge | - | - | - | - | - | 55,996 | 343,603 | 36,786 | 36,032 | 7,592 | 160,260 | 3,405 | 14,500 | - | - | **658,173** |
| Apr-2021 | DC Right of Way Tax | 255,055 | 390 | 2,345 | 0 | 4,832 | 38,971 | 174,815 | 12,299 | 15,438 | 4,353 | 88,312 | 2,043 | 9,823 | 240,295 | 5,848 | **854,819** |
| Apr-2021 | DC Right of Way Adjustment | 19,575 | 30 | 183 | - | 372 | 2,981 | 13,406 | 955 | 1,184 | 333 | 6,771 | 157 | 753 | 18,426 | 448 | **65,574** |
| Apr-2021 | SE Trust Fund | 343,222 | 540 | 3,268 | 0 | 6,694 | 53,969 | 242,099 | 17,034 | 21,379 | 6,029 | 122,288 | 2,830 | 13,602 | 332,779 | 8,099 | **1,173,833** |
| Apr-2021 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 9,004 | - | **9,004** |
| Apr-2021 | Delivery Tax | 553,210 | 846 | 5,107 | 0 | 10,482 | 92,966 | 417,010 | 29,348 | 36,825 | 9,441 | 191,490 | 4,432 | 21,300 | 565,316 | 13,715 | **1,951,489** |
| Apr-2021 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | (4,175) | 4,400 | **225** |
| Apr-2021 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | 71,228 | - | **71,228** |
| Apr-2021 | Balancing Charge | - | - | - | - | - | 8,983 | - | - | - | - | - | - | - | 14,741 | 359 | **24,083** |
| Apr-2021 | STORAGE GAS CHRG | 38,043 | 59 | 369 | 0 | 716 | 2,368 | 10,986 | 596 | 982 | 661 | 5,641 | 206 | 694 | - | - | **61,323** |
| Apr-2021 | EA Trust Fund | 63,400 | 100 | 610 | 0 | 1,237 | 9,966 | 44,698 | 3,146 | 3,947 | 1,113 | 22,578 | 523 | 2,511 | 61,440 | 1,495 | **216,763** |
| Apr-2021 | PRA | (3) | - | - | - | - | 0 | - | (0) | - | - | - | - | - | - | - | **(3)** |
| Apr-2021 | DC Tax Reform Credit | - | - | - | - | - | (5) | - | - | - | - | - | - | - | - | - | **(5)** |
| Apr-2021 | APRP | 303,541 | 464 | 2,798 | 0 | 5,751 | 21,357 | 96,063 | 6,770 | 8,424 | 2,549 | 51,479 | 1,191 | 5,722 | 64,818 | 1,579 | **572,506** |
| | **TOTAL** | **10,894,070** | **15,058** | **207,304** | **12** | **214,699** | **1,073,668** | **4,801,776** | **275,759** | **428,440** | **171,420** | **2,392,085** | **73,428** | **265,845** | **2,388,417** | **69,337** | **23,271,315** |
| May-2021 | PGA - Retroactive | (18,997) | 284 | (222) | - | (400) | (1,263) | (6,565) | (378) | (851) | (452) | (3,286) | (189) | (426) | - | - | **(32,745)** |
| May-2021 | PGC Rounding difference | 19 | 6 | (49) | (0) | (2) | (1) | (2) | (0) | (0) | (2) | (6) | (0) | (0) | - | - | **(38)** |
| May-2021 | ACA | 104,286 | (2,171) | 1,274 | 0 | 2,198 | 6,986 | 36,551 | 2,097 | 4,708 | 2,501 | 18,779 | 1,045 | 2,353 | - | - | **180,606** |
| May-2021 | DCA | (128,430) | 5,310 | (1,495) | (0) | (2,700) | (27,702) | (102,508) | (5,662) | (13,656) | (2,983) | (54,431) | (1,581) | (6,729) | - | - | **(342,566)** |
| May-2021 | GAC Current | 61,954 | (2,405) | 760 | 0 | 1,306 | 4,155 | 21,874 | 1,250 | 2,798 | 1,487 | 12,274 | 621 | 1,398 | - | - | **107,472** |
| May-2021 | Residential Essential Credit | 67,507 | (1,019) | 815 | 0 | 1,460 | 14,937 | 55,133 | 3,146 | 7,396 | 1,539 | 27,584 | 854 | 3,634 | 71,519 | 2,161 | **256,664** |
| May-2021 | RES Rider credit | (410) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(410)** |
| May-2021 | Delivery Charge | 2,034,799 | (55,625) | 21,133 | 0 | 42,316 | 342,253 | 1,431,053 | 46,085 | 190,005 | 40,686 | 746,826 | 22,281 | 94,389 | 601,180 | 24,302 | **5,581,683** |
| May-2021 | Purchased Gas Charge | 2,501,173 | (70,582) | 30,330 | 1 | 52,522 | 166,159 | 878,570 | 52,503 | 113,065 | 57,531 | 468,832 | 24,986 | 56,267 | - | - | **4,331,357** |
| May-2021 | System Charge | 2,052,657 | (79) | 129,582 | 11 | 44,832 | 120,184 | 214,738 | 36,405 | 17,382 | 15,422 | 108,606 | 13,306 | 8,879 | 12,540 | 1,430 | **2,775,894** |
| May-2021 | Peak Usage Charge | - | - | - | - | - | 1,427 | 24,734 | 27,945 | 3,899 | 968 | 15,150 | (53) | 1,090 | - | - | **75,160** |
| May-2021 | DC Right of Way Tax | 145,826 | (4,922) | 1,681 | 0 | 3,066 | 31,458 | 116,366 | 6,428 | 15,510 | 3,385 | 60,722 | 1,796 | 7,643 | 150,420 | 4,545 | **543,923** |
| May-2021 | DC Right of Way Adjustment | 11,249 | (137) | 132 | - | 236 | 2,411 | 8,864 | 493 | 1,190 | 260 | 4,416 | 138 | 586 | 11,535 | 349 | **41,721** |
| May-2021 | SE Trust Fund | 196,041 | (5,696) | 2,351 | 0 | 4,251 | 43,561 | 161,166 | 8,907 | 21,482 | 4,688 | 82,974 | 2,488 | 10,585 | 208,327 | 6,294 | **747,419** |
| May-2021 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 6,127 | - | **6,127** |
| May-2021 | Delivery Tax | 316,455 | (10,689) | 3,665 | 0 | 6,652 | 75,046 | 277,604 | 15,341 | 37,003 | 7,340 | 131,698 | 3,895 | 16,575 | 353,845 | 10,671 | **1,245,102** |
| May-2021 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 12,125 | 2,425 | **14,550** |
| May-2021 | Balancing Charge | - | - | - | - | - | 8,651 | - | - | - | - | - | - | - | 9,228 | 279 | **18,158** |
| May-2021 | STORAGE GAS CHRG | 21,874 | (1,143) | 277 | 0 | 463 | 1,475 | 7,768 | 429 | 987 | 537 | 4,630 | 220 | 495 | - | - | **38,011** |
| May-2021 | EA Trust Fund | 36,232 | (1,260) | 441 | 0 | 785 | 8,045 | 29,756 | 1,645 | 3,966 | 866 | 15,528 | 459 | 1,954 | 38,463 | 1,162 | **138,041** |
| May-2021 | PRA | 6 | 69 | - | - | - | - | - | - | - | - | (69) | - | - | - | - | **6** |
| May-2021 | DC Tax Reform Credit | (24) | 165 | - | - | - | - | - | - | - | - | (125) | - | - | - | - | **16** |
| May-2021 | APRP | 173,597 | (7,226) | 2,015 | 0 | 3,650 | 17,267 | 63,804 | 3,572 | 8,523 | 1,975 | 35,295 | 1,047 | 4,454 | 40,604 | 1,227 | **349,804** |
| | **TOTAL** | **7,575,813** | **(157,121)** | **192,689** | **12** | **160,634** | **815,049** | **3,218,906** | **200,206** | **413,407** | **135,748** | **1,675,397** | **71,311** | **203,148** | **1,515,913** | **54,844** | **16,075,955** |
| Jun-2021 | PGA - Retroactive | (9,897) | 8 | (71) | - | (210) | (1,245) | (3,762) | (385) | (750) | (67) | (1,576) | (249) | (297) | - | - | **(18,501)** |
| Jun-2021 | PGC Rounding difference | (41) | 1 | (49) | (0) | (3) | (3) | (1) | 0 | 1 | 0 | (1) | (12) | (0) | - | - | **(110)** |
| Jun-2021 | ACA | 54,082 | (80) | 402 | 0 | 1,148 | 6,881 | 20,882 | 2,131 | 4,156 | 364 | 8,750 | 1,429 | 1,642 | - | - | **101,788** |
| Jun-2021 | DCA | (66,093) | 944 | (391) | (0) | (1,443) | (28,225) | (60,612) | (5,758) | (8,750) | (504) | (25,120) | (2,207) | (4,897) | - | - | **(203,054)** |
| Jun-2021 | GAC Current | 32,154 | (372) | 194 | 0 | 683 | 4,089 | 12,456 | 1,267 | 2,466 | 192 | 5,523 | 926 | 976 | - | - | **60,554** |
| Jun-2021 | Residential Essential Credit | 34,473 | (30) | 389 | 0 | 780 | 15,226 | 33,020 | 3,215 | 4,776 | 336 | 13,029 | 979 | 2,644 | 59,755 | 1,730 | **170,320** |
| Jun-2021 | RES Rider credit | (296) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(296)** |
| Jun-2021 | Delivery Charge | 1,045,700 | (7,946) | 6,773 | 0 | 22,669 | 349,252 | 847,914 | 48,829 | 122,385 | 8,055 | 349,299 | 28,970 | 68,706 | 466,917 | 19,441 | **3,376,964** |
| Jun-2021 | Purchased Gas Charge | 1,395,326 | (9,856) | 13,236 | 1 | 29,589 | 177,941 | 544,396 | 57,708 | 108,730 | 10,697 | 233,257 | 34,452 | 42,410 | - | - | **2,637,887** |
| Jun-2021 | System Charge | 2,049,006 | 392 | 128,191 | 11 | 45,961 | 118,218 | 211,341 | 34,978 | 17,297 | 13,902 | 105,714 | 16,023 | 8,733 | 12,320 | 1,430 | **2,763,517** |
| Jun-2021 | Peak Usage Charge | - | - | - | - | - | (64) | 2,130 | (12) | 15 | (188) | 1,147 | 723 | (4) | - | - | **3,748** |
| Jun-2021 | DC Right of Way Tax | 75,025 | (709) | 457 | 0 | 1,637 | 32,059 | 68,816 | 6,542 | 9,942 | 602 | 28,166 | 2,444 | 5,562 | 125,677 | 3,639 | **359,858** |
| Jun-2021 | DC Right of Way Adjustment | 6,879 | (42) | 51 | - | 151 | 2,604 | 6,232 | 603 | 936 | 69 | 2,555 | 209 | 512 | 11,386 | 335 | **32,480** |

CUBE: tm1serv:Rate Statistics DB
RS_ACTUAL_AR DC

| | | DC Res Htg / HC | DC Res Htg / HC | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - OTH | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Non Htg | DC C&I Non Htg | DC GMA Htg / HC | DC GMA Htg / HC | DC GMA Non Htg | DC GMA Non Htg | DC Interruptible | DC Interruptible | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 1 | 2 | 1 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | |
| Jun-2021 | SE Trust Fund | 100,496 | (490) | 660 | 0 | 2,275 | 44,407 | 95,313 | 9,066 | 13,770 | 873 | 38,514 | 3,342 | 7,703 | 174,059 | 5,040 | **495,030** |
| Jun-2021 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,616 | - | **1,616** |
| Jun-2021 | Delivery Tax | 162,932 | (1,543) | 1,016 | 0 | 3,556 | 76,482 | 164,174 | 15,610 | 23,719 | 1,306 | 61,087 | 5,297 | 12,062 | 297,897 | 8,578 | **832,173** |
| Jun-2021 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 17,250 | 2,650 | **19,900** |
| Jun-2021 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | (10,455) | - | **(10,455)** |
| Jun-2021 | Balancing Charge | - | - | - | - | - | 8,940 | - | - | - | - | - | - | - | 7,710 | 223 | **16,873** |
| Jun-2021 | STORAGE GAS CHRG | 10,060 | (197) | 36 | 0 | 214 | 1,268 | 3,854 | 380 | 755 | 35 | 1,801 | 337 | 302 | - | - | **18,845** |
| Jun-2021 | EA Trust Fund | 18,569 | (170) | 128 | 0 | 420 | 8,199 | 17,598 | 1,674 | 2,542 | 155 | 7,190 | 624 | 1,422 | 32,136 | 930 | **91,418** |
| Jun-2021 | PRA | (5) | (24) | - | - | - | - | - | - | - | (1) | 24 | 1 | - | - | - | **(5)** |
| Jun-2021 | DC Tax Reform Credit | - | 206 | - | - | - | - | - | (0) | - | 7 | (156) | (8) | - | - | - | **49** |
| Jun-2021 | APRP | 102,095 | (910) | (69) | 0 | 2,231 | 20,237 | 43,198 | 4,182 | 6,388 | 472 | 18,461 | 1,695 | 3,685 | 38,551 | 1,116 | **241,332** |
| | **TOTAL** | **5,010,466** | **(20,817)** | **150,953** | **12** | **109,658** | **836,265** | **2,006,947** | **180,031** | **308,379** | **36,306** | **847,664** | **94,975** | **151,162** | **1,234,820** | **45,112** | **10,991,931** |
| Jul-2021 | PGA - Retroactive | (7,270) | (20) | (155) | - | (157) | (930) | (3,701) | (396) | (618) | (140) | (1,215) | (108) | (234) | - | - | **(14,943)** |
| Jul-2021 | PGC Rounding difference | 62 | 0 | (14) | (0) | 1 | 0 | 0 | 0 | 0 | 1 | (1) | (1) | (0) | - | - | **49** |
| Jul-2021 | ACA | 39,639 | 112 | 905 | 0 | 855 | 5,132 | 20,406 | 2,183 | 3,411 | 767 | 6,781 | 590 | 1,294 | - | - | **82,073** |
| Jul-2021 | DCA | (48,175) | (152) | (1,046) | (0) | (1,074) | (6,422) | (59,924) | (5,207) | (9,515) | (758) | (19,986) | (817) | (4,206) | - | - | **(157,282)** |
| Jul-2021 | GAC Current | 23,598 | 66 | 542 | 0 | 509 | 3,072 | 12,033 | 1,295 | 2,020 | 368 | 4,121 | 290 | 770 | - | - | **48,684** |
| Jul-2021 | Residential Essential Credit | 33,483 | 109 | 738 | 0 | 773 | 4,614 | 41,911 | 3,682 | 6,952 | 717 | 14,152 | 718 | 3,093 | 67,150 | 1,737 | **179,830** |
| Jul-2021 | RES Rider credit | (55) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(55)** |
| Jul-2021 | Delivery Charge | 762,300 | 2,405 | 14,757 | 0 | 16,867 | 92,139 | 838,572 | 46,749 | 132,679 | 11,947 | 280,966 | 13,047 | 59,325 | 384,819 | 12,522 | **2,669,094** |
| Jul-2021 | Purchased Gas Charge | 1,103,673 | 3,117 | 24,993 | 1 | 23,774 | 144,068 | 566,507 | 59,743 | 96,671 | 19,066 | 190,223 | 14,158 | 37,519 | - | - | **2,283,513** |
| Jul-2021 | System Charge | 2,044,319 | 1,083 | 127,192 | 11 | 45,422 | 120,490 | 208,443 | 34,948 | 16,676 | 13,673 | 104,898 | 14,084 | 8,806 | 12,100 | 1,430 | **2,753,575** |
| Jul-2021 | Peak Usage Charge | - | - | - | - | - | 47 | 1,976 | (6) | (61) | (135) | 219 | (3,335) | - | - | - | **(1,295)** |
| Jul-2021 | DC Right of Way Tax | 54,653 | 173 | 1,170 | 0 | 1,217 | 7,268 | 68,172 | 5,916 | 10,812 | 951 | 22,595 | 1,040 | 4,777 | 105,738 | 2,735 | **287,218** |
| Jul-2021 | DC Right of Way Adjustment | 5,014 | 16 | 105 | - | 112 | 667 | 6,311 | 544 | 998 | 93 | 2,055 | 113 | 445 | 9,732 | 252 | **26,454** |
| Jul-2021 | SE Trust Fund | 73,188 | 239 | 1,644 | 0 | 1,692 | 10,039 | 94,545 | 8,197 | 14,975 | 1,448 | 31,167 | 1,611 | 6,616 | 146,444 | 3,788 | **395,592** |
| Jul-2021 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,616) | - | **(1,616)** |
| Jul-2021 | Delivery Tax | 118,782 | 374 | 2,560 | 0 | 2,646 | 17,342 | 162,629 | 14,114 | 25,795 | 2,062 | 49,005 | 2,246 | 10,361 | 250,874 | 6,447 | **665,238** |
| Jul-2021 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 28,975 | 5,075 | **34,050** |
| Jul-2021 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 6,487 | 168 | **6,655** |
| Jul-2021 | STORAGE GAS CHRG | 7,405 | 21 | 185 | 0 | 161 | 958 | 3,701 | 404 | 618 | 94 | 1,308 | 81 | 231 | - | - | **15,166** |
| Jul-2021 | EA Trust Fund | 13,533 | 44 | 309 | 0 | 313 | 1,859 | 17,432 | 1,513 | 2,765 | 249 | 5,778 | 260 | 1,222 | 27,037 | 699 | **73,013** |
| Jul-2021 | PRA | 0 | - | - | - | - | (1) | - | - | - | (12) | - | 12 | - | - | - | **(1)** |
| Jul-2021 | DC Tax Reform Credit | 6 | - | - | - | - | (7) | (11,613) | (0) | - | 19 | (83) | 1,704 | - | - | - | **(9,975)** |
| Jul-2021 | APRP | 73,259 | 231 | 1,573 | 0 | 1,631 | 6,010 | 54,531 | 4,789 | 8,999 | 919 | 19,822 | 968 | 4,324 | 35,356 | 914 | **213,326** |
| | **TOTAL** | **4,297,412** | **7,818** | **175,458** | **12** | **94,741** | **406,346** | **2,021,932** | **178,469** | **313,176** | **51,331** | **711,804** | **46,662** | **134,343** | **1,073,097** | **35,767** | **9,548,365** |
| Aug-2021 | PGA - Retroactive | (6,624) | (27) | (242) | - | (133) | (1,256) | (3,834) | (700) | (720) | (193) | (908) | (86) | (255) | - | - | **(14,978)** |
| Aug-2021 | PGC Rounding difference | 126 | - | (10) | (0) | 4 | 2 | 0 | 0 | (0) | - | 0 | 0 | (0) | - | - | **122** |
| Aug-2021 | ACA | 35,990 | 149 | 1,379 | 0 | 720 | 6,939 | 21,200 | 3,870 | 3,980 | 1,066 | 5,019 | 478 | 1,408 | - | - | **82,199** |
| Aug-2021 | DCA | (43,834) | (162) | (1,537) | (0) | (908) | (46,863) | (68,525) | (7,261) | (9,705) | (1,287) | (17,188) | (816) | (4,055) | - | - | **(202,139)** |
| Aug-2021 | GAC Current | 21,427 | 89 | 824 | 0 | 429 | 4,126 | 12,535 | 2,299 | 2,365 | 631 | 2,982 | 284 | 837 | - | - | **48,826** |
| Aug-2021 | Residential Essential Credit | 30,508 | 117 | 1,090 | 0 | 651 | 33,833 | 47,875 | 5,237 | 7,002 | 842 | 12,443 | 589 | 2,924 | 74,859 | 1,585 | **219,555** |
| Aug-2021 | Delivery Charge | 692,765 | 2,571 | 21,731 | 0 | 14,223 | 562,309 | 949,218 | 71,329 | 135,017 | 17,815 | 243,145 | 11,447 | 56,892 | 396,153 | 13,200 | **3,187,816** |
| Aug-2021 | Purchased Gas Charge | 1,001,746 | 4,152 | 38,199 | 1 | 20,024 | 194,230 | 565,897 | 107,771 | 110,864 | 27,637 | 140,269 | 13,305 | 39,223 | - | - | **2,263,317** |
| Aug-2021 | System Charge | 2,029,747 | 1,044 | 125,802 | 11 | 45,567 | 118,174 | 212,749 | 36,130 | 16,838 | 15,321 | 103,245 | 12,996 | 8,677 | 12,650 | 1,430 | **2,740,382** |
| Aug-2021 | Peak Usage Charge | - | - | - | - | - | (272) | 8,623 | - | - | 363 | - | - | - | - | - | **8,714** |
| Aug-2021 | DC Right of Way Tax | 49,646 | 184 | 1,727 | 0 | 1,025 | 53,228 | 77,841 | 8,247 | 11,023 | 1,462 | 19,523 | 927 | 4,606 | 117,912 | 2,496 | **349,848** |
| Aug-2021 | DC Right of Way Adjustment | 4,552 | 17 | 156 | - | 94 | 4,901 | 7,056 | 759 | 1,015 | 128 | 1,797 | 85 | 424 | 10,851 | 230 | **32,063** |
| Aug-2021 | SE Trust Fund | 66,579 | 255 | 2,414 | 0 | 1,424 | 73,721 | 107,788 | 11,421 | 15,267 | 2,024 | 27,038 | 1,283 | 6,378 | 163,305 | 3,456 | **482,353** |
| Aug-2021 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 3,596 | - | **3,596** |
| Aug-2021 | Delivery Tax | 108,001 | 400 | 3,770 | 0 | 2,234 | 126,982 | 185,665 | 19,674 | 26,297 | 3,171 | 42,341 | 2,010 | 9,988 | 279,992 | 5,880 | **816,406** |
| Aug-2021 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 29,200 | 2,875 | **32,075** |
| Aug-2021 | Balancing Charge | - | - | - | - | - | 17,652 | - | - | - | - | - | - | - | 7,234 | 153 | **25,039** |
| Aug-2021 | STORAGE GAS CHRG | 6,736 | 28 | 272 | 0 | 136 | 1,277 | 4,058 | 714 | 735 | 208 | 926 | 88 | 260 | - | - | **15,438** |
| Aug-2021 | EA Trust Fund | 12,371 | 47 | 452 | 0 | 265 | 13,612 | 19,901 | 2,109 | 2,819 | 374 | 4,992 | 237 | 1,178 | 30,150 | 638 | **89,146** |
| Aug-2021 | DC Tax Reform Credit | 4 | - | - | - | - | - | (190) | - | - | - | - | - | - | - | - | **(186)** |
| Aug-2021 | APRP | 66,619 | 247 | 2,320 | 0 | 1,378 | 43,968 | 62,171 | 6,805 | 9,099 | 1,149 | 17,313 | 819 | 4,069 | 39,423 | 834 | **256,214** |
| | **TOTAL** | **4,076,360** | **9,112** | **198,348** | **12** | **87,133** | **1,206,561** | **2,210,028** | **268,405** | **331,896** | **70,711** | **602,938** | **43,644** | **132,555** | **1,165,326** | **32,776** | **10,435,804** |
| Sep-2021 | PGA - Retroactive | (6,882) | (25) | (55) | - | (152) | 605 | (4,326) | 130 | (1,263) | (91) | (1,257) | (99) | (264) | - | - | **(13,679)** |
| Sep-2021 | PGC Rounding difference | 6,728 | 26 | 147 | - | 143 | (10) | 3,950 | 327 | 665 | 88 | 1,096 | 109 | 263 | - | - | **13,532** |
| Sep-2021 | ACA | 37,405 | 137 | 342 | 0 | 826 | (3,353) | 23,919 | (723) | 6,983 | 505 | 7,010 | 507 | 1,461 | - | - | **75,017** |
| Sep-2021 | DCA | (45,068) | (148) | (444) | (0) | (1,031) | (17,228) | (51,147) | (3,919) | (13,517) | (703) | (19,385) | (873) | (4,307) | - | - | **(157,769)** |
| Sep-2021 | GAC Current | 22,268 | 81 | 207 | 0 | 492 | (1,993) | 14,210 | (429) | 4,149 | 300 | 4,201 | 279 | 868 | - | - | **44,633** |
| Sep-2021 | Residential Essential Credit | 30,990 | 106 | 303 | 0 | 741 | 12,471 | 44,258 | 2,905 | 9,724 | 507 | 13,853 | 703 | 3,107 | 73,763 | 1,597 | **195,028** |
| Sep-2021 | RES Rider credit | 165 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **165** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL_AR** DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sep-2021 | Delivery Charge | 710,843 | 2,339 | 6,218 | 0 | 16,180 | 190,653 | 771,740 | 9,164 | 188,062 | 9,828 | 273,459 | 12,675 | 60,439 | 419,501 | 13,307 | **2,684,409** |
| Sep-2021 | Purchased Gas Charge | 836,607 | 3,054 | 4,695 | 1 | 18,674 | (96,425) | 550,080 | (28,825) | 174,847 | 11,473 | 162,558 | 11,554 | 33,038 | - | - | **1,681,330** |
| Sep-2021 | System Charge | 2,045,414 | 1,122 | 125,969 | 11 | 45,297 | 120,299 | 197,742 | 35,074 | 17,034 | 15,628 | 104,578 | 13,233 | 8,826 | 12,166 | 1,430 | **2,743,822** |
| Sep-2021 | Peak Usage Charge | - | - | - | - | - | (127) | (11,910) | (1) | - | - | (66) | (129) | - | - | - | **(12,232)** |
| Sep-2021 | DC Right of Way Tax | 51,121 | 168 | 486 | 0 | 1,168 | 19,568 | 61,300 | 4,451 | 15,354 | 798 | 21,997 | 1,005 | 4,893 | 116,168 | 2,516 | **300,992** |
| Sep-2021 | DC Right of Way Adjustment | 4,673 | 16 | 41 | - | 107 | 1,803 | 6,514 | 410 | 1,413 | 73 | 2,017 | 101 | 450 | 10,690 | 231 | **28,541** |
| Sep-2021 | SE Trust Fund | 68,249 | 232 | 697 | 0 | 1,622 | 27,105 | 88,581 | 6,165 | 21,265 | 1,106 | 30,464 | 1,392 | 6,776 | 160,889 | 3,484 | **418,026** |
| Sep-2021 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 711 | - | **711** |
| Sep-2021 | Delivery Tax | 111,108 | 364 | 1,079 | 0 | 2,540 | 46,684 | 146,187 | 10,619 | 36,628 | 1,731 | 47,704 | 2,180 | 10,611 | 275,902 | 5,924 | **699,261** |
| Sep-2021 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 33,285 | 2,875 | **36,160** |
| Sep-2021 | WG Cash Out | - | - | - | - | - | - | - | - | - | - | - | - | - | (254) | - | **(254)** |
| Sep-2021 | Balancing Charge | - | - | - | - | - | 8,975 | - | - | - | - | - | - | - | 7,127 | 154 | **16,256** |
| Sep-2021 | STORAGE GAS CHRG | 6,898 | 25 | 53 | - | 152 | (624) | 4,342 | (140) | 1,275 | 92 | 1,300 | 72 | 264 | - | - | **13,708** |
| Sep-2021 | EA Trust Fund | 12,640 | 43 | 135 | 0 | 300 | 5,005 | 15,670 | 1,139 | 3,926 | 204 | 5,625 | 257 | 1,251 | 29,704 | 643 | **76,542** |
| Sep-2021 | PRA | 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **2** |
| Sep-2021 | DC Tax Reform Credit | 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **1** |
| Sep-2021 | APRP | 68,504 | 225 | 655 | 0 | 1,567 | 16,193 | 54,236 | 3,769 | 12,639 | 705 | 19,502 | 885 | 4,323 | 38,841 | 841 | **222,885** |
| | **TOTAL** | **3,961,665** | **7,765** | **140,528** | **12** | **88,624** | **329,603** | **1,915,347** | **40,114** | **479,184** | **42,244** | **674,655** | **43,851** | **131,997** | **1,178,494** | **33,004** | **9,067,086** |
| Oct-2021 | PGA - Retroactive | (7,764) | 422 | (110) | - | (172) | (518) | (4,557) | (345) | (178) | (112) | (1,145) | (93) | (250) | - | - | **(14,823)** |
| Oct-2021 | PGC Rounding difference | 7,566 | 39 | 158 | - | 171 | 571 | 4,042 | 347 | 715 | 145 | 1,188 | 102 | 271 | - | - | **15,317** |
| Oct-2021 | ACA | 42,393 | (2,309) | 595 | 0 | 943 | 2,912 | 25,429 | 1,911 | 985 | 556 | 6,241 | 485 | 1,382 | - | - | **81,524** |
| Oct-2021 | DCA | (52,024) | 3,549 | (446) | (0) | (1,206) | (25,414) | (72,954) | (6,018) | (8,104) | (673) | (19,061) | (831) | (4,327) | - | - | **(187,510)** |
| Oct-2021 | GAC Current | 25,271 | (1,727) | 259 | 0 | 571 | 1,753 | 15,234 | 1,131 | 585 | 293 | 3,629 | 271 | 821 | - | - | **48,090** |
| Oct-2021 | Residential Essential Credit | 35,378 | (846) | 558 | 0 | 846 | 18,325 | 48,558 | 4,355 | 6,401 | 621 | 13,990 | 657 | 3,121 | 74,788 | 1,820 | **208,571** |
| Oct-2021 | RES Rider credit | (645) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(645)** |
| Oct-2021 | Delivery Charge | 815,011 | (41,585) | 8,004 | 0 | 18,751 | 310,895 | 987,615 | 46,024 | 115,825 | 10,141 | 271,261 | 11,998 | 60,715 | 435,966 | 15,142 | **3,065,763** |
| Oct-2021 | Purchased Gas Charge | 1,191,644 | (48,188) | 16,124 | 1 | 26,978 | 85,406 | 690,982 | 54,133 | 29,201 | 16,918 | 177,495 | 14,159 | 39,266 | - | - | **2,294,119** |
| Oct-2021 | System Charge | 2,053,971 | 178 | 121,445 | 11 | 46,047 | 122,610 | 206,313 | 35,716 | 16,796 | 14,863 | 100,597 | 12,827 | 8,804 | 12,214 | 1,430 | **2,753,823** |
| Oct-2021 | Peak Usage Charge | - | - | - | - | - | 106 | 9,428 | 322 | (771) | (7) | (607) | (140) | - | - | - | **8,332** |
| Oct-2021 | DC Right of Way Tax | 58,901 | (3,649) | 585 | 0 | 1,357 | 28,851 | 81,397 | 6,850 | 9,312 | 787 | 21,728 | 955 | 4,915 | 117,782 | 2,866 | **332,638** |
| Oct-2021 | DC Right of Way Adjustment | 5,402 | (230) | 85 | - | 124 | 2,658 | 7,101 | 631 | 932 | 81 | 2,036 | 97 | 452 | 10,839 | 264 | **30,471** |
| Oct-2021 | SE Trust Fund | 78,524 | (4,631) | 906 | 0 | 1,873 | 39,964 | 110,938 | 9,517 | 12,900 | 1,092 | 30,143 | 1,323 | 6,807 | 163,124 | 3,969 | **456,451** |
| Oct-2021 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 6,207 | 1,285 | **7,492** |
| Oct-2021 | Delivery Tax | 127,952 | (7,904) | 1,285 | 0 | 2,949 | 68,832 | 194,196 | 16,343 | 22,220 | 1,710 | 47,122 | 2,072 | 10,659 | 279,648 | 6,754 | **773,838** |
| Oct-2021 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 32,025 | 2,875 | **34,900** |
| Oct-2021 | Balancing Charge | - | - | - | - | - | 8,660 | - | - | - | - | - | - | - | 7,226 | 176 | **16,062** |
| Oct-2021 | STORAGE GAS CHRG | 7,863 | (761) | 33 | - | 178 | 541 | 4,858 | 345 | 167 | 69 | 1,068 | 72 | 249 | - | - | **14,683** |
| Oct-2021 | EA Trust Fund | 14,524 | (931) | 158 | 0 | 348 | 7,379 | 20,814 | 1,752 | 2,382 | 202 | 5,556 | 244 | 1,257 | 30,117 | 733 | **84,535** |
| Oct-2021 | PRA | 72 | 0 | 5 | - | 1 | - | (0) | - | - | - | - | - | - | - | - | **78** |
| Oct-2021 | DC Tax Reform Credit | (7) | 141 | 566 | - | (5) | - | (107) | - | - | - | - | - | - | - | - | **587** |
| Oct-2021 | APRP | 78,713 | (6,056) | 431 | 0 | 1,817 | 23,920 | 64,859 | 5,655 | 7,986 | 623 | 19,340 | 870 | 4,342 | 39,381 | 958 | **242,840** |
| | **TOTAL** | **4,482,745** | **(114,486)** | **150,640** | **12** | **101,570** | **697,451** | **2,394,147** | **178,669** | **217,355** | **47,309** | **680,582** | **45,070** | **138,486** | **1,209,316** | **38,271** | **10,267,136** |
| Nov-2021 | PGA - Retroactive | (48) | - | (7) | - | (0) | 0 | (236) | 1 | 3 | 49 | (106) | 3 | 1 | - | - | **(340)** |
| Nov-2021 | PGC Rounding difference | (53) | (0) | 17 | - | (1) | (6) | 231 | (0) | (1) | (49) | (4) | (0) | (1) | - | - | **132** |
| Nov-2021 | ACA | 118,923 | 298 | 1,312 | 0 | 2,537 | 6,372 | 41,309 | 2,695 | 5,216 | 830 | 16,317 | 884 | 2,374 | - | - | **199,067** |
| Nov-2021 | DCA | (144,656) | (331) | (1,551) | (0) | (3,093) | (27,972) | (115,086) | (9,365) | (14,722) | (1,174) | (49,998) | (1,385) | (7,517) | - | - | **(376,849)** |
| Nov-2021 | GAC Current | 70,707 | 177 | 784 | 0 | 1,508 | 3,698 | 24,872 | 1,597 | 3,099 | 494 | 9,833 | 530 | 1,410 | - | - | **118,709** |
| Nov-2021 | Residential Essential Credit | 46,246 | 105 | 519 | 0 | 992 | 8,984 | 37,486 | 3,003 | 4,687 | 260 | 15,724 | 438 | 2,626 | 34,731 | 1,070 | **156,871** |
| Nov-2021 | RES Rider credit | (19,191) | (50) | - | - | - | - | - | - | - | - | - | - | - | - | - | **(19,241)** |
| Nov-2021 | Delivery Charge | 2,288,657 | 5,232 | 21,907 | 0 | 48,587 | 346,600 | 1,599,254 | 70,132 | 204,998 | 16,422 | 699,481 | 19,397 | 105,468 | 503,092 | 20,289 | **5,949,515** |
| Nov-2021 | Purchased Gas Charge | 3,372,879 | 8,453 | 36,830 | 1 | 71,957 | 177,563 | 1,181,303 | 76,479 | 148,031 | 23,567 | 459,365 | 25,298 | 67,356 | - | - | **5,649,080** |
| Nov-2021 | System Charge | 2,052,052 | 1,078 | 125,718 | 11 | 45,082 | 126,363 | 200,344 | 33,847 | 16,657 | 15,303 | 102,435 | 11,633 | 8,752 | 12,100 | 1,430 | **2,752,805** |
| Nov-2021 | Peak Usage Charge | - | - | - | - | - | 32,327 | 357,682 | 38,432 | 31,970 | 3,831 | 166,702 | 3,748 | 15,465 | - | - | **650,157** |
| Nov-2021 | DC Right of Way Tax | 164,245 | 376 | 1,744 | 0 | 3,510 | 31,837 | 130,144 | 10,641 | 16,722 | 1,334 | 56,234 | 1,570 | 8,538 | 123,067 | 3,791 | **553,752** |
| Nov-2021 | DC Right of Way Adjustment | 15,103 | 35 | 158 | - | 323 | 2,916 | 11,988 | 981 | 1,542 | 123 | 5,163 | 143 | 786 | 11,325 | 349 | **50,933** |
| Nov-2021 | SE Trust Fund | 226,728 | 516 | 2,435 | 0 | 4,867 | 44,206 | 180,114 | 14,738 | 23,160 | 1,848 | 77,881 | 2,175 | 11,825 | 170,444 | 5,250 | **766,186** |
| Nov-2021 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 10,371 | 1,576 | **11,947** |
| Nov-2021 | Delivery Tax | 356,361 | 814 | 3,802 | 0 | 7,617 | 75,951 | 310,469 | 25,384 | 39,892 | 2,893 | 121,953 | 3,405 | 18,517 | 291,014 | 8,917 | **1,266,989** |
| Nov-2021 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 15,900 | 2,650 | **18,550** |
| Nov-2021 | Balancing Charge | - | - | - | - | - | 8,931 | - | - | - | - | - | - | - | 7,550 | 233 | **16,714** |
| Nov-2021 | STORAGE GAS CHRG | 21,602 | 54 | 232 | - | 461 | 1,098 | 7,625 | 484 | 943 | 150 | 3,044 | 162 | 429 | - | - | **36,285** |
| Nov-2021 | EA Trust Fund | 41,873 | 95 | 456 | 0 | 899 | 8,153 | 33,264 | 2,721 | 4,276 | 341 | 14,379 | 402 | 2,183 | 31,468 | 969 | **141,481** |
| Nov-2021 | PRA | 0 | - | - | - | - | 10 | 60 | - | - | - | - | - | - | - | - | **70** |
| Nov-2021 | APRP | 220,254 | 503 | 2,349 | 0 | 4,706 | 26,371 | 107,358 | 8,786 | 13,855 | 1,178 | 49,567 | 1,393 | 7,543 | 41,148 | 1,268 | **486,280** |
| | **TOTAL** | **8,831,681** | **17,356** | **196,704** | **12** | **189,952** | **873,403** | **4,108,181** | **280,554** | **500,328** | **67,400** | **1,747,968** | **69,796** | **245,755** | **1,252,210** | **47,791** | **18,429,093** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUAL_AR** DC

| | | **DC Res Htg / HC 1** | **DC Res Htg / HC 2** | **DC Res Non Htg - IMA 1** | **DC Res Non Htg - IMA 2** | **DC Res Non Htg - OTH 1** | **DC C&I Htg / HC 1** | **DC C&I Htg / HC 2** | **DC C&I Non Htg 1** | **DC C&I Non Htg 2** | **DC GMA Htg / HC 1** | **DC GMA Htg / HC 2** | **DC GMA Non Htg 1** | **DC GMA Non Htg 2** | **DC Interruptible 1** | **DC Interruptible 2** | **TOTAL SYSTEM** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dec-2021 | PGA - Retroactive | (8,668) | (14) | (53) | - | (161) | (401) | (2,518) | (131) | (213) | (54) | (1,163) | (45) | (105) | - | - | **(13,525)** |
| Dec-2021 | PGC Rounding difference | 1 | 1 | 7 | - | 0 | 2 | (23) | (5) | 0 | (0) | 5 | 1 | (0) | - | - | **(10)** |
| Dec-2021 | ACA | 193,542 | 322 | 1,324 | 0 | 3,675 | 9,469 | 57,720 | 2,986 | 4,709 | 926 | 25,890 | 976 | 2,343 | - | - | **303,884** |
| Dec-2021 | DCA | (422,189) | (660) | (2,877) | (0) | (8,031) | (44,951) | (268,189) | (20,452) | (25,633) | (2,604) | (124,788) | (2,632) | (12,390) | - | - | **(935,396)** |
| Dec-2021 | GAC Current | 155,650 | 256 | 1,084 | 0 | 2,962 | 7,735 | 46,281 | 2,420 | 3,793 | 803 | 20,789 | 783 | 1,887 | - | - | **244,442** |
| Dec-2021 | Residential Essential Credit | 76,618 | 123 | 528 | 0 | 1,470 | 6,441 | 49,933 | 3,709 | 4,715 | 438 | 22,308 | 482 | 2,268 | 43,617 | 1,468 | **214,119** |
| Dec-2021 | RES Rider credit | (79,823) | (123) | - | - | - | - | - | - | - | - | - | - | - | - | - | **(79,945)** |
| Dec-2021 | Delivery Charge | 5,091,773 | 8,017 | 30,965 | 0 | 96,154 | 425,127 | 2,868,752 | 108,140 | 272,101 | 26,778 | 1,342,516 | 28,112 | 132,350 | 815,143 | 37,222 | **11,283,150** |
| Dec-2021 | Purchased Gas Charge | 5,460,690 | 9,093 | 37,571 | 1 | 104,006 | 267,315 | 1,629,818 | 84,050 | 132,878 | 26,104 | 729,843 | 27,525 | 66,134 | - | - | **8,575,027** |
| Dec-2021 | System Charge | 2,086,254 | 1,083 | 127,168 | 11 | 45,223 | 124,667 | 200,889 | 36,901 | 16,787 | 16,223 | 102,688 | 13,353 | 8,832 | 11,774 | 1,430 | **2,793,282** |
| Dec-2021 | Peak Usage Charge | - | - | - | - | - | 53,448 | 385,080 | 38,667 | 31,545 | 3,948 | 171,952 | 3,821 | 15,854 | - | - | **704,316** |
| Dec-2021 | Earnings Sharing Mechanisn | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Dec-2021 | DC Right of Way Tax | 365,622 | 575 | 2,467 | 0 | 6,942 | 37,912 | 233,486 | 17,667 | 22,215 | 2,175 | 107,807 | 2,276 | 10,714 | 206,243 | 6,934 | **1,023,035** |
| Dec-2021 | DC Right of Way Adjustment | 33,583 | 53 | 224 | - | 639 | 3,489 | 21,483 | 1,625 | 2,044 | 200 | 9,920 | 209 | 986 | 18,979 | 638 | **94,073** |
| Dec-2021 | SE Trust Fund | 500,078 | 785 | 3,436 | 0 | 9,614 | 52,506 | 323,370 | 24,468 | 30,767 | 3,012 | 149,309 | 3,152 | 14,839 | 285,640 | 9,603 | **1,410,579** |
| Dec-2021 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 29,352 | 4,354 | **33,706** |
| Dec-2021 | Delivery Tax | 793,003 | 1,248 | 5,375 | 0 | 15,059 | 90,443 | 556,999 | 42,146 | 52,996 | 4,717 | 233,801 | 4,936 | 23,236 | 485,006 | 16,233 | **2,325,199** |
| Dec-2021 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 3,960 | 2,200 | **6,160** |
| Dec-2021 | Balancing Charge | - | - | - | - | - | 14,004 | - | - | - | - | - | - | - | 12,653 | 425 | **27,082** |
| Dec-2021 | STORAGE GAS CHRG | 54,109 | 88 | 384 | 0 | 1,029 | 2,703 | 16,071 | 845 | 1,320 | 286 | 7,228 | 272 | 656 | - | - | **84,992** |
| Dec-2021 | EA Trust Fund | 92,366 | 145 | 641 | 0 | 1,776 | 9,695 | 59,703 | 4,518 | 5,680 | 556 | 27,567 | 582 | 2,740 | 52,737 | 1,773 | **260,479** |
| Dec-2021 | PRA | (2) | - | - | - | - | (6) | - | - | - | - | - | - | - | - | - | **(8)** |
| Dec-2021 | DC Tax Reform Credit | 30 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **30** |
| Dec-2021 | APRP | 490,587 | 771 | 3,324 | 0 | 9,298 | 31,291 | 192,580 | 14,568 | 18,331 | 1,921 | 95,205 | 2,010 | 9,465 | 68,958 | 2,318 | **940,630** |
| | **TOTAL** | **14,883,225** | **21,765** | **211,569** | **12** | **289,657** | **1,090,891** | **6,371,436** | **362,122** | **574,035** | **85,428** | **2,920,877** | **85,814** | **279,807** | **2,034,062** | **84,599** | **29,295,300** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUA** DC

| | | DC Res Htg / HC | DC Res Htg / HC | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - OTH | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Non Htg | DC C&I Non Htg | DC GMA Htg / HC | DC GMA Htg / HC | DC GMA Non Htg | DC GMA Non Htg | DC Interruptible | DC Interruptible | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 1 | 2 | 1 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | |
| Jan-2022 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | 170 | - | **170** |
| Jan-2022 | PGA - Retroactive | (12,138) | (20) | (79) | - | (230) | (585) | (3,590) | (203) | (246) | (94) | (1,565) | 96 | (118) | - | - | **(18,772)** |
| Jan-2022 | PGC Rounding difference | (47) | (0) | (22) | (0) | (1) | (0) | 1 | (0) | 0 | (0) | 11 | (0) | (0) | - | - | **(59)** |
| Jan-2022 | ACA | 225,449 | 434 | 1,594 | 0 | 4,274 | 11,041 | 66,855 | 3,776 | 4,561 | 1,822 | 29,129 | 200 | 2,191 | - | - | **351,326** |
| Jan-2022 | DCA | (584,999) | (1,191) | (3,778) | (0) | (11,081) | (57,581) | (356,594) | (20,543) | (26,903) | (4,728) | (167,391) | (2,485) | (15,739) | - | - | **(1,253,013)** |
| Jan-2022 | GAC Current | 217,228 | 387 | 1,505 | 0 | 4,119 | 10,884 | 64,211 | 3,637 | 4,404 | 1,708 | 27,962 | 511 | 2,114 | - | - | **338,669** |
| Jan-2022 | Residential Essential Credit | 105,355 | 223 | 701 | 0 | 2,028 | 10,304 | 65,294 | 3,760 | 3,690 | 871 | 30,702 | 137 | 2,881 | 47,512 | 1,578 | **275,036** |
| Jan-2022 | RES Rider credit | (143,735) | (149) | - | - | - | - | - | - | - | - | - | - | - | - | - | **(143,884)** |
| Jan-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 26,738 | 4,786 | **31,523** |
| Jan-2022 | Delivery Charge | 7,048,395 | 14,542 | 40,892 | 0 | 132,589 | 571,154 | 3,789,697 | 137,548 | 276,749 | 50,472 | 1,803,667 | 24,088 | 168,118 | 905,024 | 39,999 | **15,002,936** |
| Jan-2022 | Purchased Gas Charge | 8,484,786 | 15,074 | 58,477 | 1 | 160,908 | 422,293 | 2,503,412 | 142,036 | 172,179 | 66,302 | 1,093,113 | 19,160 | 82,618 | - | - | **13,220,359** |
| Jan-2022 | System Charge | 2,063,409 | 1,119 | 126,858 | 11 | 44,703 | 121,690 | 198,687 | 35,463 | 16,414 | 15,790 | 102,077 | 13,195 | 8,780 | 12,316 | 1,430 | **2,761,943** |
| Jan-2022 | Peak Usage Charge | - | - | - | - | - | 54,384 | 381,029 | 38,798 | 31,098 | 4,992 | 176,191 | 2,786 | 16,161 | - | - | **705,440** |
| Jan-2022 | DC Right of Way Tax | 505,900 | 1,044 | 3,269 | 0 | 9,581 | 49,584 | 308,398 | 17,764 | 22,595 | 4,099 | 144,827 | 1,907 | 13,610 | 224,476 | 7,457 | **1,314,509** |
| Jan-2022 | DC Right of Way Adjustment | 46,555 | 96 | 297 | - | 882 | 4,563 | 28,380 | 1,635 | 2,079 | 377 | 13,328 | 186 | 1,252 | 20,657 | 686 | **120,974** |
| Jan-2022 | SE Trust Fund | 689,167 | 1,431 | 4,534 | 0 | 13,269 | 68,672 | 427,121 | 24,602 | 31,293 | 5,677 | 200,580 | 2,642 | 18,849 | 310,893 | 10,327 | **1,809,058** |
| Jan-2022 | Delivery Tax | 1,097,166 | 2,264 | 7,103 | 0 | 20,781 | 118,287 | 735,708 | 42,378 | 53,901 | 8,890 | 314,087 | 4,138 | 29,516 | 527,940 | 17,461 | **2,979,617** |
| Jan-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 665 | 2,200 | **2,865** |
| Jan-2022 | Balancing Charge | - | - | - | - | - | 14,498 | - | - | - | - | - | - | - | 13,771 | 457 | **28,727** |
| Jan-2022 | STORAGE GAS CHRG | 75,559 | 133 | 530 | 0 | 1,433 | 3,805 | 22,334 | 1,265 | 1,532 | 593 | 9,719 | 175 | 735 | - | - | **117,812** |
| Jan-2022 | EA Trust Fund | 127,268 | 264 | 849 | 0 | 2,451 | 12,679 | 78,858 | 4,543 | 5,777 | 1,048 | 37,033 | 488 | 3,480 | 57,399 | 1,907 | **334,045** |
| Jan-2022 | PRA | (2) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(2)** |
| Jan-2022 | DC Tax Reform Credit | 26 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **26** |
| Jan-2022 | APRP | 678,189 | 1,399 | 4,383 | 0 | 12,844 | 40,914 | 254,475 | 14,658 | 18,644 | 3,621 | 127,945 | 1,962 | 12,023 | 75,055 | 2,493 | **1,248,607** |
| | **TOTAL** | **20,623,531** | **37,049** | **247,114** | **12** | **398,551** | **1,456,586** | **8,564,276** | **451,117** | **617,767** | **161,441** | **3,941,413** | **69,186** | **346,471** | **2,222,616** | **90,781** | **39,227,911** |
| Feb-2022 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | (170) | - | **(170)** |
| Feb-2022 | PGA - Retroactive | (13,641) | (45) | (64) | - | (256) | (769) | (3,886) | (143) | (258) | (81) | (1,515) | (65) | (114) | - | - | **(20,838)** |
| Feb-2022 | PGC Rounding difference | 21 | 6 | (26) | (0) | 1 | (0) | 6 | 0 | (0) | (0) | (6) | 0 | 0 | - | - | **1** |
| Feb-2022 | ACA | 253,324 | 837 | 1,444 | 0 | 4,742 | 14,356 | 72,063 | 2,662 | 4,783 | 1,475 | 28,142 | 1,223 | 2,120 | - | - | **387,171** |
| Feb-2022 | DCA | (657,412) | (1,675) | (3,749) | (0) | (12,395) | 12,169 | (386,690) | (20,452) | (30,052) | (10,280) | (157,629) | (3,814) | (13,963) | - | - | **(1,285,942)** |
| Feb-2022 | GAC Current | 244,146 | 767 | 1,393 | 0 | 4,571 | 13,846 | 69,352 | 2,566 | 4,609 | 1,445 | 27,159 | 1,163 | 2,043 | - | - | **373,061** |
| Feb-2022 | Residential Essential Credit | 82,125 | 266 | 444 | - | 1,584 | (4,380) | 51,996 | 2,568 | 3,814 | 1,536 | 19,869 | 495 | 1,781 | 25,751 | 1,522 | **189,370** |
| Feb-2022 | RES Rider credit | (197,067) | (156) | (11) | - | - | - | - | - | - | - | - | - | - | - | - | **(197,233)** |
| Feb-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 124,140 | 6,465 | **130,605** |
| Feb-2022 | Delivery Charge | 7,920,866 | 20,512 | 40,301 | 0 | 148,311 | (19,873) | 4,103,589 | 117,293 | 317,315 | 109,459 | 1,693,190 | 40,743 | 149,148 | 1,011,794 | 55,104 | **15,707,753** |
| Feb-2022 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,157 | - | **2,157** |
| Feb-2022 | Purchased Gas Charge | 9,537,437 | 30,191 | 54,277 | 1 | 178,536 | 540,933 | 2,709,127 | 100,236 | 179,976 | 56,922 | 1,060,536 | 45,103 | 79,821 | - | - | **14,573,094** |
| Feb-2022 | System Charge | 1,993,460 | 1,124 | 127,959 | 11 | 43,812 | 121,160 | 195,360 | 31,997 | 15,529 | 14,884 | 94,868 | 12,765 | 8,266 | 11,550 | 1,430 | **2,674,174** |
| Feb-2022 | Peak Usage Charge | - | - | - | - | - | 28 | 391,796 | 37,748 | 33,178 | 10,794 | 163,793 | 3,723 | 15,097 | - | - | **656,157** |
| Feb-2022 | DC Right of Way Tax | 568,469 | 1,472 | 3,219 | 0 | 10,720 | (10,531) | 334,943 | 17,685 | 25,907 | 8,890 | 135,953 | 3,298 | 12,074 | 192,414 | 10,337 | **1,314,850** |
| Feb-2022 | DC Right of Way Adjustment | 52,325 | 135 | 294 | - | 986 | (968) | 30,203 | 1,627 | 2,384 | 818 | 12,540 | 304 | 1,111 | 17,707 | 951 | **120,417** |
| Feb-2022 | SE Trust Fund | 770,617 | 2,024 | 4,464 | 0 | 14,844 | (14,585) | 461,494 | 24,492 | 35,880 | 12,312 | 187,715 | 4,568 | 16,722 | 266,488 | 14,317 | **1,801,351** |
| Feb-2022 | Delivery Tax | 1,232,836 | 3,193 | 6,992 | 0 | 23,246 | (25,121) | 799,058 | 42,188 | 61,802 | 19,279 | 294,850 | 7,153 | 26,185 | 447,730 | 24,215 | **2,963,606** |
| Feb-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 9,925 | 2,200 | **12,125** |
| Feb-2022 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | 24,096 | - | **24,096** |
| Feb-2022 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 672 | - | **672** |
| Feb-2022 | Balancing Charge | - | - | - | - | - | (28,502) | - | - | - | - | - | - | - | 11,805 | 634 | **(16,063)** |
| Feb-2022 | STORAGE GAS CHRG | 84,929 | 264 | 492 | 0 | 1,590 | 4,816 | 24,118 | 893 | 1,603 | 503 | 9,449 | 405 | 711 | - | - | **129,772** |
| Feb-2022 | EA Trust Fund | 142,292 | 374 | 837 | 0 | 2,742 | (2,692) | 85,648 | 4,522 | 6,624 | 2,273 | 34,764 | 844 | 3,087 | 49,201 | 2,643 | **333,161** |
| Feb-2022 | PRA | (4) | - | (0) | - | - | - | - | - | - | - | - | - | - | - | - | **(5)** |
| Feb-2022 | DC Tax Reform Credit | 63 | - | (1) | - | (2) | - | - | - | 11 | - | - | - | - | - | - | **72** |
| Feb-2022 | APRP | 1,388,056 | 3,069 | 7,893 | 0 | 26,137 | 16,561 | 500,378 | 28,453 | 40,807 | 11,875 | 222,285 | 5,275 | 19,706 | 103,555 | 5,200 | **2,379,251** |
| | **TOTAL** | **23,402,844** | **62,359** | **246,156** | **12** | **449,169** | **616,447** | **9,438,555** | **394,337** | **703,913** | **242,103** | **3,825,962** | **123,181** | **323,796** | **2,298,815** | **125,019** | **42,252,668** |
| Mar-2022 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Mar-2022 | PGA - Retroactive | (8,934) | (27) | (65) | - | (171) | (621) | (2,859) | (123) | (239) | (103) | (1,319) | (45) | (118) | - | - | **(14,622)** |
| Mar-2022 | PGC Rounding difference | (41) | (0) | (21) | (0) | (1) | (6) | (1) | (1) | 2 | (1) | (0) | (0) | 3 | - | - | **(67)** |
| Mar-2022 | ACA | 179,258 | 527 | 1,757 | 0 | 3,416 | 11,886 | 56,872 | 2,453 | 4,724 | 2,073 | 26,269 | 892 | 2,216 | - | - | **292,343** |
| Mar-2022 | DCA | (437,423) | (1,605) | (3,730) | (0) | (8,314) | (131,946) | (318,874) | (20,155) | (26,764) | (5,995) | (144,766) | (2,771) | (13,439) | - | - | **(1,115,782)** |
| Mar-2022 | GAC Current | 160,642 | 481 | 1,493 | 0 | 3,064 | 10,876 | 51,139 | 2,199 | 4,240 | 1,856 | 23,596 | 798 | 1,963 | - | - | **262,347** |
| Mar-2022 | Residential Essential Credit | 53,886 | 214 | 519 | - | 1,060 | 19,511 | 40,741 | 2,565 | 3,405 | 747 | 18,441 | 352 | 1,746 | 57,230 | 1,138 | **201,555** |
| Mar-2022 | RES Rider credit | (183,837) | (110) | (11) | - | - | - | - | - | - | - | - | - | - | - | - | **(183,958)** |
| Mar-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 109,087 | 5,951 | **115,038** |
| Mar-2022 | Delivery Charge | 5,268,860 | 19,334 | 41,199 | 0 | 99,480 | 1,220,922 | 3,388,561 | 117,173 | 283,485 | 63,812 | 1,559,023 | 29,599 | 143,775 | 1,210,621 | 41,476 | **13,487,321** |
| Mar-2022 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Mar-2022 | Purchased Gas Charge | 6,885,150 | 20,145 | 64,081 | 1 | 131,043 | 464,398 | 2,181,790 | 94,197 | 181,221 | 79,762 | 1,007,955 | 34,247 | 84,119 | - | - | **11,228,110** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUA** DC

| | | DC Res Htg / HC | DC Res Htg / HC | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - OTH | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Non Htg | DC C&I Non Htg | DC GMA Htg / HC | DC GMA Htg / HC | DC GMA Non Htg | DC GMA Non Htg | DC Interruptible | DC Interruptible | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **1** | **2** | **1** | **2** | **1** | **1** | **2** | **1** | **2** | **1** | **2** | **1** | **2** | **1** | **2** | |
| Mar-2022 | System Charge | 2,064,356 | 1,290 | 129,813 | 11 | 44,892 | 126,363 | 203,961 | 34,538 | 17,284 | 14,307 | 105,232 | 13,141 | 9,097 | 12,210 | 1,430 | **2,777,926** |
| Mar-2022 | Peak Usage Charge | - | - | - | - | - | 130,844 | 411,960 | 39,705 | 33,133 | 6,032 | 191,689 | 3,539 | 17,484 | - | - | **834,386** |
| Mar-2022 | DC Right of Way Tax | 378,167 | 1,388 | 3,291 | 0 | 7,190 | 113,925 | 275,809 | 17,428 | 23,144 | 5,182 | 125,183 | 2,396 | 11,641 | 371,162 | 7,732 | **1,343,637** |
| Mar-2022 | DC Right of Way Adjustment | 34,807 | 128 | 299 | - | 661 | 10,484 | 25,376 | 1,604 | 2,130 | 477 | 11,520 | 220 | 1,071 | 34,156 | 712 | **123,645** |
| Mar-2022 | SE Trust Fund | 509,549 | 1,912 | 4,565 | 0 | 9,955 | 157,781 | 381,986 | 24,137 | 32,054 | 7,179 | 173,374 | 3,318 | 16,122 | 514,049 | 10,708 | **1,846,688** |
| Mar-2022 | Delivery Tax | 820,124 | 3,010 | 7,148 | 0 | 15,592 | 271,778 | 657,963 | 41,576 | 55,213 | 11,237 | 271,485 | 5,196 | 25,245 | 876,990 | 18,118 | **3,080,675** |
| Mar-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 4,925 | 2,200 | **7,125** |
| Mar-2022 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Mar-2022 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Mar-2022 | Balancing Charge | - | - | - | - | - | 50,059 | - | - | - | - | - | - | - | 22,771 | 474 | **73,304** |
| Mar-2022 | STORAGE GAS CHRG | 70,511 | 200 | 621 | 0 | 1,338 | 4,802 | 22,209 | 964 | 1,849 | 819 | 10,277 | 351 | 857 | - | - | **114,798** |
| Mar-2022 | EA Trust Fund | 94,122 | 353 | 856 | 0 | 1,840 | 29,132 | 70,525 | 4,457 | 5,918 | 1,325 | 32,010 | 613 | 2,977 | 94,907 | 1,977 | **341,011** |
| Mar-2022 | PRA | (1) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(1)** |
| Mar-2022 | DC Tax Reform Credit | (4) | - | - | - | - | - | - | - | - | 1 | - | - | - | - | - | **(3)** |
| Mar-2022 | APRP | 928,348 | 3,217 | 7,616 | 0 | 17,541 | 147,526 | 435,952 | 27,644 | 36,806 | 8,617 | 204,561 | 3,917 | 18,942 | 179,962 | 3,890 | **2,024,540** |
| | **TOTAL** | **16,817,541** | **50,455** | **259,430** | **12** | **328,586** | **2,637,715** | **7,883,110** | **390,361** | **657,606** | **197,329** | **3,614,530** | **95,766** | **323,700** | **3,488,070** | **95,805** | **36,840,016** |
| Apr-2022 | PGA - Retroactive | (6,988) | 3 | (55) | - | (131) | (507) | (2,282) | (107) | (126) | (64) | (1,042) | (42) | (101) | - | - | **(11,441)** |
| Apr-2022 | PGC Rounding difference | 2 | (6) | (26) | (0) | (1) | (35) | (1) | 0 | (13) | (0) | 6 | (0) | 0 | - | - | **(73)** |
| Apr-2022 | ACA | 138,831 | (29) | 1,269 | 0 | 2,632 | 11,065 | 45,804 | 2,142 | 3,423 | 1,274 | 20,852 | 841 | 2,016 | - | - | **230,121** |
| Apr-2022 | DCA | (337,078) | (176) | (2,969) | (0) | (6,444) | (53,133) | (222,921) | (14,868) | (23,203) | (5,484) | (138,293) | (2,627) | (10,906) | - | - | **(818,102)** |
| Apr-2022 | GAC Current | 124,009 | (1) | 1,142 | 0 | 2,353 | 9,845 | 40,909 | 1,915 | 3,167 | 1,140 | 18,588 | 752 | 1,803 | - | - | **205,621** |
| Apr-2022 | Residential Essential Credit | 41,485 | (29) | 356 | - | 816 | 6,892 | 28,148 | 1,893 | 2,731 | 698 | 17,582 | 334 | 1,389 | 36,040 | 1,009 | **139,343** |
| Apr-2022 | RES Rider credit | (180,039) | (103) | (11) | - | - | - | - | - | - | - | - | - | - | - | - | **(180,154)** |
| Apr-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 113,211 | 6,127 | **119,338** |
| Apr-2022 | Delivery Charge | 4,061,330 | 1,714 | 31,971 | 0 | 77,103 | 525,922 | 2,368,497 | 84,666 | 244,498 | 58,390 | 1,489,604 | 28,056 | 116,496 | 919,053 | 36,759 | **10,044,060** |
| Apr-2022 | Purchased Gas Charge | 6,480,140 | 3,097 | 57,484 | 1 | 122,919 | 492,394 | 2,129,744 | 100,390 | 167,636 | 59,607 | 976,078 | 39,320 | 95,131 | - | - | **10,723,943** |
| Apr-2022 | System Charge | 2,061,547 | 1,069 | 127,831 | 11 | 44,479 | 125,139 | 200,379 | 34,871 | 16,451 | 15,249 | 102,183 | 13,235 | 8,833 | 12,100 | 1,430 | **2,764,807** |
| Apr-2022 | Peak Usage Charge | - | - | - | - | - | 72,131 | 399,364 | 37,930 | 32,903 | 8,741 | 175,672 | 3,569 | 15,598 | - | - | **745,910** |
| Apr-2022 | DC Right of Way Tax | 314,735 | 176 | 2,741 | 0 | 6,014 | 49,400 | 208,531 | 13,887 | 21,564 | 5,072 | 127,096 | 2,452 | 10,197 | 264,195 | 7,402 | **1,033,460** |
| Apr-2022 | DC Right of Way Adjustment | 26,823 | 11 | 231 | - | 512 | 4,235 | 17,737 | 1,183 | 1,837 | 436 | 11,007 | 209 | 868 | 22,522 | 631 | **88,244** |
| Apr-2022 | SE Trust Fund | 390,802 | 161 | 3,541 | 0 | 7,715 | 63,742 | 266,943 | 17,806 | 27,646 | 6,568 | 165,654 | 3,146 | 13,061 | 338,964 | 9,495 | **1,315,244** |
| Apr-2022 | Delivery Tax | 632,382 | 267 | 5,548 | 0 | 12,085 | 109,797 | 459,805 | 30,671 | 47,620 | 10,284 | 259,397 | 4,926 | 20,453 | 577,305 | 16,068 | **2,186,608** |
| Apr-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 225 | 2,200 | **2,425** |
| Apr-2022 | Balancing Charge | - | - | - | - | - | 7,715 | - | - | - | - | - | - | - | 15,015 | 421 | **23,151** |
| Apr-2022 | STORAGE GAS CHRG | 54,711 | 26 | 486 | 0 | 1,037 | 4,159 | 18,072 | 845 | 1,428 | 503 | 8,228 | 332 | 796 | - | - | **90,623** |
| Apr-2022 | EA Trust Fund | 72,210 | 30 | 667 | 0 | 1,427 | 11,770 | 49,285 | 3,288 | 5,104 | 1,213 | 30,584 | 581 | 2,411 | 62,582 | 1,753 | **242,904** |
| Apr-2022 | DC Tax Reform Credit | 6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **6** |
| Apr-2022 | APRP | 715,512 | 698 | 6,314 | 0 | 13,675 | 70,953 | 308,262 | 20,388 | 32,023 | 7,751 | 196,131 | 3,713 | 15,420 | 123,113 | 3,449 | **1,517,403** |
| | **TOTAL** | **14,590,418** | **6,906** | **236,521** | **12** | **286,192** | **1,511,485** | **6,316,277** | **336,901** | **584,687** | **171,380** | **3,459,329** | **98,797** | **293,465** | **2,484,325** | **86,743** | **30,463,440** |
| May-2022 | PGA - Retroactive | (3,573) | (11) | (28) | - | (69) | (142) | (1,507) | (79) | (150) | (77) | (646) | (31) | (75) | - | - | **(6,388)** |
| May-2022 | PGC Rounding difference | (29) | (0) | (10) | - | (0) | (47) | 5 | (0) | (0) | (0) | (0) | 0 | (0) | - | - | **(83)** |
| May-2022 | ACA | 71,663 | 211 | 464 | - | 1,401 | 3,824 | 30,008 | 1,409 | 3,002 | 1,677 | 12,916 | 612 | 1,507 | - | - | **128,695** |
| May-2022 | DCA | (175,806) | (528) | (1,502) | - | (3,491) | (35,405) | (149,763) | (8,471) | (18,248) | (3,778) | (35,905) | (1,885) | (9,393) | - | - | **(444,174)** |
| May-2022 | GAC Current | 64,054 | 188 | 495 | - | 1,253 | 3,537 | 26,729 | 1,215 | 2,685 | 1,229 | 11,564 | 547 | 1,348 | - | - | **114,845** |
| May-2022 | Residential Essential Credit | 21,365 | 67 | 110 | - | 440 | 4,129 | 18,860 | 1,111 | 2,319 | 398 | 4,569 | 240 | 1,196 | 28,160 | 792 | **83,756** |
| May-2022 | RES Rider credit | (3,113) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(3,113)** |
| May-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 107,948 | - | **107,948** |
| May-2022 | Delivery Charge | 2,118,978 | 6,356 | 15,085 | - | 41,774 | 331,660 | 1,591,845 | 60,810 | 193,243 | 40,787 | 386,619 | 20,132 | 100,330 | 719,861 | 28,626 | **5,656,106** |
| May-2022 | Purchased Gas Charge | 3,740,003 | 10,852 | 32,838 | - | 72,990 | 221,286 | 1,564,023 | 77,113 | 156,967 | 65,966 | 673,131 | 31,947 | 78,724 | - | - | **6,725,840** |
| May-2022 | System Charge | 2,069,516 | 1,294 | 128,332 | 29 | 44,592 | 127,991 | 200,401 | 35,488 | 16,358 | 14,321 | 102,319 | 13,182 | 8,598 | 11,880 | 1,320 | **2,775,620** |
| May-2022 | Peak Usage Charge | - | - | - | - | - | (5,509) | 9,745 | 26,295 | 209 | (226) | 1,312 | 2 | (29) | - | - | **31,799** |
| May-2022 | DC Right of Way Tax | 164,209 | 493 | 1,357 | - | 3,258 | 32,924 | 139,993 | 8,005 | 17,038 | 3,512 | 35,565 | 1,760 | 8,770 | 206,510 | 5,807 | **629,200** |
| May-2022 | DC Right of Way Adjustment | 13,976 | 42 | 108 | - | 278 | 2,870 | 11,935 | 655 | 1,452 | 325 | 2,857 | 150 | 747 | 17,600 | 495 | **53,490** |
| May-2022 | SE Trust Fund | 202,690 | 627 | 1,677 | - | 4,180 | 42,321 | 179,638 | 10,551 | 21,850 | 4,838 | 42,993 | 2,257 | 11,249 | 264,884 | 7,448 | **797,204** |
| May-2022 | Delivery Tax | 329,782 | 989 | 2,618 | - | 6,549 | 72,355 | 308,880 | 17,633 | 37,637 | 7,105 | 67,325 | 3,535 | 17,614 | 451,662 | 12,660 | **1,336,344** |
| May-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 10,000 | 2,425 | **12,425** |
| May-2022 | Balancing Charge | - | - | - | - | - | 7,445 | - | - | - | - | - | - | - | 11,733 | 330 | **19,508** |
| May-2022 | STORAGE GAS CHRG | 28,235 | 83 | 254 | - | 553 | 1,584 | 11,791 | 517 | 1,184 | 499 | 5,100 | 241 | 595 | - | - | **50,636** |
| May-2022 | EA Trust Fund | 37,460 | 116 | 317 | - | 773 | 7,757 | 33,142 | 1,924 | 4,034 | 838 | 7,938 | 417 | 2,077 | 48,905 | 1,375 | **147,072** |
| May-2022 | PRA | (11) | - | - | - | - | - | (144) | (143) | - | - | - | - | - | - | - | **(299)** |
| May-2022 | DC Tax Reform Credit | 1 | - | - | - | - | - | (166) | - | - | - | - | - | - | - | - | **(164)** |
| May-2022 | APRP | 374,514 | 1,120 | 3,352 | - | 7,409 | 50,046 | 207,155 | 12,108 | 25,028 | 5,641 | 50,774 | 2,665 | 13,279 | 96,215 | 2,705 | **852,012** |
| | **TOTAL** | **9,053,916** | **21,899** | **185,466** | **29** | **181,889** | **868,625** | **4,182,570** | **246,143** | **464,607** | **143,055** | **1,368,431** | **75,771** | **236,537** | **1,975,358** | **63,984** | **19,068,280** |
| Jun-2022 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Jun-2022 | PGA - Retroactive | (49,803) | (187) | (871) | (0) | (1,026) | (5,628) | (26,234) | (1,930) | (4,444) | (939) | (9,463) | (687) | (1,813) | - | - | **(103,025)** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUA** DC

| | | DC Res Htg / HC 1 | DC Res Htg / HC 2 | DC Res Non Htg - IMA 1 | DC Res Non Htg - IMA 2 | DC Res Non Htg - OTH 1 | DC C&I Htg / HC 1 | DC C&I Htg / HC 2 | DC C&I Non Htg 1 | DC C&I Non Htg 2 | DC GMA Htg / HC 1 | DC GMA Htg / HC 2 | DC GMA Non Htg 1 | DC GMA Non Htg 2 | DC Interruptible 1 | DC Interruptible 2 | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jun-2022 | PGC Rounding difference | 5 | 0 | 3 | - | (1) | 56 | 5 | (0) | (0) | (0) | (1) | 0 | (0) | - | - | **67** |
| Jun-2022 | ACA | 34,336 | 409 | 538 | 0 | 698 | 1,765 | 18,678 | 1,285 | 2,924 | 622 | 6,110 | 432 | 1,113 | - | - | **68,911** |
| Jun-2022 | DCA | (84,122) | (250) | (1,258) | (0) | (1,740) | (29,749) | (92,749) | (8,154) | (16,393) | (1,976) | (31,765) | (1,434) | (6,940) | - | - | **(276,529)** |
| Jun-2022 | GAC Current | 30,710 | 353 | 482 | 0 | 624 | 1,511 | 16,631 | 1,150 | 2,615 | 556 | 5,436 | 387 | 996 | - | - | **61,451** |
| Jun-2022 | Residential Essential Credit | 10,229 | 32 | 138 | - | 216 | 3,490 | 11,922 | 1,038 | 2,119 | 251 | 3,955 | 182 | 906 | 16,508 | 598 | **51,585** |
| Jun-2022 | RES Rider credit | (1,397) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(1,397)** |
| Jun-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 305,311 | 534 | **305,844** |
| Jun-2022 | Delivery Charge | 1,013,177 | 3,008 | 13,532 | 0 | 20,813 | 269,300 | 987,035 | 49,239 | 173,896 | 21,039 | 341,764 | 15,311 | 74,342 | 480,137 | 21,457 | **3,484,051** |
| Jun-2022 | Purchased Gas Charge | 2,028,221 | 17,559 | 32,346 | 1 | 41,431 | 153,184 | 1,092,429 | 76,646 | 174,961 | 37,127 | 367,138 | 26,320 | 67,665 | - | - | **4,115,028** |
| Jun-2022 | System Charge | 2,065,770 | 1,226 | 127,784 | 22 | 44,273 | 128,280 | 203,384 | 33,966 | 16,364 | 15,261 | 101,468 | 12,885 | 8,884 | 10,560 | 1,320 | **2,771,445** |
| Jun-2022 | Peak Usage Charge | - | - | - | - | - | (7,171) | 179 | 27,538 | 131 | 1 | (2,367) | (55) | 733 | - | - | **18,989** |
| Jun-2022 | DC Right of Way Tax | 78,427 | 233 | 1,178 | 0 | 1,624 | 27,843 | 86,614 | 7,613 | 15,292 | 1,845 | 29,648 | 1,341 | 6,469 | 121,062 | 4,386 | **383,575** |
| Jun-2022 | DC Right of Way Adjustment | 10,875 | 32 | 158 | - | 227 | 4,155 | 11,800 | 1,062 | 2,100 | 258 | 4,176 | 189 | 885 | 16,852 | 621 | **53,391** |
| Jun-2022 | SE Trust Fund | 97,478 | 297 | 1,510 | 0 | 2,089 | 35,688 | 111,519 | 9,766 | 19,663 | 2,367 | 37,948 | 1,717 | 8,335 | 155,282 | 5,625 | **489,284** |
| Jun-2022 | Delivery Tax | 157,824 | 468 | 2,346 | 0 | 3,265 | 60,868 | 191,540 | 16,820 | 33,869 | 3,706 | 59,423 | 2,688 | 13,052 | 265,617 | 9,570 | **821,056** |
| Jun-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 15,450 | 2,650 | **18,100** |
| Jun-2022 | Balancing Charge | - | - | - | - | - | 7,641 | - | - | - | - | - | - | - | 6,878 | 249 | **14,768** |
| Jun-2022 | STORAGE GAS CHRG | 14,564 | 143 | 236 | 0 | 298 | 784 | 7,830 | 550 | 1,252 | 266 | 2,608 | 187 | 480 | - | - | **29,198** |
| Jun-2022 | EA Trust Fund | 17,992 | 55 | 285 | 0 | 386 | 6,563 | 20,565 | 1,803 | 3,630 | 437 | 7,006 | 317 | 1,539 | 28,669 | 1,039 | **90,286** |
| Jun-2022 | PRA | (141) | - | - | - | - | (14) | (144) | - | - | - | - | - | - | - | - | **(299)** |
| Jun-2022 | DC Tax Reform Credit | (28) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(28)** |
| Jun-2022 | APRP | 178,209 | 530 | 2,695 | 0 | 3,691 | 42,473 | 127,195 | 11,181 | 22,260 | 2,794 | 44,882 | 2,030 | 9,667 | 56,404 | 2,043 | **506,055** |
| | **TOTAL** | **5,602,327** | **23,909** | **181,103** | **24** | **116,870** | **701,040** | **2,768,198** | **229,572** | **450,240** | **83,615** | **967,966** | **61,810** | **186,312** | **1,478,730** | **50,092** | **12,901,807** |
| Jul-2022 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Jul-2022 | PGA - Retroactive | (38,170) | (238) | (841) | (0) | (836) | (3,305) | (21,451) | (1,884) | (3,723) | (763) | (7,087) | (610) | (1,666) | - | - | **(80,574)** |
| Jul-2022 | PGC Rounding difference | (17) | (1) | 5 | - | (1) | 6 | (5) | (0) | 0 | 0 | 1 | (0) | (0) | - | - | **(13)** |
| Jul-2022 | ACA | 25,591 | 748 | 508 | 0 | 609 | 1,757 | 14,751 | 1,094 | 2,473 | 545 | 4,130 | 433 | 1,866 | - | - | **54,505** |
| Jul-2022 | DCA | (61,764) | (1,281) | (1,184) | (0) | (1,465) | (30,675) | (91,750) | (8,295) | (14,123) | (1,651) | (23,739) | (1,347) | (7,144) | - | - | **(244,417)** |
| Jul-2022 | GAC Current | 22,876 | 601 | 457 | 0 | 538 | 1,460 | 13,195 | 966 | 2,212 | 521 | 3,762 | 387 | 1,679 | - | - | **48,652** |
| Jul-2022 | Residential Essential Credit | 7,378 | 300 | 125 | - | 192 | 3,944 | 11,622 | 1,056 | 1,798 | 215 | 2,757 | 172 | 920 | 28,863 | 433 | **59,776** |
| Jul-2022 | RES Rider credit | (2,170) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(2,170)** |
| Jul-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | (93,827) | - | **(93,827)** |
| Jul-2022 | Delivery Charge | 743,948 | 15,784 | 12,693 | 0 | 17,561 | 281,702 | 974,818 | 44,931 | 149,580 | 17,246 | 254,301 | 14,388 | 76,107 | 720,444 | 15,580 | **3,339,083** |
| Jul-2022 | Purchased Gas Charge | 1,520,060 | 23,978 | 31,360 | 1 | 34,362 | 106,594 | 868,844 | 68,971 | 147,680 | 32,038 | 266,996 | 25,266 | 95,106 | - | - | **3,221,255** |
| Jul-2022 | System Charge | 2,058,317 | 1,760 | 126,440 | 22 | 44,391 | 126,044 | 198,188 | 34,542 | 16,297 | 16,396 | 99,729 | 13,425 | 8,677 | 12,760 | 1,100 | **2,758,086** |
| Jul-2022 | Peak Usage Charge | - | - | - | - | - | (565) | (583) | 27,544 | (8) | 65 | (2,710) | 55 | 1,469 | - | - | **25,266** |
| Jul-2022 | DC Right of Way Tax | 57,642 | 1,275 | 1,104 | 0 | 1,372 | 28,669 | 85,633 | 7,772 | 13,243 | 1,522 | 22,032 | 1,255 | 6,595 | 211,660 | 3,175 | **442,949** |
| Jul-2022 | DC Right of Way Adjustment | 8,124 | 89 | 151 | - | 186 | 4,050 | 11,880 | 1,098 | 1,869 | 192 | 3,185 | 173 | 871 | 29,460 | 442 | **61,768** |
| Jul-2022 | SE Trust Fund | 70,879 | 1,730 | 1,412 | 0 | 1,775 | 36,860 | 109,898 | 9,935 | 16,914 | 1,887 | 28,121 | 1,614 | 8,533 | 271,490 | 4,072 | **565,120** |
| Jul-2022 | Delivery Tax | 115,933 | 2,711 | 2,194 | 0 | 2,773 | 63,342 | 189,296 | 17,113 | 29,133 | 3,085 | 44,035 | 2,526 | 13,362 | 459,148 | 6,923 | **951,573** |
| Jul-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 26,100 | 2,425 | **28,525** |
| Jul-2022 | Balancing Charge | - | - | - | - | - | 7,387 | - | - | - | - | - | - | - | 12,026 | 180 | **19,594** |
| Jul-2022 | STORAGE GAS CHRG | 10,918 | 259 | 226 | 0 | 254 | 699 | 6,294 | 484 | 1,058 | 251 | 1,828 | 183 | 738 | - | - | **23,191** |
| Jul-2022 | EA Trust Fund | 13,090 | 319 | 266 | 0 | 328 | 6,790 | 20,291 | 1,835 | 3,123 | 364 | 5,192 | 298 | 1,575 | 50,124 | 752 | **104,347** |
| Jul-2022 | PRA | 0 | - | - | - | - | 1 | - | - | - | - | - | - | - | - | - | **2** |
| Jul-2022 | DC Tax Reform Credit | 7 | - | - | - | - | 56 | - | - | - | (44) | - | - | - | - | - | **19** |
| Jul-2022 | APRP | 130,953 | 2,575 | 2,466 | 0 | 3,072 | 42,148 | 125,534 | 11,374 | 19,366 | 2,129 | 34,301 | 1,901 | 9,862 | 98,614 | 1,479 | **485,774** |
| | **TOTAL** | **4,683,594** | **50,608** | **177,382** | **24** | **105,111** | **676,965** | **2,516,455** | **218,536** | **386,892** | **73,996** | **736,832** | **60,119** | **218,548** | **1,826,863** | **36,561** | **11,768,485** |
| Aug-2022 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Aug-2022 | PGA - Retroactive | (31,664) | (113) | (697) | (5) | (652) | (5,450) | (19,914) | (1,484) | (3,382) | (841) | (5,968) | (521) | (1,303) | - | - | **(71,993)** |
| Aug-2022 | PGC Rounding difference | (44) | 1 | 4 | (0) | (1) | (1) | (2) | (0) | 0 | (1) | (1) | 1 | 0 | - | - | **(44)** |
| Aug-2022 | ACA | 20,824 | (514) | 469 | 3 | 435 | 2,153 | 12,835 | 986 | 2,253 | 455 | 4,504 | 376 | 768 | - | - | **45,548** |
| Aug-2022 | DCA | (51,562) | 774 | (1,082) | (7) | (1,089) | (32,340) | (71,472) | (6,434) | (12,115) | (1,206) | (21,728) | (1,184) | (5,279) | - | - | **(204,726)** |
| Aug-2022 | GAC Current | 18,641 | (391) | 421 | 3 | 391 | 2,001 | 11,492 | 882 | 2,015 | 414 | 3,956 | 332 | 691 | - | - | **40,848** |
| Aug-2022 | Residential Essential Credit | 5,984 | (235) | 118 | 1 | 132 | 4,036 | 9,222 | 818 | 1,198 | 150 | 2,910 | 158 | 665 | 12,139 | 434 | **37,730** |
| Aug-2022 | RES Rider credit | (508) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(508)** |
| Aug-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 90,637 | 7,063 | **97,700** |
| Aug-2022 | Delivery Charge | 620,450 | (9,669) | 11,610 | 73 | 13,016 | 297,493 | 759,460 | 38,925 | 126,276 | 12,796 | 234,875 | 12,695 | 56,335 | 267,087 | 14,871 | **2,456,293** |
| Aug-2022 | Purchased Gas Charge | 1,248,553 | (10,018) | 27,515 | 193 | 25,909 | 166,112 | 775,718 | 58,887 | 134,407 | 29,919 | 248,188 | 21,677 | 48,123 | - | - | **2,775,184** |
| Aug-2022 | System Charge | 2,054,387 | 956 | 126,087 | 33 | 43,698 | 128,218 | 202,291 | 34,024 | 16,206 | 15,120 | 104,642 | 13,465 | 8,601 | 11,880 | 1,650 | **2,761,259** |
| Aug-2022 | Peak Usage Charge | - | - | - | - | - | (2,543) | 304 | 27,531 | (1,932) | 199 | 1,115 | 49 | (190) | - | - | **24,533** |
| Aug-2022 | DC Right of Way Tax | 48,087 | (801) | 1,007 | 6 | 1,016 | 30,407 | 66,355 | 6,008 | 11,150 | 1,142 | 20,365 | 1,107 | 4,929 | 89,019 | 3,180 | **282,978** |

CUBE: tm1serv:Rate Statistics DB
RS_ACTUA DC

| | | DC Res Htg / HC | DC Res Htg / HC | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - OTH | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Non Htg | DC C&I Non Htg | DC GMA Htg / HC | DC GMA Htg / HC | DC GMA Non Htg | DC GMA Non Htg | DC Interruptible | DC Interruptible | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 1 | 2 | 1 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | |
| Aug-2022 | DC Right of Way Adjustment | 6,832 | (23) | 133 | 1 | 145 | 4,372 | 8,920 | 837 | 1,616 | 176 | 2,755 | 152 | 685 | 12,392 | 439 | **39,431** |
| Aug-2022 | SE Trust Fund | 58,697 | (1,124) | 1,294 | 8 | 1,305 | 38,766 | 85,596 | 7,706 | 14,127 | 1,440 | 26,225 | 1,424 | 6,316 | 114,182 | 4,079 | **360,041** |
| Aug-2022 | Delivery Tax | 96,671 | (1,759) | 2,014 | 13 | 2,043 | 66,770 | 147,437 | 13,273 | 24,333 | 2,254 | 41,065 | 2,229 | 9,890 | 202,636 | 6,919 | **615,788** |
| Aug-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 26,550 | 2,875 | **29,425** |
| Aug-2022 | Balancing Charge | - | - | - | - | - | 7,648 | - | - | - | - | - | - | - | 5,058 | 181 | **12,887** |
| Aug-2022 | STORAGE GAS CHRG | 8,925 | (159) | 205 | 1 | 187 | 1,100 | 5,538 | 422 | 964 | 199 | 1,861 | 156 | 339 | - | - | **19,738** |
| Aug-2022 | EA Trust Fund | 10,852 | (207) | 245 | 2 | 241 | 7,158 | 15,804 | 1,423 | 2,608 | 266 | 4,842 | 263 | 1,166 | 21,081 | 753 | **66,496** |
| Aug-2022 | PRA | 0 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **0** |
| Aug-2022 | DC Tax Reform Credit | 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **5** |
| Aug-2022 | APRP | 109,382 | (1,498) | 2,285 | 14 | 2,310 | 45,584 | 96,558 | 8,824 | 17,719 | 1,669 | 30,161 | 1,662 | 7,516 | 41,475 | 1,482 | **365,141** |
| | **TOTAL** | **4,224,512** | **(24,781)** | **171,628** | **340** | **89,087** | **761,484** | **2,106,141** | **192,628** | **337,443** | **64,151** | **699,766** | **54,041** | **139,251** | **894,137** | **43,926** | **9,753,755** |
| Sep-2022 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Sep-2022 | PGA - Retroactive | (37,045) | (167) | (932) | 5 | (812) | (2,008) | (25,178) | (1,929) | (3,657) | (817) | (7,776) | (542) | (1,507) | - | - | **(82,364)** |
| Sep-2022 | PGC Rounding difference | (181) | (0) | (32) | - | (5) | (3) | 0 | (0) | (8) | (0) | 1 | (0) | - | - | - | **(228)** |
| Sep-2022 | ACA | 25,446 | 90 | 604 | (3) | 542 | 1,326 | 15,947 | 1,286 | 2,566 | 549 | 5,076 | 359 | 1,005 | - | - | **54,792** |
| Sep-2022 | DCA | (60,917) | (194) | (1,400) | 7 | (1,326) | (28,080) | (83,243) | (6,184) | (10,968) | (1,339) | (27,230) | (1,177) | (5,931) | - | - | **(227,981)** |
| Sep-2022 | GAC Current | 22,802 | 80 | 542 | (3) | 485 | 1,208 | 14,342 | 1,150 | 2,330 | 492 | 4,546 | 321 | 899 | - | - | **49,194** |
| Sep-2022 | Residential Essential Credit | 7,156 | 24 | 158 | (1) | 163 | 3,598 | 10,261 | 787 | 1,306 | 171 | 3,511 | 150 | 755 | 16,935 | 405 | **45,378** |
| Sep-2022 | RES Rider credit | (178) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(178)** |
| Sep-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 89,956 | 1,701 | **91,657** |
| Sep-2022 | Delivery Charge | 732,858 | 2,336 | 15,069 | (73) | 15,859 | 250,560 | 886,415 | 44,681 | 115,729 | 14,250 | 293,300 | 12,575 | 63,350 | 430,859 | 14,351 | **2,892,121** |
| Sep-2022 | Purchased Gas Charge | 1,569,517 | 6,117 | 37,744 | (191) | 33,842 | 83,875 | 1,031,442 | 80,532 | 159,404 | 33,617 | 319,691 | 22,571 | 62,918 | - | - | **3,441,080** |
| Sep-2022 | System Charge | 2,060,048 | 1,257 | 125,081 | 11 | 43,748 | 123,722 | 200,602 | 34,152 | 16,253 | 16,627 | 101,384 | 13,164 | 8,599 | 11,110 | 1,320 | **2,757,079** |
| Sep-2022 | Peak Usage Charge | - | - | - | - | - | 306 | (6,622) | 27,538 | (142) | 20 | (247) | - | - | - | - | **20,852** |
| Sep-2022 | DC Right of Way Tax | 56,737 | 184 | 1,306 | (6) | 1,238 | 26,239 | 77,786 | 5,773 | 10,201 | 1,250 | 25,369 | 1,099 | 5,537 | 124,188 | 2,967 | **339,869** |
| Sep-2022 | DC Right of Way Adjustment | 7,938 | 28 | 175 | (1) | 175 | 3,627 | 11,306 | 804 | 1,513 | 173 | 3,489 | 154 | 771 | 17,287 | 413 | **47,850** |
| Sep-2022 | SE Trust Fund | 69,253 | 231 | 1,679 | (8) | 1,592 | 33,665 | 100,260 | 7,406 | 13,028 | 1,602 | 32,618 | 1,410 | 7,103 | 159,292 | 3,806 | **432,939** |
| Sep-2022 | Delivery Tax | 114,295 | 364 | 2,613 | (13) | 2,489 | 57,983 | 171,050 | 12,756 | 22,441 | 2,512 | 51,075 | 2,208 | 11,122 | 273,300 | 6,464 | **730,658** |
| Sep-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 23,900 | 2,875 | **26,775** |
| Sep-2022 | Balancing Charge | - | - | - | - | - | 7,656 | - | - | - | - | - | - | - | 7,056 | 169 | **14,880** |
| Sep-2022 | STORAGE GAS CHRG | 11,687 | 43 | 285 | (1) | 251 | 638 | 7,438 | 593 | 1,193 | 247 | 2,332 | 166 | 463 | - | - | **25,335** |
| Sep-2022 | EA Trust Fund | 12,797 | 43 | 315 | (1) | 294 | 6,215 | 18,334 | 1,368 | 2,405 | 296 | 6,022 | 260 | 1,311 | 29,410 | 703 | **79,773** |
| Sep-2022 | PRA | (2) | - | - | - | - | - | 37 | - | - | - | - | - | - | - | - | **35** |
| Sep-2022 | DC Tax Reform Credit | - | - | - | - | - | - | 608 | - | - | (1) | - | - | - | - | - | **606** |
| Sep-2022 | APRP | (4,541) | (131) | (352) | (14) | (174) | (19,925) | (49,460) | (3,689) | (13,304) | 592 | 1,941 | (69) | (31) | (771) | (17) | **(89,946)** |
| | **TOTAL** | **4,587,669** | **10,305** | **182,857** | **(293)** | **98,360** | **550,603** | **2,381,323** | **207,026** | **320,291** | **70,240** | **815,104** | **52,649** | **156,364** | **1,182,522** | **35,156** | **10,650,176** |
| Oct-2022 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Oct-2022 | PGA - Retroactive | (71,386) | 19 | (927) | (0) | (1,761) | (3,996) | (35,829) | (1,986) | (4,088) | (527) | (9,623) | (1,097) | (1,730) | - | - | **(132,933)** |
| Oct-2022 | PGC Rounding difference | (128) | (0) | (33) | (0) | (5) | (11) | (1) | (1) | 0 | 1 | (0) | (0) | (0) | - | - | **(177)** |
| Oct-2022 | ACA | 47,667 | 21 | 624 | 0 | 1,174 | 2,050 | 24,047 | 1,324 | 2,744 | 359 | 6,405 | 927 | 1,153 | - | - | **88,495** |
| Oct-2022 | DCA | (114,515) | (62) | (1,394) | (0) | (2,802) | (30,980) | (120,960) | (6,671) | (19,335) | (992) | (36,634) | (2,430) | (7,368) | - | - | **(344,143)** |
| Oct-2022 | GAC Current | 42,614 | 20 | 559 | 0 | 1,050 | 2,001 | 21,506 | 1,185 | 2,449 | 319 | 5,729 | 838 | 1,032 | - | - | **79,300** |
| Oct-2022 | Residential Essential Credit | 13,769 | 9 | 158 | - | 351 | 3,772 | 15,546 | 849 | 2,466 | 132 | 4,558 | 355 | 938 | 16,853 | 471 | **60,226** |
| Oct-2022 | RES Rider credit | (697) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(697)** |
| Oct-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 204,530 | 1,813 | **206,343** |
| Oct-2022 | Delivery Charge | 1,380,194 | 751 | 15,008 | 0 | 33,523 | 283,612 | 1,282,656 | 49,976 | 204,849 | 10,555 | 393,889 | 25,929 | 78,701 | 432,400 | 16,722 | **4,208,766** |
| Oct-2022 | Purchased Gas Charge | 2,984,681 | 831 | 38,475 | 1 | 73,433 | 155,419 | 1,502,241 | 82,928 | 171,188 | 22,162 | 401,649 | 51,691 | 72,230 | - | - | **5,556,930** |
| Oct-2022 | System Charge | 2,054,028 | 1,358 | 123,606 | 22 | 43,661 | 123,086 | 205,809 | 32,910 | 15,843 | 15,503 | 99,020 | 14,207 | 8,625 | 10,890 | 1,320 | **2,749,889** |
| Oct-2022 | Peak Usage Charge | - | - | - | - | - | (1,480) | 3,960 | 27,541 | 24 | 2 | (2) | 348 | - | - | - | **30,393** |
| Oct-2022 | DC Right of Way Tax | 106,883 | 53 | 1,300 | 0 | 2,616 | 28,828 | 112,742 | 6,228 | 18,021 | 928 | 34,135 | 2,272 | 6,872 | 123,587 | 3,453 | **447,918** |
| Oct-2022 | DC Right of Way Adjustment | 15,022 | 4 | 173 | - | 367 | 4,067 | 15,377 | 868 | 2,433 | 129 | 4,777 | 277 | 948 | 17,204 | 481 | **62,126** |
| Oct-2022 | SE Trust Fund | 131,310 | 72 | 1,673 | 0 | 3,361 | 36,893 | 143,988 | 7,990 | 23,163 | 1,192 | 43,745 | 2,893 | 8,824 | 158,522 | 4,429 | **568,055** |
| Oct-2022 | Delivery Tax | 214,771 | 117 | 2,603 | 0 | 5,256 | 63,542 | 249,660 | 13,761 | 39,898 | 1,867 | 68,500 | 4,626 | 13,817 | 271,894 | 7,521 | **957,832** |
| Oct-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 25,200 | 2,875 | **28,075** |
| Oct-2022 | Balancing Charge | - | - | - | - | - | 7,380 | - | - | - | - | - | - | - | 7,022 | 196 | **14,598** |
| Oct-2022 | STORAGE GAS CHRG | 21,982 | 10 | 292 | 0 | 542 | 1,091 | 11,069 | 611 | 1,260 | 163 | 2,959 | 416 | 532 | - | - | **40,927** |
| Oct-2022 | EA Trust Fund | 24,235 | 13 | 315 | 0 | 620 | 6,811 | 26,761 | 1,475 | 4,277 | 220 | 8,076 | 545 | 1,629 | 29,267 | 818 | **105,064** |
| Oct-2022 | PRA | 1 | - | - | - | - | - | (37) | - | - | - | - | - | - | - | - | **(36)** |
| Oct-2022 | DC Tax Reform Credit | 23 | - | - | - | - | - | (608) | - | - | - | - | - | - | - | - | **(585)** |
| Oct-2022 | APRP | (14,617) | (491) | (164) | - | (373) | (19,664) | (67,909) | (3,983) | (5,176) | 6 | (484) | 388 | 390 | (702) | (20) | **(112,799)** |
| | **TOTAL** | **6,835,838** | **2,725** | **182,268** | **23** | **161,013** | **662,421** | **3,390,018** | **215,003** | **460,015** | **52,019** | **1,026,700** | **102,187** | **186,593** | **1,296,667** | **40,078** | **14,613,568** |
| Nov-2022 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |

CUBE: tm1serv:Rate Statistics DB
RS_ACTUA DC

| | | DC Res Htg / HC | DC Res Htg / HC | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - OTH | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Non Htg | DC C&I Non Htg | DC GMA Htg / HC | DC GMA Htg / HC | DC GMA Non Htg | DC GMA Non Htg | DC Interruptible | DC Interruptible | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 1 | 2 | 1 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | |
| Nov-2022 | PGA - Retroactive | (127,938) | (285) | (1,223) | (0) | (2,303) | (4,462) | (50,215) | (2,720) | (5,083) | (1,103) | (22,332) | (840) | (2,428) | - | - | **(220,933)** |
| Nov-2022 | PGC Rounding difference | (40) | - | (6) | - | (2) | (3) | (0) | (1) | 0 | (0) | 0 | 0 | 0 | - | - | **(51)** |
| Nov-2022 | ACA | 85,314 | 190 | 771 | 0 | 1,536 | 3,009 | 33,607 | 1,813 | 3,388 | 677 | 14,893 | 560 | 1,619 | - | - | **147,378** |
| Nov-2022 | DCA | (205,982) | (429) | (1,778) | (0) | (3,823) | (34,374) | (175,170) | (10,099) | (19,828) | (1,626) | (85,186) | (1,805) | (10,166) | - | - | **(550,265)** |
| Nov-2022 | GAC Current | 76,413 | 170 | 696 | 0 | 1,375 | 2,697 | 30,064 | 1,623 | 3,031 | 548 | 13,382 | 501 | 1,448 | - | - | **131,947** |
| Nov-2022 | Residential Essential Credit | 61,829 | 148 | 529 | 0 | 1,212 | 10,606 | 51,564 | 2,995 | 5,960 | 541 | 24,930 | 615 | 2,990 | 53,459 | 1,902 | **219,281** |
| Nov-2022 | RES Rider credit | (18,875) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(18,875)** |
| Nov-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 383,679 | - | **383,679** |
| Nov-2022 | Delivery Charge | 2,480,904 | 5,165 | 19,091 | 0 | 45,739 | 319,547 | 1,864,119 | 131,792 | 210,010 | 17,684 | 917,365 | 19,279 | 108,592 | 582,812 | 28,139 | **6,750,237** |
| Nov-2022 | Purchased Gas Charge | 3,758,576 | 7,451 | 35,076 | 1 | 64,626 | 119,789 | 1,488,735 | 81,726 | 149,165 | 29,103 | 661,130 | 21,073 | 71,852 | - | - | **6,488,303** |
| Nov-2022 | System Charge | 2,048,618 | 1,451 | 123,188 | 23 | 43,591 | 126,598 | 214,266 | 34,113 | 16,579 | 14,186 | 105,076 | 13,176 | 8,972 | 10,890 | 1,320 | **2,762,047** |
| Nov-2022 | Peak Usage Charge | - | - | - | - | - | 31,321 | 353,665 | 34,198 | 31,794 | 3,467 | 162,703 | 3,866 | 15,157 | - | - | **636,171** |
| Nov-2022 | DC Right of Way Tax | 192,278 | 400 | 1,652 | 0 | 3,569 | 32,092 | 163,674 | 9,427 | 18,513 | 1,550 | 79,535 | 1,685 | 9,492 | 165,057 | 5,874 | **684,799** |
| Nov-2022 | DC Right of Way Adjustment | 26,826 | 56 | 231 | - | 499 | 4,462 | 23,054 | 1,312 | 2,577 | 233 | 11,072 | 235 | 1,321 | 22,977 | 818 | **95,672** |
| Nov-2022 | SE Trust Fund | 245,713 | 514 | 2,114 | 0 | 4,581 | 41,164 | 210,556 | 12,095 | 23,747 | 2,074 | 102,016 | 2,162 | 12,175 | 211,714 | 7,535 | **878,160** |
| Nov-2022 | Delivery Tax | 386,273 | 804 | 3,301 | 0 | 7,170 | 70,917 | 361,170 | 20,830 | 40,903 | 3,075 | 159,747 | 3,385 | 19,065 | 360,979 | 12,783 | **1,450,401** |
| Nov-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 10,150 | 2,425 | **12,575** |
| Nov-2022 | Balancing Charge | - | - | - | - | - | 7,648 | - | - | - | - | - | - | - | 9,378 | 334 | **17,360** |
| Nov-2022 | STORAGE GAS CHRG | 39,394 | 88 | 367 | 0 | 709 | 1,388 | 15,485 | 838 | 1,562 | 287 | 6,900 | 258 | 746 | - | - | **68,022** |
| Nov-2022 | EA Trust Fund | 45,393 | 95 | 396 | 0 | 846 | 7,602 | 38,713 | 2,233 | 4,384 | 366 | 18,835 | 399 | 2,248 | 39,088 | 1,391 | **161,989** |
| Nov-2022 | PRA | (6) | - | - | - | - | (0) | 19 | - | - | (7) | - | - | - | - | - | **7** |
| Nov-2022 | DC Tax Reform Credit | (46) | - | - | - | - | (4) | 608 | - | - | 42 | 192 | - | - | - | - | **791** |
| Nov-2022 | APRP | (26,520) | (56) | (413) | - | (499) | (20,424) | (106,817) | (6,070) | (11,834) | (135) | (522) | (21) | (54) | (938) | (33) | **(174,336)** |
| | **TOTAL** | **9,068,124** | **15,762** | **183,992** | **24** | **168,825** | **719,573** | **4,517,097** | **316,104** | **474,869** | **70,962** | **2,169,736** | **64,528** | **243,030** | **1,849,243** | **62,487** | **19,924,356** |
| Dec-2022 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Dec-2022 | PGA - Retroactive | (267,185) | (726) | (1,903) | (3) | (5,222) | (13,208) | (84,771) | (3,846) | (6,110) | (1,954) | (38,488) | (1,579) | (2,998) | - | - | **(427,993)** |
| Dec-2022 | PGC Rounding difference | 8,845 | 23 | 51 | 0 | 173 | 426 | 2,709 | 124 | 204 | 64 | 1,251 | 52 | 100 | - | - | **14,023** |
| Dec-2022 | ACA | 306,192 | 427 | 2,148 | 3 | 6,033 | 14,989 | 96,261 | 4,579 | 7,022 | 2,194 | 44,079 | 1,823 | 3,434 | - | - | **489,184** |
| Dec-2022 | DCA | (482,949) | (403) | (3,335) | (4) | (9,472) | (54,555) | (314,667) | (22,018) | (24,844) | (3,717) | (148,793) | (3,425) | (13,985) | - | - | **(1,082,167)** |
| Dec-2022 | GAC Current | 159,150 | 79 | 1,121 | 1 | 3,101 | 7,889 | 50,910 | 2,451 | 3,644 | 1,146 | 23,012 | 951 | 1,780 | - | - | **255,234** |
| Dec-2022 | Residential Essential Credit | 84,931 | 104 | 615 | 1 | 1,701 | 9,728 | 57,837 | 3,969 | 4,582 | 624 | 26,580 | 613 | 2,493 | 46,172 | 1,346 | **241,296** |
| Dec-2022 | RES Rider credit | (74,069) | - | (25) | - | (23) | - | - | - | - | - | - | - | - | - | - | **(74,117)** |
| Dec-2022 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 53,857 | - | **53,857** |
| Dec-2022 | Delivery Charge | 5,125,482 | 3,068 | 31,908 | 38 | 100,166 | 472,238 | 2,963,909 | 116,852 | 228,032 | 34,573 | 1,413,347 | 32,334 | 131,628 | 752,090 | 30,944 | **11,436,608** |
| Dec-2022 | Purchased Gas Charge | 8,321,188 | 6,988 | 58,538 | 78 | 162,391 | 413,445 | 2,654,516 | 127,092 | 190,563 | 59,936 | 1,204,300 | 49,660 | 93,098 | - | - | **13,341,792** |
| Dec-2022 | System Charge | 2,051,613 | 1,512 | 123,232 | 22 | 43,711 | 124,553 | 211,181 | 34,263 | 16,181 | 16,379 | 101,653 | 13,206 | 8,462 | 10,670 | 1,320 | **2,757,959** |
| Dec-2022 | Peak Usage Charge | - | - | - | - | - | 58,595 | 404,791 | 34,543 | 31,108 | 4,074 | 169,804 | 4,112 | 15,409 | - | - | **722,436** |
| Dec-2022 | DC Right of Way Tax | 397,222 | 281 | 2,761 | 3 | 7,815 | 44,939 | 260,401 | 18,179 | 20,138 | 3,041 | 122,532 | 2,825 | 11,506 | 214,227 | 6,236 | **1,112,106** |
| Dec-2022 | DC Right of Way Adjustment | 55,335 | 76 | 382 | 0 | 1,094 | 6,255 | 36,083 | 2,514 | 2,878 | 425 | 17,052 | 392 | 1,603 | 29,821 | 868 | **154,778** |
| Dec-2022 | SE Trust Fund | 504,286 | 305 | 3,537 | 4 | 10,076 | 57,643 | 333,319 | 23,350 | 25,784 | 3,894 | 157,175 | 3,625 | 14,758 | 274,783 | 7,998 | **1,420,537** |
| Dec-2022 | Delivery Tax | 797,772 | 478 | 5,536 | 7 | 15,694 | 99,291 | 575,643 | 40,221 | 44,413 | 6,098 | 246,119 | 5,677 | 23,109 | 468,087 | 13,527 | **2,341,673** |
| Dec-2022 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 4,850 | 2,200 | **7,050** |
| Dec-2022 | Balancing Charge | - | - | - | - | - | 8,426 | - | - | - | - | - | - | - | 12,172 | 354 | **20,952** |
| Dec-2022 | STORAGE GAS CHRG | 105,766 | 148 | 735 | 1 | 2,057 | 5,202 | 33,463 | 1,565 | 2,423 | 772 | 15,246 | 627 | 1,185 | - | - | **169,189** |
| Dec-2022 | EA Trust Fund | 93,150 | 56 | 661 | 1 | 1,851 | 10,643 | 61,701 | 4,311 | 4,760 | 719 | 29,019 | 669 | 2,725 | 50,732 | 1,477 | **262,475** |
| Dec-2022 | PRA | 2 | - | - | - | 3 | - | (19) | - | - | (1) | - | - | - | - | - | **(16)** |
| Dec-2022 | DC Tax Reform Credit | 22 | - | - | - | 29 | - | (608) | - | - | - | - | - | - | - | - | **(557)** |
| Dec-2022 | APRP | (56,261) | (1,638) | (467) | (0) | (1,102) | (28,510) | (160,258) | (10,794) | (19,128) | (29) | 503 | 5 | (69) | (1,217) | (35) | **(279,000)** |
| | **TOTAL** | **17,130,492** | **10,780** | **225,495** | **151** | **340,076** | **1,237,989** | **7,182,400** | **377,356** | **531,648** | **128,241** | **3,384,392** | **111,567** | **294,236** | **1,916,244** | **66,235** | **32,937,299** |

CUBE: tm1serv:Rate Statistics DB
RS ACTUA DC

| | | DC Res Htg / HC | DC Res Htg / HC | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - OTH | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Non Htg | DC C&I Non Htg | DC GMA Htg / HC | DC GMA Htg / HC | DC GMA Non Htg | DC GMA Non Htg | DC Interruptible | DC Interruptible | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 1 | 2 | 1 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | 1 | 2 | |
| Jan-2023 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **170** |
| Jan-2023 | PGA - Retroactive | (344,680) | (1,139) | (2,301) | (4) | (6,557) | (18,573) | (114,732) | (4,404) | (7,506) | (2,719) | (45,702) | (1,950) | (3,772) | - | - | **(18,772)** |
| Jan-2023 | PGC Rounding difference | 29 | 2 | (3) | - | (1) | (8) | 125 | 0 | 3 | 2 | (11) | 0 | 0 | - | - | **(59)** |
| Jan-2023 | ACA | 409,268 | 1,350 | 2,737 | 5 | 7,788 | 21,988 | 136,350 | 5,375 | 8,915 | 3,176 | 54,407 | 2,314 | 4,479 | - | - | **351,326** |
| Jan-2023 | DCA | (647,395) | (1,992) | (4,157) | (6) | (12,353) | (66,299) | (420,832) | (22,023) | (33,196) | (7,109) | (184,018) | (4,243) | (17,109) | - | - | **(1,253,013)** |
| Jan-2023 | GAC Current | 212,480 | 701 | 1,422 | 2 | 4,044 | 11,386 | 70,945 | 2,725 | 4,629 | 1,685 | 28,203 | 1,203 | 2,326 | - | - | **338,669** |
| Jan-2023 | Residential Essential Credit | 113,102 | 354 | 746 | 1 | 2,189 | 11,751 | 74,865 | 3,932 | 5,894 | 1,298 | 32,557 | 754 | 3,038 | 66,611 | 1,881 | **275,036** |
| Jan-2023 | RES Rider credit | (146,583) | - | (174) | - | (344) | - | - | - | - | - | - | - | - | - | - | **(143,884)** |
| Jan-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 344,248 | - | **31,523** |
| Jan-2023 | Delivery Charge | 6,870,480 | 21,134 | 39,629 | 61 | 130,188 | 582,195 | 3,943,864 | 125,567 | 309,691 | 67,222 | 1,743,990 | 39,923 | 160,975 | 1,083,765 | 43,268 | **15,002,936** |
| Jan-2023 | Purchased Gas Charge | 12,126,527 | 39,815 | 80,938 | 138 | 230,913 | 651,423 | 4,035,943 | 153,265 | 264,000 | 96,469 | 1,611,421 | 68,676 | 132,783 | - | - | **13,220,359** |
| Jan-2023 | System Charge | 2,060,213 | 1,476 | 154,648 | 22 | 43,275 | 124,788 | 214,236 | 34,494 | 16,091 | 15,364 | 97,659 | 13,319 | 8,609 | 10,890 | 1,320 | **2,761,943** |
| Jan-2023 | Peak Usage Charge | - | - | - | - | - | 59,311 | 404,885 | 34,511 | 32,830 | 5,687 | 167,571 | 4,189 | 15,330 | - | - | **705,440** |
| Jan-2023 | DC Right of Way Tax | 532,451 | 1,638 | 3,431 | 5 | 10,160 | 54,487 | 346,535 | 18,068 | 27,301 | 5,890 | 151,222 | 3,490 | 14,071 | 308,512 | 8,711 | **1,314,509** |
| Jan-2023 | DC Right of Way Adjustment | 74,144 | 228 | 473 | 1 | 1,415 | 7,597 | 48,031 | 2,514 | 3,800 | 823 | 21,072 | 486 | 1,959 | 42,946 | 1,213 | **120,974** |
| Jan-2023 | SE Trust Fund | 671,340 | 2,101 | 4,383 | 7 | 12,998 | 69,870 | 444,711 | 23,175 | 35,018 | 7,548 | 193,925 | 4,476 | 18,048 | 395,720 | 11,174 | **1,809,058** |
| Jan-2023 | Delivery Tax | 1,069,344 | 3,290 | 6,880 | 11 | 20,405 | 120,351 | 766,006 | 39,921 | 60,317 | 11,819 | 303,666 | 7,009 | 28,261 | 673,622 | 18,883 | **2,979,617** |
| Jan-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 450 | 2,200 | **2,865** |
| Jan-2023 | Balancing Charge | - | - | - | - | - | 8,766 | - | - | - | - | - | - | - | 17,529 | 495 | **28,727** |
| Jan-2023 | STORAGE GAS CHRG | 141,221 | 466 | 935 | 2 | 2,688 | 7,599 | 47,073 | 1,834 | 3,077 | 1,106 | 18,763 | 799 | 1,546 | - | - | **117,812** |
| Jan-2023 | EA Trust Fund | 123,957 | 388 | 821 | 1 | 2,401 | 12,900 | 82,106 | 4,280 | 6,465 | 1,394 | 35,804 | 827 | 3,332 | 73,060 | 2,063 | **334,045** |
| Jan-2023 | PRA | (12) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(2)** |
| Jan-2023 | DC Tax Reform Credit | 53 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **26** |
| Jan-2023 | APRP | 653,392 | 1,888 | 4,235 | 6 | 12,508 | 43,404 | 252,431 | 14,722 | 21,411 | 4,134 | 126,010 | 2,895 | 11,682 | 88,948 | 2,524 | **1,248,607** |
| | **TOTAL** | **20,623,531** | **37,049** | **247,114** | **12** | **398,551** | **1,456,586** | **8,564,276** | **451,117** | **617,767** | **161,441** | **3,941,413** | **69,186** | **346,471** | **2,222,616** | **90,781** | **39,227,911** |
| Feb-2023 | Commodity Charge Int | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(170)** |
| Feb-2023 | PGA - Retroactive | (296,322) | (842) | (1,934) | (6) | (5,579) | (15,788) | (94,403) | (3,891) | (6,931) | (3,598) | (40,841) | (1,757) | (3,441) | - | - | **(20,838)** |
| Feb-2023 | PGC Rounding difference | (2) | 2 | (2) | (0) | 1 | (0) | (18) | (0) | 1 | 1 | 1 | 2 | 0 | - | - | **1** |
| Feb-2023 | ACA | 352,013 | 980 | 2,320 | 7 | 6,632 | 18,665 | 110,564 | 4,602 | 8,335 | 4,272 | 50,028 | 2,105 | 4,087 | - | - | **387,171** |
| Feb-2023 | DCA | (555,848) | (1,440) | (3,518) | (10) | (10,526) | (60,915) | (357,401) | (22,650) | (30,316) | (7,089) | (167,048) | (3,886) | (15,384) | - | - | **(1,285,942)** |
| Feb-2023 | GAC Current | 183,005 | 499 | 1,215 | 4 | 3,445 | 9,627 | 56,595 | 2,384 | 4,247 | 2,218 | 26,838 | 1,107 | 2,123 | - | - | **373,061** |
| Feb-2023 | Residential Essential Credit | 96,321 | 254 | 640 | 2 | 1,857 | 10,819 | 63,527 | 4,015 | 5,406 | 1,259 | 29,609 | 697 | 2,732 | 61,288 | 1,811 | **189,370** |
| Feb-2023 | RES Rider credit | (180,362) | - | (234) | - | (1,069) | - | - | - | - | - | - | - | - | - | - | **(197,233)** |
| Feb-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 316,459 | - | **130,605** |
| Feb-2023 | Delivery Charge | 5,899,098 | 15,178 | 33,701 | 94 | 110,982 | 530,239 | 3,341,200 | 115,037 | 282,249 | 66,475 | 1,589,648 | 36,739 | 144,743 | 1,014,921 | 41,657 | **15,707,753** |
| Feb-2023 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **2,157** |
| Feb-2023 | Purchased Gas Charge | 10,441,774 | 28,634 | 68,602 | 213 | 196,617 | 551,414 | 3,261,218 | 136,459 | 240,788 | 126,493 | 1,502,575 | 62,955 | 121,169 | - | - | **14,573,094** |
| Feb-2023 | System Charge | 2,053,836 | 1,495 | 122,014 | 22 | 43,532 | 124,243 | 204,766 | 33,142 | 15,334 | 15,100 | 103,936 | 13,738 | 8,616 | 10,780 | 1,320 | **2,674,174** |
| Feb-2023 | Peak Usage Charge | - | - | - | - | - | 60,982 | 388,555 | 34,698 | 32,013 | 5,694 | 177,931 | 4,231 | 15,309 | - | - | **656,157** |
| Feb-2023 | DC Right of Way Tax | 457,204 | 1,179 | 2,916 | 8 | 8,660 | 50,073 | 293,732 | 18,622 | 24,881 | 5,830 | 137,696 | 3,208 | 12,652 | 283,861 | 8,388 | **1,314,850** |
| Feb-2023 | DC Right of Way Adjustment | 63,615 | 166 | 397 | 1 | 1,205 | 6,984 | 41,050 | 2,593 | 3,468 | 812 | 18,947 | 444 | 1,761 | 39,515 | 1,168 | **120,417** |
| Feb-2023 | SE Trust Fund | 572,267 | 1,509 | 3,726 | 10 | 11,009 | 64,213 | 376,749 | 23,886 | 31,915 | 7,477 | 176,761 | 4,119 | 16,228 | 364,100 | 10,759 | **1,801,351** |
| Feb-2023 | Delivery Tax | 918,324 | 2,363 | 5,852 | 16 | 17,394 | 110,596 | 648,643 | 41,145 | 54,973 | 11,708 | 277,061 | 6,450 | 25,412 | 619,774 | 18,208 | **2,963,606** |
| Feb-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 225 | 2,200 | **12,125** |
| Feb-2023 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **24,096** |
| Feb-2023 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **672** |
| Feb-2023 | Balancing Charge | - | - | - | - | - | 8,758 | - | - | - | - | - | - | - | 16,129 | 477 | **(16,063)** |
| Feb-2023 | STORAGE GAS CHRG | 121,554 | 338 | 790 | 2 | 2,288 | 6,434 | 38,100 | 1,589 | 2,859 | 1,474 | 17,339 | 725 | 1,411 | - | - | **129,772** |
| Feb-2023 | EA Trust Fund | 105,712 | 279 | 701 | 2 | 2,034 | 11,855 | 69,526 | 4,411 | 5,892 | 1,381 | 32,667 | 761 | 2,996 | 67,223 | 1,986 | **333,161** |
| Feb-2023 | PRA | 5 | - | 0 | - | - | 3 | - | - | - | - | - | - | - | - | - | **(5)** |
| Feb-2023 | DC Tax Reform Credit | (62) | - | (1) | - | - | - | - | - | - | - | - | - | - | - | - | **72** |
| Feb-2023 | APRP | 563,408 | 1,327 | 3,603 | 10 | 10,678 | 39,483 | 232,075 | 14,725 | 19,511 | 4,804 | 115,647 | 2,679 | 10,531 | 82,255 | 2,431 | **2,379,251** |
| | **TOTAL** | **23,402,844** | **62,359** | **246,156** | **12** | **449,169** | **616,447** | **9,438,555** | **394,337** | **703,913** | **242,103** | **3,825,962** | **123,181** | **323,796** | **2,298,815** | **125,019** | **42,252,668** |
| Mar-2023 | PGA - Retroactive | (229,222) | (259) | (1,863) | (8) | (4,300) | (12,313) | (78,462) | (3,329) | (5,557) | (2,263) | (35,090) | (1,608) | (3,001) | - | - | **(14,622)** |
| Mar-2023 | PGC Rounding difference | 42 | (5) | 13 | 0 | (0) | 6 | 0 | (0) | (0) | 2 | 9 | 0 | (0) | - | - | **(67)** |
| Mar-2023 | ACA | 252,042 | (300) | 2,048 | 9 | 4,729 | 13,735 | 87,315 | 3,654 | 6,189 | 2,441 | 38,431 | 1,768 | 3,300 | - | - | **292,343** |
| Mar-2023 | DCA | (432,563) | 2,035 | (3,346) | (13) | (8,136) | (51,270) | (317,460) | (14,583) | (26,192) | (4,900) | (143,370) | (3,528) | (13,816) | - | - | **(1,115,782)** |
| Mar-2023 | GAC Current | 141,261 | (901) | 1,152 | 5 | 2,652 | 7,515 | 49,428 | 2,043 | 3,431 | 1,393 | 21,714 | 992 | 1,851 | - | - | **262,347** |
| Mar-2023 | Residential Essential Credit | 74,332 | (262) | 602 | 2 | 1,431 | 9,260 | 56,321 | 2,590 | 4,660 | 881 | 25,430 | 627 | 2,453 | 54,333 | 1,557 | **201,555** |
| Mar-2023 | RES Rider credit | (190,431) | - | (335) | - | (1,022) | - | - | - | - | - | - | - | - | - | - | **(183,958)** |
| Mar-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 127,264 | - | **115,038** |
| Mar-2023 | Delivery Charge | 4,588,798 | (21,037) | 31,954 | 123 | 85,739 | 443,488 | 2,971,011 | 91,863 | 244,042 | 46,082 | 1,361,176 | 33,203 | 129,994 | 890,640 | 35,801 | **13,487,321** |
| Mar-2023 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Mar-2023 | Purchased Gas Charge | 4,172,434 | (36,848) | 34,102 | 143 | 78,083 | 208,502 | 1,503,977 | 59,597 | 97,277 | 38,998 | 650,345 | 29,891 | 54,578 | - | - | **11,228,110** |
| Mar-2023 | System Charge | 2,042,130 | 464 | 120,544 | 22 | 42,927 | 116,712 | 213,090 | 31,661 | 14,806 | 16,082 | 101,706 | 13,369 | 8,772 | 10,780 | 1,320 | **2,777,926** |
| Mar-2023 | Peak Usage Charge | - | - | - | - | - | 59,236 | 413,656 | 34,354 | 32,447 | 5,126 | 174,470 | 4,285 | 15,416 | - | - | **834,386** |
| Mar-2023 | DC Right of Way Tax | 355,627 | (1,777) | 2,767 | 11 | 6,691 | 42,221 | 261,080 | 11,992 | 21,513 | 4,041 | 118,009 | 2,902 | 11,363 | 251,645 | 7,210 | **1,343,637** |
| Mar-2023 | DC Right of Way Adjustment | 49,524 | (69) | 379 | 1 | 932 | 5,878 | 36,175 | 1,672 | 2,995 | 563 | 16,417 | 404 | 1,582 | 35,030 | 1,004 | **123,645** |
| Mar-2023 | SE Trust Fund | 442,010 | (1,604) | 3,527 | 14 | 8,492 | 54,368 | 334,183 | 15,388 | 27,595 | 5,183 | 151,366 | 3,722 | 14,575 | 322,778 | 9,248 | **1,846,688** |
| Mar-2023 | Delivery Tax | 714,211 | (3,937) | 5,544 | 21 | 13,438 | 93,264 | 577,192 | 26,491 | 47,531 | 8,117 | 237,023 | 5,829 | 22,822 | 549,766 | 15,646 | **3,080,675** |
| Mar-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,200 | 2,200 | **7,125** |
| Mar-2023 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Mar-2023 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Mar-2023 | Balancing Charge | - | - | - | - | - | 7,289 | - | - | - | - | - | - | - | 14,298 | 410 | **73,304** |
| Mar-2023 | STORAGE GAS CHRG | 123,729 | (265) | 990 | 4 | 2,323 | 6,721 | 42,523 | 1,798 | 3,041 | 1,226 | 18,874 | 862 | 1,621 | - | - | **114,798** |
| Mar-2023 | EA Trust Fund | 81,670 | (445) | 663 | 3 | 1,570 | 10,004 | 61,848 | 2,840 | 5,095 | 957 | 27,946 | 687 | 2,691 | 59,593 | 1,707 | **341,011** |
| Mar-2023 | PRA | 4 | (23) | - | - | - | (10) | 23 | 0 | - | - | - | - | - | - | - | **(1)** |
| Mar-2023 | DC Tax Reform Credit | (4) | 367 | - | - | - | 94 | (279) | 2 | - | - | - | - | - | - | - | **(3)** |
| Mar-2023 | APRP | 438,779 | (2,180) | 3,387 | 13 | 8,251 | 33,253 | 206,513 | 9,477 | 17,316 | 3,228 | 98,030 | 2,398 | 9,458 | 72,920 | 2,089 | **2,024,540** |
| | **TOTAL** | **16,817,541** | **50,455** | **259,430** | **12** | **328,586** | **2,637,715** | **7,883,110** | **390,361** | **657,606** | **197,329** | **3,614,530** | **95,766** | **323,700** | **3,488,070** | **95,805** | **36,840,016** |
| Apr-2023 | PGA - Retroactive | (174,054) | 1,067 | (1,455) | (0) | (3,288) | (10,580) | (68,263) | (3,128) | (6,645) | (2,130) | (32,032) | (1,537) | (3,101) | - | - | **(11,441)** |
| Apr-2023 | PGC Rounding difference | 32 | (19) | (3) | - | 0 | 8 | 0 | (0) | 4 | 0 | 18 | (0) | 3 | - | - | **(73)** |
| Apr-2023 | ACA | 190,966 | (3,348) | 1,603 | 0 | 3,616 | 11,597 | 75,263 | 3,438 | 7,408 | 2,342 | 37,382 | 1,690 | 3,525 | - | - | **230,121** |
| Apr-2023 | DCA | (329,498) | 4,933 | (2,659) | (0) | (6,277) | (50,353) | (250,841) | (16,168) | (28,186) | (4,118) | (127,073) | (3,394) | (12,325) | - | - | **(818,102)** |
| Apr-2023 | GAC Current | 106,837 | (2,309) | 913 | 0 | 2,027 | 6,513 | 42,483 | 1,929 | 4,248 | 1,314 | 21,421 | 948 | 1,997 | - | - | **205,621** |
| Apr-2023 | Residential Essential Credit | 56,008 | (1,185) | 477 | 0 | 1,101 | 8,947 | 44,314 | 2,870 | 5,041 | 732 | 22,835 | 603 | 2,218 | 56,683 | 1,590 | **139,343** |
| Apr-2023 | RES Rider credit | (210,882) | - | (451) | - | (1,071) | - | - | - | - | - | - | - | - | - | - | **(180,154)** |
| Apr-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 132,915 | - | **119,338** |
| Apr-2023 | Delivery Charge | 3,492,885 | (60,867) | 25,413 | 0 | 66,151 | 428,393 | 2,348,285 | 87,723 | 264,303 | 38,625 | 1,213,881 | 31,937 | 116,491 | 906,051 | 36,542 | **10,044,060** |
| Apr-2023 | Purchased Gas Charge | 3,887,275 | (100,798) | 32,497 | 1 | 74,146 | 241,861 | 1,558,412 | 70,183 | 160,949 | 47,978 | 799,192 | 34,646 | 74,031 | - | - | **10,723,943** |
| Apr-2023 | System Charge | 2,045,651 | 614 | 124,835 | 22 | 43,332 | 122,664 | 199,995 | 33,071 | 16,939 | 14,798 | 106,045 | 13,483 | 9,230 | 10,560 | 1,320 | **2,764,807** |
| Apr-2023 | Peak Usage Charge | - | - | - | - | - | 58,482 | 373,453 | 34,405 | 32,925 | 4,699 | 176,513 | 4,241 | 14,781 | - | - | **745,910** |
| Apr-2023 | DC Right of Way Tax | 340,614 | (4,604) | 2,765 | 0 | 6,481 | 52,079 | 257,146 | 16,703 | 28,880 | 4,249 | 130,021 | 3,504 | 12,649 | 329,657 | 9,244 | **1,033,460** |
| Apr-2023 | DC Right of Way Adjustment | 37,765 | (452) | 298 | - | 719 | 5,769 | 28,689 | 1,851 | 3,223 | 471 | 14,433 | 389 | 1,406 | 36,546 | 1,025 | **88,244** |
| Apr-2023 | SE Trust Fund | 332,039 | (6,469) | 2,785 | 0 | 6,533 | 53,109 | 264,609 | 17,054 | 29,904 | 4,345 | 135,269 | 3,580 | 13,070 | 336,742 | 9,443 | **1,315,244** |
| Apr-2023 | Delivery Tax | 543,669 | (10,129) | 4,412 | 0 | 10,368 | 91,481 | 455,766 | 29,376 | 51,510 | 6,803 | 211,816 | 5,607 | 20,466 | 573,902 | 15,980 | **2,186,608** |
| Apr-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 4,400 | 2,200 | **2,425** |
| Apr-2023 | Balancing Charge | - | - | - | - | - | 8,078 | - | - | - | - | - | - | - | 14,917 | 418 | **23,151** |
| Apr-2023 | STORAGE GAS CHRG | 93,968 | (953) | 786 | 0 | 1,775 | 5,674 | 36,874 | 1,693 | 3,552 | 1,150 | 17,688 | 830 | 1,691 | - | - | **90,623** |
| Apr-2023 | EA Trust Fund | 61,365 | (1,194) | 528 | 0 | 1,208 | 9,807 | 48,852 | 3,149 | 5,521 | 802 | 24,974 | 661 | 2,413 | 62,172 | 1,743 | **242,904** |
| Apr-2023 | DC Tax Reform Credit | - | - | (8) | - | - | - | - | - | - | - | - | - | - | - | - | **6** |
| Apr-2023 | APRP | 333,831 | (7,513) | 2,682 | 0 | 6,362 | 32,228 | 163,988 | 10,501 | 18,141 | 2,821 | 88,069 | 2,321 | 8,474 | 76,075 | 2,133 | **1,517,403** |
| | **TOTAL** | **14,590,418** | **6,906** | **236,521** | **12** | **286,192** | **1,511,485** | **6,316,277** | **336,901** | **584,687** | **171,380** | **3,459,329** | **98,797** | **293,465** | **2,484,325** | **86,743** | **30,463,440** |
| May-2023 | PGA - Retroactive | (74,979) | (288) | (960) | (13) | (1,562) | (5,001) | (44,360) | (2,128) | (3,689) | (1,481) | (13,994) | (1,091) | (2,098) | - | - | **(6,388)** |
| May-2023 | PGC Rounding difference | (42) | (0) | (5) | 0 | (1) | (0) | 69 | (0) | (0) | (0) | (0) | (0) | 0 | - | - | **(83)** |
| May-2023 | ACA | 82,478 | 316 | 1,054 | 15 | 1,719 | 5,634 | 49,080 | 2,331 | 4,055 | 1,630 | 15,385 | 1,200 | 2,307 | - | - | **128,695** |
| May-2023 | DCA | (143,147) | (514) | (1,758) | (22) | (2,998) | (40,386) | (160,413) | (11,647) | (18,042) | (7,216) | (59,704) | (2,433) | (9,368) | - | - | **(444,174)** |
| May-2023 | GAC Current | 46,311 | 177 | 598 | 8 | 964 | 3,098 | 27,341 | 1,307 | 2,276 | 905 | 8,632 | 676 | 1,294 | - | - | **114,845** |
| May-2023 | Residential Essential Credit | 24,285 | 91 | 320 | 4 | 526 | 7,213 | 28,473 | 2,068 | 3,204 | 1,354 | 10,514 | 431 | 1,663 | 36,863 | 1,058 | **83,756** |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| May-2023 | RES Rider credit | (3,413) | - | (11) | - | - | - | - | - | - | - | - | - | - | - | - | (3,113) |
| May-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 86,433 | - | 107,948 |
| May-2023 | Delivery Charge | 1,518,453 | 5,456 | 16,807 | 206 | 31,592 | (123,772) | 1,501,616 | 66,333 | 168,320 | 68,301 | 565,679 | 22,887 | 88,144 | 1,315,866 | 24,264 | 5,656,106 |
| May-2023 | Purchased Gas Charge | 1,691,376 | 6,482 | 21,378 | 298 | 35,248 | 107,192 | 1,043,180 | 48,011 | 82,984 | 31,848 | 315,090 | 24,694 | 47,350 | - | - | 6,725,840 |
| May-2023 | System Charge | 2,005,621 | 1,484 | 120,947 | 22 | 42,579 | 122,772 | 204,849 | 32,923 | 15,646 | 15,037 | 101,455 | 14,798 | 8,823 | 10,890 | 1,320 | 2,775,620 |
| May-2023 | Peak Usage Charge | - | - | - | - | - | 2,359 | 21,287 | 23,927 | 775 | 3,327 | 2,460 | 143 | 1,147 | - | - | 31,799 |
| May-2023 | DC Right of Way Tax | 147,747 | 531 | 1,817 | 22 | 3,094 | 41,421 | 163,681 | 12,025 | 18,635 | 6,816 | 61,760 | 2,510 | 9,679 | 214,386 | 6,155 | 629,200 |
| May-2023 | DC Right of Way Adjustment | 16,457 | 59 | 197 | 2 | 346 | 4,622 | 18,361 | 1,334 | 2,066 | 835 | 6,827 | 278 | 1,073 | 23,767 | 682 | 53,490 |
| May-2023 | SE Trust Fund | 144,188 | 539 | 1,858 | 23 | 3,124 | 42,570 | 169,240 | 12,285 | 19,032 | 7,682 | 62,907 | 2,563 | 9,882 | 218,994 | 6,287 | 797,204 |
| May-2023 | Delivery Tax | 236,434 | 849 | 2,916 | 36 | 4,953 | 73,329 | 291,514 | 21,163 | 32,783 | 12,030 | 98,506 | 4,019 | 15,475 | 374,575 | 10,674 | 1,336,344 |
| May-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 9,925 | 2,425 | 12,425 |
| May-2023 | Balancing Charge | - | - | - | - | - | 7,780 | - | - | - | - | - | - | - | 9,701 | 278 | 19,508 |
| May-2023 | STORAGE GAS CHRG | 40,489 | 155 | 508 | 7 | 842 | 2,783 | 23,358 | 1,145 | 1,994 | 805 | 7,564 | 591 | 1,133 | - | - | 50,636 |
| May-2023 | EA Trust Fund | 26,715 | 99 | 350 | 4 | 579 | 7,861 | 31,246 | 2,269 | 3,514 | 1,419 | 11,614 | 474 | 1,825 | 40,432 | 1,161 | 147,072 |
| May-2023 | PRA | (3) | - | - | - | - | - | - | - | - | - | - | (0) | - | - | - | (299) |
| May-2023 | DC Tax Reform Credit | (36) | - | - | - | - | - | - | - | - | - | - | (1) | - | - | - | (164) |
| May-2023 | APRP | 144,986 | 521 | 1,827 | 22 | 3,037 | 25,403 | 100,329 | 7,546 | 11,719 | 4,026 | 41,209 | 1,664 | 6,413 | 49,474 | 1,420 | 852,012 |
| | **TOTAL** | **9,053,916** | **21,899** | **185,466** | **29** | **181,889** | **868,625** | **4,182,570** | **246,143** | **464,607** | **143,055** | **1,368,431** | **75,771** | **236,537** | **1,975,358** | **63,984** | **19,068,280** |
| Jun-2023 | PGA - Retroactive | (3,703) | (12) | 75 | (0) | (81) | (621) | (1,793) | (125) | (285) | (67) | (6,426) | (66) | (30) | - | - | (13,133) |
| Jun-2023 | PGC Rounding difference | (123) | - | (32) | (0) | (4) | (2) | (27) | (1) | (0) | 0 | 69 | (0) | (3) | - | - | (124) |
| Jun-2023 | ACA | 56,102 | 224 | 759 | 7 | 1,192 | 5,087 | 28,703 | 1,948 | 4,312 | 1,326 | 17,689 | 1,062 | 1,966 | - | - | 120,377 |
| Jun-2023 | DCA | (96,103) | (391) | (1,269) | (11) | (2,313) | (8,914) | (115,497) | (9,978) | (17,941) | (2,550) | (49,899) | (2,252) | (7,792) | - | - | (314,907) |
| Jun-2023 | GAC Current | 31,476 | 126 | 421 | 4 | 670 | 2,862 | 16,295 | 1,077 | 2,419 | 744 | 9,773 | 596 | 1,083 | - | - | 67,546 |
| Jun-2023 | Residential Essential Credit | 16,155 | 69 | 200 | 2 | 407 | 1,580 | 20,657 | 1,774 | 3,186 | 455 | 8,914 | 400 | 1,354 | 30,355 | 984 | 86,492 |
| Jun-2023 | RES Rider credit | (1,383) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,383) |
| Jun-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 83,404 | - | 83,404 |
| Jun-2023 | Delivery Charge | 1,019,028 | 4,151 | 11,626 | 103 | 24,382 | 86,268 | 1,081,665 | 50,348 | 167,380 | 23,939 | 473,873 | 21,189 | 72,785 | 525,740 | 22,584 | 3,585,060 |
| Jun-2023 | Purchased Gas Charge | 1,079,717 | 4,312 | 11,945 | 140 | 22,981 | 101,950 | 558,883 | 37,173 | 83,145 | 26,544 | 392,165 | 20,473 | 35,857 | - | - | 2,375,284 |
| Jun-2023 | System Charge | 2,051,274 | 1,483 | 122,615 | 22 | 43,535 | 122,986 | 207,763 | 31,195 | 15,625 | 15,588 | 99,913 | 13,461 | 7,690 | 10,450 | 1,320 | 2,744,922 |
| Jun-2023 | Peak Usage Charge | - | - | - | - | - | 621 | (791) | 23,690 | (230) | 217 | 12,546 | - | (310) | - | - | 35,742 |
| Jun-2023 | DC Right of Way Tax | 99,322 | 404 | 1,313 | 11 | 2,388 | 9,091 | 120,622 | 10,310 | 18,552 | 2,598 | 49,698 | 2,326 | 8,074 | 176,540 | 5,721 | 506,969 |
| Jun-2023 | DC Right of Way Adjustment | 6,235 | 25 | 63 | 1 | 151 | 610 | 7,616 | 654 | 1,170 | 177 | 3,744 | 147 | 498 | 11,184 | 362 | 32,638 |
| Jun-2023 | SE Trust Fund | 96,092 | 411 | 1,272 | 11 | 2,421 | 9,423 | 121,865 | 10,539 | 18,926 | 2,693 | 52,698 | 2,376 | 8,151 | 180,334 | 5,844 | 513,057 |
| Jun-2023 | Delivery Tax | 158,653 | 646 | 2,018 | 18 | 3,824 | 16,226 | 209,903 | 18,118 | 32,600 | 4,217 | 82,519 | 3,720 | 12,764 | 309,014 | 9,955 | 864,195 |
| Jun-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 13,250 | 2,425 | 15,675 |
| Jun-2023 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 7,988 | 259 | 8,247 |
| Jun-2023 | STORAGE GAS CHRG | 30,158 | 120 | 460 | 4 | 640 | 2,673 | 15,653 | 1,040 | 2,313 | 699 | 8,449 | 570 | 1,107 | - | - | 63,885 |
| Jun-2023 | EA Trust Fund | 17,750 | 76 | 243 | 2 | 447 | 1,740 | 22,499 | 1,943 | 3,494 | 497 | 9,730 | 439 | 1,505 | 33,295 | 1,079 | 94,738 |
| Jun-2023 | PRA | 2 | - | 0 | - | - | - | (0) | (0) | - | - | - | - | - | - | - | 2 |
| Jun-2023 | DC Tax Reform Credit | 16 | - | (22) | - | - | - | - | 6 | - | - | - | - | - | - | - | (0) |
| Jun-2023 | APRP | 80,425 | 326 | 973 | 9 | 1,932 | 4,620 | 61,339 | 5,247 | 9,423 | 1,457 | 27,102 | 1,299 | 4,424 | 39,542 | 1,281 | 239,397 |
| | **TOTAL** | **4,641,095** | **11,968** | **152,660** | **323** | **102,573** | **356,201** | **2,355,356** | **184,958** | **344,088** | **78,533** | **1,192,557** | **65,741** | **149,125** | **1,421,094** | **51,813** | **11,108,084** |
| Jul-2023 | PGA - Retroactive | (3,521) | 175 | 42 | (0) | (52) | 477 | 2,561 | (143) | (228) | (339) | (264) | (54) | (105) | - | - | (1,452) |
| Jul-2023 | PGC Rounding difference | (154) | (2) | (29) | (0) | (4) | (7) | 4 | (0) | (0) | (0) | (1) | (0) | - | - | - | (193) |
| Jul-2023 | ACA | 41,305 | (75) | 970 | 7 | 833 | 2,953 | 20,552 | 1,985 | 3,572 | 1,514 | 7,681 | 810 | 1,678 | - | - | 83,784 |
| Jul-2023 | DCA | (71,402) | 53 | (1,646) | (10) | (1,462) | (63,737) | (92,395) | (8,345) | (15,016) | (2,612) | (34,722) | (1,725) | (6,964) | - | - | (299,984) |
| Jul-2023 | GAC Current | 23,513 | (39) | 548 | 4 | 468 | 1,490 | 11,559 | 1,114 | 2,004 | 849 | 4,308 | 454 | 941 | - | - | 47,213 |
| Jul-2023 | Residential Essential Credit | 11,959 | (12) | 299 | 2 | 257 | 11,326 | 16,436 | 1,482 | 2,666 | 464 | 6,166 | 306 | 1,237 | 26,613 | 772 | 79,972 |
| Jul-2023 | RES Rider credit | (1,123) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,123) |
| Jul-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 68,275 | - | 68,275 |
| Jul-2023 | Delivery Charge | 760,672 | (594) | 15,724 | 94 | 15,414 | 371,453 | 865,296 | 47,452 | 140,094 | 24,499 | 329,378 | 16,235 | 65,518 | 491,034 | 17,557 | 3,159,826 |
| Jul-2023 | Purchased Gas Charge | 830,855 | (2,984) | 18,544 | 127 | 16,064 | 39,980 | 408,404 | 38,549 | 68,865 | 29,553 | 146,593 | 15,635 | 32,345 | - | - | 1,642,531 |
| Jul-2023 | System Charge | 2,044,055 | 1,284 | 120,457 | 22 | 43,539 | 120,472 | 210,577 | 33,045 | 15,721 | 16,024 | 102,481 | 13,484 | 8,780 | 10,670 | 1,320 | 2,741,930 |
| Jul-2023 | Peak Usage Charge | - | - | - | - | - | (2,403) | (8,127) | 23,785 | - | 154 | 88 | (15) | - | - | - | 13,483 |
| Jul-2023 | DC Right of Way Tax | 73,417 | (2) | 1,698 | 10 | 1,509 | 66,058 | 95,749 | 8,605 | 15,507 | 2,698 | 35,970 | 1,781 | 7,191 | 154,776 | 4,488 | 469,456 |
| Jul-2023 | DC Right of Way Adjustment | 4,744 | (18) | 99 | 1 | 95 | 4,125 | 5,784 | 547 | 983 | 192 | 2,223 | 113 | 456 | 9,805 | 284 | 29,432 |
| Jul-2023 | SE Trust Fund | 71,896 | (60) | 1,745 | 10 | 1,532 | 67,045 | 97,561 | 8,805 | 15,841 | 2,756 | 36,629 | 1,821 | 7,346 | 158,102 | 4,585 | 475,613 |
| Jul-2023 | Delivery Tax | 118,538 | (92) | 2,725 | 16 | 2,417 | 115,479 | 168,045 | 15,165 | 27,285 | 4,316 | 57,357 | 2,851 | 11,503 | 271,241 | 7,806 | 804,652 |
| Jul-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 21,100 | 2,650 | 23,750 |
| Jul-2023 | Balancing Charge | - | - | - | - | - | 15,697 | - | - | - | - | - | - | - | 7,003 | 203 | 22,904 |
| Jul-2023 | STORAGE GAS CHRG | 22,029 | (10) | 535 | 4 | 447 | 1,820 | 11,176 | 1,060 | 1,916 | 800 | 4,148 | 434 | 900 | - | - | 45,258 |
| Jul-2023 | EA Trust Fund | 13,293 | (11) | 328 | 2 | 283 | 12,379 | 18,013 | 1,626 | 2,925 | 509 | 6,763 | 336 | 1,356 | 29,190 | 846 | 87,837 |
| Jul-2023 | PRA | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Jul-2023 | DC Tax Reform Credit | (20) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) |
| Jul-2023 | APRP | 60,585 | 4 | 1,351 | 8 | 1,218 | 32,854 | 46,582 | 4,372 | 7,895 | 1,554 | 19,919 | 995 | 4,019 | 34,667 | 1,005 | 217,027 |
| | **TOTAL** | **4,000,640** | **(2,382)** | **163,388** | **296** | **82,560** | **797,460** | **1,877,776** | **179,103** | **290,030** | **82,931** | **724,716** | **53,459** | **136,201** | **1,282,476** | **41,517** | **9,710,171** |
| Aug-2023 | PGA - Retroactive | (1,613) | (12) | (136) | (0) | (30) | (355) | (6,789) | (108) | (198) | 281 | (3,483) | (40) | (85) | - | - | (12,568) |
| Aug-2023 | PGC Rounding difference | (257) | 0 | (28) | (0) | (7) | (3) | 20 | (1) | (0) | (2) | 5 | (0) | - | - | - | (275) |
| Aug-2023 | ACA | 32,751 | 192 | 840 | 6 | 678 | 3,344 | 31,037 | 1,723 | 3,152 | 186 | 10,363 | 643 | 1,351 | - | - | 86,265 |
| Aug-2023 | DCA | (56,590) | (319) | (1,370) | (9) | (1,195) | (34,877) | (102,126) | (6,172) | (13,029) | (823) | (28,349) | (1,379) | (5,621) | - | - | (251,861) |
| Aug-2023 | GAC Current | 18,374 | 108 | 485 | 3 | 381 | 1,860 | 17,627 | 966 | 1,768 | 90 | 5,871 | 361 | 758 | - | - | 48,652 |
| Aug-2023 | Residential Essential Credit | 9,480 | 56 | 249 | 2 | 209 | 6,169 | 18,308 | 1,096 | 2,313 | 129 | 5,123 | 245 | 998 | 25,538 | 620 | 70,536 |
| Aug-2023 | RES Rider credit | (302) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (302) |
| Aug-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 169,459 | - | 169,459 |
| Aug-2023 | Delivery Charge | 599,066 | 3,388 | 13,179 | 87 | 12,587 | 212,706 | 959,878 | 40,325 | 121,554 | 7,401 | 271,866 | 12,976 | 52,885 | 443,336 | 14,054 | 2,765,287 |
| Aug-2023 | Purchased Gas Charge | 626,147 | 3,711 | 17,538 | 119 | 12,911 | 65,784 | 615,170 | 33,206 | 60,764 | 790 | 228,446 | 12,393 | 26,042 | - | - | 1,703,020 |
| Aug-2023 | System Charge | 2,032,984 | 1,493 | 120,958 | 22 | 43,386 | 122,496 | 214,827 | 33,225 | 15,670 | 14,693 | 103,117 | 13,280 | 8,841 | 10,560 | 1,320 | 2,736,871 |
| Aug-2023 | Peak Usage Charge | - | - | - | - | - | (11,316) | 10,278 | 23,718 | - | (619) | 4,494 | - | - | - | - | 26,554 |
| Aug-2023 | DC Right of Way Tax | 58,375 | 330 | 1,392 | 9 | 1,237 | 36,010 | 104,526 | 6,374 | 13,455 | 924 | 28,332 | 1,424 | 5,805 | 148,522 | 3,604 | 410,319 |
| Aug-2023 | DC Right of Way Adjustment | 3,640 | 21 | 94 | 1 | 76 | 2,281 | 7,118 | 404 | 850 | 27 | 2,207 | 90 | 368 | 9,409 | 228 | 26,812 |
| Aug-2023 | SE Trust Fund | 56,451 | 335 | 1,461 | 10 | 1,249 | 36,757 | 108,237 | 6,512 | 13,745 | 823 | 30,236 | 1,455 | 5,929 | 151,715 | 3,681 | 418,597 |
| Aug-2023 | Delivery Tax | 93,326 | 527 | 2,283 | 15 | 1,974 | 63,245 | 186,435 | 11,215 | 23,675 | 1,288 | 47,344 | 2,278 | 9,285 | 260,390 | 6,267 | 709,548 |
| Aug-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 25,725 | 2,650 | 28,375 |
| Aug-2023 | Balancing Charge | - | - | - | - | - | 7,993 | - | - | - | - | - | - | - | 6,720 | 163 | 14,876 |
| Aug-2023 | STORAGE GAS CHRG | 17,703 | 103 | 451 | 3 | 367 | 1,736 | 16,081 | 924 | 1,691 | 161 | 5,169 | 345 | 725 | - | - | 45,460 |
| Aug-2023 | EA Trust Fund | 10,447 | 62 | 276 | 2 | 231 | 6,781 | 19,984 | 1,202 | 2,538 | 152 | 5,583 | 269 | 1,095 | 28,011 | 680 | 77,310 |
| Aug-2023 | PRA | (0) | - | - | - | - | (2) | - | - | - | - | - | - | - | - | - | (2) |
| Aug-2023 | DC Tax Reform Credit | (24) | - | - | - | - | 12 | - | - | - | - | - | - | - | - | - | (12) |
| Aug-2023 | APRP | 46,691 | 266 | 1,119 | 8 | 992 | 18,258 | 55,412 | 3,244 | 6,844 | 475 | 15,436 | 796 | 3,244 | 33,266 | 807 | 186,858 |
| | **TOTAL** | **3,546,648** | **10,262** | **158,789** | **277** | **75,046** | **538,878** | **2,256,023** | **157,853** | **254,794** | **25,975** | **731,759** | **45,135** | **111,618** | **1,312,651** | **34,073** | **9,259,780** |
| Sep-2023 | PGA - Retroactive | (2,453) | 17 | (35) | (1) | (52) | 103 | 125 | (89) | (236) | (50) | (396) | (57) | (102) | - | - | (3,226) |
| Sep-2023 | PGC Rounding difference | (212) | (0) | (36) | (0) | (6) | (4) | (0) | (0) | (0) | (0) | 1 | (1) | 0 | - | - | (260) |
| Sep-2023 | ACA | 40,428 | 81 | 562 | 8 | 852 | 2,029 | 23,631 | 1,420 | 3,755 | 621 | 6,623 | 882 | 1,630 | - | - | 82,524 |
| Sep-2023 | DCA | (68,669) | (161) | (968) | (13) | (1,491) | (33,137) | (86,489) | (8,555) | (16,342) | (944) | (28,582) | (1,841) | (6,801) | - | - | (253,992) |
| Sep-2023 | GAC Current | 22,690 | 46 | 320 | 5 | 478 | 1,135 | 13,304 | 796 | 2,107 | 349 | 3,734 | 495 | 914 | - | - | 46,373 |
| Sep-2023 | Residential Essential Credit | 11,530 | 28 | 180 | 2 | 262 | 5,883 | 15,358 | 1,519 | 2,902 | 168 | 5,073 | 327 | 1,208 | 28,299 | 628 | 73,366 |
| Sep-2023 | RES Rider credit | (749) | - | (67) | - | - | - | - | - | - | - | - | - | - | - | - | (816) |
| Sep-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | (41,256) | - | (41,256) |
| Sep-2023 | Delivery Charge | 728,709 | 1,706 | 9,256 | 120 | 15,725 | 196,691 | 809,530 | 42,630 | 152,460 | 8,856 | 271,103 | 17,322 | 63,987 | 500,853 | 14,278 | 2,833,225 |
| Sep-2023 | Purchased Gas Charge | 735,072 | 1,411 | 9,826 | 154 | 15,500 | 36,058 | 417,244 | 25,590 | 68,408 | 11,461 | 122,044 | 16,082 | 29,677 | - | - | 1,488,527 |
| Sep-2023 | System Charge | 2,046,567 | 1,320 | 121,712 | 22 | 43,697 | 122,694 | 204,169 | 32,795 | 15,651 | 15,839 | 101,154 | 13,975 | 8,521 | 10,340 | 1,320 | 2,739,777 |
| Sep-2023 | Peak Usage Charge | - | - | - | - | - | (465) | (2,506) | 23,718 | - | 57 | (101) | (6) | - | - | - | 20,698 |
| Sep-2023 | DC Right of Way Tax | 70,917 | 169 | 992 | 13 | 1,540 | 34,292 | 89,811 | 8,834 | 16,876 | 974 | 29,523 | 1,901 | 7,023 | 164,580 | 3,655 | 431,101 |
| Sep-2023 | DC Right of Way Adjustment | 4,460 | 9 | 60 | 1 | 97 | 2,147 | 5,467 | 559 | 1,069 | 51 | 1,861 | 121 | 445 | 10,426 | 232 | 27,004 |
| Sep-2023 | SE Trust Fund | 68,622 | 168 | 1,025 | 13 | 1,556 | 34,954 | 91,239 | 9,025 | 17,239 | 997 | 30,148 | 1,942 | 7,174 | 168,118 | 3,733 | 435,955 |
| Sep-2023 | Delivery Tax | 113,491 | 266 | 1,602 | 21 | 2,465 | 60,204 | 157,155 | 15,545 | 29,694 | 1,560 | 47,210 | 3,042 | 11,234 | 288,661 | 6,353 | 738,501 |
| Sep-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 23,300 | 2,650 | 25,950 |
| Sep-2023 | Balancing Charge | - | - | - | - | - | 7,962 | - | - | - | - | - | - | - | 7,447 | 165 | 15,574 |
| Sep-2023 | STORAGE GAS CHRG | 22,868 | 49 | 328 | 5 | 482 | 1,173 | 13,641 | 808 | 2,119 | 348 | 3,749 | 498 | 920 | - | - | 46,987 |
| Sep-2023 | EA Trust Fund | 12,698 | 31 | 195 | 2 | 288 | 6,454 | 16,845 | 1,666 | 3,183 | 184 | 5,566 | 359 | 1,325 | 31,039 | 689 | 80,524 |
| Sep-2023 | PRA | 0 | - | - | - | - | - | - | - | - | - | - | 1 | - | - | - | 2 |
| Sep-2023 | DC Tax Reform Credit | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Sep-2023 | APRP | 57,262 | 127 | 819 | 11 | 1,244 | 17,435 | 45,216 | 4,497 | 8,591 | 517 | 16,475 | 1,062 | 3,925 | 36,863 | 819 | 194,862 |
| | **TOTAL** | **3,863,231** | **5,266** | **145,770** | **364** | **82,635** | **495,608** | **1,813,740** | **160,759** | **307,478** | **40,987** | **615,186** | **56,104** | **131,079** | **1,228,670** | **34,522** | **8,981,399** |
| Oct-2023 | PGA - Retroactive | (3,831) | 1,475 | 185 | (0) | (72) | (27) | (4,076) | (356) | (220) | (116) | (338) | (56) | (98) | - | - | (7,530) |
| Oct-2023 | PGC Rounding difference | (205) | (7) | (31) | (0) | (6) | (4) | 9 | 1 | (1) | (0) | 0 | (1) | 0 | - | - | (246) |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oct-2023 | ACA | 54,636 | (2,176) | 530 | 8 | 1,162 | 2,804 | 32,909 | 2,598 | 3,501 | 1,843 | 7,761 | 806 | 1,564 | - | - | **107,945** |
| Oct-2023 | DCA | (91,192) | 4,492 | (958) | (11) | (2,036) | (34,023) | (136,623) | (10,261) | (17,092) | 4,175 | (34,736) | (1,811) | (7,299) | - | - | **(327,375)** |
| Oct-2023 | GAC Current | 30,660 | (1,236) | 297 | 4 | 652 | 1,570 | 18,694 | 1,438 | 1,972 | 1,034 | 4,354 | 478 | 877 | - | - | **60,795** |
| Oct-2023 | Residential Essential Credit | 15,437 | (837) | 174 | 2 | 358 | 6,044 | 24,426 | 1,829 | 3,035 | (860) | 6,164 | 318 | 1,296 | 27,687 | 866 | **85,939** |
| Oct-2023 | RES Rider credit | (51) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(51)** |
| Oct-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | (393,410) | 4,385 | **(389,025)** |
| Oct-2023 | Delivery Charge | 967,339 | (48,250) | 9,077 | 108 | 21,460 | 209,423 | 1,283,829 | 60,412 | 159,555 | (40,372) | 329,331 | 17,048 | 68,679 | 482,697 | 19,537 | **3,539,872** |
| Oct-2023 | Purchased Gas Charge | 994,697 | (51,653) | 7,064 | 138 | 21,127 | 49,173 | 633,538 | 48,976 | 64,421 | 33,550 | 140,780 | 15,634 | 28,482 | - | - | **1,985,926** |
| Oct-2023 | System Charge | 2,031,592 | 144 | 120,230 | 22 | 43,476 | 124,253 | 213,537 | 31,779 | 15,613 | 15,237 | 99,576 | 14,938 | 8,774 | 9,460 | 1,738 | **2,730,369** |
| Oct-2023 | Peak Usage Charge | - | - | - | - | - | (199) | 5,320 | 23,893 | - | (5,420) | (1,125) | 67 | - | - | - | **22,534** |
| Oct-2023 | DC Right of Way Tax | 94,431 | (4,225) | 1,029 | 12 | 2,102 | 35,180 | 140,389 | 10,568 | 17,663 | (3,217) | 36,075 | 1,851 | 7,538 | 161,837 | 5,038 | **506,272** |
| Oct-2023 | DC Right of Way Adjustment | 5,909 | (456) | 40 | 1 | 133 | 2,216 | 9,221 | 690 | 1,123 | (627) | 2,203 | 117 | 478 | 9,961 | 319 | **31,327** |
| Oct-2023 | SE Trust Fund | 91,891 | (4,798) | 999 | 12 | 2,127 | 35,913 | 144,614 | 10,860 | 18,041 | (4,539) | 36,627 | 1,887 | 7,700 | 164,482 | 5,146 | **510,963** |
| Oct-2023 | Delivery Tax | 150,629 | (7,511) | 1,574 | 19 | 3,364 | 61,815 | 249,092 | 18,646 | 31,076 | (7,109) | 57,354 | 3,007 | 12,058 | 282,382 | 8,673 | **865,070** |
| Oct-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 9,800 | 2,875 | **12,675** |
| Oct-2023 | Balancing Charge | - | - | - | - | - | 7,697 | - | - | - | - | - | - | - | 7,286 | 228 | **15,211** |
| Oct-2023 | STORAGE GAS CHRG | 30,834 | (999) | 340 | 4 | 656 | 1,608 | 18,027 | 1,421 | 1,982 | 1,040 | 4,398 | 460 | 883 | - | - | **60,654** |
| Oct-2023 | EA Trust Fund | 16,999 | (886) | 191 | 2 | 393 | 6,627 | 26,700 | 1,999 | 3,331 | (838) | 6,762 | 354 | 1,422 | 30,368 | 950 | **94,374** |
| Oct-2023 | PRA | - | - | (0) | - | - | - | - | 1 | - | - | - | (1) | - | - | - | **0** |
| Oct-2023 | DC Tax Reform Credit | - | - | (1) | - | - | - | - | 8 | - | - | - | (7) | - | - | - | **(0)** |
| Oct-2023 | APRP | 76,319 | (3,304) | 882 | 9 | 1,699 | 17,944 | 71,474 | 5,296 | 8,964 | (1,574) | 20,023 | 1,044 | 4,212 | 36,340 | 1,128 | **240,456** |
| | **TOTAL** | **4,466,093** | **(120,227)** | **141,621** | **329** | **96,596** | **528,013** | **2,731,080** | **209,797** | **312,964** | **(7,794)** | **715,208** | **56,134** | **136,566** | **828,891** | **50,885** | **10,146,155** |
| Nov-2023 | PGA - Retroactive | (8,509) | 4,432 | (86) | (1) | (179) | (384) | (6,006) | (194) | (193) | (2) | (734) | (103) | (138) | - | - | **(12,098)** |
| Nov-2023 | PGC Rounding difference | (39) | (24) | (23) | 0 | (2) | (1) | 12 | 0 | 0 | (0) | 13 | (0) | (0) | - | - | **(63)** |
| Nov-2023 | ACA | 138,560 | (6,132) | 1,281 | 11 | 2,861 | 6,302 | 57,843 | 2,636 | 4,208 | 51 | 19,223 | 1,636 | 2,206 | - | - | **230,688** |
| Nov-2023 | DCA | (235,682) | 11,444 | (2,113) | (16) | (4,923) | (40,924) | (210,294) | (13,383) | (21,886) | (2,349) | (88,915) | (3,243) | (10,742) | - | - | **(623,026)** |
| Nov-2023 | GAC Current | 77,792 | (3,396) | 724 | 6 | 1,606 | 3,617 | 32,390 | 1,480 | 2,215 | 29 | 10,861 | 918 | 1,238 | - | - | **129,481** |
| Nov-2023 | Residential Essential Credit | 69,210 | (2,069) | 617 | 5 | 1,446 | 12,136 | 60,599 | 3,934 | 6,435 | 732 | 26,159 | 949 | 3,167 | 50,980 | 1,916 | **236,213** |
| Nov-2023 | RES Rider credit | (13,807) | - | (227) | - | (202) | - | - | - | - | - | - | - | - | - | - | **(14,235)** |
| Nov-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | (3,150) | 13,551 | **10,401** |
| Nov-2023 | Delivery Charge | 2,500,840 | (122,355) | 20,190 | 154 | 51,881 | 284,534 | 1,970,303 | 75,314 | 201,997 | 22,213 | 843,609 | 30,517 | 101,073 | 625,495 | 26,545 | **6,632,311** |
| Nov-2023 | Purchased Gas Charge | 2,522,108 | (151,765) | 23,479 | 198 | 52,089 | 117,194 | 1,074,861 | 48,364 | 72,163 | 949 | 351,395 | 29,797 | 40,178 | - | - | **4,181,009** |
| Nov-2023 | System Charge | 2,042,875 | (1,552) | 122,193 | 22 | 43,993 | 124,022 | 208,852 | 34,579 | 15,486 | 15,970 | 102,190 | 13,373 | 8,433 | 11,660 | 1,540 | **2,743,636** |
| Nov-2023 | Peak Usage Charge | - | - | - | - | - | 27,402 | 338,172 | 29,788 | 27,873 | 5,692 | 144,165 | 3,538 | 13,569 | - | - | **590,199** |
| Nov-2023 | DC Right of Way Tax | 243,376 | (10,333) | 2,171 | 17 | 5,082 | 42,255 | 216,214 | 13,815 | 22,583 | 2,220 | 91,967 | 3,349 | 11,094 | 180,056 | 6,721 | **830,587** |
| Nov-2023 | DC Right of Way Adjustment | 15,395 | (1,207) | 136 | 1 | 322 | 2,681 | 14,029 | 878 | 1,461 | 218 | 5,777 | 212 | 703 | 11,697 | 426 | **52,730** |
| Nov-2023 | SE Trust Fund | 247,702 | (12,163) | 2,235 | 17 | 5,178 | 43,292 | 221,872 | 14,118 | 22,686 | 2,500 | 93,858 | 3,421 | 11,332 | 184,760 | 6,865 | **847,672** |
| Nov-2023 | Delivery Tax | 389,343 | (19,046) | 3,503 | 27 | 8,133 | 74,574 | 382,171 | 24,320 | 39,077 | 3,915 | 146,972 | 5,358 | 17,745 | 315,380 | 11,588 | **1,403,060** |
| Nov-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 23,350 | 2,425 | **25,775** |
| Nov-2023 | Balancing Charge | - | - | - | - | - | 8,008 | - | - | - | - | - | - | - | 8,184 | 304 | **16,497** |
| Nov-2023 | STORAGE GAS CHRG | 78,231 | (2,642) | 723 | 6 | 1,614 | 3,545 | 32,166 | 1,483 | 2,513 | 29 | 10,931 | 924 | 1,246 | - | - | **130,769** |
| Nov-2023 | EA Trust Fund | 45,823 | (2,246) | 420 | 3 | 958 | 7,995 | 40,963 | 2,607 | 4,188 | 462 | 17,329 | 632 | 2,092 | 34,112 | 1,267 | **156,606** |
| Nov-2023 | PRA | 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **2** |
| Nov-2023 | DC Tax Reform Credit | (12) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(12)** |
| Nov-2023 | APRP | 196,646 | (8,810) | 1,775 | 14 | 4,107 | 21,678 | 110,036 | 7,025 | 11,512 | 1,219 | 50,484 | 1,872 | 6,199 | 40,238 | 1,505 | **445,500** |
| | **TOTAL** | **8,309,854** | **(327,861)** | **176,998** | **464** | **173,965** | **737,926** | **4,544,183** | **246,765** | **412,320** | **53,847** | **1,825,284** | **93,150** | **209,393** | **1,482,763** | **74,653** | **18,013,701** |
| Dec-2023 | PGA - Retroactive | (54,521) | 2,956 | (24) | (2) | (1,057) | (2,680) | (20,839) | (1,148) | (803) | (534) | (9,211) | (314) | (574) | - | - | **(88,753)** |
| Dec-2023 | PGC Rounding difference | (18) | (11) | 6 | 0 | 0 | (2) | 13 | 1 | (2) | 0 | 0 | (0) | 0 | - | - | **(12)** |
| Dec-2023 | ACA | 242,457 | (4,875) | 1,208 | 9 | 4,687 | 12,469 | 84,930 | 4,152 | 4,606 | 2,405 | 33,046 | 1,315 | 2,540 | - | - | **388,949** |
| Dec-2023 | DCA | (518,518) | 8,774 | (2,838) | (16) | (10,117) | 344,777 | (383,305) | (21,023) | (30,739) | (5,563) | (180,955) | (3,768) | (15,225) | - | - | **(818,517)** |
| Dec-2023 | GAC Current | 149,493 | (2,648) | 778 | 5 | 2,891 | 7,702 | 51,899 | 2,516 | 2,789 | 1,481 | 20,090 | 817 | 1,567 | - | - | **239,380** |
| Dec-2023 | Residential Essential Credit | 185,508 | (1,574) | 1,130 | 6 | 3,622 | (62,516) | 136,028 | 7,436 | 11,294 | 2,007 | 62,692 | 1,371 | 5,467 | 195,187 | 4,005 | **551,664** |
| Dec-2023 | RES Rider credit | (47,245) | (127) | (474) | - | (761) | - | - | - | - | - | - | - | - | - | - | **(48,606)** |
| Dec-2023 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (13,551) | **(13,551)** |
| Dec-2023 | Delivery Charge | 4,798,483 | (93,667) | 22,946 | 137 | 92,994 | (1,827,262) | 3,149,757 | 114,517 | 248,485 | 45,464 | 1,516,698 | 30,717 | 125,274 | 3,215,690 | 39,572 | **11,479,804** |
| Dec-2023 | Purchased Gas Charge | 4,309,425 | (111,894) | 19,498 | 156 | 83,381 | 220,697 | 1,542,417 | 75,873 | 72,426 | 42,589 | 608,333 | 23,353 | 45,177 | - | - | **6,931,429** |
| Dec-2023 | System Charge | 2,060,577 | (5,073) | 121,174 | 22 | 44,287 | 129,674 | 231,697 | 33,923 | 15,747 | 14,934 | 104,439 | 13,598 | 8,750 | 10,157 | 1,540 | **2,785,446** |
| Dec-2023 | Peak Usage Charge | - | - | - | - | - | (81,389) | 371,743 | 31,721 | 28,225 | 4,729 | 165,840 | 3,599 | 14,319 | - | - | **538,787** |
| Dec-2023 | DC Right of Way Tax | 467,038 | (8,196) | 2,565 | 15 | 9,111 | (333,140) | 346,266 | 18,970 | 27,737 | 5,013 | 163,319 | 3,371 | 13,750 | 664,507 | 10,002 | **1,390,328** |
| Dec-2023 | DC Right of Way Adjustment | 29,564 | (868) | 126 | 1 | 577 | (33,007) | 22,306 | 1,235 | 1,710 | 316 | 11,032 | 213 | 871 | 53,987 | 634 | **88,697** |
| Dec-2023 | SE Trust Fund | 787,980 | (9,098) | 4,595 | 25 | 15,389 | (353,014) | 585,478 | 31,989 | 48,093 | 8,501 | 269,283 | 5,841 | 23,145 | 969,571 | 17,464 | **2,405,242** |
| Dec-2023 | Delivery Tax | 746,963 | (14,580) | 3,981 | 24 | 14,576 | (639,714) | 611,091 | 33,539 | 48,396 | 8,006 | 264,254 | 5,393 | 21,994 | 1,217,411 | 17,113 | **2,338,448** |
| Dec-2023 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,425 | 2,200 | **4,625** |
| Dec-2023 | Balancing Charge | - | - | - | - | - | (104,102) | - | - | - | - | - | - | - | 31,444 | 453 | **(72,205)** |
| Dec-2023 | STORAGE GAS CHRG | 150,496 | (2,196) | 828 | 5 | 2,908 | 7,771 | 51,636 | 2,485 | 2,999 | 1,497 | 19,825 | 822 | 1,576 | - | - | **240,651** |
| Dec-2023 | EA Trust Fund | 87,458 | (1,721) | 474 | 3 | 1,709 | (68,568) | 65,501 | 3,595 | 5,187 | 944 | 31,157 | 636 | 2,593 | 131,057 | 1,886 | **261,912** |
| Dec-2023 | PRA | - | - | - | - | - | (1) | - | - | - | - | - | - | - | - | - | **(1)** |
| Dec-2023 | DC Tax Reform Credit | - | - | - | - | - | (2) | - | - | - | - | - | - | - | - | - | **(2)** |
| Dec-2023 | APRP | 376,970 | (7,645) | 1,994 | 12 | 7,360 | (141,912) | 176,874 | 9,690 | 13,826 | 2,793 | 91,863 | 1,884 | 7,684 | 142,940 | 2,240 | **686,573** |
| | **TOTAL** | **13,772,111** | **(252,443)** | **177,966** | **401** | **271,556** | **(2,924,219)** | **7,023,489** | **349,472** | **499,979** | **134,581** | **3,171,705** | **88,850** | **258,905** | **6,634,376** | **83,559** | **29,290,288** |

CUBE: tm1serv:Rate Statistics DB
**RS_ACTUA** DC

| | | DC Res Htg / HC | DC Res Htg / HC | DC Res Non Htg - IMA | DC Res Non Htg - IMA | DC Res Non Htg - OTH | DC C&I Htg / HC | DC C&I Htg / HC | DC C&I Non Htg | DC C&I Non Htg | DC GMA Htg / HC | DC GMA Htg / HC | DC GMA Non Htg | DC GMA Non Htg | DC Interruptible | DC Interruptible | TOTAL SYSTEM |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **1** | **2** | **1** | **2** | **1** | **1** | **2** | **1** | **2** | **1** | **2** | **1** | **2** | **1** | **2** | |
| Jan-2024 | PGA - Retroactive | (71,967) | (203) | (473) | (1) | (1,377) | (4,045) | (20,050) | (918) | (1,424) | (1,020) | (8,554) | (432) | (642) | - | - | **(18,772)** |
| Jan-2024 | PGC Rounding difference | (79) | 0 | (16) | 0 | (2) | (2) | (3) | (0) | (0) | (0) | 4 | (0) | (0) | - | - | **(59)** |
| Jan-2024 | ACA | 318,092 | 924 | 2,055 | 4 | 6,093 | 17,806 | 91,022 | 4,047 | 6,298 | 4,513 | 36,329 | 1,912 | 2,840 | - | - | **351,326** |
| Jan-2024 | DCA | 529,120 | 625 | 3,363 | 6 | 10,327 | 32,052 | 353,310 | 18,061 | 29,337 | 3,168 | 163,064 | 3,979 | 13,793 | - | - | **(1,253,013)** |
| Jan-2024 | GAC Current | 196,237 | 567 | 1,272 | 2 | 3,759 | 11,058 | 56,232 | 2,497 | 3,885 | 2,784 | 22,366 | 1,179 | 1,752 | - | - | **338,669** |
| Jan-2024 | Residential Essential Credit | 241,281 | 633 | 1,610 | 3 | 4,703 | 14,970 | 171,344 | 8,351 | 13,348 | 3,454 | 78,957 | 1,833 | 6,818 | 136,592 | 4,554 | **275,036** |
| Jan-2024 | RES Rider credit | (158,706) | (176) | (1,255) | - | (1,881) | - | - | - | - | - | - | - | - | - | - | **(143,884)** |
| Jan-2024 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **31,523** |
| Jan-2024 | Delivery Charge | 6,412,336 | 17,198 | 38,519 | 64 | 124,922 | 356,420 | 3,922,893 | 126,141 | 304,969 | 77,765 | 1,841,906 | 41,907 | 157,472 | 1,276,327 | 44,995 | **15,002,936** |
| Jan-2024 | Purchased Gas Charge | 6,660,411 | 18,620 | 43,017 | 80 | 127,670 | 373,693 | 1,896,476 | 84,676 | 131,954 | 90,065 | 761,983 | 40,028 | 59,506 | - | - | **13,220,359** |
| Jan-2024 | System Charge | 2,072,180 | 1,491 | 121,867 | 22 | 44,559 | 130,444 | 212,198 | 33,310 | 15,607 | 15,759 | 105,182 | 13,520 | 8,877 | 10,340 | 1,540 | **2,761,943** |
| Jan-2024 | Peak Usage Charge | - | - | - | - | - | 35,313 | 385,912 | 31,629 | 31,924 | 6,787 | 179,730 | 4,087 | 16,504 | - | - | **705,440** |
| Jan-2024 | DC Right of Way Tax | 613,599 | 1,650 | 4,037 | 6 | 11,864 | 37,293 | 427,206 | 20,846 | 33,213 | 8,541 | 197,548 | 4,578 | 17,027 | 341,165 | 11,372 | **1,314,509** |
| Jan-2024 | DC Right of Way Adjustment | 38,918 | 105 | 254 | 0 | 752 | 2,328 | 26,992 | 1,321 | 2,104 | 541 | 12,559 | 290 | 1,079 | 21,612 | 720 | **120,974** |
| Jan-2024 | SE Trust Fund | 1,024,890 | 2,743 | 6,839 | 11 | 19,965 | 63,576 | 728,783 | 35,472 | 56,517 | 14,719 | 335,470 | 7,785 | 28,950 | 580,058 | 19,334 | **1,809,058** |
| Jan-2024 | Delivery Tax | 981,745 | 2,639 | 6,481 | 10 | 18,980 | 65,600 | 751,442 | 36,678 | 58,439 | 13,662 | 316,195 | 7,324 | 27,235 | 593,960 | 19,433 | **2,979,617** |
| Jan-2024 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 225 | 2,200 | **2,865** |
| Jan-2024 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 15,437 | 515 | **28,727** |
| Jan-2024 | STORAGE GAS CHRG | 197,426 | 569 | 1,278 | 2 | 3,782 | 11,079 | 56,684 | 2,513 | 3,909 | 2,801 | 22,429 | 1,187 | 1,763 | - | - | **117,812** |
| Jan-2024 | EA Trust Fund | 113,757 | 308 | 762 | 1 | 2,215 | 7,032 | 80,544 | 3,932 | 6,264 | 1,611 | 37,281 | 864 | 3,211 | 64,342 | 2,145 | **334,045** |
| Jan-2024 | PRA | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **(2)** |
| Jan-2024 | DC Tax Reform Credit | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **26** |
| Jan-2024 | APRP | 602,106 | 1,550 | 3,951 | 6 | 11,646 | 23,397 | 267,472 | 13,103 | 20,913 | 5,439 | 130,499 | 3,034 | 11,231 | 78,727 | 2,624 | **1,248,607** |
| | **TOTAL** | **20,623,531** | **37,049** | **247,114** | **12** | **398,551** | **1,456,586** | **8,564,276** | **451,117** | **617,767** | **161,441** | **3,941,413** | **69,186** | **346,471** | **2,222,616** | **90,781** | **39,227,911** |
| Feb-2024 | PGA - Retroactive | (74,879) | (732) | (471) | (3) | (1,424) | (4,193) | (19,317) | (968) | (1,360) | 3,560 | (11,962) | (496) | (869) | - | - | **(20,838)** |
| Feb-2024 | PGC Rounding difference | (32) | 0 | 11 | 0 | 1 | (1) | (1) | 0 | (0) | (31) | 29 | (0) | 0 | - | - | **1** |
| Feb-2024 | ACA | 331,125 | 1,610 | 2,155 | 15 | 6,297 | 18,650 | 87,481 | 4,408 | 6,142 | (7,396) | 46,069 | 2,133 | 3,524 | - | - | **387,171** |
| Feb-2024 | DCA | 557,322 | (64) | 4,464 | 22 | 10,764 | 37,043 | 328,389 | 19,479 | 26,913 | 20,424 | 155,352 | 4,227 | 12,883 | - | - | **(1,285,942)** |
| Feb-2024 | GAC Current | 204,283 | 937 | 1,266 | 9 | 3,885 | 11,317 | 54,048 | 2,724 | 3,793 | (4,898) | 28,707 | 1,313 | 2,156 | - | - | **373,061** |
| Feb-2024 | Residential Essential Credit | 248,975 | 804 | 1,678 | 10 | 4,867 | 15,618 | 144,260 | 8,814 | 12,228 | (1,480) | 79,250 | 1,984 | 6,289 | 169,241 | 5,218 | **189,370** |
| Feb-2024 | RES Rider credit | (268,894) | (191) | (2,380) | - | (3,056) | - | - | - | - | - | - | - | - | - | - | **(197,233)** |
| Feb-2024 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **130,605** |
| Feb-2024 | Delivery Charge | 7,724,870 | 28,915 | 56,519 | 382 | 165,623 | 462,392 | 3,755,074 | 149,378 | 323,825 | (108,015) | 2,133,678 | 51,751 | 167,956 | 1,494,356 | 55,877 | **15,707,753** |
| Feb-2024 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **2,157** |
| Feb-2024 | Purchased Gas Charge | 5,749,897 | 33,051 | 34,116 | 262 | 109,269 | 312,863 | 1,515,064 | 76,972 | 105,686 | (223,245) | 875,532 | 37,215 | 62,570 | - | - | **14,573,094** |
| Feb-2024 | System Charge | 2,218,298 | 1,347 | 131,306 | 24 | 47,420 | 128,201 | 210,261 | 33,543 | 16,000 | 17,701 | 111,266 | 15,881 | 10,366 | 10,562 | 1,375 | **2,674,174** |
| Feb-2024 | Peak Usage Charge | - | - | - | - | - | 40,780 | 374,274 | 39,188 | 32,844 | (12,254) | 209,012 | 4,819 | 16,572 | - | - | **656,157** |
| Feb-2024 | DC Right of Way Tax | 638,833 | 2,455 | 4,009 | 26 | 12,324 | 38,146 | 359,142 | 21,966 | 30,474 | (9,401) | 202,262 | 5,003 | 15,949 | 422,623 | 13,030 | **1,314,850** |
| Feb-2024 | DC Right of Way Adjustment | 40,500 | 205 | 252 | 2 | 781 | 2,379 | 22,683 | 1,388 | 1,926 | (1,118) | 13,193 | 319 | 1,022 | 26,773 | 825 | **120,417** |
| Feb-2024 | SE Trust Fund | 1,057,529 | 3,777 | 7,036 | 43 | 20,664 | 65,691 | 612,854 | 37,399 | 51,945 | (10,361) | 339,450 | 8,447 | 26,815 | 718,555 | 22,154 | **1,801,351** |
| Feb-2024 | Delivery Tax | 1,022,087 | 4,142 | 6,289 | 41 | 19,715 | 66,355 | 631,634 | 38,633 | 53,598 | (21,067) | 327,879 | 8,012 | 25,541 | 735,976 | 22,351 | **2,963,606** |
| Feb-2024 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,200 | - | **12,125** |
| Feb-2024 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **24,096** |
| Feb-2024 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **672** |
| Feb-2024 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 19,123 | 590 | **(16,063)** |
| Feb-2024 | STORAGE GAS CHRG | 205,513 | 863 | 1,339 | 9 | 3,909 | 11,716 | 54,480 | 2,747 | 3,825 | (1,927) | 26,523 | 1,316 | 2,151 | - | - | **129,772** |
| Feb-2024 | EA Trust Fund | 117,355 | 486 | 734 | 5 | 2,293 | 7,119 | 67,703 | 4,141 | 5,745 | (2,484) | 38,659 | 945 | 3,011 | 79,705 | 2,457 | **333,161** |
| Feb-2024 | PRA | - | - | 3 | - | - | (10) | - | - | - | (3) | - | - | - | - | - | **(5)** |
| Feb-2024 | DC Tax Reform Credit | - | - | 152 | - | - | 68 | - | - | - | (31) | - | - | - | - | - | **72** |
| Feb-2024 | APRP | 827,952 | 2,829 | 5,293 | 33 | 15,982 | 19,892 | 190,591 | 11,708 | 16,208 | (9,682) | 99,104 | 2,365 | 7,596 | 87,011 | 2,683 | **2,379,251** |
| | **TOTAL** | **23,402,844** | **62,359** | **246,156** | **12** | **449,169** | **616,447** | **9,438,555** | **394,337** | **703,913** | **242,103** | **3,825,962** | **123,181** | **323,796** | **2,298,815** | **125,019** | **42,252,668** |
| Mar-2024 | PGA - Retroactive | (52,199) | 715 | (356) | (2) | (1,002) | (2,495) | (18,123) | (970) | (1,157) | (507) | (7,953) | (394) | (566) | - | - | **(14,622)** |
| Mar-2024 | PGC Rounding difference | (20) | 0 | (6) | - | 1 | (4) | (1) | (0) | 0 | (0) | 2 | (0) | 0 | - | - | **(67)** |
| Mar-2024 | ACA | 249,586 | (1,845) | 1,754 | 8 | 4,768 | 13,679 | 86,374 | 4,310 | 5,531 | 2,525 | 35,036 | 1,883 | 2,704 | - | - | **292,343** |
| Mar-2024 | DCA | 393,321 | 3,495 | 3,080 | 12 | 7,624 | 29,224 | 324,917 | 17,930 | 25,901 | 10,473 | 129,370 | 3,761 | 12,406 | - | - | **(1,115,782)** |
| Mar-2024 | GAC Current | 151,280 | (1,060) | 1,072 | 5 | 2,889 | 8,269 | 52,426 | 2,320 | 3,352 | 1,519 | 21,166 | 1,142 | 1,639 | - | - | **262,347** |
| Mar-2024 | Residential Essential Credit | 173,381 | (1,256) | 1,283 | 5 | 3,431 | 11,621 | 152,955 | 7,904 | 11,877 | 4,786 | 62,858 | 1,722 | 5,689 | 139,360 | 4,926 | **201,555** |
| Mar-2024 | RES Rider credit | (291,338) | (177) | (2,689) | - | (3,573) | - | - | - | - | - | - | - | - | - | - | **(183,958)** |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mar-2024 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **115,038** |
| Mar-2024 | Delivery Charge | 5,728,209 | (47,925) | 48,622 | 199 | 126,236 | 382,425 | 4,101,747 | 128,540 | 321,407 | 132,481 | 1,735,837 | 47,101 | 155,639 | 1,330,720 | 57,556 | **13,487,321** |
| Mar-2024 | Interruption Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Mar-2024 | Purchased Gas Charge | 4,405,822 | (35,554) | 30,814 | 150 | 84,240 | 233,937 | 1,531,384 | 67,452 | 97,673 | 44,757 | 623,846 | 33,245 | 47,749 | - | - | **11,228,110** |
| Mar-2024 | System Charge | 2,258,182 | 391 | 131,364 | 24 | 48,918 | 141,913 | 247,263 | 35,836 | 17,329 | 18,389 | 115,780 | 15,019 | 9,709 | 11,132 | 1,923 | **2,777,926** |
| Mar-2024 | Peak Usage Charge | - | - | - | - | - | 46,402 | 492,581 | 39,145 | 37,331 | 13,112 | 201,956 | 4,819 | 19,221 | - | - | **834,386** |
| Mar-2024 | DC Right of Way Tax | 448,989 | (4,765) | 3,190 | 13 | 8,747 | 28,313 | 382,581 | 19,327 | 29,659 | 12,230 | 158,861 | 4,299 | 14,206 | 348,007 | 12,301 | **1,343,637** |
| Mar-2024 | DC Right of Way Adjustment | 28,434 | (376) | 196 | 1 | 554 | 1,741 | 24,245 | 1,215 | 1,879 | 773 | 10,167 | 272 | 900 | 22,046 | 779 | **123,645** |
| Mar-2024 | SE Trust Fund | 736,236 | (6,069) | 5,418 | 23 | 14,572 | 49,032 | 652,162 | 33,480 | 50,431 | 20,081 | 267,670 | 7,310 | 24,154 | 591,691 | 20,914 | **1,846,688** |
| Mar-2024 | Delivery Tax | 718,242 | (7,751) | 5,114 | 21 | 13,996 | 49,504 | 673,059 | 33,603 | 52,185 | 19,555 | 254,293 | 6,877 | 22,724 | 606,025 | 20,924 | **3,080,675** |
| Mar-2024 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 4,625 | 4,400 | **7,125** |
| Mar-2024 | Overrun Penalty | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Mar-2024 | Pilot Commodity Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| Mar-2024 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 15,747 | 557 | **73,304** |
| Mar-2024 | STORAGE GAS CHRG | 118,705 | (1,084) | 821 | 4 | 2,264 | 6,372 | 42,548 | 1,982 | 2,627 | 1,079 | 16,969 | 897 | 1,285 | - | - | **114,798** |
| Mar-2024 | EA Trust Fund | 81,705 | (916) | 597 | 3 | 1,618 | 5,309 | 72,143 | 3,616 | 5,594 | 2,306 | 29,982 | 811 | 2,679 | 65,632 | 2,320 | **341,011** |
| Mar-2024 | PRA | - | - | - | - | - | 5 | - | (25) | - | - | - | - | - | - | - | **(1)** |
| Mar-2024 | DC Tax Reform Credit | - | - | - | - | - | 5 | - | 175 | - | - | - | - | - | - | - | **(3)** |
| Mar-2024 | APRP | 582,570 | (4,215) | 4,206 | 17 | 11,322 | 15,127 | 204,564 | 10,383 | 15,770 | 6,126 | 75,533 | 2,022 | 6,681 | 71,649 | 2,533 | **2,024,540** |
| | **TOTAL** | **16,817,541** | **50,455** | **259,430** | **12** | **328,586** | **2,637,715** | **7,883,110** | **390,361** | **657,606** | **197,329** | **3,614,530** | **95,766** | **323,700** | **3,488,070** | **95,805** | **36,840,016** |
| Apr-2024 | PGA - Retroactive | (38,742) | 269 | (250) | 24 | (756) | (3,325) | (14,153) | (663) | (1,063) | (550) | (5,354) | (312) | (550) | - | - | **(11,441)** |
| Apr-2024 | PGC Rounding difference | (23) | - | (11) | (0) | (1) | (0) | 0 | (1) | (0) | (0) | (0) | (0) | (0) | - | - | **(73)** |
| Apr-2024 | ACA | 184,916 | (1,202) | 1,127 | (97) | 3,611 | 15,794 | 67,562 | 3,394 | 4,919 | 2,632 | 25,604 | 1,490 | 2,629 | - | - | **230,121** |
| Apr-2024 | DCA | (460,416) | 209 | (3,855) | 68 | (9,156) | (36,102) | (346,966) | (23,399) | (38,343) | (8,648) | (168,724) | (5,023) | (16,607) | - | - | **(818,102)** |
| Apr-2024 | GAC Current | 112,514 | (700) | 696 | (56) | 2,198 | 9,599 | 41,059 | 2,065 | 2,996 | 1,601 | 15,573 | 906 | 1,599 | - | - | **205,621** |
| Apr-2024 | Residential Essential Credit | 127,500 | (1,000) | 852 | (42) | 2,584 | 12,910 | 103,371 | 6,970 | 11,093 | 2,577 | 48,920 | 1,448 | 4,818 | 127,481 | 3,952 | **139,343** |
| Apr-2024 | RES Rider credit | (247,540) | (139) | (3,453) | - | (3,120) | - | - | - | - | - | - | - | - | - | - | **(180,154)** |
| Apr-2024 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 134,459 | - | **119,338** |
| Apr-2024 | Delivery Charge | 4,243,166 | (36,498) | 34,735 | (1,645) | 95,562 | 418,304 | 2,801,588 | 112,135 | 301,854 | 71,650 | 1,349,794 | 39,616 | 131,773 | 1,215,733 | 46,588 | **10,044,060** |
| Apr-2024 | Purchased Gas Charge | 2,768,503 | (24,026) | 15,505 | (1,812) | 54,066 | 239,785 | 1,023,422 | 50,441 | 75,120 | 39,377 | 381,977 | 22,293 | 39,376 | - | - | **10,723,943** |
| Apr-2024 | System Charge | 2,251,021 | (1,287) | 132,060 | (121) | 48,745 | 143,935 | 242,203 | 35,567 | 17,187 | 17,471 | 112,472 | 15,034 | 9,377 | 11,132 | 1,694 | **2,764,807** |
| Apr-2024 | Peak Usage Charge | - | - | - | - | - | 54,322 | 430,350 | 39,568 | 34,955 | 9,889 | 198,019 | 4,790 | 17,145 | - | - | **745,910** |
| Apr-2024 | DC Right of Way Tax | 275,389 | (3,609) | 1,668 | (154) | 5,475 | 27,662 | 214,560 | 14,424 | 23,006 | 5,371 | 102,539 | 2,994 | 9,968 | 263,605 | 8,171 | **1,033,460** |
| Apr-2024 | DC Right of Way Adjustment | 21,062 | (236) | 131 | (11) | 418 | 2,057 | 16,328 | 1,092 | 1,759 | 408 | 7,843 | 229 | 762 | 20,167 | 625 | **88,244** |
| Apr-2024 | SE Trust Fund | 541,424 | (4,640) | 3,592 | (198) | 10,970 | 54,979 | 439,077 | 29,628 | 47,213 | 10,936 | 208,076 | 6,149 | 20,454 | 541,255 | 16,778 | **1,315,244** |
| Apr-2024 | Delivery Tax | 531,968 | (5,586) | 3,425 | (246) | 10,575 | 57,019 | 454,167 | 30,512 | 48,829 | 10,311 | 197,051 | 5,785 | 19,243 | 555,036 | 16,889 | **2,186,608** |
| Apr-2024 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,425 | 2,200 | **2,425** |
| Apr-2024 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 14,405 | 447 | **23,151** |
| Apr-2024 | STORAGE GAS CHRG | 87,799 | (717) | 490 | (54) | 1,716 | 7,602 | 32,248 | 1,622 | 2,345 | 1,250 | 12,141 | 708 | 1,248 | - | - | **90,623** |
| Apr-2024 | EA Trust Fund | 60,099 | (661) | 390 | (29) | 1,218 | 6,113 | 48,680 | 3,271 | 5,234 | 1,216 | 23,233 | 682 | 2,269 | 60,038 | 1,861 | **242,904** |
| Apr-2024 | DC Tax Reform Credit | 6 | - | (1) | - | - | - | - | - | - | - | - | - | - | - | - | **6** |
| Apr-2024 | APRP | 423,017 | (3,154) | 2,884 | (148) | 8,405 | 27,014 | 226,575 | 15,271 | 24,496 | 5,625 | 107,867 | 3,192 | 10,600 | 64,821 | 2,009 | **1,517,403** |
| | **TOTAL** | **14,590,418** | **6,906** | **236,521** | **12** | **286,192** | **1,511,485** | **6,316,277** | **336,901** | **584,687** | **171,380** | **3,459,329** | **98,797** | **293,465** | **2,484,325** | **86,743** | **30,463,440** |
| May-2024 | PGA - Retroactive | (17,229) | 122 | (202) | (0) | (354) | (1,214) | (7,549) | (412) | (260) | (325) | (4,109) | (314) | (508) | - | - | **(6,388)** |
| May-2024 | PGC Rounding difference | 213 | 0 | 17 | (0) | 5 | 12 | 62 | 4 | 5 | 3 | 27 | 2 | 3 | - | - | **(83)** |
| May-2024 | ACA | 82,126 | (684) | 921 | 0 | 1,692 | 5,737 | 34,607 | 1,983 | 2,585 | 1,609 | 18,516 | 1,494 | 2,478 | - | - | **128,695** |
| May-2024 | DCA | (206,861) | 913 | (2,568) | (0) | (4,336) | (15,469) | (228,870) | (9,476) | (26,075) | (4,842) | (96,942) | (3,615) | (13,027) | - | - | **(444,174)** |
| May-2024 | GAC Current | 49,937 | (407) | 570 | 0 | 1,030 | 3,495 | 21,146 | 1,207 | 1,594 | 978 | 11,226 | 908 | 1,504 | - | - | **114,845** |
| May-2024 | Residential Essential Credit | 56,157 | (2,048) | 632 | 0 | 1,211 | 4,287 | 63,381 | 2,723 | 7,240 | 1,561 | 30,637 | 1,341 | 4,162 | 92,895 | 3,003 | **83,756** |
| May-2024 | RES Rider credit | (49,519) | (8) | (1,066) | - | (662) | - | - | - | - | - | - | - | - | - | - | **(3,113)** |
| May-2024 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | (21,737) | - | **107,948** |
| May-2024 | Delivery Charge | 1,891,270 | (63,674) | 24,533 | 1 | 45,171 | 142,333 | 1,713,032 | 61,205 | 193,125 | 42,941 | 845,832 | 36,465 | 113,611 | 907,157 | 35,185 | **5,656,106** |
| May-2024 | Purchased Gas Charge | 1,407,763 | (12,697) | 15,954 | 1 | 29,016 | 98,588 | 589,688 | 34,107 | 38,889 | 27,690 | 323,452 | 26,157 | 43,066 | - | - | **6,725,840** |
| May-2024 | System Charge | 2,245,500 | (422) | 133,239 | 12 | 48,956 | 139,632 | 229,516 | 35,653 | 16,009 | 20,329 | 122,297 | 18,008 | 11,200 | 10,583 | 1,694 | **2,775,620** |
| May-2024 | Peak Usage Charge | - | - | - | - | - | (330) | 61 | 26,858 | (1,732) | 555 | 12,347 | 638 | 2,542 | - | - | **31,799** |
| May-2024 | DC Right of Way Tax | 122,561 | (5,531) | 1,333 | 0 | 2,586 | 8,836 | 128,515 | 5,607 | 14,249 | 3,327 | 66,035 | 2,916 | 8,855 | 192,087 | 6,210 | **629,200** |
| May-2024 | DC Right of Way Adjustment | 9,375 | (360) | 99 | 0 | 197 | 680 | 9,947 | 429 | 1,075 | 248 | 4,975 | 215 | 664 | 14,695 | 475 | **53,490** |
| May-2024 | SE Trust Fund | 238,603 | (8,840) | 2,691 | 0 | 5,143 | 18,253 | 269,559 | 11,555 | 30,598 | 6,626 | 130,607 | 5,704 | 17,682 | 394,409 | 12,751 | **797,204** |
| May-2024 | Delivery Tax | 237,120 | (9,068) | 2,609 | 0 | 5,000 | 18,911 | 276,244 | 11,934 | 30,747 | 6,282 | 124,799 | 5,428 | 16,770 | 405,480 | 12,906 | **1,336,344** |
| May-2024 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 9,925 | 2,425 | **12,425** |
| May-2024 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 10,497 | 339 | **19,508** |
| May-2024 | STORAGE GAS CHRG | 38,937 | (403) | 418 | 0 | 803 | 2,700 | 16,168 | 940 | 1,178 | 784 | 8,983 | 749 | 1,228 | - | - | **50,636** |
| May-2024 | EA Trust Fund | 26,490 | (1,069) | 307 | 0 | 571 | 2,028 | 29,610 | 1,280 | 3,296 | 741 | 14,714 | 640 | 1,977 | 43,749 | 1,414 | **147,072** |
| May-2024 | PRA | (4) | - | (0) | - | - | - | - | - | - | - | - | - | - | - | - | **(299)** |
| May-2024 | DC Tax Reform Credit | 26 | - | (3) | - | - | - | - | - | - | - | - | - | - | - | - | **(164)** |
| May-2024 | APRP | 188,582 | (5,999) | 2,088 | 0 | 3,974 | 9,573 | 141,989 | 6,026 | 16,279 | 3,330 | 65,847 | 2,780 | 8,916 | 47,235 | 1,527 | **852,012** |
| | **TOTAL** | **9,053,916** | **21,899** | **185,466** | **29** | **181,889** | **868,625** | **4,182,570** | **246,143** | **464,607** | **143,055** | **1,368,431** | **75,771** | **236,537** | **1,975,358** | **63,984** | **19,068,280** |
| Jun-2024 | PGA - Retroactive | (7,670) | 1,005 | (28) | (0) | (151) | (862) | (3,506) | (310) | (519) | (220) | (1,897) | (129) | (267) | - | - | **(14,554)** |
| Jun-2024 | PGC Rounding difference | 30 | (4) | (22) | - | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | (0) | - | - | **9** |
| Jun-2024 | ACA | 49,370 | (3,408) | 357 | 0 | 1,062 | 5,383 | 24,656 | 2,091 | 3,567 | 1,460 | 12,118 | 882 | 1,811 | - | - | **99,348** |
| Jun-2024 | DCA | (119,667) | 1,382 | (1,506) | (0) | (2,771) | (13,881) | (170,745) | (15,695) | (24,686) | (3,860) | (56,763) | (2,875) | (11,024) | - | - | **(422,092)** |
| Jun-2024 | GAC Current | 28,981 | (2,125) | 207 | 0 | 621 | 3,162 | 14,397 | 1,226 | 2,087 | 858 | 7,147 | 517 | 1,061 | - | - | **58,139** |
| Jun-2024 | Residential Essential Credit | 32,357 | (2,024) | 282 | 0 | 763 | 4,247 | 47,927 | 4,624 | 7,128 | 994 | 17,856 | 857 | 3,179 | 23,540 | 2,301 | **144,030** |
| Jun-2024 | RES Rider credit | (52,489) | (8) | (1,116) | - | (664) | - | - | - | - | - | - | - | - | - | - | **(54,277)** |
| Jun-2024 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | 70,049 | - | **70,049** |
| Jun-2024 | Delivery Charge | 1,096,575 | (70,060) | 11,262 | 1 | 28,428 | 139,842 | 1,300,847 | 70,224 | 193,742 | 27,441 | 499,571 | 23,567 | 86,948 | 340,720 | 26,870 | **3,775,980** |
| Jun-2024 | Purchased Gas Charge | 980,977 | (72,940) | 7,581 | 1 | 20,820 | 106,700 | 484,455 | 40,193 | 69,750 | 28,399 | 230,589 | 17,112 | 35,294 | - | - | **1,948,931** |
| Jun-2024 | System Charge | 2,252,579 | (884) | 132,724 | 12 | 49,529 | 142,208 | 232,014 | 37,844 | 16,783 | 18,007 | 118,297 | 15,646 | 9,694 | 9,466 | 1,694 | **3,035,611** |
| Jun-2024 | Peak Usage Charge | - | - | - | - | - | 685 | (2,377) | 25,761 | - | (364) | 5,910 | 60 | (29) | - | - | **29,646** |
| Jun-2024 | DC Right of Way Tax | 71,353 | (5,841) | 380 | 0 | 1,622 | 9,051 | 98,768 | 9,745 | 14,739 | 1,926 | 39,134 | 1,810 | 6,574 | 48,626 | 4,757 | **302,645** |
| Jun-2024 | DC Right of Way Adjustment | (11,453) | (481) | (252) | (0) | (269) | (1,228) | (14,005) | (1,390) | (2,337) | (394) | (4,473) | (260) | (1,044) | (26,939) | (754) | **(65,277)** |
| Jun-2024 | SE Trust Fund | 137,707 | (9,093) | 1,147 | 0 | 3,238 | 18,183 | 203,787 | 19,773 | 30,264 | 4,190 | 76,430 | 3,647 | 13,497 | 99,945 | 9,768 | **612,484** |
| Jun-2024 | Delivery Tax | 137,827 | (10,115) | 923 | 0 | 3,140 | 18,999 | 210,645 | 20,537 | 31,319 | 3,852 | 74,106 | 3,462 | 12,698 | 102,375 | 9,952 | **619,719** |
| Jun-2024 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 5,800 | 2,650 | **8,450** |
| Jun-2024 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 2,660 | 260 | **2,920** |
| Jun-2024 | STORAGE GAS CHRG | 17,037 | (1,711) | 35 | 0 | 361 | 1,916 | 8,322 | 796 | 1,239 | 550 | 4,985 | 323 | 638 | - | - | **34,490** |
| Jun-2024 | EA Trust Fund | 15,396 | (1,193) | 109 | 0 | 360 | 2,037 | 22,579 | 2,202 | 3,357 | 454 | 8,738 | 408 | 1,497 | 11,086 | 1,084 | **68,114** |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jun-2024 | PRA | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Jun-2024 | DC Tax Reform Credit | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Jun-2024 | APRP | 157,479 | (6,779) | 1,723 | 0 | 3,616 | 12,212 | 139,741 | 13,427 | 21,064 | 3,139 | 50,813 | 2,510 | 9,486 | 29,083 | 1,794 | 439,309 |
| | **TOTAL** | **4,786,388** | **(184,279)** | **153,804** | **15** | **109,705** | **448,656** | **2,597,508** | **231,047** | **367,498** | **86,432** | **1,082,559** | **67,537** | **170,014** | **716,413** | **60,376** | **10,693,672** |
| Jul-2024 | PGA - Retroactive | (3,914) | (12) | (10) | - | (110) | (557) | (3,072) | (193) | (413) | (267) | (975) | (141) | (179) | - | - | (9,842) |
| Jul-2024 | PGC Rounding difference | 14 | 0 | (24) | (0) | 0 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | (0) | - | - | (4) |
| Jul-2024 | ACA | 31,094 | 84 | 352 | 0 | 762 | 3,883 | 20,928 | 1,336 | 2,825 | 1,591 | 6,656 | 798 | 1,231 | - | - | 71,543 |
| Jul-2024 | DCA | (86,473) | (240) | (1,999) | (0) | (1,893) | (9,926) | (132,806) | (8,428) | (19,013) | (3,432) | (40,011) | (2,217) | (7,927) | - | - | (314,365) |
| Jul-2024 | GAC Current | 18,225 | 49 | 196 | 0 | 447 | 2,272 | 12,256 | 781 | 1,654 | 951 | 3,897 | 466 | 720 | - | - | 41,915 |
| Jul-2024 | Residential Essential Credit | 23,348 | 69 | 264 | 0 | 532 | 2,882 | 38,165 | 2,423 | 5,491 | 1,743 | 11,615 | 678 | 2,289 | 132,448 | 1,886 | 223,832 |
| Jul-2024 | RES Rider credit | (47,436) | (8) | (567) | - | (672) | - | - | - | - | - | - | - | - | - | - | (48,683) |
| Jul-2024 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | (59,841) | - | (59,841) |
| Jul-2024 | Delivery Charge | 776,794 | 2,205 | 10,413 | 1 | 19,831 | 94,545 | 1,036,312 | 43,437 | 149,253 | 46,786 | 319,131 | 19,006 | 62,599 | 1,570,806 | 22,023 | 4,173,141 |
| Jul-2024 | Purchased Gas Charge | 606,410 | 1,645 | 7,496 | 1 | 14,862 | 75,585 | 407,713 | 26,154 | 55,092 | 28,331 | 129,682 | 15,535 | 24,070 | - | - | 1,392,575 |
| Jul-2024 | System Charge | 2,177,887 | 1,345 | 127,346 | 12 | 47,727 | 133,965 | 225,710 | 35,306 | 15,860 | 16,645 | 111,657 | 15,271 | 9,027 | 11,858 | 1,694 | 2,931,309 |
| Jul-2024 | Peak Usage Charge | - | - | - | - | - | (41) | (547) | 25,463 | (10) | 1,220 | 1,521 | 88 | (579) | - | - | 27,115 |
| Jul-2024 | DC Right of Way Tax | 49,785 | 143 | 441 | 0 | 1,138 | 5,957 | 79,406 | 5,006 | 11,354 | 3,747 | 24,062 | 1,494 | 4,733 | 273,877 | 3,900 | 465,044 |
| Jul-2024 | DC Right of Way Adjustment | (8,451) | (23) | (209) | (0) | (179) | (936) | (12,790) | (800) | (1,788) | (135) | (3,825) | (179) | (751) | (24,175) | (618) | (54,859) |
| Jul-2024 | SE Trust Fund | 98,741 | 293 | 1,104 | 0 | 2,254 | 12,262 | 162,813 | 10,292 | 23,313 | 7,373 | 49,314 | 2,908 | 9,717 | 562,345 | 8,008 | 950,739 |
| Jul-2024 | Delivery Tax | 96,891 | 277 | 1,006 | 0 | 2,196 | 12,641 | 168,398 | 10,646 | 24,126 | 6,834 | 46,417 | 2,823 | 9,142 | 581,035 | 8,149 | 970,581 |
| Jul-2024 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 30,675 | 2,650 | 33,325 |
| Jul-2024 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 14,966 | 213 | 15,179 |
| Jul-2024 | STORAGE GAS CHRG | 10,487 | 29 | 34 | 0 | 265 | 1,358 | 7,310 | 459 | 985 | 746 | 2,341 | 307 | 428 | - | - | 24,749 |
| Jul-2024 | EA Trust Fund | 10,948 | 33 | 128 | 0 | 252 | 1,356 | 18,050 | 1,142 | 2,586 | 806 | 5,473 | 333 | 1,078 | 62,377 | 888 | 105,449 |
| Jul-2024 | PRA | 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 2 |
| Jul-2024 | DC Tax Reform Credit | (20) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) |
| Jul-2024 | APRP | 112,240 | 317 | 1,471 | 0 | 2,495 | 8,475 | 113,281 | 7,176 | 16,206 | 4,030 | 34,611 | 1,955 | 6,829 | 92,534 | 1,470 | 403,091 |
| | **TOTAL** | **3,866,573** | **6,204** | **147,443** | **13** | **89,907** | **343,722** | **2,141,128** | **160,201** | **287,521** | **116,970** | **701,569** | **59,125** | **122,427** | **3,248,905** | **50,263** | **11,341,973** |
| Aug-2024 | PGA - Retroactive | (4,265) | 373 | (84) | (0) | (89) | (677) | (3,522) | (327) | (426) | (133) | (736) | (78) | (178) | - | - | (10,141) |
| Aug-2024 | PGC Rounding difference | 17 | (0) | (25) | - | 1 | 1 | 0 | 0 | (0) | (0) | 0 | 1 | (0) | - | - | (6) |
| Aug-2024 | ACA | 30,335 | (1,988) | 659 | 0 | 616 | 4,590 | 24,063 | 2,155 | 2,927 | 1,342 | 4,820 | 535 | 1,245 | - | - | 71,299 |
| Aug-2024 | DCA | (71,911) | 1,476 | (1,715) | (0) | (1,577) | (11,397) | (128,381) | (11,978) | (19,355) | (2,978) | (35,179) | (1,970) | (8,328) | - | - | (293,293) |
| Aug-2024 | GAC Current | 17,723 | (1,197) | 386 | 0 | 361 | 2,689 | 14,091 | 1,266 | 1,713 | 802 | 2,830 | 313 | 727 | - | - | 41,705 |
| Aug-2024 | Residential Essential Credit | 18,700 | (1,174) | 478 | 0 | 443 | 3,358 | 37,333 | 3,594 | 5,611 | 1,252 | 10,072 | 572 | 2,361 | 72,249 | 1,733 | 156,584 |
| Aug-2024 | RES Rider credit | (57,068) | (8) | (1,259) | - | (692) | - | - | - | - | - | - | - | - | - | - | (59,027) |
| Aug-2024 | WG Purchases | - | - | - | - | - | - | - | - | - | - | - | - | - | (10,453) | - | (10,453) |
| Aug-2024 | Delivery Charge | 636,726 | (36,732) | 18,129 | 1 | 16,460 | 110,234 | 1,012,699 | 61,418 | 152,588 | 33,227 | 273,918 | 15,640 | 64,635 | 710,218 | 20,219 | 3,089,380 |
| Aug-2024 | Purchased Gas Charge | 593,945 | (34,909) | 12,729 | 1 | 12,022 | 89,243 | 468,764 | 41,750 | 57,137 | 24,249 | 94,002 | 10,453 | 24,361 | - | - | 1,393,748 |
| Aug-2024 | System Charge | 2,233,905 | (679) | 131,269 | 12 | 49,100 | 141,144 | 234,341 | 37,562 | 16,907 | 19,476 | 119,072 | 15,274 | 9,744 | 10,769 | 1,694 | 3,019,589 |
| Aug-2024 | Peak Usage Charge | - | - | - | - | - | 271 | (84) | 26,234 | 68 | 911 | 1,430 | 4 | - | - | - | 28,833 |
| Aug-2024 | DC Right of Way Tax | 40,895 | (2,957) | 1,004 | 0 | 942 | 6,979 | 77,605 | 7,482 | 11,628 | 2,577 | 20,375 | 1,184 | 4,871 | 149,397 | 3,584 | 325,568 |
| Aug-2024 | DC Right of Way Adjustment | (7,051) | (169) | (170) | (0) | (151) | (1,037) | (11,982) | (1,109) | (1,827) | (265) | (3,431) | (186) | (788) | (23,565) | (568) | (52,300) |
| Aug-2024 | SE Trust Fund | 79,225 | (5,021) | 2,013 | 0 | 1,877 | 14,280 | 158,815 | 15,271 | 23,842 | 5,244 | 42,597 | 2,429 | 10,026 | 306,754 | 7,358 | 664,710 |
| Aug-2024 | Delivery Tax | 79,540 | (5,037) | 1,937 | 0 | 1,821 | 14,775 | 164,475 | 15,805 | 24,681 | 4,791 | 39,638 | 2,286 | 9,432 | 316,710 | 7,474 | 678,329 |
| Aug-2024 | Minimum monthly Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 22,100 | 2,650 | 24,750 |
| Aug-2024 | Balancing Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | 8,164 | 196 | 8,360 |
| Aug-2024 | STORAGE GAS CHRG | 10,219 | (1,058) | 224 | 0 | 213 | 1,625 | 8,581 | 793 | 1,028 | 567 | 1,573 | 187 | 422 | - | - | 24,374 |
| Aug-2024 | EA Trust Fund | 8,837 | (594) | 231 | 0 | 210 | 1,585 | 17,630 | 1,695 | 2,645 | 565 | 4,674 | 270 | 1,112 | 34,026 | 816 | 73,701 |
| Aug-2024 | PRA | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Aug-2024 | DC Tax Reform Credit | (6) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (6) |
| Aug-2024 | APRP | 92,388 | (3,586) | 2,210 | 0 | 2,077 | 9,781 | 109,768 | 10,437 | 16,550 | 3,250 | 30,174 | 1,703 | 7,087 | 56,268 | 1,351 | 339,459 |
| | **TOTAL** | **3,702,155** | **(93,261)** | **168,017** | **15** | **83,635** | **387,444** | **2,184,196** | **212,049** | **295,716** | **94,876** | **605,831** | **48,616** | **126,732** | **1,652,639** | **46,507** | **9,515,166** |

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

| | | |
|---|---|---|
| **In the Matter of** | **§** | |
| **The Application of Washington Gas** | **§** | |
| **Light Company for Authority to** | **§** | **Formal Case No. 1180** |
| **Increase Existing Rates and Charges** | **§** | |
| **for Gas Service** | **§** | |
| | **§** | |

**DIRECT TESTIMONY**
**AND SUPPORTING EXHIBITS OF**
**BION C. OSTRANDER**
**PUBLIC VERSION**

**Exhibit OPC (B)**

**On Behalf of the**
**Office of the People's Counsel**
**for the District of Columbia**

**January 24, 2025**

**TABLE OF CONTENTS**

**EXHIBIT LIST**

| | |
|---|---|
| Exhibit OPC (B)-1 | Curriculum Vitae (CV) of Bion C. Ostrander |
| Exhibit OPC (B)-2 | Ratemaking Results and Revenue Requirement |
| Exhibit OPC (B)-3 | Summary of WGL and OPC Adjustments (Confidential and Public Versions) |
| Exhibit OPC (B)-4 | Revenue Requirement of OPC Adjustments at OPC Recommended ROR |
| Exhibit OPC (B)-5 | Schedules on Individual Adjustments to Rate Base and Net Operating Income (Confidential and Public Versions) |
| Exhibit OPC (B)-6 | WGL Response to OPC Data Request No. 4-5 |
| Exhibit OPC (B)-7 | WGL Response to OPC Follow Up Data Request No. 4-7 and Response to Follow Up Data Request |
| Exhibit OPC (B)-8 | WGL Response to OPC Data Request No. 4-8 (some attachments omitted) and Response to Follow Up Data Request |
| Exhibit OPC (B)-9 | WGL Response to OPC Data Request No. 4-9 and Response to Follow Up Data Request |
| Exhibit OPC (B)-10 | WGL Confidential Response to OPC Data Request No. 4-12 (some attachments omitted) and Confidential Response to Follow Up Data Request |
| Exhibit OPC (B)-11 | WGL Confidential and Attorneys' Eyes Only Response to OPC Data Request No. 4-14 |
| Exhibit OPC (B)-12 | WGL Response to OPC Data Request No. 4-15 |
| Exhibit OPC (B)-13 | WGL Response to OPC Data Request No. 4-16 |

| | |
|---|---|
| Exhibit OPC (B)-45 | WGL Confidential and Attorneys' Eyes Only Response to OPC Data Request No. 6-1 |
| Exhibit OPC (B)-46 | WGL Confidential Response to OPC Data Request No. 6-7 and Confidential Response to Follow Up Data Request |
| Exhibit OPC (B)-47 | WGL Confidential Response to OPC Data Request No. 6-8 and Confidential Response to Follow Up Data Request |
| Exhibit OPC (B)-48 | WGL Response to OPC Data Request No. 6-12 |
| Exhibit OPC (B)-49 | WGL Response to OPC Data Request No. 6-13 |
| Exhibit OPC (B)-50 | WGL Confidential Response to OPC Data Request No. 6-14 (some attachments omitted) and Confidential Response to Follow Up Data Request (some attachments omitted) |
| Exhibit OPC (B)-51 | WGL Confidential and Attorneys' Eyes Only Response to OPC Data Request No. 6-17 |
| Exhibit OPC (B)-52 | WGL Confidential Response to OPC Data Request No. 6-19 |
| Exhibit OPC (B)-53 | WGL Confidential and Attorneys' Eyes Only Response to OPC Data Request No. 6-20 |
| Exhibit OPC (B)-54 | WGL Response to OPC Data Request No. 10-3 |
| Exhibit OPC (B)-55 | WGL Response to OPC Data Request No. 10-5 and Response to Follow Up Data Request |
| Exhibit OPC (B)-56 | WGL Confidential Response to OPC Data Request No. 10-6 and Confidential Response to Follow Up Data Request |
| Exhibit OPC (B)-57 | WGL Confidential Response to OPC Data Request No. 10-7 |
| Exhibit OPC (B)-58 | WGL Response to OPC Data Request No. 10-15 |
| Exhibit OPC (B)-59 | WGL Response to OPC Data Request No. 11-2 |
| Exhibit OPC (B)-60 | WGL Response to OPC Data Request No. 11-3 |
| Exhibit OPC (B)-61 | WGL Response to OPC Data Request No. 11-4 |
| Exhibit OPC (B)-62 | WGL Response to OPC Data Request No. 11-5 |
| Exhibit OPC (B)-63 | WGL Response to OPC Follow Up Data Request No. 11-6 |
| Exhibit OPC (B)-64 | WGL Response to OPC Data Request No. 11-8 and Response to Follow Up Data Request |
| Exhibit OPC (B)-65 | WGL Response to OPC Data Request No. 11-10 and Response to Follow Up Data Request |
| Exhibit OPC (B)-66 | WGL Confidential Response to OPC Data Request No. 11-11 |
| Exhibit OPC (B)-67 | WGL Response to OPC Data Request No. 11-12 |
| Exhibit OPC (B)-68 | WGL Response to OPC Data Request No. 11-13 |
| Exhibit OPC (B)-69 | WGL Response to OPC Data Request No. 11-14 |
| Exhibit OPC (B)-70 | WGL Response to OPC Data Request No. 11-15 |
| Exhibit OPC (B)-71 | WGL Response to OPC Data Request No. 11-17 |
| Exhibit OPC (B)-72 | WGL Response to OPC Data Request No. 11-18 |

| | |
|---|---|
| Exhibit OPC (B)-73 | WGL Confidential Response to OPC Follow Up Data Request No. 11-19 |
| Exhibit OPC (B)-74 | WGL Response to OPC Data Request No. 11-20 |
| Exhibit OPC (B)-75 | WGL Response to OPC Data Request No. 12-1 |
| Exhibit OPC (B)-76 | WGL Response to OPC Data Request No. 12-2 |
| Exhibit OPC (B)-77 | WGL Response to OPC Data Request No. 15-2 |
| Exhibit OPC (B)-78 | WGL Response to OPC Data Request No. 15-3 |
| Exhibit OPC (B)-79 | WGL Confidential Response to OPC Data Request No. 17-1 and Confidential Response to Follow Up Data Request |
| Exhibit OPC (B)-80 | WGL Response to OPC Data Request No. 17-2 |
| Exhibit OPC (B)-81 | WGL Response to OPC Data Request No. 17-3 |
| Exhibit OPC (B)-82 | WGL Response to OPC Data Request No. 17-4 |
| Exhibit OPC (B)-83 | WGL Response to OPC Data Request No. 17-5 |
| Exhibit OPC (B)-84 | WGL Response to OPC Data Request No. 18-1 and Confidential Response to Follow Up Data Request |
| Exhibit OPC (B)-85 | WGL Response to OPC Data Request No. 18-2 |
| Exhibit OPC (B)-86 | WGL Confidential Response to OPC Data Request No. 18-9 |
| Exhibit OPC (B)-87 | WGL Confidential Response to OPC Data Request No. 18-10 |
| Exhibit OPC (B)-88 | WGL Response to OPC Data Request No. 4-10 |
| Exhibit OPC (B)-89 | WGL Confidential Response to OPC Data Request No. 10-1 |
| Exhibit OPC (B)-90 | WGL Response to OPC Data Request No. 15-1 |

## I. INTRODUCTION

**Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.**

A. My name is Bion C. Ostrander. I am President of Ostrander Consulting. My business address is 1121 S.W. Chetopa Trail, Topeka, Kansas 66615-1408. I am an independent regulatory consultant specializing in revenue requirement/accounting issues related to electric, gas, renewable energy, and telecommunications industries.

**Q. PLEASE SUMMARIZE YOUR EDUCATIONAL EXPERIENCE.**

A. I graduated from the University of Kansas in 1978 with a Bachelor of Science degree in Business Administration with a major in Accounting.

**Q. HAVE YOU PREPARED AN ATTACHMENT SUMMARIZING YOUR QUALIFICATIONS AND REGULATORY EXPERIENCE?**

A. Yes. I have attached Exhibit OPC (B)-1, which is a summary of my regulatory experience and qualifications.

**Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.**

A. I am an independent regulatory consultant with a specialization in regulatory utility issues, and particularly revenue requirement/accounting issues. I have 43 years of regulatory and accounting experience, including 32 years with my firm Ostrander Consulting.

I started my current consulting practice in 1990 after leaving the Kansas Corporation Commission ("KCC"). I previously served as the Chief of Telecommunications for the KCC from 1986 to 1990 and was the lead witness on most major telecom issues, while still assisting with electric/gas utility issues on a periodic basis.

I served as Chief Auditor for the KCC from 1983 to 1986, addressing issues regarding the telecom, gas, electric, and transportation industries.

In addition, I have worked for international and regional certified public accounting firms, including Deloitte, Haskin and Sells (now Deloitte) and Mize, Houser, Mehlinger and Kimes (now Mize CPAs Inc.).

I previously held a permit to practice as a certified public accountant ("CPA") in Kansas up until recent years, but I no longer perform any CPA-type services requiring a permit to practice.

I have addressed many regulatory issues for various state regulatory agencies and for international regulatory and other governmental entities. My experience includes addressing issues related to rate cases under rate of return regulation, alternative regulation/price cap plans, management audits, specialized accounting and regulatory issues, cost modeling, and other matters. I have addressed a broad range of regulatory issues in my career, including analysis of the levelized cost of renewable energy alternatives, specialized accounting matters, affiliate transactions/Cost Allocation Manual, income taxes (including net operating losses), sale/leaseback, compensation, cross-subsidization, depreciation, retail and wholesale cost studies for telecom, competition, affordable rates/universal service, service quality, infrastructure/modernization, rate design for telecom, sales/acquisitions and many other matters.

**Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?**

A. I am testifying on behalf of the Office of the People's Counsel of the District of Columbia ("OPC" or "Office") in this proceeding involving Washington Gas Light Company's

("WGL", "Company", or "Washington Gas") Application for authority to increase existing rates and charges for gas service in the District of Columbia ("D.C." or "DC") before the Public Service Commission of the District of Columbia ("Commission" or "DC PSC").[1]

**Q. HAVE YOU TESTIFIED BEFORE IN THE DISTRICT OF COLUMBIA?**

A. Yes. I filed confidential and public direct (November 4, 2022) errata direct (December 7, 2022), and surrebuttal testimony (May 19, 2023) with the Commission in the previous WGL rate case in Formal Case No. 1169.[2]

In addition, I filed confidential and public direct (August 14, 2020) with the Commission in WGL's rate case in Formal Case No. 1162.[3]

**Q. HAVE YOU TESTIFIED IN WGL PROCEEDINGS IN OTHER STATE JURISDICTIONS?**

A. Yes. I appeared and testified in a WGL rate proceeding before the Public Service Commission of Maryland ("Maryland Commission"), Case No. 9704, on behalf of the Staff

---

1 *Formal Case No. 1180, Washington Gas Light Company's Application for Authority to Increase Existing Rates and Charges for Gas Service in the District of Columbia* ("*Formal Case No. 1180*"), filed August 5, 2024 ("Application"), *as updated and supplemented in* WGL's Supplemental Direct Testimony and Supporting Exhibits and Updated Supplemental Information filed on November 4, 2024 (generally referred to as "Supplemental Filing"). As a general matter, for the remainder of my testimony, any references to WGL's "Application" include WGL's Supplemental Direct Testimony and Supporting Exhibits, Updated Supplemental Information, and Errata to Direct Testimony of Company Witnesses.

2 *Formal Case No. 1169, Washington Gas Light Company's Application for Authority to Increase Existing Rates and Charges for Gas Service in the District of Columbia* ("*Formal Case No. 1169*"), filed April 4, 2022, *as updated and supplemented in* WGL's Supplemental Direct Testimony and Supporting Exhibits and Updated Supplemental Information filed on September 2, 2022 (generally referred to herein as "2022 Application"). In support of its 2022 Application, WGL also submitted WGL's Rebuttal Testimony and Supporting Exhibits filed on January 1, 2023, and WGL's Additional Supplemental Direct Testimony of Company Witness Robert E. Tuoriniemi filed on March 30, 2023 ("2022 Application Supplements").

3 *Formal Case No. 1162, Washington Gas Light Company's Application for Authority to Increase Existing Rates and Charges for Gas Service in the District of Columbia* ("*Formal Case No. 1162*"), filed January 13, 2020, *as updated and supplemented in* WGL's Supplemental Direct Testimony and Supporting Exhibits and Updated Supplemental Information filed on May 15, 2020 (generally referred to herein as "2020 Application").

of the Maryland Commission. In that proceeding, I prepared direct testimony and exhibits (confidential and public) dated August 25, 2023, along with surrebuttal testimony and exhibits (confidential and public) dated October 12, 2023.

In addition, I appeared and testified in a WGL rate proceeding before the Maryland Commission, Case No. 9481, on behalf of the Staff of the Maryland Commission. In that proceeding, I prepared direct testimony and exhibits dated August 21, 2018, along with surrebuttal testimony and exhibits dated September 25, 2018.

**Q. WAS YOUR TESTIMONY IN THIS PROCEEDING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?**

A. Yes.

**Q. BRIEFLY DESCRIBE WGL'S APPLICATION IN THIS PROCEEDING.**

A. WGL's Application for an increase in rates and charges is based on a test period consisting of the twelve months ended March 31, 2024, with a rate effective period consisting of the twelve months ended July 31, 2026.[4] WGL's Application requests rates designed to collect approximately $257.20M in total annual revenues, representing an increase in the Company's total annual revenues (revenue deficiency) of $45.60M.[5] This request includes $11.70M related to the transfer of amounts collected pursuant to the Company's accelerated replacement program ("PROJECT*pipes*") through monthly PROJECT*pipes*

4 Application at 5; Exhibit WG (D) (Tuoriniemi) at 4:21-5:1. *See also* Exhibit WG (D) (Tuoriniemi) at 5:21-22, n.5 (noting that WGL "is proposing a procedural schedule that would allow it to place new rates into effect in May 2025," and the difference between the May 2025 date "and the rate effective period used to develop the ratemaking adjustments in [the] cost of service has little or no impact on [WGL's] revenue requirement recommendation.").

5 *See* Exhibit WG (D) (Tuoriniemi) at 3:15-4:3; Application at 1.

surcharges to base rates.[6] That is, the requested rate increase of $45.60M in WGL's Application consists of $11.70M in revenues from the transfer of PROJECT*pipes* surcharge to base rates and $33.90M for other increases in WGL's cost of service.[7]

The Company is requesting an opportunity to earn an overall rate of return of 7.874%, including a return on equity of 10.50%.[8] WGL proposes that the initial one-year period in which approved rates will be in effect is the 12-months ended July 31, 2026.[9]

## II. SCOPE AND PURPOSE OF TESTIMONY

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

A. The main focus of my Direct Testimony is the revenue requirement for WGL's distribution system for the test year ended March 31, 2024. In this testimony, I present my recommended adjustments to distribution rate base and distribution operations and the overall revenue requirement impact of my recommendations, along with the recommendations of other OPC witnesses in this case who address issues impacting WGL's proposed distribution revenue requirements.

---

6 Exhibit WG (D) (Tuoriniemi) at 3:9-12.

7 Exhibit WG (D) (Tuoriniemi) at 3:8-12. Note, however, that WGL Witness Morrow states that WGL seeks to include approximately $138.7 million of PIPES-related plant into the development of base rates in this proceeding of which $118.5M was included in the PIPES surcharge but $20.2M was not eligible for collection via the surcharge because WGL exceeded a merger-related spending cap and incurred costs in the time between the originally approved end of PIPES 2 and the beginning of the PIPES 2 extension in March 2024. *See* Exhibit WG (I) (Morrow) at 6:7-16. Witness Morrow acknowledges that these amounts do not match those in Witness Tuoriniemi's Direct Testimony because Witness Morrow's amounts are actuals through March 2024 whereas Witness Tuoriniemi's amounts reflect accruals during this timeframe and notes that Witness Tuoriniemi expects to update PROJECT*pipes* Construction Work in Progress ("CWIP") placed into service during the rebuttal phase of this case. Exhibit WG (I) (Morrow) at 6:17-23.

8 *See*, *e.g.*, Exhibit WG (D) (Tuoriniemi) at 4:21-5:2.

9 *See* Exhibit WG (D) (Tuoriniemi) at 4:23-5:1; 18:17-22.

## III. SUMMARY OF TESTIMONY, RECOMMENDED ADJUSTMENTS, AND SPONSORED EXHIBITS

**Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.**

A. OPC proposes significant adjustments that result in an OPC recommended revenue deficiency of $9.42M as opposed to WGL's proposed revenue deficiency of $45.60M.[10]

WGL's Application significantly overstates its revenue deficiency, and this has required correction of WGL's proposed adjustments and also reflecting the impact of numerous other adjustments separately identified by OPC. The impact of two successive substantial rate cases on customer's rates is concerning and alarming.

In April 2024,WGL implemented an involuntary separation plan that downsized 70 management employees and WGL includes an adjustment in the rate case to reduce the related payroll costs. However, buried in the details of voluminous responses by WGL is information which I found that indicates a Phase 2 reduction of additional management and union employees that took place from May to November 2024 – immediately after the Phase 1 reduction.

It is of significant concern that WGL failed to acknowledge, disclose, or even provide specific written answers to data requests addressing the existence of this even larger Phase 2 plan that terminates 92 management employees and 13 union employees. I have quantified a reduction in payroll costs of $3.0M for just the management employees.

[10] *See* Exhibit OPC (B)-2 (Ratemaking Results and Revenue Requirement) and Exhibit OPC (B)-3 (Summary of WGL and OPC Adjustments).

Although WGL has filed various updates and corrections to its testimony, it has not yet acknowledged the Phase 2 employee reduction for some unknown reason.

This rate case Application, which was filed less than seven months after the rates from the last case became effective,[11] will take a toll on customer rates. While WGL espouses a position of doom and gloom regarding its financial status in this rate case, its business strategy plans and budgets for the future paint a positive financial picture in many respects. The Commission should be mindful of these and other actions when addressing rate relief for WGL.

Some of the major adjustments I recommend on OPC's behalf are summarized below (including some adjustments sponsored by other OPC witnesses):[12]

1) Consistent with Commission precedent, I recommend: (i) removing CWIP; (ii) adjusting PROJECT*pipes* to 13-month average balances; and (iii) removing excessive Gas Plant costs, resulting in an adjustment that reduces rate base by $33.40M.

2) I recommend removing the impact of WGL's adjustment that increases the net operating loss carryforward ("NOLC") and rate base by $26.40M. The Company believes that recent Internal Revenue Service ("IRS") private letter rulings disallow previous actions of the Company's tax sharing agreements whereby AltaGas shared WGL NOLC tax benefits with members of the consolidated tax group of companies. However, OPC opposes WGL's proposed flash-cut reversal of this impact in this rate case because benefits to customers were accumulated over a five-year period and WGL has not performed proper due diligence to address how this matter is being addressed by other state regulatory agencies, the Federal Energy Regulatory Commission ("FERC"), and other entities (all which can be addressed in a Commission-initiated generic investigation).

---

[11] *See Formal Case No. 1169*, Order No. 21942, rel. January 11, 2024 (establishing a January 19, 2024 effective date for the rates approved in WGL's last rate case in Formal Case No. 1169).

[12] The amounts referenced in this summary are approximate (rounded up) amounts.

3) I recommend reducing depreciation expense by $7.40M resulting from OPC's revision of WGL's proposed depreciation rates and reductions in CWIP and PROJECTpipes costs, with related impacts on rate base.

4) I recommend removing WGL's non-labor inflation adjustment of $1.0M. While the Commission approved such an adjustment in Formal Case No. 1169 in recognition of the higher inflation rates at that time, inflation rates have now declined, and such an adjustment is no longer warranted. WGL's proposed adjustment also lacks supporting documentation, and WGL has not proven the correlation between the goods and services included in the inflation factor as well as the WGL goods and services to which the inflation factor is applied.

5) I recommend reducing payroll expenses by $3.0M due to WGL's failure to acknowledge and identify a subsequent significant Phase 2 employee reduction in April to November 2024, immediately following the Phase 1 employee reductions of April 2024 that were reflected in this rate case. In addition, I recommend removing $0.9M of unjustified pay raises.

6) I recommend removing the costs to implement the Phase 1 employee reductions of $0.30M until or unless WGL acknowledges the Phase 2 employee reductions and makes appropriate reductions in its payroll costs.

7) I recommend reducing expenses by $1.20M because affiliate expenses allocated from AltaGas to WGL are excessive, unsupported, and represent significant increases in costs, which come shortly after expiration of the protections of Merger Commitment 41.

8) I recommend reducing uncollectible expenses by **BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL** because WGL's related adjustment is excessive, includes outliers, and reflects unique and non-recurring conditions from prior years.

9) I recommend reducing Call Center expense by **BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL.**

10) I recommend reducing short-term incentive expense by $1.0M because: (i) an estimated one-third of that amount is related to disallowable financial performance metrics which are historically disallowed by the Commission; (ii) the lack of supporting documentation; and (iii) the lack of

documentation and support on the value and benefit to customers of the related Value Drivers.

11) I recommend that the Commission direct WGL to ensure that consumers receive the benefit of any federal or state tax code changes that result in WGL paying lower corporate income taxes.

**Q. PLEASE SUMMARIZE THE EXHIBITS TO YOUR TESTIMONY.**

A. The Exhibits are summarized below:

1) Exhibit OPC (B)-1 is my curriculum vitae and a list of regulatory cases in which I was involved.

2) Exhibit OPC (B)-2 provides a summary of WGL's proposed ratemaking adjustments to its distribution rate base and net operating income (by high level account categories) and a summary of OPC's proposed adjustments and recommended distribution rate base and net operating income (by high level account categories) for the test year ended March 31, 2024, along with OPC's recommended increase in base distribution revenues.

3) Exhibit OPC (B)-3 provides a detailed list of all OPC proposed adjustments to the test year impacting rate base, revenues, expenses and taxes, as well as the total net income effect of all adjustments. This includes revisions to WGL-proposed adjustments, along with additional adjustments that I have identified in this Direct Testimony, and the adjustments addressed in the Direct Testimony of other OPC witnesses. The summary allows the Commission to see the totality of the adjustments to the actual test year amounts resulting in the adjusted test year amounts recommended by OPC.

4) Exhibit OPC (B)-4 reflects the impact of OPC Witness Rothschild's recommended overall rate of return calculation on the revenue requirement associated with OPC's recommended adjustments.

5) Exhibit OPC (B)-5 consists of a number of schedules, which provide the supporting calculations for the adjustments recommended in this Direct Testimony. Some of these schedules are modifications of ratemaking adjustments proposed by WGL. This exhibit also includes summary schedules showing the impact of adjustments proposed by OPC Witness Colin Fitzhenry in Exhibit OPC (C).

6) The remainder of my Exhibits are WGL's responses to data requests that I have cited in my Direct Testimony.

## IV. RECOMMENDED ADJUSTMENTS TO TRADITIONAL TEST YEAR

### *Adjustment BCO-1: Adjust CWIP and GPIS (Exhibit OPC (B)-5, Schedule 1)*

**Q. HAS WGL MADE SOME ADJUSTMENTS THAT ARE INCONSISTENT WITH THE COMMISSION'S DETERMINATIONS PERTAINING TO PROJECT*PIPES* CWIP, GAS PLANT IN SERVICE ("GPIS"), AND RELATED RATE BASE COMPONENTS IN THE PRIOR RATE CASE, FORMAL CASE NO. 1169?[13]**

A. Yes. While WGL has proposed some adjustments that are consistent with the Commission's determinations in Order No. 21939, as I address below in my testimony, not all of WGL's plant-related adjustments in this rate case are consistent with Order No. 21939.

By way of background and example, in recent rate cases (including Formal Case No. 1169), WGL proposed to: (1) include PROJECT*pipes* CWIP and other gas plant CWIP in rate base at end-of-period amounts (instead of 13-month average balances); (2) include test year PROJECT*pipes* GPIS other gas plant GPIS in rate base at end-of-period amounts (instead of 13-month average balances); and (3) include significant amounts of post-test period actual and forecasted PROJECT*pipes* and other gas plant through the rate effective period at 13-month average balances.[14]

---

[13] *Formal Case No. 1169,* Order No. 21939, rel. December 22, 2023.

[14] For example, in Formal Case No. 1169, WGL proposed to include significant amounts of forecasted PROJECT*pipes* and other gas plant through the rate effective period ending March 31, 2024 (based on a rate case using a test year end of December 31, 2021).

In this rate proceeding, WGL has excluded significant other gas plant CWIP from rate base and has not proposed to include any actual or forecasted post-test period plant additions in rate base, which is consistent with the Commission's determinations in Order No. 21939. But WGL has included PROJECT*pipes* CWIP in rate base, which is not consistent with the determinations in Order No. 21939 and other Commission precedent.

I summarize below the WGL adjustments and plant balances for CWIP and GPIS PROJECT*pipes* and other gas plant included in this rate case. I also explain if the related plant adjustments and balances are consistent or inconsistent with the determinations in Order No. 21939, and I identify the adjustments that I have made to these plant balances.

1) **Other Gas Plant CWIP**: WGL has removed (and does not seek recovery of) Other Gas Plant CWIP of $66.20M from rate base.[15] This treatment is consistent with Order No. 21939, which denied all test period and post-test period CWIP because WGL's request was inconsistent with the Commission's long-standing precedent and WGL had failed to satisfy the three-prong test that the Commission applies in granting an exception to the Commission's precedent.[16] I do not propose any further adjustments to Other Gas Plant CWIP.

2) **PROJECT*pipes* CWIP**: WGL includes PROJECT*pipes* CWIP in rate base and WGL Adjustment No. 3 adjusts this balance from a 13-month average of $13.10M to an end-of-period balance of $6.90M.[17] WGL's inclusion of this CWIP in rate base is

15 *See* Exhibit WG (D)-5, Adjustment No. 2, pages 1-3. *See also* Exhibit WG (D) (Tuoriniemi) at 50:1-4.

16 *Formal Case No. 1169*, Order No. 21939 ¶¶ 128-130.

17 *See* Exhibit WG (D)-5, Adjustment No. 3, pages 1-3.

inconsistent with Order No. 21939 as I previously noted.[18] WGL Witness Tuoriniemi states that in the prior rate case, the Commission allowed into rate base the test year PROJECT*pipes* CWIP that was placed into service at November 2022, but he does not provide a specific citation to the Order No. 21939.[19] I could not find any citation in Order No. 21939 allowing PROJECT*pipes* CWIP into rate base. To the contrary, I understand that the Commission determined to "reject the inclusion of any CWIP in rate base, and plant additions beyond the test year."[20] Therefore, I propose Adjustment BCO-1 to remove the PROJECT*pipes* CWIP of $6.90M from rate base for the following reasons: (1) to be consistent with the Commission's Order in Formal Case No. 1169 and long-standing Commission precedent;[21] (2) the CWIP balance is not proven to be consistent with the Commission's three-prong test;[22] and (3) various other reasons subsequently addressed in this Direct Testimony (and the Direct Testimony of OPC Witness Colin Fitzhenry).[23]

---

18 *See, e.g., Formal Case No. 1169*, Order No. 21939 ¶ 130 (denying "all CWIP both in the test year and through the rate effective period because it does not meet the three-prong test. The Company did not provide sufficient information to deviate from the Commission's long-standing precedent. Thus, the Commission denies the $85,358,499 CWIP adjustment.").

19 Exhibit WG (D) (Tuoriniemi), at 51:15-16.

20 *Formal Case No. 1169*, Order No. 21939 ¶ 3.

21 *See Formal Case No. 1169*, Order No. 21939 ¶¶ 128-130. *See also, e.g., 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* ("*Formal Case No. 1137*"), Order No. 18712 ¶¶ 105-107, 450, rel. March 3, 2017 (rejecting WGL's request to include CWIP in rate base); *Formal Case No. 685, In the Matter of Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Sale of Electric Energy* ("*Formal Case No. 685*"), Order No. 6096 page 52, rel. June 14, 1979 ((announcing Commission's general policy of excluding CWIP from rate base).

22 *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* ("*Formal Case No. 1093*"*)*, Order No. 17132 ¶ 139, rel. May 15, 2013 (addressing the Commission's three-prong standard for including CWIP in rate base).

23 *See, e.g.*, Exhibit OPC (C) (Fitzhenry) at pages 3, 10, 15-18, 20-23 (discussing WGL's cost overruns and

3) **PROJECT*pipes* GPIS:** WGL includes PROJECT*pipes* GPIS (and related rate base components) in rate base and WGL Adjustment No. 3 increases this balance by $27.10M - adjusting from a 13-month average to an end-of-period balance of $107.60M (Exhibit WG (D)-5, Adjustment No. 3, pages 1-3). This treatment appears to be consistent with Order No. 21939, although the Commission stated that it is treating PROJECT*pipes* GPIS differently and consistent with the precedent in Order No. 18712, which accepted plant that was in-service and providing useful service for the benefit of customers at end-of-period balances, and for which the PROJECT*pipes* surcharge had previously collected these balances from customers.[24] However, I propose Adjustment BCO-1 to reduce PROJECT*pipes* GPIS by $27.10M, to adjust this balance from end-of-period to a 13-month average. I propose to adjust PROJECT*pipes* GPIS to a 13-month average for the following reasons: (1) based on concerns addressed by OPC Witness Fitzhenry; (2) to make the adjustment consistent with WGL's treatment of Other Gas Plant GPIS which is reflected on a 13-month average; and (3) other concerns that I have identified via WGL data request responses and which are subsequently addressed in this Direct Testimony. In addition, I am proposing additional reductions to PROJECT*pipes* GPIS costs based on the Direct Testimony of OPC Witness Fitzhenry, I am merely making the accounting revenue requirement adjustment and Witness Fitzhenry supports the justification for the adjustments.[25] I

poor project management associated with PROJECT*pipes* projects).

[24] Order No. 21939 ¶¶ 132, 283.

[25] *See*, *e.g.*, Exhibit OPC (C) (Fitzhenry) at pages 3, 20-23, 28-29 (discussing OPC Witness Fitzhenry's

have removed 50% of these costs as a very conservative approximation of a 13-month average, but this likely understates the adjustment and warrants further exploration during the course of this proceeding, including potentially through a true-up adjustment when I file my surrebuttal testimony.

4) **Other Gas Plant GPIS:** WGL includes Other Gas Plant GPIS (and related rate base components) in rate base at 13-month average balances, which is inconsistent with WGL's treatment of PROJECT*pipes* GPIS at end-of-period balances. However, I agree with WGL's treatment of the Gas Plant GPIS amounts at 13-month average balances. In addition, I am proposing additional reductions to Other Gas Plant GPIS costs based on the Direct Testimony of OPC Witness Fitzhenry, I am merely making the accounting revenue requirement adjustment and Witness Fitzhenry supports the justification for the adjustments. I have removed 50% of these costs as a very conservative approximation of a 13-month average, but this likely understates the adjustment and warrants further exploration during the course of this proceeding, including potentially through a true-up adjustment when I file my surrebuttal testimony.

The OPC adjustments to PROJECT*pipes* CWIP, plant in service, and other related rate base components are summarized in BCO Table 1 and explained in more detail after the table.

---

proposed disallowance of $16.7 million of PROJECT*pipes* expenditure cost overruns that exceeded the historical accelerated pipe replacement program spending rates and the $5,610,514 of cost variances associated with the non-PIPES projects identified in his testimony, which adjustment removes $22,321,552 from the Company's proposed rate base additions).

**Table 1 – OPC Adjustments to CWIP, Plant in Service, and Other Rate Base Components**

| Ln | Description | Rate Base Adjustments |
|---|---|---|
| | A | B |
| 1 | **Construction Work in Progress:** | |
| 2 | Remove PROJECT*pipes* at WGL's March 31, 2024, end-of-period balance | $ (6,884,576) |
| 3 | Other Plant in Service CWIP - These balances properly removed by WGL | $ - |
| 4 | OPC Adjustment - Remove PROJECT*pipes* CWIP | **$ (6,884,576)** |
| 5 | | |
| 6 | **Plant in Service:** | |
| 7 | PROJECT*pipes* - Adjust from WGL's end-of-period to 13-mo. average | $ (27,107,163) |
| 8 | Other Plant in Service - WGL properly reflected at 13-mo. average | $ - |
| | Other Plant in Service - Sponsored by OPC Witness Colin Fitzhenry | $ (11,160,776) |
| 9 | OPC Adjustment - Reduce PROJECT*pipes* Plant in Service | **$ (38,267,939)** |
| 10 | | |
| 11 | **Depreciation Reserve ("DR"):** | |
| 12 | Project*pipes* - Adjust from WGL's end-of-period to 13-mo. average | $ 1,589,836 |
| 13 | Plant in Service - WGL properly reflected at 13-mo. average | $ - |
| 14 | OPC Adjustment - Reduce PROJECT*pipes* DR | **1,589,836** |
| 15 | | |
| 16 | **Accumulated Deferred Taxes (ADIT):** | |
| 17 | PROJECT*pipes* ADIT - Adjust from WGL's end-of-period to 13-mo. average | $ 8,035,220 |
| 18 | Plant in Service - WGL properly reflected at 13-mo. average | $ - |
| 19 | OPC Adjustment - Reduce PROJECT*pipes* ADIT | **$ 8,035,220** |
| 20 | | |
| 21 | **Cost of Removal (COR):** | |
| 22 | PROJECT*pipes* COR - Adjust from WGL's end-of-period to 13-mo. average | $ 2,092,125 |
| 23 | OPC Adjustment - Reduce PROJECT*pipes* COR | **$ 2,092,125** |
| 24 | | |
| 25 | **Adjustment BCO-1 to Rate Base** | **$ (33,435,334)** |

**Q. PLEASE SUMMARIZE SOME OF THE PRIMARY REASONS FOR EXCLUDING ALL OF PROJECT*PIPES* CWIP FROM RATE BASE.**

A. Some of the primary reasons supporting my adjustment to exclude all of PROJECT*pipes* CWIP from rate base includes the following:

1) The Commission typically excludes CWIP from rate base, relying on its three-prong standard (discussed below) which WGL has failed to address in this rate case.

2) There continues to be concerns with WGL's budgets for PROJECT*pipes* (and Other Gas Plant), because of projects whose actual costs exceed budget resulting in excess costs that are inefficient, imprudent, exhibit poor project management and unsupported by WGL. Compared to some of the worst performing utilities in terms of gas safety and reliability in the northeastern U.S., WGL has a higher-than-average leak rate per mile of distribution mains and services. WGL should not be allowed to grow its rate base and perform below average compared to its peers and create an unnecessary and unreasonable burden on customers. These issues are addressed by OPC Witness Fitzhenry and his concerns are also applicable to CWIP. This is because most cost overruns and related problems will begin during the construction work in progress phase and carry over when these amounts are transferred to GPIS.[26]

3) The Commission did not allow WGL to recover PROJECT*pipes* CWIP in rate base in the most recent litigated WGL rate case, Formal Case No. 1169. In that case, the Commission denied all test period and post-test period CWIP (for both PROJECT*pipes* and other gas plant) because it is not consistent with the three-prong test and the Commission's long-standing precedent.[27]

4) WGL has not sought to include CWIP of other gas plant in this rate case, so its proposal to include CWIP of PROJECT*pipes* is inconsistent, unwarranted, and fails to meet a reasonable burden of proof.

5) In WGL rate case, Formal Case No. 1162, OPC Witness Walker and I raised concerns consistent with those reflected in Liberty Management's Audit Report regarding cost over-runs and tardy completion dates – those concerns continue to exist per the testimony of OPC Witness Fitzhenry.[28]

6) WGL has not made any new substantive and compelling arguments to include PROJECT*pipes* CWIP in rate base in this rate case, so the Commission should reject WGL's proposed adjustments to include this CWIP in rate base.

---

26 *See, e.g.*, Exhibit OPC (C) (Fitzhenry), at pages 2-3.

27 *Formal Case No. 1169,* Order No. 21939 ¶ ¶ 128-130, rel. December 22, 2023.

28 *See Formal Case No. 1162*, Exhibit OPC (A) (Ostrander Direct Testimony) at 24:1-29 to 25:1-17; Exhibit OPC (Walker Direct Testimony) at 4-5 & 1; 25-38 (citing *Formal Case No. 1115*, Final Report of its Management Audit of PROJECT*pipes*, filed April 19, 2019 ("Liberty Management Audit Report")).

**Q. WILL YOU EXPLAIN THE COMMISSION'S THREE-PRONG STANDARD WHICH IS USED TO DETERMINE IF CWIP SHOULD BE INCLUDED IN RATE BASE?**

A. In Order No. 21939, WGL's prior rate case in Formal Case No. 1169, the Commission stated, "[g]enerally, the Commission does not include CWIP in rate base, but has granted exceptions setting out a three-prong standard for the inclusion of CWIP as a post-test year ratemaking adjustment."[29] Order No. 21939 reiterated the following general three-prong standard established in Order No. 17132:[30]

> …the rate base of a utility can properly include the cost of a construction project that is in service during the test period, and in appropriate circumstances, a project completed outside the test period, as long as its in-service date is not too remote in time from the test period. To be placed in rate base, it must be shown that these projects and their related costs are "known and certain changes that can be calculated with precision, which were needed, reasonable, and beneficial to ratepayers during the rate-effective period. In administering this rule, we have held that it is reasonable to allow the costs of construction projects to be included in rate base when projects are in fact placed in service before the end of the test year, but are not recorded as being test year plant in service because of delays in bookkeeping.[31]

In addition, in Order No. 18712[32] pertaining to a prior WGL rate case in Formal Case No. 1137, the Commission stated that it has "on a number of occasions set out its

[29] *Formal Case No. 1169*, Order No. 21939 ¶ 128.

[30] *Formal Case No. 1093*, Order No. 17132 ¶ 139.

[31] *Formal Case No. 1169*, Order No. 21939 ¶ 128 (internal quotations and citations omitted).

[32] *Formal Case No. 1137*, Order No. 18712 ¶ 105.

standard for the inclusion of CWIP as a post-test year ratemaking adjustment,"[33] including in Order No. 17132 pertaining to a prior WGL proceeding. The Commission quoted the same passage from Order No. 17132 as I have set forth above regarding the Commission's Order No. 21939 in the prior rate case, Formal Case No. 1169.

**Q. HAS WGL MET THE THREE-PRONG STANDARD FOR INCLUDING PROJECT*PIPES* CWIP IN RATE BASE IN THIS RATE CASE?**

A. No. First, there is no WGL witness in this proceeding that specifically addresses the Commission's three-prong standard and explains if CWIP is compliant with this standard in order to justify its inclusion in rate base. WGL did not explain nor provide supporting documentation to show that its CWIP includes: 1) projects that are not too remote in time from the test period; 2) costs that are known and certain, and which can be calculated with precision; and 3) costs that are needed, reasonable, and beneficial to ratepayers during the rate-effective period.

The Commission in Order No. 18712 also noted that, in Formal Case No. 1093, the Commission identified an exception to its general rule, where it has on at least one occasion allowed some non-pollution CWIP to be included in rate base if there is a "unique and compelling" reason.[34] However, WGL has not cited to any non-pollution CWIP or other CWIP for which there is a unique and compelling reason to include this CWIP in rate base.

Accordingly, since WGL has not provided the requisite justification to include CWIP in rate base, I have removed the PROJECT*pipes* CWIP from rate base.

---

[33] *Formal Case No. 1137*, Order No. 18712 ¶ 105 & n. 256 (internal citations omitted).

[34] *Formal Case No. 1137*, Order No. 18712 ¶ 106 & n.257 (internal citation omitted).

**Q. WHAT ARE SOME OF THE PRIMARY REASONS SUPPORTING YOUR ADJUSTMENT OF PROJECT*PIPES* GPIS TO A 13-MONTH AVERAGE BALANCE.**

A. Some of the primary reasons for my proposed 13-month average adjustment for *PROJECTpipes* GPIS are essentially the same reasons and related concerns that I addressed above for removing CWIP from rate base. I also relied substantially on the concerns and related PROJECTt*pipes* adjustments proposed in the Direct Testimony of OPC Witness Fitzhenry. Witness Fitzhenry states, among other reasons:[35]

1) There continues to be concerns with WGL's budgets for PROJECT*pipes* (and Other Gas Plant), because of projects whose actual costs exceed budget resulting in excess costs that are inefficient, imprudent, exhibit poor project management and unsupported by WGL.

2) Compared to some of the worst performing utilities in in terms of gas safety and reliability in the northeastern U.S., WGL has a higher than average leak rate per mile of distribution mains and services.

3) WGL should not be allowed to grow its rate base and perform below average compared to its peers and create an unnecessary and unreasonable burden on customers.

These issues and concerns addressed by OPC Witness Fitzhenry are applicable to both CWIP and GPIS.

---

[35] *See e.g.*, Exhibit OPC (C) (Fitzhenry) at 2-3.

**Q. REGARDING YOUR ADJUSTMENT OF PROJECT*PIPES* GPIS TO A 13-MONTH AVERAGE BALANCE, DID YOU REVIEW CERTAIN WGL GPIS COSTS?**

A. Yes. I reviewed Witness Tuoriniemi's November 4, 2024, Supplemental Direct Testimony in this proceeding, including Exhibit WG (2D)-1. Exhibit WG (2D)-1 reflects a roll forward of plant in service on an end-of-period basis from December 31, 2021 (the end of the test year in Formal Case No. 1169) and shows the capital additions represented by each itemized project over $100,000 (and other project amounts), and then adds the remaining capital additions and retirements to reconcile to the GPIS for the test period end March 31, 2024, of this rate case (at end-of-period balances).[36]

Based on my review of these GPIS amounts, OPC propounded Data Request Nos. 15-1[37] and 15-2[38] to WGL and requested the following information:

1) OPC Data Request No. 15-2: Regarding DC Common Plant additions, explain and provide supporting documentation (such as work orders) explaining why certain projects have individual and cumulative actual costs that significantly exceed the original budgeted costs, and explain the reasons for these budget over-runs. Also, explain why some significant projects do not have any original budget costs identified with the project. In addition, WGL was requested to provide specific detailed information regarding capitalized software costs.

2) OPC Data Request No. 15-3: Regarding DC Operating Unit 01 additions, explain and provide supporting documentation (such as work orders) explaining why certain projects have individual and cumulative actual costs that significantly exceed the original budgeted costs, and explain the reasons for these budget over-runs. Also, explain why some significant projects do not have any original budget

[36] Exhibit WG (D) (Tuoriniemi) at 5:16-6:7.

[37] *See* WGL Response to OPC Data Request 15-1 (Exhibit OPC (B)-90).

[38] *See* WGL Response to OPC Data Request 15-2 (Exhibit OPC (B)-77).

costs identified with the project. In addition, WGL was requested to provide specific detailed information regarding capitalized software costs.

I also determined there were budget overruns regarding plant costs regarding information provided in response to OPC Data Request Nos. 15-2 and 15-3.[39] The concerns regarding these plant cost overruns will apply to the same concerns of PROJECTpipes cost overruns. OPC Data Request No. 15-2(a) and 15-3(b) both identified project costs that exceeded budget for "DC Share of Common" plant and "Operating Unit 01 DC" plant and asked for supporting documentation and reasons to address these budget overruns. WGL's response to both data requests gave the same answer, stating that the Company does not capture budget information in its property accounting system because it is not used as a tool to manage capital additions for all projects provided in Exhibit WG (2D)-1.[40] The response referred to the supplemental testimony of OPC Witness Morrow, Exhibit WG (21), which includes an analysis and explanation of variances between estimated and actual costs of capital additions from the last case with a cost more than $100,000. The bottom line is that my specific questions were not adequately answered, and when combined with OPC Witness Fitzhenry concerns, these support adoption of a 13-month average for PROJECT*pipes* GPIS.

---

[39] *See* WGL Response to OPC Data Request No. 15-2 (Exhibit OPC (B)-77); WGL Response to OPC Data Request No. 15-3 (Exhibit OPC (B)-78).

[40] *See* WGL Response to OPC Data Request No. 15-2 at page 2 (Exhibit OPC (B)-77); WGL Response to OPC Data Request No. 15-3 at page 2 (Exhibit OPC (B)-78).

**Q. WILL YOU EXPLAIN HOW YOUR POSITION ON THE CWIP RATEMAKING ISSUE IS CONSISTENT BETWEEN THIS PROCEEDING AND CASES YOU HAVE ADDRESSED BEFORE THE MARYLAND COMMISSION?**

A. I have provided testimony on behalf of the Maryland Office of People's Counsel, Montgomery County, and the staff of the Maryland Commission in ten rate case proceedings before the Maryland Commission, including three WGL rate cases. Most recently, I filed direct and surrebuttal testimony in August 2023 and October 2023, respectively in WGL's rate case in Case No. 9704.

Witness Tuoriniemi stated in prior rate case, Formal Case No. 1169, that the Maryland Commission allowed CWIP in rate base at end-of-period amounts, which is consistent with WGL's proposal for PROJECT*pipes* in this rate case.[41] I agree that this is the policy in Maryland. I have not always opposed CWIP in rate base in Maryland rate cases, although I am opposing that treatment in this rate case. However, my position is consistent on these issues because I am following Commission precedent in both jurisdictions.

### *Adjustment BCO-2: Reduce Depreciation Expense on Reduced Plant Balances at Adjustment BCO-1 and for Revising WGL's Proposed Depreciation Rates (Exhibit OPC (B)-5, Schedule 2)*

**Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO REMOVE DEPRECIATION EXPENSE ON REDUCED PLANT BALANCES AT ADJUSTMENT BCO-1 AND FOR REVISING WGL'S PROPOSED DEPRECIATION RATES.**

---

[41] *Formal Case No. 1169*, Exhibit WG (D) (Tuoriniemi) at 65:19-23.

A. This is a two-part adjustment consisting of Adjustment BCO-2(a) and Adjustment BCO-2(b) as summarized below.

1) **<u>Adjustment BCO-2(a)</u>:** Per Adjustment BCO-1, I adjusted WGL's PROJECT*pipes* GPIS from an end-of-period balance to a 13-month average balance, resulting in a reduction of gross plant of $27,107,163. Because I reduced the PROJECT*pipes* GPIS and Other Plant GPIS plant balance, it is necessary that I make a corresponding adjustment to reduce the related depreciation expense by $231,158, and this amount is from Exhibit WG (D)-5, Adjustment No. 3, pages 1 to 3. If the Commission rejects my Adjustment BCO-1 that adjusts PROJECT*pipes* GPIS from an end-of-period balance to a 13-month average balance, then it will be necessary to also remove this related depreciation expense adjustment. In addition, my depreciation expense adjustment reflects a reduction in depreciation expense related to reducing certain PROJECT*pipes* GPIS and Other GPIS costs based on the recommendations of WGL Witness Fitzhenry as I explained at Adjustment BCO-1.

2) **<u>Adjustment BCO-2(b)</u>:** WGL proposes Adjustment No. 4 to increase depreciation expense by $7,691,665 to reflect the impact of proposed increased depreciation rates. OPC Witness Brian Andrews is sponsoring testimony to propose revisions to WGL's proposed depreciation rates in Exhibit OPC (E), and I am merely calculating the impact of the OPC-proposed depreciation rates on depreciation expense. I have taken the proposed depreciation rates of Witness Andrews and included them in the same Excel workpaper that WGL used to reflect its proposed increased depreciation rates (Exhibit WG (D)-5, Adjustment No. 4, pages 1 to 10). In addition, I adjusted WGL's PROJECT*pipes* GPIS from an end-of-period balance to a 13-month average balance, resulting in a reduction of gross plant of $27,107,163 – and this impact is reflected on adjusted depreciation expense. In addition, I removed $11,160,776 of PROJECT*pipes* GPIS and Other General Plant GPIS based on OPC Witness Fitzhenry's Direct Testimony, and this impact is reflected on the adjusted depreciation expense. The OPC-proposed depreciation rates result in a reduction in depreciation expense to WGL depreciation expense of $7,385,773, and this reduces WGL's depreciation expense adjustment from an increase of $7,691,665 to an increase of $305,892.

This adjustment also has a corresponding impact of reducing the Depreciation Reserve by $7,385,773 (an increase in rate base) and reducing the ADIT by $2,014,791 (an increase in rate base).

### *Adjustment BCO-3: Reverse the Impact of WGL's NOLC PLR Adjustment (Exhibit OPC (B)-5, Schedule 3)*

**Q. PLEASE SUMMARIZE ADJUSTMENT BCO-3 REGARDING WGL'S PROPOSED NOLC PLR ADJUSTMENT.**

A. I am proposing Adjustment BCO-3 to reverse the impact of WGL's proposed NOLC PLR adjustment. This results in a total decrease to the rate base of $26,370,613, consisting of a reduction to the Federal NOLC balance of $27,248,768[42](decrease in rate base), an increase to the State/DC NOLC balance of $878,155[43] (increase in rate base),[44] and an increase to income tax expense of 140,599.[45]

WGL Witness Kimberly M. Bell addresses the IRS PLR and the policy reasons supporting WGL's proposed adjustment to the NOLC, and WGL Witness Tuoriniemi primarily quantifies the related adjustment.[46]

It is WGL's position that a PLR issued for another company is applicable to the Company because of similar treatment of tax sharing payments that WGL has received from other members of the consolidated group in exchange for the use of WGL's NOLC tax benefits. WGL's adjustment will reverse the historical cumulative impact of these tax sharing payments from other affiliates to WGL on a flash-cut basis and this will increase

---

[42] Exhibit WG (D) (Tuoriniemi), November 6, 2024, Replacement Page at 98:10.

[43] Exhibit WG (D) (Tuoriniemi) at 98:8.

[44] The netting of the Federal and State/DC NOLC results in a net reduction in the NOLC of $26,370,613 (decrease in rate base) per Exhibit BCO-3, Adjustment BCO 3.

[45] Exhibit WG (D) (Tuoriniemi) at 98:13.

[46] Exhibit WG (D) (Tuoriniemi) at 97:12-104:11.

rate base by a significant amount of $26.40M and effectively treat this transaction as if it never occurred. Any benefits that customers may have received via this tax sharing payment arrangement over about a five-year basis will be removed immediately in this one-time (flash-cut) adjustment proposed by WGL.

**Q. HAS A REVISION BEEN MADE TO WITNESS TUORINIEMI'S TESTIMONY REGARDING THE PROPOSED NOLC PLR ADJUSTMENT?**

A. Yes, a revision has been made to Witness Tuoriniemi's Direct Testimony to correct one component of the NOLC adjustment,[47] the Federal NOLC component has been corrected from $24,088,259 to $27,248,768.[48]

**Q. WHAT IS A NOLC (OR NOL OR DTA-NOL)?**

A. Although different acronyms may be used in WGL's testimony, the acronym NOLC, NOL, or DTA-NOL are intended to be the same and refer to the same type of deferred tax asset related to net operating loss carryforwards. I primarily use the acronym NOLC, and the Federal NOLC (Federal income tax portion of the NOLC), State or DC NOLC (State/DC income tax portion of the NOLC).

The NOLC is a deferred tax asset (debit amount) recorded on the balance sheet that acts as an increase to rate base, and it offsets (or decreases) the similar accumulated

---

47 This issue is addressed in WGL's Response to OPC Data Request No. 17-2 (Exhibit OPC (B)-80).

48 Exhibit WG (D) (Tuoriniemi) at 98:10 showed an adjustment to the Federal NOLC of $24,088,259, which did not agree with the adjustment to the Federal NOLC of $27,248,768 (Exhibit WG (D)-2, page 2 of 3), and on October 31, 2024, OPC issued Data Request No. 12-2 (b)(iii) (Exhibit OPC (B)-76) that asked why there was a discrepancy between the NOLC amounts in Witness Tuoriniemi's Direct Testimony and the amount in Exhibit WG (D)-2, page 2 of 3. On November 6, 2024, WGL issued a Replacement Page for Witness Tuoriniemi's adjustment that revised the original NOLC amount of $24,088,259 that was referenced in Witness Tuoriniemi's Direct Testimony to a corrected amount of $27,248,768.

deferred income tax (ADIT) liability account (credit amount) that acts to decrease rate base. Thus, an increase in the NOLC balance as proposed by WGL's adjustment will act to increase rate base.

The NOLC is a deferred tax asset that reflects the income tax effect on timing differences that cause taxable losses (both federal and state/DC tax losses), and the timing difference that mostly contributes to these tax losses is accelerated tax depreciation.

**Q. PLEASE EXPLAIN WGL'S RATIONALE FOR PROPOSING THIS ADJUSTMENT TO THE NOLC.**

A. There is a "Tax Sharing Agreement"[49] between AltaGas and WGL (and other members/affiliates of the consolidated group) that allows AltaGas to use the NOLC tax benefits of WGL (and other affiliates) for its consolidated income tax returns, and in return AltaGas reimburses WGL (and other affiliates) for the benefits from using its NOLC on its consolidated income tax returns.[50] The tax sharing agreement has been approved by the Virginia State Corporate Commission, but has not been approved by the D.C. Commission because WGL states there is no such requirement.[51]

Witness Bell states that WGL has become aware of IRS PLRs[52] issued to other companies that indicates WGL's accounting for the receipts of the tax sharing payments from AltaGas as a reduction of the NOLC (via the Tax Sharing Agreement) can cause a

---

[49] The Tax Sharing Agreement was provided by WGL in response to Confidential OPC Data Request No. 6-7. Exhibit OPC (B)-46.

[50] Exhibit WG (H) (Bell), at 2:15-17 and 4:1-13.

[51] Exhibit OPC (B)-81.

[52] PLRs 202462002, 202462003, and 202462004.

normalization violation under the tax rules.[53] Therefore, to avoid a tax normalization violation, WGL proposes to reverse the cumulative impact of tax sharing transactions with AltaGas since the merger, and this will cause the NOLC (and rate base) to increase immediately by about $26.400M.

**Q. DOES WGL PROPOSE URGENT ACTION ON THIS MATTER IN THIS RATE CASE?**

A. Yes. WGL states that the IRS allows for safe harbor relief for inadvertent normalization violations under Revenue Procedural 2017-47 and Revenue Procedure 2020-39, and a potential penalty is avoided if the taxpayer and rate-setting commission agree to correct the normalization violation at the next available opportunity after the violation, and this rate case provides that opportunity for WGL to avoid any normalization and penalty.[54]

**Q. DO YOU BELIEVE URGENT ACTION IS NECESSARY AND THAT THE COMMISSION NEEDS TO APPROVE WGL'S NOLC ADJUSTMENT TO AVOID ANY POTENTIAL NORMALIZATION VIOLATION?**

A. No. First, I believe the Commission should reverse WGL's adjustment as I propose in this rate case.

Second, the Commission should open a "generic" investigation into this matter for all impacted utilities in D.C. and get appropriate feedback from utilities and intervenors regarding this matter. If this matter was truly urgent and necessary of immediate resolution in order to avoid a potential normalization violation, then it would seem the Commission

53 Exhibit WG (H) (Bell) at 2:10-22.

54 Exhibit WG (H) (Bell) at 6:1-21.

would have already heard from numerous utility companies in the D.C. jurisdiction. Playing the “normalization violation” card is a tactical way to put pressure on the Commission to act prematurely and without all the facts to WGL’s benefit, and it is mostly WGL that has not been forthcoming with facts or done its due diligence on this issue. If WGL seriously faced the urgency of a normalization violation, it could and should have taken the following actions, none of which it has taken: (1) already had voluntary discussions with the IRS regarding this issue; (2) determined how other state regulatory agencies in other jurisdictions (including jurisdictions where it operates) are addressing this issue; (3) explored and raised the idea of a generic investigation with the Commission; and (4) alerted regulatory utility agencies in jurisdictions where it operates of this pending matter. As such, WGL has taken no actions that would be indicative of the urgency that it foments.

Third, I believe that requiring WGL and other DC utilities to seek a specific PLR should be avoided if at all possible. I believe these matters can be reasonably addressed and resolved after substantial research and options are explored via a generic investigation.

Fourth, as part of the generic investigation the Commission should encourage all parties to do their research on this issue and provide feedback on the following:

1) All impacted utilities should open a dialogue with the IRS and get feedback regarding resolution alternatives.
2) The Commission (and WGL) should continue to monitor the actions that FERC is taking on this issue.

3) The Commission should encourage utilities and all parties to research and determine how state regulatory agencies in other jurisdictions are addressing this issue, and utilities should provide feedback on how this issue is being addressed in other jurisdictions where they operate.

I believe an open and honest dialogue on this issue among all parties is the most important goal regarding this matter.

**Q. IS IT NECESSARY FOR THE D.C. COMMISSION TO MAKE A DECISION ON THIS NOLC TAX SHARING ISSUE IN THIS RATE CASE AS A MATTER OF FIRST IMPRESSION IN THE DC PSC, ESPECIALLY WITHOUT HELPFUL INFORMATION FROM WGL?**

A. No. WGL Witness Bell states that similar tax sharing agreements and related tax payments are common and typical among regulated utilities.[55] If this tax sharing agreement and payment arrangement is common and widespread then it should have provided sufficient evidence and support for the Commission's consideration. WGL did not provide citation to any utility commission decision that supports its position on this specific issue.

I believe it would have been more efficient and reasonable approach for WGL to have first researched this issue and had some contact with the IRS regarding this matter prior to filing this rate case and requesting rate relief for this tax sharing NOLC issue.

---

55 Exhibit WG (H) (Bell), at 4:14-18 and 5:6-10.

**Q. DID WGL PERFORM PROPER AND REASONABLE DUE DILIGENCE ON THIS ISSUE PRIOR TO FILING THIS RATE CASE, AND HAVE THEIR RESPONSES TO DATA REQUESTS BEEN OPEN AND HELPFUL?**

A. No. OPC has issued various data requests to WGL trying to determine the status of this matter in other jurisdictions, but WGL has not provided any helpful information. WGL has objected to several OPC data requests that were attempting to find out the current status of this issue via any communication it has had with the IRS, and via actions by other regulatory agencies in those other jurisdictions where WGL operates, but there has been little useful information provided. WGL should have done its due diligence on this issue prior to filing its rate case and should have cited to any recent precedent and actions of the IRS, state regulatory agencies, FERC, and other parties regarding this NOLC tax sharing matter.

**Q. DID WGL EITHER OBJECT OR FAIL TO PROVIDE MEANINGFUL INFORMATION SOUGHT IN OPC DATA REQUESTS REGARDING BACKGROUND INFORMATION, PRECEDENT, OR WGL'S EXPERIENCE WITH THIS ISSUE IN OTHE JURISDICTIONS?**

A. I will provide one primary example. OPC Data Request No. 12-1[56] asked WGL: (a) if WGL, AltaGas or any other affiliate has been contacted by the IRS regarding a possible tax normalization violation regarding this matter; (b) if WGL or any affiliate has voluntarily initiated contact with state or federal tax agencies to discuss any possible tax

56 *See* WGL Response to OPC Data Request No. 12-1 (Exhibit OPC (B)-75).

normalization violation; (c) identify all other rate cases (including WGL/affiliate rate cases) where utility companies have proposed similar adjustments and sought rate relief for this issue, or jurisdictions where this issue is being addressed in some manner; (d) explain why it is more reasonable and necessary for the Commission to accept WGL's ratemaking adjustments for this NOLC tax sharing payment as a matter of first impression and without precedent – instead of deferring this issue until the Company files tax returns addressing this issue or there is definitive widespread determination on this issue by state and federal tax agencies; and (e) additional information sought in this data request.

As one example, WGL's response to OPC Data Request No. 12-1 objected to two subpart questions; both asking WGL to identify all other rate cases (including WGL/affiliate rate cases) where utility companies have proposed similar adjustments and sought rate relief for this NOLC tax sharing payment issue, or jurisdictions where this issue is being addressed in some manner. The remainder of the WGL responses did not provide much of any helpful information, WGL stated it had not been contacted by the IRS although it had reported the normalization issue on its 2023 federal corporate tax return, and WGL focused on concerns regarding an inadvertent normalization violation. WGL was unable to identify any other rates cases or proceedings where this issue was being addressed.

**Q. DOES THIS NOLC TAX SHARING PAYMENT ARRANGEMENT CREATE A POSSIBLE VIOLATION OF MERGER COMMITMENT NO. 44?**

A. I am not an attorney, so my comments are from a broader regulatory perspective. Also, OPC Data Request No. 17-4[57] asked WGL if the NOLC tax sharing payment arrangement did or did not result in a violation of Merger Commitment No. 44. WGL objected to this data request on the grounds that it calls for a legal conclusion and legal research.

Commitment No. 44 requires that, "no tax elections or accounting methods shall be employed related to the Merger that would in any way result in any reduction to Washington Gas's net accumulated deferred income tax balances that are used to reduce rate base in Washington Gas's rate cases."[58] In prior rate case, Case No. 1169, Witness Tuoriniemi's Direct Testimony (135:1 – 136-2) explains that, per Merger Commitment No. 44, the merger has not affected any accounting and ratemaking policies, including income tax policies (and it has not impacted accumulated deferred income taxes, accumulated deferred income tax credits, and net operating losses).

However, in this rate case, WGL proposes adjustments to reverse the cumulative impact of tax sharing arrangements between WGL and AltaGas, which causes an increase in rate base and the bottom line revenue requirement by $2,840,840.[59] Although I assume WGL likely did not know that its actual Tax Sharing Agreement among AltaGas and the consolidated group of companies could lead to a tax normalization violation, I believe these actions could be possibly viewed as a violation of the Merger Commitment No. 44. It's

---

57 Exhibit OPC (B)-82.

58 Formal Case No. 1142, Order No. 19396, Appendix A, pages 18-19.

59 (Exhibit D) (Tuoriniemi), at 98:14-17, which discloses the adjustment will increase the revenue requirement by $2,840,840.

important to understand that neither the Commission nor customers have had any part of causing any repercussions from this NOLC tax payment arrangement, it is all a result of the Company initiating and putting into place arrangements intended to benefit the consolidated group by using the tax benefits of WGL and other utilities.

I have related concerns that ratepayers: (1) may have received little to no benefit in periodic rate case proceedings related to the annual impact of the tax sharing arrangements (and tax payments from AltaGas to WGL) that were spread out over years 2019 (first year after merger) to 2023 and (2) will be harmed by WGL's proposed cumulative flash-cut adjustment that will increase rate base immediately in this rate proceeding by $26.40M (a rate case during the period that tax sharing payments were made from AltaGas to WGL could have resulted in smaller increments of adjustments but ratepayers are now faced with a significant rate impact in this case). This is not an equitable or reasonable resolution to this issue that may be interpreted as a violation of Merger Commitment No. 44 (for at least that part of the tax payments that took place after the AltaGas and WGL merger) and the resulting WGL-proposed negative regulatory impact on customers ($26.40M rate base increase) that resulted from the merger of AltaGas and WGL.

**Q. ARE YOU CONCERNED ABOUT WGL'S FLASH-CUT APPROACH TO INCREASING RATE BASE IN THIS RATE CASE, WHEN THE RELATED TAX SHARING PAYMENT BENEFITS ACCUMULATED OVER ABOUT FIVE YEARS?**

A. As I previously noted, WGL's position and adjustment in this rate case seeks to recover the cumulative impact of the NOLC tax payment issue on a flash-cut immediate basis from ratepayers, which is inconsistent with how benefits were conveyed to ratepayers for this issue via periodic rate cases (and the degree to which customers received rate relief for this issue in prior rate cases is a concern). I recommend the Commission consider the following alternatives to ameliorate this adverse impact on ratepayers. First, at the very minimum, the negative impact of this adjustment on ratepayers should be amortized over the same number of years that any such benefits accrued to ratepayers. Second, only the amount of any such tax sharing payment benefits that were reflected in rate cases and which flowed through to ratepayers (as a reduction in customer rates) should now be subject to recovery via any amortization process.

**Q. ARE YOU CONCERNED THE TAX SHARING AGREEMENT WAS NEVER APPROVED BY THE DC COMMISSION?**

A. Yes. Witness Bell states that the tax sharing agreement (as part of affiliate agreements) was approved by the Virginia State Corporation Commission on December 14, 2023 – and this VA-approved tax sharing agreement replaced the previous tax sharing arrangement in place at July 6, 2018.[60] However, the tax sharing agreement was never formally approved by the DC Commission.[61] This raises the concern that if the tax sharing agreement was never formally approved by the DC Commission, then it could be argued that tax sharing payments should have never taken place in the DC jurisdiction. This raises additional questions about the justification for WGL's adjustment that seeks recovery of the cumulative impact of this NOLC tax sharing payments from DC ratepayers.

---

60 Exhibit WG (H) (Bell) at 4:1-6.

61 *See* WGL Response to OPC Data Request No. 17-3 (Exhibit OPC (B)-81).

**Q. ARE YOU STILL EVALUATING THE DETAILED FINANCIAL IMPACTS OF WGL'S PROPOSED NOLC ADJUSTMENT, HOW AMOUNTS WERE RECORDED ON THE BOOKS, AND THE TIMING OF ANY BENEFITS RECEIVED BY CUSTOMERS?**

A. Yes. OPC Data Request Nos. 12-2, 17-1 Confidential, 17-5, 18-1, and 18-2[62] all address related financial issues and how the NOLC and tax sharing payments were recorded on the books for GAAP and regulatory purposes. I reserve the ability to address this issue in more detail in surrebuttal testimony.

***Adjustment BCO-4: Adjust Pay Raises to Reflect Reduced Payroll Costs for Additional May to November 2024 Employee Reductions (Exhibit OPC (B)-5, Schedule 4)***

**Q. PLEASE SUMMARIZE WGL'S PROPOSED PAYROLL ADJUSTMENTS IN THIS CASE AND YOUR ADJUSTMENT TO PAY RAISES TO REFLECT THE REDUCED PAYROLL COSTS RELATED TO ADDITIONAL MAY TO NOVEMBER 2024 EMPLOYEE REDUCTIONS.**

A. WGL's Adjustment No. 5 consists of three primary components that impact the calculation of the proposed total increase in payroll expense of $1,001,057 as set forth below:

1) **Elimination of 70 management employees reflected in pay raise calculation:** WGL correctly reduced gross payroll costs by $9.9M (total WGL basis)[63] for the

---

[62] *See* WGL Response to OPC Data Request No. 12-2 (Exhibit OPC (B)-76); WGL Confidential Response to OPC Data Request No. 17-1 (Exhibit OPC (B)-79); WGL Response to OPC Data Request No. 17-5 (Exhibit OPC (B)-83); WGL Response to OPC Data Request No. 18-1 and Confidential Response to Follow Up Data Request (Exhibit OPC (B)-84); and WGL Response to OPC Data Request No. 18-2 (Exhibit OPC (B)-85).

[63] Gross payroll costs of $9.9M includes expensed and capitalized payroll costs of WGL prior to applying the expense factor and DC allocation factor.

impact of the involuntary separation program that eliminated 70 management employees (but no union employees) in April 2024, for purposes of determining the going-forward level of payroll costs used in calculating pay raises in the test period and post-test period. However, WGL's adjustment is substantially flawed because it failed to disclose and reflect a reduction in approximate gross payroll costs of about $17.5M[64] (total WGL basis) for the even larger subsequent elimination of 92 management employees from May to November 2024 (also, 13 union employees were eliminated) from May to November 2024. I am proposing an adjustment to address this issue.

2) **Union and management pay raises:** WGL proposes a payroll expense increase of $999,100 (WGL-DC basis) for union pay raises of 3% applied to the test period and post-test period[65] and for management pay raises of 3.97% for the test period and 4.97% for the post-test period.[66] I propose an adjustment to allow test period pay raises for union employees, disallow post-test period pay raises for union employees, disallow test period and post-test period pay raises for management

---

64 I refer to the additional $17.5M (management payroll cost reduction adjustment that I propose as "approximate", because it is based on my best effort calculation due to WGL's failure to disclose and provide the actual payroll cost reduction for this additional reduction in management and union employees from May to November 2024 – and some employee reductions may be continuing after November 2024.

65 The test period pay raises were effective April 1, 2023, June 1, 2023, August 1, 2023, and August 1, 2023, for the four union-employee groups and effective January 1, 2024, for management employees.

66 The post-test period pay raises were effective April 1, 2024, June 1, 2024, August 1, 2024, and August 1, 2024, for the four union-employee groups and effective January 1, 2025, for management employees.

employees, and to reduce the management pay raises to 3% for the test period and post-test period.[67]

3) **Union ratification bonus:** WGL proposes a payroll expense increase of $1,957 related to the 5-year amortization of the union ratification bonus. I am not contesting this adjustment.

**Q. PLEASE PROVIDE MORE DETAIL ON WGL'S PROPOSAL TO INCREASE PAYROLL COSTS FOR UNION AND MANAGEMENT PAY RAISES AND EXPLAIN YOUR RELATED ADJUSTMENTS.**

A. WGL proposes to increase payroll costs for union and management pay raises as follows.

1) **WGL's calculation of the base amount for pay raise adjustments:** WGL started with its total actual test year end March 31, 2024, payroll costs (including expensed and capitalized payroll costs) of $194.1M (which includes base pay of $168.4M and short-term incentives of $15.8M, but excludes long-term incentives), and WGL removed $9.9M of payroll costs related to the April 2024 management involuntary separation plan (that eliminated 70 management employees beginning in April 2024), resulting in net payroll costs of $184.2M used as the base amount for calculating the union and management test period and post-test period pay raise adjustments.[68]

---

[67] If the Commission decides to allow management pay raises, these raises should be limited to 3%.

[68] All of these amounts are total WGL payroll costs (expensed and capitalized costs), and WGL subsequently applies an O&M allocation factor that allocates 75.53% of payroll costs to expense and then applies a 19.36% DC allocation factor that allocates the portion of payroll costs to the DC jurisdiction. *See, e.g.*, WGL Response to OPC Data Request No. 11-10 (Exhibit OPC (B)-65 at 3).

2) **Union test period pay raises effective in 2023:** WGL increased payroll expense by $370,949 related to the test period pay raises of five union groups with negotiated contracts and pay raises of 3% effective on April 1, 2023, June 1, 2023, and August 1, 2023 (this pay raises applies to two union groups).[69] These are gross WGL costs (expensed and capitalized), prior to applying the O&M expense factor and the WGL-DC jurisdictional factor. I do not oppose the test period union percentage pay raise of 3% or WGL's related pay raise adjustment amount.

3) **Union post-test period increases effective in 2024:** WGL increased payroll expense by $1,960,796 (Exhibit OPC (B)-5, Schedule 4, page 2 of 2), using the same 3% pay raise for the same union groups in point (2) above and for the post-test periods starting one year after the dates in point (2) above (effective April 1, 2024, June 1, 2024, and August 1, 2024).[70] These are gross WGL costs (expensed and capitalized), prior to applying the O&M expense factor and the WGL-DC jurisdictional factor. I do not oppose the post-test period union percentage pay raise of 3%. However, I have removed WGL's pay raise adjustment amount because the Company has failed to disclose and reflect the impact of the May to November 2024 elimination of 13 union employees in this adjustment. If WGL will disclose and properly adjust for the elimination of these union employees, then my surrebuttal testimony will consider

[69] Exhibit WG (D)-5, Adjustment No. 5, pages 2-5.

[70] Exhibit WG (D)-5, Adjustment No. 5, pages 2-5.

allowing a post-test period payroll increase based on correct going-forward union employee levels.[71]

4) **Management test period increases effective in 2024:** WGL increased payroll expense by $3,138,466 (Exhibit OPC (B)-5, Schedule 4, page 2 of 2), applying the actual average 3.97% pay raise effective January 1, 2024.[72] These are gross WGL costs (expensed and capitalized), prior to applying the O&M expense factor and the WGL-DC jurisdictional factor. I oppose WGL's test period management percentage pay raise of 3.97% and propose a 3% pay raise. Also, I have removed WGL's test period pay raise adjustment amount because the Company has failed to disclose and reflect the impact of the May to November 2024 elimination of 92 management employees in this adjustment. If WGL will disclose and properly adjust for the elimination of these management employees, then my surrebuttal testimony will consider allowing a test period payroll increase based on correct going-forward management employee levels.[73] If WGL provides all requested information and the final additional reduction in management employees remains at 92, I estimate that WGL's test period pay raise increase of $3,138,466 would be reduced to $2,216,923, a reduction of $921,543.

---

[71] This condition also requires that WGL provide OPC with complete and correct calculations and supporting documentation for a revised union payroll adjustment on a timely basis (to allow me adequate review time), and which should also include any additional reductions in union employees beyond November 2024.

[72] Exhibit WG (D)-5, Adjustment No. 5, pages 2-5.

[73] This condition also requires that WGL provide OPC with complete and correct calculations and supporting documentation for a revised management payroll adjustment on a timely basis (to allow me adequate review time), and which should also include any additional reductions in management employees beyond November 2024.

5) **Management post-test period increases effective in 2025:** WGL increased payroll expense by $1,362,578 (Exhibit OPC (B)-5, Schedule 4, page 2 of 2), applying a 3-year average 4.97% pay raise to the effective date January 1, 2025.[74] These are gross WGL costs (expensed and capitalized), prior to applying the O&M expense factor and the WGL-DC jurisdictional factor. I oppose WGL's post-test period management percentage pay raise of 4.97% and propose a 3% pay raise. I have removed WGL's post-test period pay raise adjustment amount because the Company has failed to disclose and reflect the impact of the May to November 2024 elimination of 92 management employees in this adjustment. If WGL will disclose and properly adjust for the elimination of these management employees, then my surrebuttal testimony will consider allowing a test period payroll increase based on correct going-forward management employee levels.[75] If WGL provides all requested information and the final additional reduction in management employees remains at 92, I estimate that WGL's post-test period pay raise increase of $1,362,578 would be reduced to $681,256, i.e., a reduction of $681,322.

**Q. ARE THERE DIFFERENCES IN THIS RATE CASE RELATING TO PAYROLL ADJUSTMENTS OF NOTE AS COMPARED TO THE LAST RATE CASE?**

[74] 4.97% is the average pay raises for 2022 of 5.22%, 2023 of 5.73%, and 2024 of 3.97%. Exhibit WG (D)-5, Adjustment No. 5, pages 2-5.

[75] This condition also requires that WGL provide OPC with complete and correct calculations and supporting documentation for a revised management payroll adjustment on a timely basis (to allow OPC adequate review time), and which should also include any additional reductions in management employees beyond November 2024.

A. Yes. WGL proposes union and management pay raises effective within 12 months after the test year end March 31, 2024, in this rate case. However, in the prior rate case (Formal Case No. 1169), WGL proposed management pay increases that were effective both 24 months (effective January 2023) and 36 months (effective January 2024) after that rate case's test period end of December 31, 2021. In the prior rate case, the Commission adopted WGL's pay raises for union and management employees that were effective within 12 months of the test year end as being known and measurable but rejected WGL's pay raises beyond that point as not being known and measurable.[76]

WGL states that its pay raise adjustments in this rate case are consistent with Order 21939 in the prior rate case because they are effective within 12 months of the test period end and reflect the April 2024 management involuntary separation plan.[77] I disagree with this conclusion because WGL has not clearly addressed, acknowledged, or reflected any of the additional decrease in payroll costs related to the impact of the May to November 2024 elimination of 92 management employees and 13 union employees. Thus, WGL has calculated pay raises based on overstated payroll costs that do not reflect the known and measurable reduction of payroll costs related to the May through November 2024 reduction in management and union employees.

**Q. DID WGL DISCLOSE AND PROPERLY REDUCE PAYROLL COSTS FOR THE IMPACT OF THE MAY TO NOVEMBER 2024 EMPLOYEE TERMINATIONS IN ADJUSTMENT NO. 5?**

---

[76] *Formal Case No. 1169*, Order No. 21939 ¶ 209.

[77] Exhibit WG (H) (Bell) at 6:9-13.

A. No. WGL has failed to disclose and properly reduce payroll costs related to its May to November 2024 management and union employee terminations. Specifically, WGL's Adjustment No. 5 approach appropriately removes $9.9M of payroll costs (related to the elimination of 70 employees via the April 2024 management involuntary separation plan) from the total amount of payroll costs, in order to determine the going-forward level of payroll costs used for calculating the amount of pay raises for the test period and post-test period. WGL's Adjustment No. 13 also uses the correct approach to remove the payroll costs related to the April 2024 management involuntary separation plan as a separate stand-alone adjustment to the revenue requirement of this rate case. However, WGL's Adjustment Nos. 5 and 9 are fatally flawed because WGL failed to disclose and consistently reflect the additional reduction in payroll costs related to the similar and much larger termination of an additional 92 management employees and 13 union employees from May to November 2024.[78]

**Q. ARE THE PAYROLL EXPENSES RELATED TO THE UNION PAY RAISES KNOWN AND MEASURABLE?**

[78] The November 2024 level of termination is the latest information reflected in headcount reports provided by WGL, but there may be additional employee reductions subsequent to November 2024. Because this section of testimony (Adjustment BCO-4) proposes to reduce WGL's Adjustment No. 5 regarding the calculation of pay raises, I will only summarize my concerns with WGL's failure to reduce payroll costs related to the May to November 2024 employee reductions. However, the next section of my testimony (Adjustment BCO-5) will address my concerns in more detail regarding WGL's failure to reduce payroll costs related to the May to November employee reductions, and that adjustment reduces WGL's stand-alone Adjustment No. 13. My corresponding stand-alone Adjustment BCO-5 (as a revision to WGL's stand-alone Adjustment No. 13), is the more appropriate section to address my concerns and calculations in more detail regarding the May to November 2024 employee reductions not reflected in WGL's Adjustment No. 5 or No. 9.

A. I have determined that WGL's adjustment to increase union test period pay raise expense by $370,949 (that have been annualized through the test period end March 31, 2024) is known and measurable. Thus, I have not adjusted this pay raise expense, and I do not oppose the percent pay raise of 3% used for both the test period and the post-test period.

However, I have determined that WGL's adjustment to increase union post-test period pay raise expense by $1,960,796 is not currently known and measurable, so I have removed these expenses. As previously explained, WGL has not disclosed or adjusted payroll costs for the impact of the May to November 2024 reduction of 13 union employees, therefore WGL's adjustment is not known and measurable because it does not reflect the impact of the 13 eliminated union employees.

If WGL subsequently provides OPC with previously requested information regarding the May to November 2024 reduction of 13 union employees, then my surrebuttal testimony will reflect my final position on this issue. If the 13 terminated union employees reflect a permanent and ongoing reduction in union employees (along with perhaps additional union employee reductions), then I will reduce WGL's pay raise adjustment for the impact of the 13 union employees, but I will include some proper reduced level of pay raise expense for existing union employees in the adjustment.

Most importantly, the number of ongoing union employees (and their related payroll costs) are the largest issue driving the amount of union pay raise expenses. Thus, if the number of union employees receiving pay raises cannot be determined with reasonable certainty and is not known and measurable, then the related pay raise calculation is also not known and measurable even if the percentage raise (such as 3%) is known and measurable.

**Q. ARE THE PAYROLL EXPENSES RELATED TO THE MANAGEMENT PAY RAISES KNOWN AND MEASURABLE?**

A. No. Based on the information received in this case, neither of WGL's test period or post-test period pay raise adjustments are known or measurable, so I have removed both the WGL test period pay raise expense of $3,138,466 and the post-test period pay raise expense of $1,362,578.

Both WGL's test period pay raise adjustment (effective January 1, 2024) and post-test period pay raise adjustment (effective January 1, 2025) to increase payroll expense are impacted by the level of management employees in 2024,[79] and because WGL has not disclosed or adjusted payroll raise expenses for the impact of the May to November 2024 reduction of 92 management employees, the WGL pay raise adjustment is not known and measurable. In addition, I oppose WGL's pay increase percentages for the test year (3.97%) and the post-test year (4.97%), and I propose management pay increases of 3%.

If WGL subsequently provides OPC with previously requested information regarding the May to November 2024 reduction of 92 management employees, then my surrebuttal testimony will reflect my final position on this issue. If WGL provides the payroll costs related to the 92 terminated management employees (and any other

---

[79] This is because the test period pay increase effective January 1, 2024, is impacted by changes in management employee levels and related payroll expenses from January to December 2024, and the January 1, 2025, post-test period pay raise expenses begin with the carryover of management employee levels and payroll costs from the test period.

management employees terminated after November 2024) and agrees that some adjustment to test year and post-test year pay raises are necessary, then I will consider this adjustment to be known and measurable and I will include a proper allowance for both test year and post-test year pay raise expenses in the rate case.

Most importantly, the number of ongoing management employees (and their related payroll costs) are the largest issue driving the amount of pay raise expenses, and if the number of management employees receiving pay raises cannot be determined with reasonable certainty and is not known and measurable, then the related pay raise calculation is also not known and measurable even if the percentage raise is known and measurable.

**Q. WHY ARE YOU USING 3% FOR YOUR PAY RAISE ADJUSTMENTS AND NOT THE COMPANY'S PROPOSED PAY RAISES?**

A. In this regard, I am not proposing to change Company policy but I am aiming to propose an adjustment that the Commission can apply in its regulatory decision consistent with the Commission's past decisions to remove Long-Term Incentives ("LTI")[80] and sometimes short-term incentives ("STI").[81]

**Q. WGL PROPOSES SIGNIFICANTLY DIFFERENT MANAGEMENT PAY RAISE PERCENTAGES FOR THE SAME YEARS IN THE TWO MOST RECENT RATE**

---

[80] *See e.g., Formal Case No. 1139, In the Matter of the Application of the Potomac Electric Power Company For Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Order No. 18846 ¶ 243 rel. July 28, 2017 (finding that Pepco failed to demonstrate that ratepayers receive a tangible benefit from the Long-Term Incentive Program).¶

[81] *Formal Case No. 1169*, Order No. 21939 ¶ 504 (denying WGL's STI costs related to Customer Strategy Value Driver and fringe expenses).

**CASES. IS THIS CONTRARY TO WGL'S CLAIMS OF "KNOWN AND MEASURABLE" IN THESE TWO RECENT RATE CASES?**

A. Yes. Please see the following explanation of WGL's proposed widely varying and inconsistent pay raises for the same periods between the two most recent rate cases.

**Table 2 – Varying Inconsistent Pay Raise Percentages for the Same Year in Two Most Recent Rate Cases**

| A | B | C |
|---|---|---|
| | WGL Proposed Pay Raise % for Management Employees | |
| Management Pay Raise Year | Prior Case Case No. 1169 Note 1 | Current Case Case No. 1180 Note 2 |
| 2022 | 3% | 5.22% |
| 2023 | 3% | 5.73% |
| 2024 | 3% | 3.97% |
| | | |
| | Source: Exh. WG (D)-5 Adj. 17, p. 5 of 17 | Source: Exh. WG (D)-5 Adj. 5 p. 4 of 15 |

Note 1 - For post-test period pay raises in 2022, 2023, and 2024, WGL used individual year pay raises of 3% for 2022, 2023 and 2024, and did not use averages of the three most recent years.

Note 2 - For pay raises in the test period WGL used the January 2024 effective pay raise of 3.97%, and for post-test period pay raises WGL used an an average of 4.97% based on pay raises of 5.22% for 2022, 5.73% for 2023, and 3.97% for 2024.

All individual year raise percentages are based on average pay raise percentages for the period that vary above and below the average for each management employee.

As shown in the table above, in both the prior rate case (Formal Case No. 1169) and this rate case, WGL has proposed two different and widely varying pay raise percentages for the same years and has asserted in both rate cases that these inconsistent pay raise percentages (and the resulting proposed increase in pay raise costs) are known and measurable. For example, in the prior rate case, WGL proposed a "known and measurable" 2022 period pay raise of 3% for calculating pay raise costs. And in this rate case, for the same 2022 period, WGL used a larger and different "known and measurable" 2022 pay raise of 5.22%.[82] Similarly, for the 2023 period in both rate cases, WGL asserted the 3% pay raise in the prior rate case was "known and measurable" and also claimed the significantly greater pay raise of 5.73% in this rate case is also "known and measurable."

Finally, for the 2024 period in both rate cases, WGL asserts the 3% pay raise in the prior rate case was "known and measurable" and also asserts the greater pay raise of 3.97% in this rate case is also "known and measurable." However, the fact that these pay raise percentages proposed for the same years in two different rate cases are inconsistent and widely varying, is proof that these WGL-proposed pay raises are not known and measurable and will not produce the same pay raise cost amounts.

If the WGL-proposed pay raises were known and measurable, they would remain the same between the two different rate cases, and not drastically change. It is not reasonable for WGL to assert in one rate case that proposed pay raise percentages (and resulting pay raise cost increases) are known and measurable, because if these same pay raise percentages are trued-up to greater (or smaller) pay raise percentages in a subsequent rate case, the "true-up" is evidence by itself that the original estimated pay raise percentages were not "known and measurable" but were in fact gross estimates without the reasonably certainty that is necessary to be considered "known and measurable."

[82] The 2022 pay raise of 5.22%, the 2023 pay raise of 5.73%, and the 2024 pay raise of 3.97% are used to calculate a three-year average pay raise of 4.97% that is used for the 2025 post-test period of this rate case.

In addition, regarding assertions of known and reasonable, it is not accurate to claim that even if the pay raise percentage is not known and measurable the pay raise cost increase is known and measurable as long as the other components are known and reasonable. Not only is this untrue, but it is neither reasonable nor consistent with sound regulatory policy to selectively pick and choose some components of a pay raise adjustment that are known and measurable and other components that are not known and measurable and then arrive at a final conclusion that the pay raise is known and measurable. In order for the pay raise cost increase to be known and measurable, all components of the underlying calculations must also be known and measurable.

**Q. FROM THE INFORMATION PROVIDED BY WGL IN THIS CASE, CAN YOU TELL IF THE INCONSISTENT AND UNEXPLAINED INCREASES IN MANAGEMENT PAY RAISES FROM THE PRIOR RATE CASE TO THE CURRENT RATE CASE ARE RELATED TO INCREASING INFLATION?**

A. No. As I previously explained, Table 2 shows WGL's substantive increases in proposed management pay raise percentages from the prior rate case to the current rate case, despite these increases pertaining to the same years. I am not aware that WGL specifically asserts that the proposed increase in pay raise percentages in this rate case for the same years 2022, 2023, and 2024 is related to increasing inflation in recent years.

However, to the extent WGL relies in part on this argument, this is a faulty argument that is inconsistent with the facts and without any specific supporting documentation provided by WGL. For example, in the prior rate, WGL used 3% pay raises for calculating increased payroll costs for union employees, and WGL also used this same

3% pay raise for management employees for calculating increased payroll costs for test period and post-test periods 2021, 2022, 2023, and 2024. However, in this rate case, the union pay raises remain at 3% and the proposed management pay raises have increased significantly to levels ranging from 3.97% to 5.73%.

If the increase in management pay raise percentages in this rate case is attributed in part to increasing inflation, then this argument is faulty because WGL has failed to include any similar "inflation" impacts in the union pay raises (which remain at the same 3% as the prior rate case), and this type of inconsistent, arbitrary, and potentially discriminatory treatment of union pay raises compared to management pay raises is not acceptable or justified.

**Q. ARE THE INCONSISTENT AND UNEXPLAINED INCREASED MANAGEMENT PAY RAISES IN THIS RATE CASE, COMPARED TO THE PRIOR RATE CASE, RELATED TO MERIT?**

A. It is my understanding that management pay raises awarded by utilities are typically based on merit. In addition, WGL's Confidential Response to OPC Data Request No. 11-11(a)[83] states that **BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL**. I believe WGL's management pay raises are based on merit because the specific pay raise percentage point (such as 3% for prior rate case years test period and post-test periods of 2022 to 2024, or 3.97% for the current year rate case 2024 test period, etc.) is the "average" of all specific individual merit pay raises awarded

[83] *See* WGL Confidential Response to OPC Data Request No. 11-11 (Exhibit OPC (B)-66).

each management employee, and individual pay raises may range fairly substantially above and below the average pay raise. For example, an average 3% pay raise for an individual year may actually consist of individual pay raises ranging up to 10% or more for some management employees, or as low as 0% for some management employees.

However, WGL has not provided any specific explanation, supporting documentation, or calculations to address why the asserted "known and measurable" pay raises of 3% in the prior rate case that are now reflected at an increased "known and measurable" range from 3.97% to 5.73% in the current rate – although these pay increases relate to the same years of the prior rate case. Therefore, there is no specific justification and supporting documentation for the arbitrary, inconsistent, and substantially increased level of asserted "known and measurable" management pay raises in this rate case compared to the prior rate case – for the same years.

WGL's response to Confidential OPC Data Request No. 11-11(f) states that pay raises can vary from year-to-year depending on various factors such as **BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL.**[84] However, these WGL-cited reasons are unduly vague, and WGL does not provide the information requested by OPC, the specific reasons for significant increases in management pay raise percentages for 2022 and 2023

[84] *See* WGL Confidential Response to OPC Data Request No. 11-11 (Exhibit OPC (B)-66).

compared to 2024. WGL's response provides a broad list of "potential" reasons for increases in the pay raise percentages in any particular year but does not address OPC's request for the specific reasons related to pay raise percentage increases in the specific years 2022 and 2023 compared to 2024. WGL's response does not impart any useful or meaningful information to support its pay raise percentages (used for calculating increased payroll costs) for the test period and post-test period in this rate case.

Therefore, my recommendation to use a 3% management pay raise for the test period and post-test period in this rate case is reasonable, given WGL's failure to meet a reasonable burden of proof to support its inconsistent, unexplained, and substantially increased pay raise levels in this rate case.

**Q. HAS WGL PROVIDED SPECIFIC COMPENSATION STUDIES FROM OUTSIDE CONSULTANTS TO SUPPORT THE INCONSISTENT AND UNEXPLAINED PAY RAISES IN THIS RATE CASE COMPARED TO THE PRIOR RATE CASE?**

A. No. OPC Data Request No. 11-11 asked for supporting documentation along with compensation studies, benchmark and market studies of comparable companies, and other documentation that WGL relied upon to support the management pay raises of 3.97% related to test period January 2024; the 3-year average pay increase of 4.97% related to post-test period 2025 (and the January 2022 pay raise of 5.22%, January 2023 pay raise of 5.73%; and the January 2024 pay raise of 3.97% that are used in calculating the 3-year average of 4.97%). WGL's Confidential Response to OPC Data Request No. 11-11 refers to Confidential Attachments 1, 2, 3, and 4.[85] **BEGIN CONFIDENTIAL*** [redacted] *****END CONFIDENTIAL**.

It would be necessary for me to review the actual compensation studies in order to place any reliance on the AltaGas summary information because compensation data can vary significantly depending upon the benchmark companies, and their related geographic location, size, type of industry, the date of the study (and whether it has been rolled forward using estimated inflation factors), and various other factors.

In fact, OPC Data Request No. 11-11(b) asked for this type of specific benchmark data and statistics for all compensation studies relied upon, but none of this specific detailed information was provided by WGL. Regarding compensation studies, the adage, "the devil is in the details", is very appropriate and I cannot reach any definitive conclusions about market or estimated pay raises from the AltaGas summary without knowing the underlying assumptions and composition of data used to reach these conclusions. WGL has failed to meet a reasonable burden of proof in this regard.

---

85 *See* WGL Confidential Response to OPC Data Request No. 11-11 (Exhibit OPC (B)-66 at 2).

**Q. DID WGL ALSO FAIL TO PROVIDE THE ACTUAL COMPENSATION STUDIES THAT OPC REQUESTED IN OPC DATA REQUEST NO. 11-19?[86]**

A. Yes. WGL Witness Burgum's direct testimony states that he describes the approach WGL takes to ensure it pays competitive and reasonable compensation that will ensure value for customers.[87] I could not find any meaningful information in Witness Burgum's testimony that specifically described how WGL ensures it pays competitive and reasonable compensation that ensure value for customers. Therefore, OPC Data Request No. 11-19 was issued and requested that WGL provide compensation studies and other information that Witness Burgum relied upon to reach a conclusion that WGL's compensation is competitive, reasonable, and ensures value for customers. **BEGIN CONFIDENTIAL***** [redacted]

---

86 *See* WGL Confidential Response to OPC Data Request No. 11-19 (Exhibit OPC (B)-73).

87 Exhibit WG (M) (Burgum) at 2:13-15.

88 *See* WGL Confidential Response to OPC Follow Up Data Request No. 11-19 (Exhibit OPC (B)-73) (which includes the response to the original data request and the follow up response).

[redacted]***END CONFIDENTIAL. This means that WGL did not provide any reasonable compensation studies or similar information to OPC in order to support a conclusion that WGL's management pay raises, short-term incentives, long-term incentives, base salaries, and total compensation are reasonable, competitive with the market, and ensure value for customers. The same facts would also apply to WGL's specific short-term incentives. WGL has failed to meet a reasonable burden of proof to support its broad conclusions that WGL's compensation (including short-term incentives) is reasonable, competitive with the market, and ensures value for customers.

**Q. DOES WGL'S CONFIDENTIAL RESPONSE TO OPC DATA REQUEST NO. 11-11 INCLUDE CONFLICTING INFORMATION REGARDING THE REASONABLE AND COMPETITIVE LEVELS OF PAY RAISES?**

A. Yes. The Confidential AltaGas summary information included in Confidential Attachments 1, 2, 3, and 4 includes **BEGIN CONFIDENTIAL***** [redacted]

[redacted] as [redacted] *****END CONFIDENTIAL**.

The bottom line is that my proposed 3% management pay raise for the test period and post-test period is not unreasonable based on information included in the Confidential Attachments included in the response to Confidential OPC Data Request No. 11-11, and **BEGIN CONFIDENTIAL***** [redacted]

---

[89] Exhibit WG (D)-5, Adjustment No. 5, page 4 of 15.

[redacted]

*****END CONFIDENTIAL.** The Commission should adopt my recommended management pay raises for regulatory policy purposes in this rate case.

**Q. ARE YOUR RECOMMENDED 3% MANAGEMENT PAY RAISES PROPOSED ONLY FOR REGULATORY POLICY PURPOSES IN THIS RATE CASE?**

A. Yes. I am recommending that 3% management pay raises be used for calculating the test period and post-test period pay raise cost increases in this rate case, so this is strictly a regulatory policy recommendation for rate case purposes only. I am not recommending that WGL be required to change any of its actual or budgeted management pay raises that differ from my regulatory policy recommendation. Therefore, my recommendations will not impact WGL's ability to pay whatever pay raise it deems to be reasonable for financial purposes outside of a rate case.

My recommended pay raises from a regulatory policy perspective are consistent with the Commission regulatory policy it has adopted regarding long-term incentives. The Commission has typically disallowed WGL's long-term incentive expenses in rate cases, because these amounts are primarily driven by financial performance metrics that favor the interests of the Company and shareholders over the interests of customers.[90] The Commission's policy to disallow long-term incentives in rate cases is not intended to impact or influence the amount or percentage of long-term incentives that WGL decides to pay its employees, that remains a management decision of WGL. Similarly, my

90 *See e.g., Formal Case No. 1139*, Order No. 18846 ¶ 243.

recommendation to use a lesser management pay raise than that used by WGL in this rate case is strictly a regulatory policy recommendation and is not intended to impact or influence the percent of management pay increase that WGL decides to pay its employees.

***Adjustment BCO-5: Remove Payroll for Phase 2 Employee Reduction (Exhibit OPC (B)-5, Schedule 5)***

**Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO REMOVE PAYROLL EXPENSE RELATED TO THE ADDITIONAL MAY TO NOVEMBER 2024 ELIMINATION OF 92 MANAGEMENT EMPLOYEES?**

A. WGL's Adjustment No. 13 is a separate stand-alone adjustment that reduces WGL's payroll expense by $10.2M (and reduced payroll expense by $2.0M on a WGL-DC basis) to reflect the elimination of 70 management employees in April 2024 via the management involuntary separation program.

However, WGL failed to disclose and reduce payroll costs for the additional May to November 2024 elimination of 92 management employees and 13 union employees and has not been forthcoming in providing this information in OPC data requests. Therefore, I have reduced gross (capital and expense) WGL payroll costs by $17.6M (and reduced payroll expense by $15.5M on a WGL basis and by $3.0M on a WGL-DC basis) related to the May to November 2024 elimination of 92 management employees.[91]

---

[91] My Direct Testimony does not reduce payroll costs related to the May to November 2024 elimination of 13 union employees because there is insufficient information to confirm these reflect permanent forward-looking reductions in employee levels. However, my surrebuttal testimony will reflect my final position to allow or remove the payroll cost related to these union employees.

**Q. PLEASE SUMMARIZE WGL'S FAILURE TO DISCLOSE AND PROPERLY REDUCE PAYROLL COSTS FOR THE IMPACT OF THE MAY TO NOVEMBER 2024 EMPLOYEE TERMINATIONS IN ADJUSTMENT NO. 5?**

A. WGL's Adjustment No. 13 approach is correct in removing 10.2M of payroll expenses ($2.0M on a WGL-DC basis) related to the elimination of 70 employees via the April 2024 management involuntary separation plan. However, WGL's payroll Adjustment No. 13 is fatally flawed because it fails to disclose and properly reflect the additional reduction in payroll costs related to the May to November 2024 elimination of 92 management employees and 13 union employees.

**Q. WHAT DO YOU MEAN THAT WGL FAILED TO DISCLOSE, OR TO ACKNOWLEDGE AND ADDRESS THE ADDITIONAL ELIMINATION OF 105 EMPLOYEES IN THE MAY TO NOVEMBER 2024 TIMEFRAME?**

A. WGL failed to disclose, acknowledge, and propose a reduction in payroll costs related to the subsequent May to November 2024 elimination of 92 management and 13 union employees in numerous OPC data requests that specifically asked about current and future separation programs or employee reductions, reasons for changes in post-test period employee headcount, other potential changes in payroll costs, as well as in response to other data requests that served as an opportunity for WGL to disclose these additional significant employee terminations. As discussed below, WGL's responses to these OPC data requests have continued through December 2024 and should have elicited a straight-forward response identifying and explaining the additional termination of significant employees from May to November 2024 – immediately following the April 2024 terminations reflected in WGL Adjustment No. 5 and 13.

Some of those OPC data requests that should have disclosed the subsequent May to November 2024 management and union employee termination include the following:

1) OPC Data Request No. 11-2[92] – This data request is labeled, "Other Separation Plans" and asked WGL to identify all other voluntary and involuntary separation plans that were implemented by AltaGas and/or WGL from January 1, 2015, through the most recent date in 2024, and to provide supporting documentation such as date implemented, the number of employee reductions, the total cost savings and various other information. WGL's four-line response was very brief and stated there had been no other separation programs implemented that resulted in a reduction in WGL employees from January 1, 2020, beyond the normal course of business in rightsizing and optimizing employee headcount.[93] Clearly this data request should have elicited disclosure of the May to November 2024 employee reduction, but this was not mentioned by WGL.

2) OPC Data Request No. 11-3[94] – This data request asked WGL to reconcile the costs to implement the April 2024 involuntary separation plan to the annual or quarterly financial reports for the related amounts, employees, and impact. WGL's response states this information was not disclosed in these financials because the costs were

---

92 *See* WGL Response to OPC Data Request No. 11-2 (Exhibit OPC (B)-59).

93 Exhibit OPC (B)-59 at 2.

94 *See* WGL Response to OPC Data Request No. 11-3 (Exhibit OPC (B)-60).

not material.[95] Again, this response was dated November 22, 2024, and should have elicited a response addressing the subsequent May to November 2024 employee reduction plans going on at that time, including some comment on how or where these costs and employee reduction are disclosed.

3) OPC Data Request No. 11-4[96] – This data request asked WGL to provide the updated actual number of employees eliminated beyond the 70 in the first April 2024 involuntary management reduction plan, and provide the impact on salary costs and other supporting information. WGL's response was confined to the initial 70 management employee reduction plan.[97] Although the data request asked for an "update", WGL did not provide an update or address the May to November 2024 subsequent management and union employee reduction.

4) OPC Data Request No. 11-6 and Follow-Up Data Request No. 11-6[98] – This data request is titled, "Future Involuntary Separation Plans", and is perhaps the best example of a data request that should have disclosed the subsequent May to November 2024 employee reduction. This data request asked WGL to explain any formal plans or projections to eliminate additional employees in <u>2024 and future years,</u> and to provide the impact, including the number of employees to be

---

95 Exhibit OPC (B)-60 at 2.

96 *See* WGL Response to OPC Data Request No. 11-4 (Exhibit OPC (B)-61).

97 Exhibit OPC (B)-61 at 3. *See also* WGL Response to OPC Data Request No. 11-5 (Exhibit OPC (B)-62 at 2).

98 *See* WGL Response to OPC Follow Up Data Request No. 11-6 (Exhibit OPC (B)-63) (which includes the response to the original data request and the follow up response).

eliminated. WGL's response is very brief and stated, "[t]he Company currently has no plans or projections for any future involuntary separation programs to eliminate any additional employees."[99] This data request should have clearly resulted in disclosure of the subsequent May to November 2024 employee reductions, WGL should have been forthcoming in addressing the subsequent employee reductions, especially because this response was dated November 22, 2024.

5) Other Data Requests – Other data requests that could have elicited a response identifying the subsequent May to November 2024 employee reduction includes OPC Data Request Nos. 11-5[100] and others.

In addition, WGL's application and direct testimony were filed August 5, 2024, and by that time there had already been additional reductions in management and union employees beyond the initial April 2024 management reductions identified by WGL. Regarding the additional termination of 105 employees from May to November 2024, September 2024 included the largest reduction of 70 management employees, which is only about a month after WGL filed its application. It is reasonable to assume that WGL had some advanced knowledge of this pending additional significant employee reduction, although this was not identified, addressed, or adjusted for in WGL's rate case filing.

WGL has subsequently filed several replacement pages or errata to the direct testimonies of WGL accounting witnesses Tuoriniemi and Smith (both of whom address the initial April 2024 management involuntary separation plan in their direct

---

99 WGL Response to OPC Data Request No. 11-6 (Exhibit OPC (B)-63 at 1).

100 *See* WGL Response to OPC Data Request No. 11-5 (Exhibit OPC (B)-62 at 2).

testimonies),[101] but WGL has not been forthcoming in filing any amended or errata testimony identifying or addressing the additional reduction of 105 employees from May to November 2024.

WGL's failure to disclose or adjust for the continuing significant elimination of 105 additional employees raises substantive overarching concerns about the accuracy, reasonableness, and proper disclosure regarding other potential issues and adjustments that could reduce the revenue requirement of this rate case.

**Q. HOW DID YOU IDENTIFY THE SUBSEQUENT MAY TO NOVEMBER 2024 REDUCTION IN MANAGEMENT AND UNION EMPLOYEES?**

A. OPC Data Request No. 11-12[102] asked for employee headcount for each month of the post-test period (after the test period end March 31, 2024) for both management and union employees and asked WGL to explain the reasons for the changes in headcount for periods 2021, 2022, 2023 and 2024 year-to-date. Although WGL did provide some brief explanations for the changes in headcount from 2021 through the test period end March 31, 2024,[103] WGL did not provide any explanation for changes in headcount for the post-test period April to November 2024. I thought that WGL's overt failure to address significant reductions in the post-test period was particularly unusual, especially because the elimination of 92 management employees from May to November 2024 was even greater than the previous elimination of 70 management employees in April 2024 related

---

[101] Exhibit WG (D) (Tuoriniemi) at 60:8-61:20; Exhibit WG (F) (Smith) at 19:6-18.

[102] WGL Response to OPC Data Request No. 11-12 (Exhibit OPC (B)-67).

[103] Exhibit OPC (B)-67 at 2.

to the involuntary separation program – and the period May to November also included the reduction of 13 union employees (and there were no reductions to union employees in the April 2024 involuntary separation program).

The May to November 2024 employee reductions are shown at WGL's Response to OPC Data Request No. 11-12, Attachment 1 (page 1 of 7)[104] and are summarized in the table below (also see Exhibit OPC (B)-5, Schedule 5, page 2 of 3, for this listing of employee headcount)..

**Table 3 – Employee Headcount Reduction for Phase 2 (May to November 2024)**

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| | | Employee Headcount Reduction Post-Test Period | | | | |
| | | Management | Change | Union | Change | Total Change |
| | Mar-24 | 806.25 | | 695 | | |
| Involuntary Separation Plan | Apr-24 | 732.75 | **(73.5)** | 690 | (5.0) | (78.5) |
| Additional employee elimination not | May-24 | 726.75 | (6.0) | 688 | (2.0) | (8.0) |
| explained by WGL for months | Jun-24 | 733.75 | 7.0 | 686 | (2.0) | 5.0 |
| May to November 2024, and | Jul-24 | 729.75 | (4.0) | 689 | 3.0 | (1.0) |
| not identified as an additional | Aug-24 | 721.75 | (8.0) | 687 | (2.0) | (10.0) |
| formal separation plan for | Sep-24 | 652.25 | **(69.5)** | 685 | (2.0) | (71.5) |
| management or union employees | Oct-24 | 650.25 | (2.0) | 683 | (2.0) | (4.0) |
| in WGL responses to OPC discovery | Nov-24 | 640.25 | (10.0) | 677 | (6.0) | (16.0) |
| | | | | | | |
| Employee Reduction May to November 2024 | | | **(92.5)** | | **(13.0)** | **(105.5)** |

**Q. DID YOU FIND ADDITIONAL INFORMATION ABOUT THE MAY TO NOVEMBER 2024 EMPLOYEE REDUCTIONS WITHIN THE VOLUMINOUS**

104 Exhibit OPC (B)-67 at 3.

**DETAILS OF WGL'S CONFIDENTIAL ATTORNEYS' EYES ONLY RESPONSE TO OPC DATA REQUEST NO. 6-17?**[105]

A. Yes. OPC Data Request No. 6-17 (titled "Involuntary Separation Program Documents") asked WGL to provide all business planning and strategy documents that address the involuntary separation program, including forecasted costs, savings, and headcount reduction. WGL's written response to this data request was brief (10 lines) and did not mention the subsequent May to November 2024 management and union employee reduction plan.

However, as I was reviewing WGL's Confidential Attorneys' Eyes Only Response to OPC Data Request No. 6-17, **BEGIN CONFIDENTIAL***** [redacted]. [redacted]

---

[105] *See* WGL's Confidential Attorneys' Eyes Only Response to OPC Data Request No. 6-17 (Exhibit OPC (B)-51). OPC obtained permission from WGL to provide me access the "Attorneys' Eyes Only Responses".

[106] Exhibit OPC (B)-51 at 14-18.

[redacted]*** END CONFIDENTIAL.

***Adjustment BCO-6: Amortization of Implementation Expenses for Involuntary Separation Program (Exhibit OPC (B)-5, Schedule 6)***

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE AMORTIZATION OF IMPLEMENTATION EXPENSES RELATED TO THE MANAGEMENT INVOLUNTARY SEPARATION PROGRAM?**

A. WGL implemented an involuntary separation program in April 2024 that eliminated 70 management employees. WGL proposed Adjustment No. 14 (Exhibit WG (D)-5,

---

[107] Exhibit OPC (B)-51 at 18.

[108] Exhibit OPC (B)-51 at 58, 60- 64, and 83-91.

Adjustment No. 14, page 1 of 5) to amortize, over 5 years, the nonrecurring costs related to implementing the management involuntary separation program. The nonrecurring implementation costs include expenses such as severance, COBRA continuation coverage, short-term incentive, consultant/legal services,[109] paid time off and other expenses that total $6,998,583 ($7.0M) on a WGL basis. When the $7.0M of implementation costs are amortized over 5 years this results in an annual amortization of $1,399,717, and after applying the DC Allocation Factor, the WGL-DC portion of this adjustment is an increase in amortization expense of $271,011. I have removed this adjustment, and will reconsider this matter if WGL is forthcoming with additional information and calculations regarding the Phase 2 additional employee reductions from May to November 2024.

In addition, WGL has failed to disclose and make adjustments to reduce payroll expenses (and other relevant expenses) for additional employees eliminated from May to November 2024, including 92 management employees and 13 union employees. I identified this additional employee reduction while reviewing post-test period employee headcount statistics. I do not know if the elimination of these additional employees resulted in additional costs to implement the elimination of these employees, but WGL has not identified any additional costs in various OPC data requests.

---

[109] WGL's Confidential and Attorneys' Eyes Only Response to OPC Data Request No. 6-20 (Exhibit OPC (B)-53) provides the expenses (by consultant), invoices, and other supporting documents for the outside consultants used in the initial April 2024 involuntary separation plan.

OPC issued OPC Data Request No. 4-48[110] asking WGL to provide a sample of management consulting firms allocating/assigning expenses to WGL, and to provide the related expense amounts and invoices, for calendar year 2022 and test year ending March 31, 2024. The purpose of this data request was to obtain billing rates of management consultants to compare to those used in Witness Baryenbruch's lower of cost or market study. I reviewed WGL's confidential response to this data request and noticed **BEGIN CONFIDENTIAL***** [redacted]

[110] *See* WGL Confidential Response to OPC Data Request No. 4-48 and Confidential Responses to Further Follow Up Data Requests (Exhibit OPC (B)-33).

[redacted]

[111] WGL Confidential Response to OPC Data Request No. 4-12 (with some attachments omitted) and Confidential Response to Follow Up Data Request (Exhibit OPC (B)-10).

[redacted] *****END CONFIDENTIAL.**

Because WGL has not disclosed or adjusted expenses for the additional reduction of 105 employees in this rate case from May to November 2024,[112] I propose to remove the $271,011 amortization expense related to the April 2024 management involuntary separation program until, or unless, WGL is forthcoming and identifies all proper reductions in payroll-related and other expenses tied to the additional reduction of 105 management and union employees from May to November 2024.

If WGL is forthcoming and provides supporting documentation and calculations regarding the additional reduction of these 105 employees, then I will reconsider restoring WGL Adjustment No. 14 regarding the five-year amortization of implementation expenses in my surrebuttal testimony – along with some possible revision to this adjustment. I have additional concerns regarding the nonrecurring expenses related to implementing the April 2024 management involuntary separation program, and I will continue evaluating these issues to address in my surrebuttal testimony if necessary.

---

[112] WGL's Confidential Response to OPC Data Request No. 6-19 (Exhibit OPC (B)-52) identifies the amortizable costs to implement the initial April 2024 involuntary separation, showing costs incurred from April 2024 to October 2024. If there were any additional implementation costs related to the subsequent May to November 2024 employee reductions, then much of these costs should be reflected on this schedule, but there does not appear to be any such costs.

***Adjustment BCO-7: Adjust Payroll Overtime Expense to a Normalized Annual Level (Exhibit OPC (B)-5, Schedule 7)***

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REDUCE PAYROLL OVERTIME EXPENSE TO A NORMALIZED ANNUAL LEVEL.**

A. WGL did not propose an adjustment to reduce payroll overtime expenses to a normalized annual level for the test year end March 31, 2024, I have identified this concern via WGL's responses to OPC data requests.

OPC Data Request No. 11-13[113] asked WGL to provide overtime expense incurred by union employees for calendar years 2020, 2021, 2022, 2023 and the test year end March 31, 2024 (and provide the number of union employees for each of these periods, and all months subsequent to the test year end March 31, 2024), and to identify the reasons for changes in overtime expenses from year-to-year, including overtime related to gas leak identification and repair.

WGL's response showed that union gross overtime costs (expensed and capitalized costs) varied from $71.9M in 2020, to $72.6M in 2021, $74.3M in 2022, $78.0M in 2023 and peaking at its highest levels of $80.0M for the test year end March 31, 2024. These amounts are shown in the table below.

[*REMAINDER OF PAGE LEFT BLANK]*

[113] WGL Response to OPC Data Request No. 11-13 (Exhibit OPC (B)-68).

**Table 4 – Adjust Overtime to Normalized Four-Year Average**

| A | B | |
|---|---|---|
| Period | Overtime Costs | |
| Calendar 2020 | $ | 71,873,434 |
| Calendar 2021 | $ | 72,617,537 |
| Calendar 2022 | $ | 74,338,367 |
| Test Year End March 2024 | $ | 80,033,317 |
| Total Overtime Costs | $ | 298,862,655 |
| Divide by Four Years | | 4.0 |
| Four-Year Average | $ | 74,715,664 |
| Test Year Excess Four-Year Average OT | $ | (5,317,653) |
| O&M Expense Allocation Factor | | 75.53% |
| DC Allocation Factor | | 19.36% |
| Normalize Test Year to Four-Year Average | $ | (777,580) |
| **OPC Adjustment to Normalize Overtime** | **$** | **(777,580)** |

The calculations supporting my adjustment to test year end March 31, 2024, overtime costs are shown in Table 4 above. I averaged the WGL four year totals of overtime costs,[114] which equals $74.7M, then I deducted the excess of test year end March 31, 2024, overtime costs of $80.0M from the four-year average overtime costs of $74.7M to arrive at the WGL excess overtime costs of $5.3M. I am adjusting the $5.3M of excess overtime costs for test year end March 31, 2024, to the four-year average to reflect a normalized level of overtime expense in the test period of this rate case. Finally, I apply the related O&M expense allocation factor and the DC allocation factor to arrive at a WGL-DC adjustment to reduce test year end March 31, 2024, overtime expense by $777,580.

[114] I did not include calendar year 2023 overtime costs in my average overtime cost calculation because this period covers overtime costs for nine months (or most) of the test year end March 31, 2024, and using approximately two years of the similar excessive overtime costs would have created an adjustment that was overstated and unreasonable.

**Q. DID WGL IDENTIFY THE SPECIFIC REASONS FOR INCREASES IN OVERTIME COST EACH YEAR, ESPECIALLY FOR RECENT YEAR INCREASES FOR CALENDAR YEAR 2022 AND TEST YEAR END MARCH 31, 2024?**

A. No. WGL's response to OPC Data Request No. 11-13 stated that the changes in overtime costs from year-to-year were primarily driven by emergency work for meter repairs, leak repairs, and other critical maintenance, as well as varying number of union employees, pay increases, and the amount of overtime incurred.[115] However, WGL did not identify which of these conditions and the related specific costs impacted year-to-year changes in overtime costs, especially related to the substantial increased overtime costs for calendar years 2022, 2023, and the test year end March 31, 2024. I did not include overtime expense of calendar year 2023 in my "average" calculation adjustment, because that time period overlaps significantly with the test period end March 31, 2024. However, for just the three-month time frame between calendar year ending December 31, 2023, and test year ending March 31, 2024, overtime expense increased from $78.0M to $80.0M, almost a $2.0M increase.[116] This is an especially significant increase in overtime costs considering the short time period.

Because WGL is unable to identify specific reasons and related costs to explain the changes in year-to-year overtime costs, this supports my adjustment to normalize the

115 WGL Response to OPC Data Request No. 11-13 (Exhibit OPC (B)-68 at 2).

116 Besides the change in three months from December 31, 2023, to March 31, 2024, this also means that January to March 2023 were also part of the different time frame in this comparison.

unusually high level of test year ended March 31, 2024, overtime costs to a more normal average of the three historical periods (plus the test year ended March 31, 2024). In addition, this adjustment will contribute to a more even and consistent impact on the revenue requirement and customer rates, versus allowing unexplained and significant fluctuations in overtime costs from year-to-year to be unreasonably borne by customers on a permanent basis in rates going forward.

Also, WGL's failure to provide the requested reasons and related dollar impacts for the increases in overtime costs means that WGL has failed to meet a reasonable burden of proof, and this supports the adoption of my proposed adjustment.

**Q. IS YOUR ADJUSTMENT TO REDUCE OVERTIME COSTS IN THE TEST YEAR SUPPORTED BY THE WGL MOST RECENT CONFIDENTIAL BUSINESS ACTION PLAN IN OPC DATA REQUEST NO. 6-1?**[117]

A. **BEGIN CONFIDENTIAL***** [redacted]

[117] *See* WGL Confidential and Attorneys' Eyes Only Response to OPC Data Request No. 6-1 (Exhibit OPC (B)-45).

[118] Exhibit OPC (B)-45 at page 182.

[119] Exhibit OPC (B)-45 at page 182.

[redacted] ***END CONFIDENTIAL.[121]

**Q. IS YOUR APPROACH TO USE MULTI-YEAR AVERAGING TO ESTABLISH NORMALIZED COSTS GOING FORWARD CONSISTENT WITH THE SAME APPROACH THAT WGL USES FOR CERTAIN ADJUSTMENTS?**

A. Yes. The Commission should adopt this adjustment to overtime costs because it is reasonable and consistent with a similar five-year averaging method that WGL uses to normalize and adjust uncollectible expenses to a more even and consistent level in this rate case via WGL Adjustment No. 1 (Exhibit WG (D)-5, page 32 of 46). The Commission should adopt my adjustment to normalize overtime costs to a reasonable level going forward.

### *Adjustment BCO-8: Remove WGL's Non-Labor Inflation Adjustment (Exhibit OPC (B)-5, Schedule 8)*

**Q. PLEASE SUMMARIZE YOUR ADJUSTMENT AND CONCERNS RELATED TO WGL'S NON-LABOR INFLATION ADJUSTMENT.**

---

[120] Exhibit OPC (B)-45 at page 182.

[121] Exhibit OPC (B)-45 at page 182.

A. I propose Adjustment BCO-8 to reverse and remove WGL's Non-Labor Inflation Adjustment No. 21 of $1,043,643[122]. In prior rate case, Formal Case No. 1169, WGL proposed the same adjustment and I also proposed to remove the full amount of the adjustment in that rate case. In this adjustment, WGL seeks to increase its non-labor expenses by the 2024 projected inflation rate of 2.49%. However, economic conditions have changed since the last rate case when inflation rates were higher for the for the post-test period late in 2022 when my direct testimony was filed – and this has a significant bearing on the adjustment in this rate case.

**Q. DOES THE SIGNIFICANT REDUCTION IN INFLATION RATES FROM THE PRIOR RATE CASE, ALONG WITH THE COMMISSION'S ORDER IN THAT RATE CASE, SUPPORT REJECTION OF WGL'S NON-LABOR INFLATION ADJUSTMENT?**

A. Yes. The primary reason is due to a substantive change in the economic conditions and reductions in inflation rates from the 3.75% inflation rate used in WGL's non-labor inflation adjustment in the prior rate case (related to the 2022 post-test period – subsequent to the test period end December 31, 2021, in prior FC No. 1169) compared to the 2024 post-test period inflation rate of 2.49% used in WGL's non-labor inflation adjustment in this rate case. The 2.49% inflation rate in this rate case is not too far removed from normal historical inflation rates and does not reflect extraordinary circumstances that justify a unique non-labor inflation adjustment. Order No. 21939 in the last rate case FC No. 1169

[122] Exhibit WG (D)-5, Adjustment No. 21, Page 1 of 22.

accepted WGL's non-labor inflation adjustment because of the unique and extraordinarily high inflation rates at the time, but those conditions no longer exist, as evidenced by WGL's non-labor inflation adjustment in this rate case that reflects a substantially lower inflation rate of 2.49%.

In the prior rate case, the Commission accepted WGL's adjustment and stated:

> In this instance, the Commission acknowledges that inflation has increased substantially in the post-test year period. Due to these circumstances, the Commission accepts WGL's non-labor inflation adjustment of $1,553,329 only for 2022, since these costs are not too remote in time from the test year and provide a more accurate reflection of the current economic situation. The Commission denies WGL's 2023 and 2024 non-labor inflation adjustments of $1,271,482 as they are beyond the 12 months post-test year exception.[123]

In fact, in the prior rate case, the Commission only accepted the 2022 post-test period inflation rate of 3.75% (for one-year beyond WGL's test year ending December 31, 2021), and rejected WGL's other inflation adjustments (and related inflation rates) stretching beyond 2022. The Commission rejected WGL's additional proposed post-test period 2023 inflation adjustment (inflation rate of 2.37%) and post-test period 2024 inflation adjustment (inflation rate of 2.30%) because they were too far removed from the test year ending December 31, 2021. But it is also true that these substantially reduced projected inflation rates did not justify a unique rate case adjustment, and the WGL inflation rate of 2.49% in this rate case is more in line with declining inflation rates of

123 *Formal Case No. 1169*, Order No. 21939 at ¶ 270.

2.37% and 2.30% in the prior rate case. This reduced level of inflation does not justify a unique and extraordinary rate case adjustment.

The 2.49% inflation used in WGL's non-labor inflation adjustment is from the Survey of Professional Forecasters' ("SPF"),[124] and is the 2024 first quarter consumer price index ("CPI") inflation rate at that website. That website (as of January 14, 2025), showed CPIA inflation rates of 2.49% (first quarter 2024) 3.12% (second quarter 2024), and then declining inflation rates of 2.85% (third quarter 2024), and the recent low mark of 2.51% (fourth quarter 2024). The other types of inflation indexes at this website are all less than the fourth quarter 2.51% CPIA inflation rate, and for the fourth quarter they show inflation rates of 2.39% (CPIB) and 2.30% (CPIC).[125] These trends all show inflation is declining and it would be unreasonable to reward WGL with a unique and extraordinary inflation factor adjustment in this rate case.

**Q. WHAT OTHER PRIMARY REASONS SUPPORT REMOVING WGL'S NON-LABOR INFLATION ADJUSTMENT?**

A. Some of the other primary reasons that support my adjustment to remove WGL's non-labor inflation adjustment are summarized below:

1) I relied on WGL's Confidential 2024 Budget document provided in response to OPC Data Request No. 6-1.

2) WGL's non-labor inflation adjustment is flawed because it is not supported by any specific studies or analysis.

---

[124] *See* Exhibit WG (D) (Tuoriniemi) at 73:9-19 (and footnote 113 includes a link to the related website).

[125] The inflation rates can be located at https://www.philadelphiafed.org/surveys-and-data/cpi-spf.

3) WGL's increases in non-labor costs are likely related to other factors besides inflation, and WGL has not provided any analysis or testimony to show the change in costs driven by all other factors, including inflation.

4) WGL has not performed any analysis or study to show there is a correlation between the percent cost increase of the CPI inflation factors that it relied upon and the percent increase in costs of WGL's non-labor costs to which these inflation factors are applied – this is a significant shortcoming that should have been part of any basic review of this issue.

5) WGL has not performed proper due diligence and review of outside vendor contracts and invoices (supporting its non-labor expenses) to determine if these vendors have already included inflation factors in their costs, and WGL's adjustment would result in a duplication of these inflation impacts.

6) WGL has not proposed to include any offsetting "productivity" factors to likewise reflect the impact of future reductions in certain of WGL's non-labor expenses, it is unreasonable for WGL to only reflect a biased and subjective inflation adjustment that increases non-labor costs without balancing this with offsetting productivity factors to reflect decreases in certain WGL non-labor costs.

**Q. DO YOU RELY ON WGL'S MOST RECENT CONFIDENTIAL 2024 BUDGET TO REJECT ITS NON-LABOR INFLATION ADJUSTMENT?**

A. Yes. OPC Data Request No. 6-1[126] requested WGL's Business Plans/Budgets and the Company's response provided Confidential WGL Budgets for 2020, 2021, 2022, 2023, and 2024. WGL's 2024 Budget states the following regarding inflation issues, **BEGIN CONFIDENTIAL***** [redacted]

126 *See* WGL Confidential and Attorneys' Eyes Only Response to OPC Data Request No. 6-1 (Exhibit OPC (B)-45).

[redacted]***END CONFIDENTIAL.[127]

**Q. DID WGL ADEQUATELY EXPLAIN WHY IT USED THE "CPIA" INFLATION FACTOR, VERSUS SOME OTHER OPTION OR LOWER INFLATION INDEX?**

A. No. OPC Data Request No. 6-12[128] and 6-13[129] asked WGL why it used the "CPIA" inflation rate versus some other inflation index, and asked if there is a reasonable correlation between the goods and services measured by the CPIA inflation rate and the types of goods and services included in WGL's actual non-labor expense adjustment. WGL's response to OPC Data Request No. 6-13 was brief and stated that WGL has not performed an independent analysis of this issue. Similarly, WGL's response to OPC Data Request No. 6-12 was vague and did not include a sufficiently explain why WGL used the CPIA inflation rate in its adjustment. WGL's non-labor inflation adjustment should be rejected, adequate supporting documentation does not exist for this adjustment.

**Q. HAS WGL PROVIDED ANY DOCUMENTATION TO PROVE THAT NON-LABOR EXPENSE INCREASES WERE THE RESULT OF INFLATION (VERSUS OTHER REASONS)?**

A. No. This should probably be the first type of analysis that WGL performs to determine if a non-labor inflation adjustment is reasonable and has merit, but WGL has not performed this type of analysis. It is not reasonable to automatically assume that inflation is the reason

---

[127] WGL Confidential 2023 Budget, page 177 of 233.

[128] *See* WGL Response to OPC Data Request No. 6-12 (Exhibit OPC (B)-48).

[129] *See* WGL Response to OPC Data Request No. 6-13 (Exhibit OPC (B)-49).

for increases in various types of non-labor expenses from year-to-year, and it would likely be very difficult for WGL to prove that inflation is the primary driver of any non-labor expense increases. An increase in non-labor expenses can be due to various reasons that are unrelated to price increases related to inflation, including but not limited to the following reasons:

- ✓ **Increases in volumes of goods or services purchased can cause total non-labor expense increases that are unrelated to price/cost inflation:**

  If WGL is purchasing an increased volume of widgets from an outside vendor or consultant, this can lead to increased total non-labor expenses from year-to-year, but this is not driven by a change in price/cost that is due to inflation. Likewise, if an outside vendor or consultant is providing additional services and has increased their number of billable hours, this can also lead to increased total non-labor expenses from year-to-year, but this is not driven by a change in price/cost that is due to inflation.

- ✓ **Increased customer growth drives increased volumes of goods or services purchased that can cause total non-labor expense increases that are unrelated to price/cost inflation:**

  Increases in the number of customers can drive related increases in non-labor expenses that are unrelated to inflation. For example, customer growth can cause increases in non-labor maintenance costs related to mains, meters, and measuring and regulating station equipment that are unrelated to inflation. Similarly, customer growth can also cause increases in non-labor expenses related to meter reading, billing and accounting, office supplies, uncollectibles, and other costs that are unrelated to inflation.

- ✓ **WGL policy decisions can cause increases in total non-labor discretionary expenses that are unrelated to price/cost inflation:**

  Certain non-labor expenses such as advertising, training, dues, donations, and customer incentives are called discretionary expenses because these types of non-labor expenses can vary from year-to-year due to WGL's specific focus or emphasis on different policies or preferred outcomes. For example, in some years, advertising expenses may increase because WGL elects to emphasize a "call before you dig" campaign to customers, contractors, and outside parties. However, these increases in non-labor discretionary expenses are not necessarily related to price/cost inflation.

- ✓ **Changes in allocation methods, assumptions and the pool of allocated costs can cause increases in total non-labor expenses that are unrelated to inflation:**

  Certain non-labor expenses that are allocated from WGL to WGL-DC, including any ALA-related affiliate charges, may increase from year-to-year due to changes in the methods and assumptions used to determine the allocation factor, or due to a change in the total pool of expenses that are subject to allocation to WGL-DC each year. However, these increases in non-labor allocated expenses from year-to-year are not necessarily related to price/cost inflation.

There could be numerous other examples of non-labor expenses that may increase from year-to-year, although the change is not driven by price/cost inflation.

**Q. BASED ON YOUR PREVIOUS EXPLANATION, WOULD IT BE REASONABLE FOR WGL TO MERELY COMPARE CHANGES IN NON-LABOR EXPENSES BY ACCOUNT FROM YEAR-TO-YEAR, AND ATTRIBUTE ALL INCREASES TO INFLATION?**

A. No, this would be an overly simplistic analysis that would not identify the true reasons for changes in these non-labor expenses from year-to-year. To perform proper due diligence and analysis, it would be necessary for WGL to specifically analyze all of the reasons for increases in components of each non-labor expense, in order to determine how much of the increase in expense was due to inflation and non-inflation reasons. Each type of non-labor expense may have several reasons that drive the increase in the related expense, and inflation may or may not be one of those reasons.

In order to determine if the expense increase was due to inflation, WGL would need to analyze supporting contracts, invoices and other documents to determine if the vendor's price for a particular non-labor expense (for goods or services) increased from year-to-year. WGL has not stated that it has performed this level of review, and it has not provided this type of detailed analysis to OPC. Therefore, WGL's proposed inflation adjustment lacks the necessary due diligence to address the specific reasons for changes in non-labor expenses and the Commission should reject WGL's inflation adjustment.

**Q. HAS WGL PROVEN THERE IS A STRONG CORRELATION BETWEEN THE CPIA AND THE ACTUAL ANNUAL PERCENT CHANGE IN WGL'S NON-LABOR EXPENSES?**

A. No. WGL uses the CPIA as a surrogate for the percent change in actual WGL non-labor expenses to which the CPIA is applied. For example, WGL applies a projected 2.49% inflation rate to its non-labor expenses in this rate case.[130] However, WGL has not performed any analysis or studies to show there is a strong correlation between the CPIA increase of 2.49% and either 1) the historical trend of increases in actual WGL non-labor expenses; or 2) the expected increases in actual WGL non-labor expenses in 2023, 2024, or other future years. Thus, there is no documentation to validate or show that WGL's proposed inflation adjustment is reasonable.

At the very minimum, WGL should have performed an analysis to determine if there is any correlation between the 2.49% CPIA and WGL's actual change in non-labor expenses before proposing this adjustment. It is disappointing that WGL did not make any effort to support this adjustment with even the most obvious and remedial analysis to

130 Exhibit WG (D)-5, Adjustment No. 9D & 30, page 24 of 34.

determine if there is a strong correlation between the CPIA and WGL's change in actual non-labor expenses.

I have not performed an analysis to determine if WGL's projected CPIA has a strong correlation to WGL's actual change in non-labor expenses because the OPC does not bear the burden of proof on this issue. WGL bears the burden of proof for this adjustment, and it has failed to provide even the most basic meaningful analysis and documentation to support this adjustment.

**Q. DID THE MARYLAND PUBLIC SERVICE COMMISSION REJECT WGL'S NON-LABOR INFLATION ADJUSTMENT IN A PRIOR PROCEEDING?**

A. Yes. In Case Number 9651 the Maryland Commission accepted the Public Utility Law Judge's ("PULJ") finding that "[a] proposed inflation adjustment must be considered on a case-by-case basis. In this case, I find that the adjustment proposed by WGL to reflect the inflationary impacts on the Company's non-labor expenses is unwarranted."[131]

> ***7.* WGL Adjustment 21 – Inflation on Non-Labor Expenses**
> 23. AOBA proposes elimination of Inflation for Non-Labor Expenses. Staff, likewise, proposes the elimination of WGL Adjustment 21, arguing that based on its analysis, customer growth in the rate year balances out any growth in non-labor O&M expense. A proposed inflation adjustment must be considered on a case by case basis. In this case, I find that the adjustment proposed by WGL to reflect the inflationary impacts on the Company's non-labor expenses is unwarranted.

[131] *Washington Gas Light Company's Application for Authority to Increase Its Rates and Charges*, Maryland PSC Case No. 9651 ("*MD Case No. 9651*"), Proposed Order, rel. February 12, 2021, and Errata to the Proposed Order ¶ 23, rel. February 19, 2021.

In addition, the Maryland Commission subsequently affirmed the PULJ's decision to reject WGL's inflation adjustment.[132] Specifically, the Maryland Commission found as follows:

> The Commission finds that the PULJ's decision to reject Washington Gas's proposed inflation adjustment was correct. Although Washington Gas correctly notes that the Commission has in some cases approved inflation adjustments similar to that requested by Washington Gas, such an adjustment is not automatic but depends on a showing by the utility that the adjustment is necessary for resulting rates to be fair, just, and reasonable.[133]

The Commission should deny WGL's adjustment to increase non-labor expenses using an inflation rate for the previous reasons cited.

***Adjustment BCO-9: A&G/Affiliate Expenses Allocated to WGL (Exhibit OPC (B)-5, Schedule 9)***

**Q. PLEASE SUMMARIZE THE BACKGROUND OF AFFILIATE EXPENSES AND EXPLAIN YOUR ADJUSTMENT TO REDUCE ALTAGAS/ASUS AFFILIATE EXPENSES ALLOCATED TO WGL.**

A. For the test year end March 31, 2024, I have removed $7.10M of the total $26.10M of ALA corporate expenses allocated to WGL, and this translates to removing $1.20M of the $5.1M WGL-DC portion (the DC jurisdictional affiliate expense is the amount included in the revenue requirement of this rate case).

I believe it is important to first provide some historical background for affiliate charges, prior to addressing the specific details of my adjustment to affiliate charges.

---

132 *MD Case No. 9651*, Order No. 89799 ¶ 15, rel. April 9, 2021.

133 *MD Case No. 9651*, Order No. 89799 ¶ 15.

After the AltaGas/WGL merger, AltaGas ("Parent Company" or "ALA") began allocating a new (first time) significant level of corporate overhead costs to WGL, which was an increase in ALA allocated expenses of $18.40M for 2019, the first effective year after the merger. Since that time, ALA expenses allocated to WGL have averaged about $20.60M for the five-year period of calendar years 2019, 2020, 2021, 2022, and test year ending March 31, 2024 (these amounts are on a WGL basis, not a WGL-DC basis).

However, after the last rate case in FC 1169 and with the expiration of ratepayer protections under Merger Commitment 41 in 2023, ALA wasted no time in substantially increasing its allocated expenses to WGL. ALA expenses allocated to WGL increased by about $6.30M (31%) in only one year, from $20.50M in 2022 to $26.80M in 2023.[134] From the first year of ALA affiliate allocations in 2019 and through 2022, ALA affiliate expenses allocated to WGL were fairly consistent and did not vary much each year, averaging about $19.90M per year. However, I have concerns about the significant increase in affiliate charges that began in the 2023 calendar year and carried over to the test year ending March 31, 2024. It is highly concerning that once the protection of Merger Commitment 41 expired, the affiliate expenses increased significantly and almost immediately. These affiliate charges are unreasonable, excessive, not supported by adequate documentation, and fail virtually every test of reasonableness.

[134] WGL's Annual CAM filing made with the Commission in Formal Case No. 1142, and WGL Response to OPC Data Request No. 4-10 (Exhibit OPC (B)-88) showing changes from 2019 to 2022, and test year ending March 31, 2024.

The intent of Merger Commitment 41 was to protect ratepayers from ALA allocating a new significant layer of corporate overheads to WGL for at least an initial period. If the combined new ALA allocated expenses plus the new expenses incurred for implementing the merger were greater than the offsetting cost savings from the merger, then WGL was required to impute net merger savings of at least $400,000 to the benefit of customers (in essence, WGL was required to "eat" the excess of merger costs over merger savings). With the Merger Commitment 41 now expired, there is no specific limitation on the amount of ALA expenses that AltaGas can allocate to WGL. This appears to explain the $6.30M (31%) increase in ALA allocated expenses beginning in calendar year 2023. In the last rate case, FC 1169, WGL showed that merger savings exceeded merger costs by $484,000, and since this exceeded the $400,000 required benefit threshold, WGL was not required to impute any more savings to the customer.

I will now briefly explain the allocation process using amounts from the test year ending March 31, 2024.

First, AltaGas had total Corporate expenses of $51.10M, and it allocated $35.50M (about 70%) to ASUS[135] (or U.S. operations) and $15.80M (about 30%) to its Canadian operations (which is primarily Midstream) – using an "AltaGas" 3-factor MMF allocation method.[136]

---

135 ASUS is the U.S. Holding Company for all U.S. affiliates include WGL Holdings, which includes WGL.

136 The AltaGas/ALA MMF allocation method allocates expenses using the 3 factors of: 1) Property; 2) Payroll; and 3) Earnings before interest, taxes, depreciation and amortization ("EBITDA").

Second, ASUS then allocates the $35.50M among various U.S. affiliates, with WGL receiving by far the largest allocation of $26.10M (about 75%), with the WGL-DC portion of this being $5.10M, and other U.S. affiliates receive the remaining allocation of about $9.40 ($35.50M less $26.10M)[137]- using a different "ASUS" 3-factor MMF allocation method.[138] I will explain in more detail this allocation process in the following "policy" portion of the affiliate section of my testimony. As previously explained, I removed $7.0M of WGL affiliate expenses, which translates to removing $1.20M on a WGL-DC basis.

Besides the amount of AltaGas/ASUS affiliate expenses allocated to WGL, WGL also allocates expenses of about $5.60M to various other affiliates, and I am not proposing an adjustment for these allocations. I am concerned that a portion of WGL's payroll expense that is allocated to affiliates has declined significantly in recent years. This indicates that WGL incurs increased payroll expenses on its books – subject to recovery in this rate case. However, I believe that much of these "retained" payroll expenses are offset by reductions in WGL's payroll expenses via Phase 1 and Phase 2 management and union employee reductions and related payroll cost savings.[139] I believe my adjustment to

[137] SEMCO is the next largest U.S. affiliate which receives $3.90M of allocated expenses.

[138] The ASUS MMF allocation method allocates expenses using the 3 factors of: 1) Average Invested Capital; 2) Payroll; and 3) Net Revenue.

[139] WGL proposes to remove payroll expense related to Phase 1 of an involuntary reduction plan for management employees that took place in April 2024, and I am proposing to remove the additional payroll expenses related to Phase 2 for the period May to November 2024 (which reduces both management and union employees) which WGL does not acknowledge and has failed to disclose in this proceeding.

remove ALA expenses allocated to WGL is reasonable, and I am evaluating additional possible adjustments that consider a revision to the MMF allocation factors.

This section of my testimony will address the AltaGas/ASUS expenses allocated to WGL in three different sections as noted below:

1) **<u>Section 1</u>** - I will explain in more detail my proposed adjustment to reduce ALA expenses allocated to WGL.
2) **<u>Section 2</u>** – I will provide an explanation of the process that is used to allocate ALA expenses to WGL on top-down basis, beginning with AltaGas corporate expenses and through the final allocation of costs to WGL.
3) **<u>Section 3</u>** – WGL Witnesses Baryunbruch and Block are the primary affiliate/allocations witnesses for WGL, and both conclude that ALA expenses allocated to WGL are reasonable. I will address their flawed analysis and conclusions regarding the following areas which they address:
    a) Peer/Market Comparison.
    b) Lower of Cost or Market.
    c) Benefits of Affiliate Charges (and the absence of redundant expenses).

**Q. PLEASE EXPLAIN PART 1 OF YOUR ADJUSTMENT TO REDUCE ALA AFFILIATE EXPENSES ALLOCATION TO WGL.**

A. I will explain this portion of my affiliate adjustment following the table below.

**Table 5 – Part 1 of Adjustment – Reduce ALA Expenses Allocated to WGL**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Function | CY2019 | CY2020 | CY2021 | CY2022 | TYE March 31, 2024 |
| Accounting and Tax | $ 3,115,288 | $ 5,500,731 | $ 3,955,910 | $ 3,541,200 | $ 5,273,385 |
| Board of Directors | 514,752 | 643,561 | 531,104 | 555,042 | 1,236,472 |
| Exec Mgmt | 1,433,343 | 1,800,528 | 2,691,506 | 2,480,795 | 3,191,420 |
| Finance | 1,910,168 | 1,844,002 | 2,394,428 | 1,717,075 | 1,734,851 |
| HR | 2,810,876 | 2,550,543 | 1,170,295 | 2,729,478 | 2,874,638 |
| IT | 4,843,255 | 4,499,675 | 4,563,108 | 5,322,496 | 7,328,854 |
| Legal and Compliance | 2,300,618 | 2,900,409 | 3,748,950 | 3,859,489 | 4,061,908 |
| Supply Chain | 235,911 | 341,301 | 396,790 | 270,518 | 349,914 |
| Cost-To-Achieve | 1,220,964 | 613,564 | 465,940 | 74,753 | |
| **Total** | **$ 18,385,175** | **$ 20,694,313** | **$19,918,031** | **$20,550,846** | **$ 26,051,443** |
| | | | | | |
| **Annual Change $** | | **$ 2,309,138** | **$ (776,282)** | **$ 632,815** | **$ 5,500,597** |
| **Annual Change %** | | **13%** | **-4%** | **3%** | **27%** |

Table 5 above shows the significant increase in affiliate allocations to WGL from CY 2022 to TYE March 31, 2024. In addition, this table includes some of the information used in the largest portion of my two-step adjustment to reduce ALA expenses allocated to WGL, although the remaining information which discloses my adjustment methodology is considered confidential at reflected at Confidential Exhibit OPC (B)-5, Schedule 9, page 2 of 3.[140] Part 1 of my adjustment above removes a portion of the affiliate expenses in the table based on the calculation method disclosed later in this testimony.. Part 2 of my adjustment removes a portion of the AltaGas CEO/President compensation costs allocated

[140] This table is from OPC Data Request No. 4-10 (Exhibit OPC (B)-88), also see OPC Data Request No. 4-5 (Exhibit OPC (B)-6) and WGL annual filings made with the Commission in Formal Case No. 1142, although these PDF spreadsheets show do not show affiliate expense allocated to WGL for the most recent test year ending March 31, 2024.

to WGL which is a confidential amount. Although the information in the table above for Part 1 of my adjustment is not confidential,[141] I need to redact both the expense adjustment and the calculation method so that parties without confidential access cannot view my adjustment amount or my calculation method. This will prevent these parties from being able to back into determining Part 1 of my adjustment and being able to determine the confidential Part 2 of the adjustment. Thus, the total adjustment is not confidential, only the individual Part 1 and Part 2 adjustments and the method that I used to calculate the Part 1 adjustment – and this approach will keep parties from being able to determine the Part 2 of the adjustment related to confidential compensation of the CEO/President.

The table above shows ALA expenses allocated to WGL by function for each calendar year 2019 to 2022, plus the test year ending March 31, 2024. For example, for the test year ending March 31, 2024 (Column F), ALA allocated expenses of $26.10M to WGL.[142] In addition, WGL's response to OPC Data Request No. 4-8[143] provides similar information for the same period, except for WGL Holdings, which includes ALA expenses allocated to WGL and other U.S. affiliates.

The year 2019 was the first year after the merger that ALA allocated corporate expenses to WGL, in the amount of $18.40M. For calendar years 2019 to 2022, the ALA expenses allocated to WGL stayed relatively stable and did not fluctuate much, as shown by the rows showing annual changes in amounts and percentages. However, in calendar

---

[141] WGL Response to OPC Data Request No. 4-10 (Exhibit OPC (B)-88).

[142] The WGL-DC portion is $5.10M, which is $26.10M multiplied by the DC allocation factor of 19.5408%.

[143] WGL Response to OPC Data Request No. 4-8 (Exhibit OPC (B)-8).

year 2023 (which is not shown in this table) and for test year ending March 31, 2024, ALA expenses allocated to WGL increased by $5.50M, 27%. The significant increase in ALA allocated expenses occurred at about the same time that Merger Commitment 41 expired. Without the customer protection provisions and expense constraints of Merger Commitment 41, WGL acted quickly to increase the ALA expenses allocated to WGL.

My adjustment is intended to normalize these ALA expenses and remove part of the abrupt significant increase for the test year ending March 31, 2024. The method I use to adjust these ALA expenses is described in this confidential passage. **BEGIN CONFIDENTIAL*****[redacted]*****END CONFIDENTIAL.** [144] I used this adjustment method because WGL was unable to provide adequate supporting

[144] The specific calculation is at Confidential Exhibit OPC (B)-5, Schedule 9, page 2 of 3.

documentation and explanation for the significant increase in ALA affiliate expenses for the test year ending March 31, 2024.

**Q. HAS WGL PROVIDED ADEQUATE SUPPORTING DOCUMENTATION AND EXPLANATION FOR THE SIGNIFICANT INCREASE IN AFFILIATE EXPENSES FOR THE TEST YEAR ENDING MARCH 31, 2024?**

A. No. OPC Data Request No. 4-5[145] asked for WGL to explain the reasons for changes in ALA expenses (and underlying subaccounts) allocated to WGL for each of the calendar years 2019 to 2022, and the test year end March 31, 2024, and provide supporting calculations and supporting documentation. WGL's explanations were vague, brief, unclear, and did not include any calculations or supporting documentation. Although WGL provided a brief explanation for the significant change in allocated expenses from 2022 to 2023, WGL did not provide any information for the changes in affiliate expenses from 2022 (or from 2023) to test year ending March 31, 2024.[146]

Regarding the single largest historical increase in ALA expenses allocated to WGL from 2022 to 2023 ($5.50M and 27% increase), WGL did not provide any more detailed explanation (and no supporting documentation) than it provided for prior years where there was little or no change in allocated expenses. WGL's side-by-side spreadsheet provided with its annual CAM filing in FC No. 1142 is reproduced at Exhibit OPC(B)-3, Schedule

[145] WGL Response to OPC Data Request No. 4-5 (Exhibit OPC (B)-6).

[146] Although the side-by-side analysis spreadsheet from Formal Case No. 1142 that WGL addresses has the advantage of showing affiliate expenses by underlying detailed accounts, the affiliate expenses are only available through December 31, 2023, and information in that format is not available for the test year ending March 31, 2024. WGL should have relied upon and addressed reasons for changes in affiliate expenses from 2023 to test year ending March 31, 2024, that are available in OPC Data Request No. 4-10 and other data requests.

9, and this spreadsheet shows the amount of annual changes in affiliate expenses by subaccount that WGL is supposed to address in OPC Data Request No. 4-5. Some of WGL's reasons for the significant increase in affiliate expenses from 2022 to 2023 are set forth below:

1) The $1.90M increase for Accounting & Tax function is primarily due to a shift of corporate risk services from Legal to Accounting & Tax, and increased salaries, wages, audit fees, and tax consulting. WGL states that expenses shifted from Legal to Accounting & Tax by $1.90M, but Legal expense did not decline by $1.90M for this shift; instead it actually increased from $3.90M to $4.20M. Thus, WGL's explanation is not correct, not sufficient and not supported by the facts. Also, WGL never identifies how much of the claimed shift in expenses is due to each of the components of wages, audit fees, and tax consulting – or why these amounts were shifted between these two functions.

2) WGL states there was a $2.20M increase in IT from 2022 to 2023, related to increases in salaries, cloud related services and contractor costs. This explanation is vague, inaccurate and not supported by the facts. First, WGL does not explain why any of these specific expenses, including salaries, increased by $2.20M. Second, WGL states that part of the increase is due to contractor costs, but there were no amounts recorded in the "Outside Services Employed" for IT. There are only two subaccounts for all of the affiliate expenses allocated to WGL (although other accounts are shown, the fields are blank), so all expenses are either recorded in the "Administrative and General Salaries" or "Office Supplies and Expense." If

there was an increase in IT outside contractor costs, and these amounts were recorded in either the Administrative and General Salaries account or the Office Supplies and Expense account, then this is not correct and accurate uniform recording of expenses. Outside contractor costs should be recorded in the separate Outside Services Employed account to ensure these amounts can be accurately tracked and evaluated by both WGL and other parties (such as for purposes of this rate case).

3) WGL states that part of the affiliate expense increases in the Executive Management and Board of Directors accounts were due to "executive restructuring." I am not sure what this is, but it sounds like an expense that could be a one-time nonrecurring expense that should either be removed from the test period or amortized. WGL does not explain this restructuring expense, or why it is being allocated to WGL from AltaGas.

4) WGL did not explain if any of the increases in expenses were due to changes in MMF allocation factor inputs.

5) WGL states that AltaGas expenses (the starting point for allocations to WGL) were $6.30M higher in 2022, but WGL does not explain why these expenses increased, or why this is reasonable and justified.

**Q. PLEASE EXPLAIN PART 2 OF YOUR ADJUSTMENT TO DECREASE AFFILIATE EXPENSES ALLOCATED TO WGL.**

A. I will address this in the table below.

**Table 6 – Remove CEO/President Compensation**

**BEGIN CONFIDENTIAL*****

[redacted]

*****END CONFIDENTIAL.**

Per Table 6 above, for the AltaGas CEO/President, I have removed **BEGIN CONFIDENTIAL***** [redacted]

[redacted]***END CONFIDENTIAL.**

Per the AltaGas publicly available 2024 Management Information Circular ("Management Circular"), with a cover letter to shareholders dated March 7, 2024,[148] the new AltaGas CEO/President Mr. Vern Yu's appointment was effective July 1, 2023 (in the

[147] This information is depicted at the last row of my table, column F.

[148] AltaGas, *Management Information Circular*, (May 2, 2024) https://www.altagas.ca/sites/default/files/inline-files/AltaGas-Ltd_Proxy%20Circular%202024.pdf. ("Management Circular").

test year ending March 31, 2024). According to the Management Circular, Mr. Yu was paid a sign-on bonus,[149] and my adjustment to remove part of this compensation may include some portion of the sign-on bonus. If any portion of the one-time nonrecurring sign-on bonus was allocated to WGL, this amount should be removed from the revenue requirement because it is not a reasonable and recurring expense. However, regardless of whether my adjustment is related to base compensation, short-term incentive, long-term incentive or sign-on bonus, the amount is reasonably removed from the revenue requirement. According to the Management Circular, Mr. Yu's 2023 total compensation is about $2,073,755, and with the addition of share-based award of $9,400,000, the total compensation is $12,318,855.

**Q. HAVE YOU MADE ANY ADJUSTMENTS TO AFFILIATE EXPENSES ALLOCATED TO WGL BASED ON A REVISION OF MMF ALLOCATION FACTORS?**

A. Not at this time, although I am continuing to review this issue, and I have still not received any of the requested "AltaGas" MMF allocation factors from WGL.

OPC Data Request No. 4-8[150] asked for the MMF allocation factors (and any other allocation factors) and supporting documentation and calculations used to allocate expenses from ASUS (U.S. operations) to U.S. affiliates, including WGL and others for calendar years 2019 to 2023, and the test year ending March 31, 2024. WGL provided the

149 The Management Circular addresses the sign-on bonus but does not appear to disclose the amount. *See* Management Information Circular at 76.

150 WGL Response to OPC Data Request No. 4-8 (Exhibit OPC (B)-8).

"ASUS" MMF allocation factors on a quarterly basis for each of the requested periods and I have reviewed these allocation factors.

OPC Data Request No. 4-7[151] asked for the MMF allocation factors (and any other allocation factors) and supporting documentation and calculations used to allocate expenses from AltaGas to ASUS (U.S. Operations) and to the Canadian operations (Midstream) – this is called the "AltaGas" MMF allocation factors.[152] WGL objected to this data request on grounds of relevance, stating it related to excluded costs that are not recovered in rates. WGL objects to providing allocation factors and supporting documentation used to allocate costs to Canada, because these amounts are not included in the revenue requirement of this rate case.[153]

I have two primary concerns. First, WGL's response to OPC Data Request No. 4-7 has not provided the requested "AltaGas" MMF allocation factors and supporting documentation used to allocate AltaGas expenses to ASUS (U.S. operations). Second, WGL has not provided the 'AltaGas" MMF allocation factors and supporting documentation used to allocate AltaGas expenses to Canada/Midstream operations.

---

151 WGL Response to OPC Data Request No. 4-7 (Exhibit OPC (B)-7)

152 The "AltaGas" MMF allocation factors differ from the "ASUS" MMF allocation factors. The AltaGas 3-factor MMF allocation factors use factors/inputs of: 1) Property; 2) Payroll; and 3) EBITDA to allocate expenses from AltaGas to ASUS (U.S. operations) and Canada/Midstream operations. The ASUS 3-factor MMF allocation factors use factors/inputs of: 1) Average Invested Capital; 2) Net Revenue; and 3) Payroll to allocate expenses from ASUS to each U.S. affiliate, including WGL and others.

153 WGL's response to OPC Data Request No. 4-7(g) provided some high level "AltaGas" allocation factors used to allocate expenses between ASUS (U.S. operations) and Canada operations (Midstream), but the ASUS and Midstream amounts subject to allocation are less than and do not equal amount shown in other data request – which raises questions about the accuracy of this information. Plus, the PDF attachment does not provide any of the financial inputs and supporting documentation for the "AltaGas" 3-factor MMF allocation factors for the underlying amounts of the allocation inputs/factors: 1) Property; 2) Payroll; and 3) EBITDA. WGL Response to OPC Data Request No. 4-7 (Exhibit OPC (B)-7).

It is not possible for me to determine the reasonableness of the "AltaGas" allocations to ASUS (U.S. operations) if I do not have the MMF allocation factors for Canada/Midstream operations, because allocations to both U.S. and Canda operations rely on a percent of the total allocation factor (such as Property) that is allocated to each of the operations. However, I cannot validate either the AltaGas allocations to ASUS (U.S. operations) or Canada/Midstream operations at this stage, because I do not have allocations factors and underlying supporting documentation for either.

I cannot determine the overall reasonableness of AltaGas allocations to WGL if I do not have the AltaGas MMF allocation factors and supporting documentation. If I receive this missing AltaGas MMF allocation information, then I will be able to make some determination regarding the reasonableness of these allocation factors and the related amounts allocated to WGL. If I do not receive the missing AltaGas MMF allocation factors and supporting documentation, then I may need to make certain assumptions and determine if additional adjustments are necessary.

At this stage, WGL has failed to meet a reasonable burden of proof regarding its expenses allocated to WGL, and this presents a stronger case for the Commission adopting my proposed adjustments – which will be subject to true-up in my surrebuttal testimony.

### *Explanation and Illustration of the AltaGas Allocation Process*

**Q. PLEASE SUMMARIZE THE SERVICES PROVIDED BY AFFILIATES TO WGL, AND BY WGL TO AFFILIATES, AND PRIORITIZE YOUR REVIEW.**

A. Please see my explanation below the two following tables.

**Table 7– Services Provided by Affiliates to WGL**[154]

| | | A | B | C | D | E |
|---|---|---|---|---|---|---|
| | Test Year End March 31, 2024 | | | | | |
| | | | | | | |
| | **Services Provided by Parent/Affiliates to WGL (millions)** | | | | | |
| Lne | Parent/Affiliates | Type | WGL | WGL-DC | Labor | Non-Labor |
| 1 | AltaGas (ALA) - Parent | Allocated | $ 26.10 | $ 5.10 | $ 3.10 | $ 2.00 |
| 2 | AltaGas (ALA) - Parent | Direct | $ 1.80 | $ 0.30 | | $ 0.30 |
| 3 | Subtotal AltaGas | | **$ 27.90** | **$ 5.40** | $ 3.10 | $ 2.30 |
| 4 | SEMCO Energy (SEMCO) | Direct | $ 0.80 | $ 0.10 | | |
| 5 | SubTotal Affiliate Services Provided to WGL | | **$ 28.70** | **$ 5.50** | | |
| 6 | Hampshire Gas Co. (Hampshire) | Direct | $ 12.00 | | | |
| 7 | Total Affiliate Services Provided to WGL | | **$ 40.70** | | | |
| 8 | WGL Allocated to Affiliates (expense offset) | | $ (1.50) | | | |
| 9 | **Affiliate Services Provided to WGL** | | **$ 39.20** | | | |
| | | | | | | |
| | Source: Tuoriniemi Direct - Exhibit WG (D)-5), p. 33 | | | | | |

I will first identify the bottom line expenses allocated from affiliates to WGL, and in subsequent testimony I will explain and show the top-down allocation process steps from AltaGas to WGL.

The table above identifies the expensed (not including any capitalized amounts) services provided by parent company AltaGas (ALA) and other affiliates to WGL during the test year end March 31, 2024 (showing allocated and direct assigned amounts). There are also other "costs" charged from affiliates to WGL that are capitalized to plant accounts (or reflected on the balance sheet), but I have not identified those in the above table because my review will focus on the amount of expenses charged by affiliates to WGL. The

154 The highlighted amounts in Table 7 are not confidential; they are highlighted for emphasis.

expensed amounts are larger and have a more significant impact on the revenue requirement in this rate case.

The total expenses charged by affiliates to WGL are $39.20M, consisting of $27.90M from parent company AltaGas, $.80M from SEMCO, $12.0M from Hampshire, and an offsetting amount of $1.50M.

My review will focus primarily on the $27.90M charged by AltaGas to WGL, which is $5.40M on a WGL-DC basis (included in the revenue requirement of this rate case) – and I will focus more on the larger "allocated" amounts.[155] The $5.40M charged by affiliates to WGL consists of $3.10M of labor and $2.30M of non-labor amounts.

I will address SEMCO charges to WGL briefly. I will not address Hampshire charges to WGL because this is related to gas storage costs that are based on more exacting usage, are not subject to discretionary allocation factors, and are more precise.

In my subsequent testimony I will explain the process used for allocating costs from affiliates to WGL, compare the amounts allocated for historical years, address allocation factors, identify the problems with WGL's testimony addressing affiliate charges, and address other important underlying detailed information.

[*REMAINDER OF PAGE LEFT BLANK*]

[155] The WGL amounts include costs for the jurisdictions of District of Columbia, Virginia, Maryland, along with Hampshire costs, and other minor costs – whereas the DC costs are specifically related to costs for which this Commission has jurisdiction in establishing rates in this rate case.

**Table 8 – Services Provided by WGL to Affiliates**

| | **Services Provided by WGL to Affiliates** | | | |
|---|---|---|---|---|
| Lne | Parent/Affiliates | Type | WGL | WGL-DC |
| 1 | ***WGL Holdings Affiliates:*** | | Total WGL | |
| 2 | WGL Holdings | | $ 0.20 | Not |
| 3 | Hampshire Gas Company | | $ 1.30 | available |
| 4 | WGL Energy Services | | $ 2.00 | |
| 5 | WGL Energy Systems | | $ 0.10 | |
| 6 | WGL Midstream MVP | | $ 0.10 | |
| 7 | SEMCO Energy | | $ 0.30 | |
| 8 | ***AltaGas Affiliates:*** | | | |
| 9 | AltaGas Services U.S. (ASUS) | | $ 0.80 | |
| 10 | AltaGas, Ltd. | | $ 0.70 | |
| 11 | Other AltaGas Affiliates | | $ 0.10 | |
| 12 | **WGL Services Provided to Affiliates** | | **$ 5.60** | |
| | | | | |
| | Source: Tuoriniemi Direct - Exhibit WG (D)-5), p. 34 | | | |

The table above identifies the expense amount of services provided by WGL to AltaGas and other affiliates during the test year end March 31, 2024.

The total expenses charged by WGL to affiliates is about $5.60M for the test year end March 31, 2024, and for the test-year end these amounts charged by WGL to affiliates are relatively immaterial. However, the total labor expenses charged by WGL to affiliates has declined significantly from $9.40M in calendar 2019 to $4.0M for the test year end March 31, 2024 – although WGL has not reduced its staff levels to consider this reduction in charges to affiliates.[156] Ordinarily, I would view this as a concern related to possible overstated payroll costs of WGL for the test year end March 31, 2024. However, because WGL has reduced the number of management and union employees in 2024, with the

[156] WGL Response to OPC Data Request No. 4-9 (Exhibit OPC (B)-8 & Attachment 1 thereto).

related impact of reduced payroll costs, this helps mitigate my concerns regarding this matter. I have previously addressed the involuntary separation plan, and I will address this related affiliate impact subsequently in my testimony.

My review does not focus much on the charges from WGL to affiliates because of lesser concerns and the smaller amount of the charges.

**Q. PLEASE SUMMARIZE AND SHOW THE TOP-DOWN PROCESS FOR ALLOCATING COSTS FROM ALTAGAS TO U.S. AND CANADIAN AFFILIATES.**

A. Please see my explanation below the following table.

[*REMAINDER OF PAGE LEFT BLANK*]

**Table 9 – Top-Down Allocation from AltaGas to U.S. and Canadian Affiliates**

**Part A**

| **AltaGas (Corporate/Parent)** | | | |
|---|---|---|---|
| Source (a) Period | Total Corporate Costs | Exclusion (Not Allocated) | Allocation to U.S. & Canada |
| TYE 2024 | $ 118.10 | $ (67.00) | $ 51.10 |
| CY 2023 | $ 110.40 | $ (62.70) | $ 47.70 |
| CY 2022 | $ 100.30 | $ (52.80) | $ 47.50 |
| CY 2021 | $ 112.20 | $ (69.80) | $ 42.40 |
| CY 2020 | $ 74.70 | $ (36.90) | $ 37.80 |
| CY 2019 | $ 85.70 | $ (47.40) | $ 38.30 |

AltaGas Costs Allocated to ASUS/Canada using MMF 3-Factors:
1) Property; 2) Payroll; and 3) EBITDA
(Supporting documentation not provided)

**Part B1**

| ***Allocation to AltaGas U.S. (ASUS) - U.S. Affiliates*** | | |
|---|---|---|
| Period | Amount | Percent |
| TYE 2024 | $ 35.50 | 69% |
| CY 2023 | $ 37.70 | 79% |
| CY 2022 | $ 31.30 | 66% |
| CY 2021 | $ 31.10 | 73% |
| CY 2020 | $ 32.80 | 87% |
| CY 2019 | $ 35.60 | 93% |
| Source: (a) (b) | | |

**Part B2**

| ***Allocation to Canadian Affiliates - Midstream*** | |
|---|---|
| Amount | Percent |
| $ 15.80 | 31% |
| $ 14.30 | 30% |
| $ 14.90 | 31% |
| $ 13.50 | 32% |
| $ 8.70 | 23% |
| $ 6.70 | 18% |
| Source: (a) | |

ASUS Costs Allocated to U.S. Affiliates using MMF 3-Factors:
1) Avg. Invested Capital; 2) Net Revenue; and 3) Payroll

**Part C**

| | ***Allocation to Individual U.S. Affiliates*** *(Source (a),(b), (c))* | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | WGL Holdings, Inc. | | | | | | | | |
| Period | **WGL** | Hampshire | WG Energy | WG Resources | WG Midstream | SEMCO | AltaGas Power Holdings | Other | Grand Total |
| TYE 2024 | **$ 26.10** | $ 0.20 | $ 1.30 | $ - | $ 0.70 | $ 3.90 | $ 1.20 | $ 2.00 | $ 35.40 |
| CY 2023 | **$ 27.80** | $ 0.20 | $ 1.50 | $ - | $ 0.80 | $ 4.90 | $ 1.40 | $ 2.10 | $ 38.70 |
| CY 2022 | **$ 20.60** | $ 0.20 | $ 1.30 | $ 0.10 | $ 0.80 | $ 5.60 | $ 1.10 | $ 1.80 | $ 31.50 |
| CY 2021 | **$ 19.90** | $ 0.20 | $ 1.40 | $ 0.10 | $ 0.80 | $ 5.50 | $ 1.20 | $ 1.80 | $ 30.90 |
| CY 2020 | **$ 20.70** | $ 0.20 | $ 1.60 | $ 0.20 | $ 0.80 | $ 6.00 | $ 1.80 | $ 1.40 | $ 32.70 |
| CY 2019 | **$ 18.40** | $ 0.20 | $ 1.60 | $ - | $ 0.40 | $ 7.10 | $ 3.70 | $ 1.10 | $ 32.50 |

Source:
(a) - OPC Data Request No. 4-7(a); (b) - OPC Data Request No. 4-8(a); and (c) - OPC Data Request No. 4-10(a)

The table above illustrates the top-down three-step approach for allocating expenses from AltaGas to final amounts at WGL/U.S. affiliates and Canada operations. The three-steps include:

**<u>Step 1 – AltaGas Corporate Expenses Subject to Allocation to Affiliates:</u>**

Step 1 Table 9 Part A, shows that AltaGas' (Parent Company) total corporate expenses are the starting point for subsequent allocations to final U.S. and Canada affiliates.[157] WGL states these corporate expenses are reviewed each business cycle to determine which expenses should be subject to allocation to other affiliates, and these expenses must provide benefits to all operating businesses and have the following characteristics: a) strategic in nature; b) focused on business oversight; c) development and exercise of corporate governance and stewardship; and d) ensuring businesses have appropriate access to capital.[158]

The corporate expenses not meeting these criteria are excluded and not subject to allocation to other affiliates, and this includes expenses such as long-term incentives, deferred share units plan, stock options, vehicle allowance, supplemental executive retirement plan ("SERP"), charter flights, social events, advertising, tradeshows and conferences, and various other expenses.[159]

---

[157] All of the Part A AltaGas corporate expenses in WGL's response to OPC Data Request No. 4-7(a) were provided in Canada currency only, so I converted the Canadian currency to U.S. currency using information from WGL's response to OPC Follow-Up Data Request No. 4-7(a) for all periods CY 2019 to 2023, and TYE 2024 (the ratio of the U.S. expenses "Adjusted Amount translated to USD" to Canadian expenses "ASUS Allocation CAD Yearly Actuals Adjusted for timing").

[158] WGL Response to OPC Follow Up Data Request No. 4-7 (Exhibit OPC (B)-7).

[159] WGL Response to OPC Follow Up Data Request No. 4-7 (Exhibit OPC (B)-7).

The remaining expenses that are subject to allocation to U.S. and Canada operations are included in the Modified Massachusetts Formula ("MMF") Cost Pool.[160] Thus, Table 9 Part A shows (for the test year end March 31, 2024 and calendar years 2019 to 2023) the total AltaGas corporate expenses (i.e., $118.1M for TYE 2024), expenses excluded from allocation (i.e., ($67.0M) for TYE 2024), and the remaining net expenses in the MMF Cost Pool that are subject to allocation to U.S. and Canada operations (i.e., $51.10M for TYE 2024).

The Table 9 Part A AltaGas net corporate expenses subject to allocation to U.S. and Canada operations have increased significantly over time by a total amount of about $13.0M and 33% from CY 2019 expenses of $38.30M (the first full year after the AltaGas/WGL merger) through TYE 2024 expenses of $51.10 – resulting in an average annual increase of about $7.0M and 7% (with a substantive increase to $51.10M expenses in TYE 2024 from CY 2022 and 2023 consistent amounts). I will address my concerns with the unsupported and significant increase in AltaGas net corporate expenses subject to allocation to U.S. and Canada operations in subsequent testimony explaining the OPC adjustments to affiliate expenses.

**<u>Step 2 – AltaGas Allocations to ASUS (U.S. Operations) and Canadian Operations:</u>**

Step 2 Table 9 Part B illustrates the allocation of AltaGas net corporate expenses in the MMF Cost Pool at Part A to both: a) Part B1 ASUS[161] U.S. Operations; and b) Part

[160] WGL Response to OPC Follow Up Data Request No. 4-7 (Exhibit OPC (B)-7).

[161] ASUS is the holding company of AltaGas' U.S. businesses.

B2 Canada Operations using the "AltaGas MMF" allocator that includes three different allocators (or "drivers"):[162]

1) **Property** - Plant, Property, and Equipment, including CWIP, Materials and Supplies Inventory, and Gas Inventory.

2) **Payroll**[163] **-** Salary, Wages, Non-Productive Time, Short-Term Incentives, and Other (Excludes Long-Term Incentives).

3) **EBITDA** – Earnings Before Interest, Tax, and Depreciation.

Table 9 Part B1 shows that expenses allocated from AltaGas to ASUS/U.S. affiliates for most of the periods CY 2019 through TYE 2024 have been fairly stable and consistent, ranging from $31.10M (CY 2021 and CY 2021) to $35.50M (CY 2019, CY 2024), with a five-period average of 78% allocated to U.S. Operations. Also, the same applies for Table Part B2 expenses allocated to Canadian affiliates/Midstream, with most years in the range of $30.0M to $32.0M (CY 2021, CY 2022, CY 2023, and CY 2024), and a five-year average of 28% allocated to Canada operations.

Although WGL's responses to OPC data requests showing fairly consistent "total" AltaGas expenses allocated to each of U.S. and Canada operations for most years, I am unable to verify the related underlying calculations and supporting documentation for AltaGas expenses allocated to U.S. and Canada operations. The AltaGas expenses allocated to U.S. and Canada operations are driven by the underlying financial inputs of

---

[162] Exhibit WG (K) (Block) at 13:19 – 14:11.

[163] Payroll expenses subject to allocation should not include long-term incentives and other excluded payroll expenses which are not beneficial to other affiliates, per WGL's criteria which I previously cited.

Property, Payroll, and EBITDA for each of the specific U.S. and Canada operations. However, WGL has objected to OPC discovery requesting the MMF financial inputs for Payroll, Property, and EBITDA for Canada operations and I have previously addressed this concern.[164] WGL has failed to provide the underlying MMF financial inputs for Payroll, Property, and EBITDA for U.S. operations[165] – and the Payroll expense for the "AltaGas" MMF factor may vary from the Payroll expense for the "ASUS" MMF factor which I do have.[166] Because I cannot verify the AltaGas expenses allocated to U.S. operations at Part B1, there is the risk that these expenses have been overstated and that $26.10M of these expenses subsequently allocated to WGL at Part C will also be overstated.

Finally, at Table 9 Parts B1 and B2, the AltaGas expenses and allocation percentages for each of U.S. operations and Canada operations (for all periods CY 2019 through TYE 2024) do not add up to the total amounts subject to allocation from AltaGas at Table Part A, and this is likely due to the combination of some rounding error when I converted Canadian dollars to U.S. dollars (because WGL did not provide this conversion

164 WGL objected to OPC Data Request No. 4-7 as to relevance, and WGL essentially objected to providing any Canadian financial input data for Payroll, Property, and EBITDA (and other information) because Canada operations costs are not recovered in rates in this rate case via the Commission's jurisdiction. However, if the Canada financial inputs and allocated amounts are not provided, then the allocation of AltaGas corporate expenses to U.S. operations cannot be determined or validated.

165 WGL's response to OPC Data Request No. 4-17(g) (Exhibit OPC (B)-14) shows certain Payroll, Property, and EBITDA financial input amounts and related allocation percentages, but the resulting allocated expenses for ASUS, Midstream, and Power affiliates appear to be understated, inaccurate, and inconsistent with other amounts provided for these same affiliates at the response to OPC Data Request No. 4-17(a), OPC Follow-Up Data Request No. 4-17(a), and OPC Data Request No. 4-8(a) (Exhibit OPC (B)-8).

166 Although I have the underlying Payroll expense input for each U.S. affiliate, this is rendered meaningless by not having the Payroll expense input for Canada operations, because it is necessary to know the Payroll expense for both U.S. and Canada operations in order to know the percentage (or MMF allocation factor percentage) to allocate to each of U.S. and Canada operations to ensure that neither is overstated or understated.

for all amounts), different allocated expense amounts provided by WGL in various data request responses, some AltaGas allocated amounts may include more than expenses (may include some capitalized amounts), and other factors I cannot determine. These unlocated differences are shown in the table below. In the big picture these unlocated differences are not material and I am not overly concerned because I do not believe they are the product of any intentional actions or errors.

**Table 10 – Unlocated Differences Between AltaGas Corporate Expenses and Amounts Allocated to U.S. and Canada Operations**

| Table Part A | Table Part B1 and Part B2 | Unlocated Difference |
|---|---|---|
| $ 51.10 | $ 51.30 | $ (0.20) |
| $ 47.70 | $ 52.00 | $ (4.30) |
| $ 47.50 | $ 46.20 | $ 1.30 |
| $ 42.40 | $ 44.60 | $ (2.20) |
| $ 37.80 | $ 41.50 | $ (3.70) |
| $ 38.30 | $ 42.30 | $ (4.00) |

**<u>Step 3 – ASUS Allocations to WGL/U.S. Affiliates:</u>**

Step 3 Table 9 Part C illustrates the allocation of ASUS U.S. operation expenses to each individual U.S. affiliate, including WGL and other affiliates via the "ASUS" MMF allocator,[167] which is a simple average of the three-factors (drivers)[168] for each affiliate as

[167] The ASUS MMF factor based on allocators of AIC, Net Revenue, and Payroll is per the December 31, 2023, CAM, Exhibit WG (J)-2, at 37.

[168] The "ASUS" MMF factor includes the same Payroll factor as the "AltaGas" MMF factor but includes two different factors of AIC and Net Revenue.

shown below includes two different factors than the "AltaGas" MMF factor as shown below:[169]

1) **<u>Average Invested Capital ("AIC")</u>** – Capitalization (Sum of Common Stock includes Retained Earnings), plus Net Income (Current Year before closing Retained Earnings), plus Total Long-Term Debit, plus Notes Payable, Preferred Stock, and Long-Term Debt due in one year, plus Money Pool Borrowings, less Investment in Subsidiaries.

2) **<u>Net Revenue</u>** – Operating Revenue less Cost of Sales, less Revenue Taxes.

3) **<u>Payroll</u>** – Salary, Wages, Non-Productive Time, Short-Term Incentives, and Other (Excludes Long-Term Incentives).

Table Part C shows the expenses allocated from ASUS/U.S. operations to WGL and each individual U.S. affiliate for the CY's 2019 to 2023, and FYE 2024. The expenses allocated to WGL have increased significantly over time,

The Table 9 Part A AltaGas net corporate expenses subject to allocation to U.S. and Canada operations have increased significantly over time, increasing by a total amount of about $13.0M and 33% from CY 2019 expenses of $38.30M (the first full year after the AltaGas/WGL merger) through TYE 2024 expenses of $51.10 – resulting in an average annual increase of about $7.0M and 7% (with a substantive increase to $51.10M expenses in TYE 2024 from CY 2022 and 2023 consistent amounts). I

[169] WGL Response to OPC Data Request No. 4-8 (Exhibit OPC (B)-8).

**Q. PLEASE EXPLAIN THE CONSTRAINTS UPON YOUR REVIEW OF AFFILIATE ISSUES IMPOSED BY WGL OBJECTIONS TO OPC DISCOVERY, ALONG WITH ITS FAILURE TO PROVIDE RESPONSIVE INFORMATION TO OTHER OPC DISCOVERY.**

A. WGL filed objections to all or subparts of nineteen OPC data requests related to affiliate transactions, including Data Request Nos. 4-1, 4-2, 4-5, 4-7, 4-9, 4-10, 4-15, 4-21, 4-26, 4-29, 4-31, 4-34, 4-40, 4-49, 4-50, 4-51, 4-52, 4-53, and 4-54.[170] OPC and WGL were able to reach a compromise on a number of these affiliate data requests. However, I will summarize my concerns regarding the most important affiliate information that WGL failed to provide, and explain how this unreasonably compromised and constrained my review of affiliate transactions, limited my ability to propose additional adjustments, and how this can overstate WGL's revenue requirement and lead to excessive customer rates.

Most importantly, not having this requested information will put me at a significant disadvantage in addressing and rebutting WGL's position on affiliate issues. This is because it has sole access to this affiliate financial data, so WGL can unfairly decide which information is favorable or unfavorable to its position and it can cherry pick this information to rebut my position. In contrast, I will not have equal access to this same

---

[170] Some of these data requests and associated response are provided as exhibits to this Direct Testimony. *See* WGL Responses to Data Request Nos. 4-5 (Exhibit OPC (B)-6); 4-7 (Exhibit OPC (B)-7); 4-9 (Exhibit OPC (B)-9); 4-10 (Exhibit OPC (B)-89); 4-15 (Exhibit OPC (B)-12); 4-21 (Exhibit OPC (B)-16); 4-29 (Exhibit OPC (B)-18); 4-31 (Exhibit OPC (B)-20); 4-34 (Exhibit OPC (B)-23); 4-40 (Exhibit OPC (B)-29); 4-49 (Exhibit OPC (B)-34); 4-50 (Exhibit OPC (B)-35); 4-51 (Exhibit OPC (B)-36); 4-52 (Exhibit OPC (B)-37); 4-53 (Exhibit OPC (B)-38);and 4-54 (Exhibit OPC (B)-39).

information to determine if WGL is adequately representing all the correct and unbiased facts and information.

My primary concerns are as follows:

**Canada (and U.S.) Affiliate MMF Allocation Information Not Provided**:

OPC Data Request No. 4-7[171] requested various information, including: (a) the amount of expenses allocated to U.S. affiliates and Canada affiliates by function (Accounting & Tax, Legal, Board of Directors, and other categories set forth in the Company's CAM); and (b) the financial and other inputs to the MMF allocation factors used to allocate these costs to U.S. and Canada operations. WGL objected to providing this information on the grounds of relevance because it relates to excluded costs that are not recovered in rates. In other words, WGL objected to this data request because it believes the requested allocated Canadian expenses and inputs to the related allocation factors are not relevant to this rate case because these costs are not recovered in the rates to be set by this Commission. I disagree, because it is impossible to determine if costs allocated to each the U.S. and Canada operations via the Company's proposed MMF allocation factors are reasonable, without knowing the underlying financial inputs for U.S. and Canada operations that are driving these common/indirect costs to each of U.S. and Canada operations.

As previously explained at Step 2 of the AltaGas allocation process, AltaGas allocates a bucket of its common/indirect corporate expenses to U.S. operations and the

---

171 WGL Response to OPC Data Request No. 4-7 (Exhibit OPC (B)-7).

Canada/Midstream operations using the "AltaGas" MMF 3-factor formula of: 1) Property; 2) Payroll; and 3) EBITDA. WGL's response to OPC Data Request No. 4-7 provided information showing the total amounts of expenses allocated to U.S. and Canada operations for periods 2019 to TYE 2024, and this has resulted in an average of 78% of costs allocated to U.S. operations (including 69% for TYE 2024) and an average of 22% of costs allocated to Canada/Midstream operations (including 31% for TYE 2024).

However, WGL has not provided the underlying calculations and inputs to the ASUS MMF allocation factors to show how the amounts and percentages allocated to each of U.S. and Canada operations was determined. It is not possible to determine the allocation of AltaGas corporate costs to U.S. and Canada operations without the underlying MMF factor information of Property, Payroll, and EBITDA for both U.S. and Canada. And although WGL objects to providing the underlying MMF factor information for Canada operations, WGL has also failed to provide this same information for U.S. operations.[172]

I will provide a brief example of why both MMF factor input information is necessary for both U.S. and Canada operations using the MMF Payroll factor as an example. If the total U.S. operations Payroll expense is $200M and the Canada operations Payroll expense is $125M, then the combined Payroll expense of $325M would result in a U.S. Payroll allocation factor of 62% ($200M/$325M) and a Canada Payroll allocation factor of 38% ($125M/$325M). These allocation percentages/factors would then be

[172] In contrast, WGL's response to OPC Data Request No. 4-8 (Exhibit OPC (B)-8) did provide the underlying financial and other inputs for the "ASUS" allocation factor components of AIC, Net Revenues, and Payroll used to allocate U.S. operation expenses to each U.S. affiliate.

applied to the total AltaGas corporate expense pool of $51.10M[173] (for TYE 2024), and this would allocate $31.70M ($51.10M x 62%) of AltaGas corporate expenses to U.S. operations and $19.40M ($51.10M x 38%) of AltaGas corporate expenses to Canada operations. This same example could be used for the other two MMF factors of Property and EBITDA. As illustrated by this example, if I just have the U.S. operations Payroll expense, and not the Canada operations Payroll expense, then I cannot calculate the correct percentage and amount of AltaGas corporate expenses to be allocated to either U.S. or Canada operations.

The Company determined and supports this MMF methodology, it is not reasonable to withhold information to evaluate the validity and objectivity of the related allocations that directly impact WGL expenses and related rates in this rate case. WGL has failed to meet a reasonable burden of proof to support its MMF allocation method and the related amount of AltaGas corporate costs allocated to U.S. operations (and ultimately to WGL in this rate case).

I will propose certain adjustments to address allocation of affiliate expenses to WGL because other information suggests that the Company's 69% of AltaGas corporate expenses allocated to U.S. operations are overstated, and the 31% of AltaGas corporate expenses allocated to Canada operations is understated. However, the best course of action is for WGL to be forthcoming in providing this information so that all parties have equal

---

[173] This is the actual amount of AltaGas corporate expenses subject to allocation to U.S. and Canada operations for TYE 2024 per Table 9 Part A.

access to this information for a proper and objective evaluation of the allocation process and the related affiliate expenses allocated to WGL in this rate case.

**WGL Allocated Expenses by Detailed Function for Test Period End March 31, 2024, Is Not Provided.**

OPC Data Request No. 4-5[174] requested various information, including: (a) the amount of expenses allocated from AltaGas/ASUS corporate expenses allocated to WGL by both detailed function (Accounting & Tax, Legal, Board of Directors, and other categories set forth in the Company's CAM) and account number – and in the same format as the side-by-side comparison that WGL provided in prior rate case FC 1169, but updated for recent periods including the TYE March 31, 2024, of this rate case.

WGL objected to this OPC data request to the extent it required a special study which the Company has not performed. In addition, WGL stated this side-by-side comparison of affiliates allocations to WGL for prior years can be obtained at the Commission website in Formal Case No. 1142, Order No. 19396, per Appendix A, Merger Commitment 26.

I downloaded WGL's most recent side-by-side filing from the Commission's website and it included the information requested in OPC Data Request No. 45 through the calendar year December 31, 2023 – but this did not include information through the TYE March 31, 2024, of this rate case. This same type of side-by-side analysis had not been

[174] WGL Response to OPC Data Request No. 4-5 (Exhibit OPC (B)-6).

prepared by WGL for the TYE March 31, 2024, because WGL considers this a special study that it is not required to provide to OPC. I strongly disagree with WGL.

My concerns with WGL's failure to provide the OPC-requested side-by-side analysis with OPC Data Request No. 4-5 are set forth below:

a) First, WGL's response to OPC Data Request No. 4-10(a), Attachment 1, did provide the side-by-side allocated expense analysis requested in OPC Data Request No. 4-5 through the TYE March 31, 2024 – except the only information missing was the allocated expenses by "detail" function and account. In other words, the allocated expenses are provided by the "primary" function/account like "Accounting and Tax", "Finance", "IT", etc., but it did not include underlying expense detail (or subaccount) such as "Administrative and General Salaries Account 920", "Office Supplies and Expenses Account 921", "Outside Services Employed Account 923", etc. I contend that if WGL was able to query its records to provide all allocated expenses by primary account numbers (i.e. "Accounting and Tax" expense total) as provided at OPC Data Request No. 4-10, then it should also be able to readily query the same financial records to get the underlying expense detail (i.e., "Administrative and General Salaries Account 920", etc.). Also, there are at most only two underlying subaccounts of: (1) "Administrative and General Salaries Account 920"; and (2) "Office Supplies and Expenses Account 921" that have expense balances for each primary account from CY 2019 through March 31, 2024, and only fifteen subaccount expenses balances in total that were requested by OPC. Thus, OPC's request was reasonable and not excessive, burdensome, or time consuming.

b) Second, it was WGL that selected the twelve months ending March 31, 2024, for this rate case, meaning that all financial and other data supporting the Company's filing had to be provided for this period. And when it is beneficial to WGL's interest in this rate case, it provides significant and voluminous financial and other data to support costs beyond the test period that it seeks to recover in rates, and it even provides substantial underlying data for prior year's costs that it seeks to recover in rates. OPC's request for detailed affiliate expenses by subaccount through the TYE March 31, 2024, is reasonable and consistent with other subaccount financial data that WGL has filed to support the recovery of other costs. It is not reasonable for WGL to withhold subaccount financial data for affiliate transactions when it has voluntarily provided subaccount and detailed financial information for other costs which it seeks to recover in this rate case. WGL has selectively opposed the provision of underlying detailed affiliate expense information because it understands this may not be in its best interest, but WGL should not be able to arbitrarily decide which information is important and relevant for this rate case.

c) Third, Table 9 Part C shows that affiliate expenses allocated to WGL were $27.80M in CY 2023 and had declined to $26.10M in TYE March 31, 2024. However, because WGL did not provide the detailed affiliate expenses for TYE March 31, 2024, I am unable to identify the specific subaccounts that are unusual, significant, or causing changes in the total account balance, and which would allow me to propose a focused and specific adjustment. Without access to the affiliate expenses by detailed subaccount for TYE March 31, 2024, WGL leaves me no other option but to propose surrogate adjustments using the best and most recent detailed subaccount affiliate expenses in CY 2023. WGL should not be able to argue the accuracy of my surrogate affiliate expense adjustments with a straight face, when it was their decision to oppose my access to OPC-requested detailed affiliate expenses for TYE March 31, 2024. The bottom line is that WGL's has failed to meet a reasonable burden of proof to support the corporate expenses allocated to WGL in this rate case, and the Commission should adopt my proposed adjustments.

### *Ostrander Rebuttal to WGL Witnesses Affiliate Expense Testimony*

**Q. PLEASE SUMMARIZE THE TESTIMONY OF WGL'S FOUR WITNESSES ADDRESSING AFFILIATE ISSUES AND SUMMARIZE YOUR CONCERNS.**

A. WGL has filed the testimony of four witnesses addressing affiliate issues, including Witness Patric Baryenbruch (Exhibit WG (L), Witness Eric Block (Exhibit WG (K), Witness Tuoriniemi (Exhibit WG (D), and Witness Ghislaine Quenum (Exhibit WG (J). Because Witness Baryenbruch and Witness Block are the only witnesses that include some analysis in their testimonies to specifically conclude that WGL's affiliate expenses are "reasonable",[175] my direct testimony will focus on the testimony of these witness (and mostly focus on Witness Baryenbruch).

---

[175] Exhibit WG (L) (Baryenbruch) at 3:14-16, 6:1-3, 12:6-8, and 15:1-3, all conclude that 2024 affiliate costs

**WGL Witness Baryenbruch** (an outside consultant) is the primary witness addressing affiliate issues.[176] Witness Baryenbruch's direct testimony concludes that test year end March 31, 2024, affiliate expenses allocated to WGL (along with the larger group of A&G expenses that include affiliate expenses) are reasonable for the following reasons and my concerns:

**Overall Concerns:**

I am concerned that Witness Baryenbruch reaches a conclusion that AltaGas expense allocated to WGL are reasonable when he has not performed any detailed analysis of the actual costs and cost allocation processes underlying these costs, he has merely performed some high level "reasonableness" tests such as comparing WGL affiliate charges on a per customer basis to that of the market. Witness Baryenbruch has not performed the following analysis:

- Did not review any of the detailed costs, invoices, contracts or other documentation comprising the AltaGas costs, which are the starting point for costs allocated to ASUS and eventually to WGL.
- Did not test the MMF allocations or underlying inputs for accuracy or validity (or compare such MMF allocation factors to allocation factors used by other entities).

allocated to WGL are reasonable. Also, Exhibit WG (K) (Block) at 2:9-14, concludes that affiliate costs charged to WGL are reasonable.

[176] Among the four WGL witnesses addressing affiliate issues, Witness Baryenbruch's direct testimony incorporates the most pages, fifteen pages of direct testimony and thirty-one pages of exhibits at Exhibit WG (L)-2.

- Did not review the detailed costs, invoices, contracts or other documentation comprising the ASUS costs allocated to WGL (this was another opportunity to review these costs).
- Did not review the MMF allocations from AltaGas to U.S. operations and Canada operations to determine there is a reasonable and accurate method for allocating costs between these jurisdictions.

**Peer/Market Comparison:**

Witness Baryenbruch states the administrative and general ("A&G") expenses compare favorably to those of certain peer utility companies.[177] Also, Witness Baryenbruch appears to conclude that because WGL's A&G expenses are reasonable compared to peer utility companies, then the underlying affiliate charges included in A&G expenses are also reasonable,[178] and this understanding is confirmed in WGL's response to OPC Follow-Up Data Request No. 4-56 when he provides a specific comparison of WGL's affiliate expenses to peer utilities for the first time.

I disagree with Witness Baryenbruch's conclusion. I address this issue in detail below.

**Lower of Cost or Market:**

Witness Baryenbruch incorrectly concludes cost of affiliate services provided by AltaGas to WGL are properly reflected at the lower of cost or market.[179] Witness

[177] Exhibit WG (L) (Baryenbruch) at 6:1-8, 10:19 – 13:14, along with Exhibit WG (L)-2, pages 24 to 28).

[178] Exhibit WG (L) (Baryenbruch) at 11:6-7.

[179] Exhibit WG (L) (Baryenbruch) at 6:1-8, 8:17 – 10:18, along with Exhibit WG (L)-2, pages 11 to 23.

Baryenbruch's underlying premise is substantially flawed. For each of the types of services provided by outside professionals to clients consisting of: (1) CPAs; (2)Attorneys; (3)IT professionals; and (4) Management Consultants, Witness Baryenbruch assigns the estimated billing rates per hour of each of these professionals as a "cost" per hour assigned to WGL employees in related departments that perform accounting work, IT work, legal work and management consulting work (multiplying each WGL's employees hours by the outside billing rate of the related professional to arrive the "market" cost).[180] And then he concludes that it is less expensive for WGL employees to provide services to affiliates at their actual hourly rate instead of hiring these respective outside professionals(CPA, Attorney, IT, Management Consultant) to perform all of these services and charge their much higher "market" billing rates/costs to affiliates. This is not a proper "lower of cost or market" analysis.[181]

This "lower of cost or market" analysis is substantially flawed and over-simplified.

First, Witness Baryenbruch assumes that outside consulting "professionals" are the market for WGL employees that are not even qualified as a CPA, Attorney, IT and Management Consultant. Witness Baryenbruch did not determine how many and which employees in each WGL department were qualified as CPAs, Attorneys, IT, or

[180] It is important to understand that Witness Baryenbruch does not identify the specific cost of services (or the underlying billing rates) provided by CPAs, Attorneys, IT professionals and Management Consultants to WGL (or AltaGas) as part of his analysis. His analysis is flawed and assumes that each of these professional's billing rates/costs are substituted for the cost of all WGL/AltaGas employees in departments that he believes perform general accounting, legal, IT, and management consulting type duties.

[181] WGL's response to OPC Data Request 4-36 (Exhibit OPC (B)-25) explains how Witness Baryenbruch's "lower of cost or market" analysis is flawed.

Management Consultants – so that he could match the proper billing rate of the WGL employee with the consulting professional. He didn't even consider that some CPAs are practicing CPAs and some are not, each with different credentials and billing rates. He didn't even consider that some CPAs have different billing rates because they are a Senior Partner, Partner, Manager, Junior, etc. based on different levels of tenure and experience. He didn't match the tenure and experience level of WGL employees with those of the related consulting professionals. He basically randomly assigned CPA billing rates to a group of WGL employees that may not have any degree in accounting and are not qualified as a CPA or even an intern.

Second, Witness Baryenbruch did not consider that outside professional CPAs (and Attorneys, etc.) charge a firm billing rate to clients that is marked up 3 to 4 times greater than their base salary costs, in order to recoup the employee's salaries, overhead, firm costs and overheads, and contribute to the profits of the firm. A CPA's billing rate is "not" the same as the CPA's specific base salary, it is much greater. Thus, it makes no sense to compare a CPA's billing rate (that has a multiple mark-up to the "salary") to the salary cost of a WGL employee that does not have a similar mark-up. Witness Baryenbruch is comparing apples to oranges and it's not even close.

Third, when WGL goes to the market in most cases it hires a new or replacement employee that does not have CPA credentials, and does not need CPA credentials, WGL does not hire an expensive CPA that is over-qualified for the job. Witness Baryenbruch does not understand the "market" for WGL's employees, the market is not all outside contracting professionals that are either a CPA, Attorney, IT, or Management Consultant.

I am reasonably postulating that most WGL employees are not any of these, and they do not need to be for their jobs. It is alarming to me that WGL appears to agree with Witness Baryenbruch's analysis that all of WGL employees' "market" is an outside contracting professional of some kind.

Fourth, it appears that Witness Baryenbruch's intent was to try and determine the highest possible level of "market" costs to make it appear that WGL's actual payroll costs are reasonable in comparison to those of outside contracting professionals so this would fit his skewed criteria of lower of cost or market, with WGL employees representing the "lower of the cost" and outside contracting professionals representing the "higher of market cost." This analysis is fatally flawed.

**Benefits of Affiliate Charges/Absence of Redundance:**

Witness Baryenbruch states that AltaGas services provided to and allocated to WGL are beneficial, necessary, and not redundant. However, Witness Baryenbruch did not identify or provide any detailed analysis, studies, or supporting documentation for this conclusion. He merely put some "x's" in boxes on a spreadsheet for Exhibits 2 and 3 (Exhibit WG (L)-2, pages 9 and 10, Exhibits 2 and 3). There is no independent analysis to reach this conclusion based on WGL's responses to OPC data requests.

**WGL Witness Block's** direct testimony describes the types of corporate services provided by AltaGas to WGL and concludes the services and related affiliate charges allocated to WGL are reasonable, necessary, beneficial to customers, and not duplicative of services provided by WGL to itself. He also explains how AltaGas manages the costs incurred in providing corporate services to WGL and briefly describes the MMF allocation factor used to allocate AltaGas corporate costs to WGL. Witness Block reaches the same conclusion as Witness Baryenbruch on certain common conclusions related to the necessary, beneficial, and non-duplicative nature of these affiliate allocations to WGL. I address Witness Block's positions below.

**Overall Concerns:**

My concerns with Witness Block are essentially the same as those I expressed regarding Witness Baryenbruch, he reaches a conclusion that AltaGas expenses allocated to WGL are reasonable when he has not performed any detailed analysis of the actual costs and cost allocation processes underlying these costs, he has merely reached an unsupported conclusion. Witness Block has not performed the following analysis, or at least has not provided supporting documentation:

- Did not review any of the detailed costs, invoices, contracts or other documentation comprising the AltaGas costs, which are the starting point for costs allocated to ASUS and eventually to WGL.
- Did not test the MMF allocations or underlying inputs for accuracy or validity (or compare such MMF allocation factors to allocation factors used by other entities.
- Did not review the detailed costs, invoices, contracts or other documentation comprising the ASUS costs allocated to WGL (this was another opportunity to review these costs).
- Did not review the MMF allocations from AltaGas to U.S. operations and Canada operations to determine there is a reasonable and accurate method for allocating costs between these jurisdictions.

Witness Block states that AltaGas provides services allocated to WGL tare beneficial, necessary, and not redundant. However, Witness Block did not identify or provide any detailed analysis, studies, or supporting documentation for this conclusion. There is no independent analysis to reach this conclusion.

**Witness Tuoriniemi's** direct testimony identifies how WGL transactions with affiliates are reflected in the development of the revenue requirement in this rate case, and he provides the test year end March 31, 2024, amount of "WGL" and "WGL-DC" affiliate transactions reflected in the income statement and balance sheet for both direct and allocated services provided by affiliates to WGL and for services provided by WGL to affiliates.[182] Witness Tuoriniemi's testimony is focused on presenting the accounting impacts on WGL's books and this rate case, so he does not make any statements regarding the reasonableness of affiliate transactions costs charged by affiliates to WGL or charged by WGL to affiliates. I will not address Witness Tuoriniemi's testimony, although I will rely on the affiliate transaction amounts included in his testimony regarding potential affiliate transaction adjustments that I propose.

**Witness Quenum's** direct testimony describes the transactions between WGL and its affiliates for the test year end March 31, 2024, and addresses the Affiliate Cost of Service Study ("ACOSS") that she sponsors at Exhibits WG (J)-4 a(Public) and (J)-5 (Confidential). Witness Quenum's primarily sponsors scheduling identifying the amounts of affiliate transactions on WGL's income statement and balance sheet via the ACOSS,

---

[182] Exhibit WG (D) (Tuoriniemi) at 32:1 – 36:15.

and she does not reach any conclusions regarding the reasonableness of WGL's affiliate transaction costs charged by affiliates to WGL or charged by WGL to affiliates. I will not address Witness Quenum's testimony. However, I do believe the current ACOSS format for identifying affiliate transaction amounts can be confusing to the lay person, it incorrectly comingles both balance sheet and income statement amounts for some transactions which largely renders this information useless, and it is not organized in a meaningful format to show the impacts of affiliate transactions on the revenue requirement of WGL in this rate case.

**Q. CAN YOU IDENTIFY THOSE WGL DATA REQUEST RESPONSES THAT SUPPORT YOUR CONCERNS REGARDING WITNESS BARYENBRUCH'S FLAWED ANALYSIS?**

A. These data requests include OPC Data Request Nos. 4-13, 4-14, 4-15, 4-17, 4-19, 4-21, 4-28, 4-29, 4-30, 4-31, 4-32, 4-33, 4-34, 4-35, 4-36, 4-37, 4-38, 4-39, 4-40, 4-41, 4-42, 4-44, 4-48, 4-49, 4-50, 4-51, 4-52, 4-53, 4-54, 4-55, 4-56, 4-57, 4-58, and 4-59.[183]

**Q. WITNESS BARYENBRUCH'S ANALYSIS CONCLUDES THAT WGL'S A&G AND AFFILIATE EXPENSES ARE REASONABLE COMPARED TO THE MARKET. PLEASE EXPLAIN HOW YOUR CORRECTION OF A SIGNIFICANT ERROR REACHES AN OPPOSITE CONCLUSION THAT WGL'S NET A&G EXPENSES SIGNIFICANTLY EXCEED THE MARKET.**

---

[183] Some of these data responses are included in my testimony. *See* Exhibit OPC (B)-11 through Exhibit OPC (B)-44.

A. Witness Baryenbruch concludes that both WGL's (a) A&G expenses and (b) affiliate expenses (AltaGas corporate expenses allocated to WGL, and included in the A&G account) are reasonable when compared to A&G and affiliate expenses of peer utility companies.[184] Although I do not agree with all of Witness Baryenbruch's approach, I used his same WGL data (except converting expenses from a WGL basis to a correct WGL-DC basis) and used his same peer utility data, but after correcting a significant error (removing the affiliate expenses from the A&G expenses) the results are the opposite and show that WGL's net A&G expenses are significantly greater than those of peer utility companies.

Witness Baryenbruch correctly concludes that affiliate expenses are a subset of A&G expenses (i.e., affiliate expenses are included in the larger total A&G expenses). However, he made one significant error in failing to net (or remove) the peer company affiliate expenses from the peer company A&G expenses, in order to arrive at "net" A&G expenses to compare to the same net A&G expenses for WGL. Witness Baryenbruch may have selected peer utilities with inflated affiliate expenses in order to make WGL's affiliate expenses appear much lower and more reasonable than peer utilities. And that might explain why he did not properly net or remove the peer utility A&G and affiliate expenses (because affiliate expenses are a subset of A&G expenses, they must be removed from the A&G expense). When I properly netted the A&G and affiliate expenses for both the peer utility companies and for WGL-DC, and compared these amounts, the WGL-DC net A&G expense of $135 per customer is $41 (and 44%) greater than that of the peer utility

[184] Both the WGL and peer utility A&G expenses and affiliate expenses are expressed on a "per customer basis" by Witness Baryenbruch.

companies. Therefore, if Witness Baryenbruch had used his data correctly, and simply and correctly removed peer utility affiliate expenses from peer utility A&G expenses, he would have arrived at an opposite conclusion that WGL's A&G expenses greatly exceed that of the market, instead of concluding that both WGL's A&G expenses and affiliate expenses are reasonable.

**Q. PLEASE ADDRESS AND ILLUSTRATE THE FLAWS OF WITNESS BARYENBRUCH'S ANALYSIS, AND EXPLAIN HOW THE CORRECTION OF A MAJOR ERROR LEADS TO THE OPPOSITE CONCLUSION THAT WGL'S NET A&G EXPENSES SIGNIFICANTLY EXCEED THOSE OF THE MARKET?**

A. I will address my concerns after the illustrative tables below.[185]

[*REMAINDER OF PAGE LEFT BLANK*]

---

[185] The source documents for the amounts included in the table are reflected at this similar schedule included at Exhibit OPC (B)-5, Schedule 9.

**Table 11 – Correction of Witness Baryenbruch Flawed Analysis – WGL Net A&G is Excessive Compared to Peer Utilities**[186]

| Lne | Description | WGL | A&G - No Adjs. | A&G Adjusted |
|---|---|---|---|---|
| | | | | |
| | **Part A** | **A&G Expense Allocated to WGL and WGL-DC** | | |
| 1 | WGL A&G Expense | $ 218,749,642 | $ 39,138,720 | $ 37,200,773 |
| 2 | WGL Customers | 1,226,879 | 163,908 | 163,908 |
| 3 | WGL A&G Expense per Customer | **$ 178** | **$ 239** | **$ 227** |
| | | | | |
| | **Part B** | | | |
| | | | | |
| 4 | AltaGas Affil. Exp. Allocated to WGL | $ 26,781,103 | $ 5,090,660 | $ 5,090,660 |
| 5 | SEMCO Affil. Exp. Allocated to WGL | $ 1,556,406 | $ - | $ - |
| 6 | WGL Affiliate Expenses | $ 28,337,509 | $ 5,090,660 | $ 5,090,660 |
| 7 | WGL Customers | 1,226,879 | 163,908 | 163,908 |
| 8 | WGL Affiliate Expense per Customer | **$ 23** | **$ 31** | **$ 31** |
| | | | | |
| | **Part C - Amounts per Customer** | | | |
| 9 | WGL A&G Expense | $ 178 | $ 239 | $ 227 |
| 10 | WGL Affiliate Expense | $ (23) | $ (31) | $ (31) |
| 11 | **WGL Net A&G Median Expense** | **$ 155** | **$ 208** | **$ 196** |
| | | | | |
| 12 | Peer Group Median A&G Expense | $ 160 | $ 160 | $ 160 |
| 13 | Peer Group Median Affiliate Expense | $ (99) | $ (99) | $ (99) |
| 14 | **Peer Group Net A&G Median Expense** | **$ 61** | **$ 61** | **$ 61** |
| | | | | |
| 15 | **WGL Exceeds Peer Group Net A&G Expense** | **$ 94** | **$ 147** | **$ 135** |
| | | | | |
| | **Part D** | **WGL Net A&G Exceeds Peer Group Net A&G** | | |
| 16 | WGL Excess Net A&G Compared to Peer Group | $ 94 | $ 147 | $ 135 |
| 17 | Customers | $ 1,226,879 | $ 163,908 | $ 163,908 |
| 18 | **WGL Excess Net A&G Compared to Peer Group** | **$ 115,572,514** | **$ 24,049,672** | **$ 22,111,725** |

Witness Baryenbruch calculates WGL's 2023 A&G expense per customer of $178, and compares this to the median A&G expense per customer of $160 for a group of thirty-

186 The highlighted portion of this Table 11 is not confidential; it is highlighted for emphasis.

one peer utility companies.[187] Although he states that WGL's A&G expense per customer of $178 is in the middle of the third quartile of the peer utility companies, with eighteen utilities having a lower A&G expense, he still concludes that WGL's A&G expense is reasonable when he concludes, "I consider WGL's relative cost position to be reasonable."[188] Witness Baryenbruch's direct testimony did not include any similar comparison of WGL's affiliate expenses on a per customer basis to peer utility companies.

However, Witness Baryenbruch appears to infer that if WGL's A&G expenses are reasonable (compared to peer companies), then WGL's 2023 affiliate expense of $28.30M - which are a subset of WGL's 2023 A&G expense of $218.70M – are also considered to be reasonable, when he states, "Thus, a comparison of WGL's total A&G expenses to those of other utilities also involves a comparison of the affiliate charges component."[189] Witness Baryenbruch also concludes that WGL's affiliate charges of $28.30M (which are 13% of WGL's total A&G expense of $218.70M0 "…represent a sizeable portion of WGL's A&G expenses."[190] Although WGL affiliate expenses of $28.30M and 13% are material and important to review for potential rate case adjustments, I do not consider this level of affiliate expenses to be a "sizeable" portion of the $218.70M of WGL A&G expenses. Because Witness Baryenbruch considers the larger WGL A&G expenses to be reasonable, it then becomes easier for him to apply the same "reasonable" conclusion to

[187] Exhibit WG (L) (Baryenbruch) at 11:14-25 (and Table 7) to 12:25 (and Table 8).

[188] Exhibit WG (L) (Baryenbruch) at 12:5-8.

[189] Exhibit WG (L) (Baryenbruch) at 11:6-7.

[190] Exhibit WG (L) (Baryenbruch) at 10:22-24.

the underlying WGL affiliate expenses if these amounts are also considered to be a significant portion of the WGL affiliate expenses.

Witness Baryenbruch's direct testimony did not compare WGL's affiliate expense levels to the affiliate expense levels of peer utility companies on a per customer basis or in any manner. Therefore, OPC Data Request No. 4-56 asked WGL if its affiliate expenses (included in the A&G expenses) were the reason for WGL's A&G expenses being greater than the median level of peer utility companies. Witness Baryenbruch's response to OPC Data Request No. 4-56 provided information for the first time comparing WGL's affiliate expenses to the peer utilities' affiliate expenses on a per customer basis.

He stated that WGL's affiliate charge expense per customer of $23.00 were lower than those of the "holding" companies in the peer group, and the peer group holding companies have had an affiliate expense per customer range from $53.00 to $237.00. It is important to consider that Witness Baryenbruch's thirty-one peer utility companies used in his A&G comparison study are different than the twenty-two larger "holding" companies used for is included in his affiliate charge peer group. Witness Baryenbruch's response to OPC Data Request No. 4-56 also stated that WGL's A&G expenses are larger than the peer companies due to a higher cost of living in Washington D.C. compared to the locations of headquarters for the peer group of utilities.

Finally, Table 11 can be used to show the flawed conclusions of Witness Baryenbruch. First, at Table 11, column 1 of Part A, Witness Baryenbruch calculates an incorrect A&G expense per customer of $178 by using total WGL expenses and customers (for all utilities in Maryland, Virginia, and D.C., plus SEMCO). Table 11, column 3 of

Part A, shows my correctly calculated A&G expense per customer of $227, using specific WGL-DC expenses and customers. Second, Table 11, Part B, column 1 shows Witness Baryenbruch's incorrect calculation of affiliate expenses allocated to WGL of $23 per customers (using total WGL, and not WGL-DC), and column 3 of Part B shows my correct calculation of affiliate expenses allocated to WGL of $31 per customer using specific WGL-DC amounts.

Third, Table 11, Part C shows the correct netting of the WGL A&G expenses with the WGL affiliate expenses, and the correct netting of peer group A&G expenses with peer group affiliate expenses. Although Witness Baryenbruch's testimony agrees that WGL affiliate expenses are a subset of (and included in) the larger category of WGL A&G expenses, he never properly nets these two expenses in his analysis to arrive at net A&G expense.

Witness Baryenbruch's WGL netted A&G expenses are $155 per customer at column 1, Part C, and when compared to his peer/market group netted A&G of $61 per customer, this actually shows that WGL's netted A&G expenses are $94 per customer greater than the peer group. Thus, WGL's net A&G/Affiliate expenses are greater than the peer group, which means that WGL's A&G/Affiliate expenses on a per customer basis are greater than the peer group. This is an opposite conclusion than Witness Baryenbruch reached in his testimony, he instead concludes in his faulty analysis that both WGL's A&G expenses and affiliate expense are both reasonable compared to the peer group. However, Witness Baryenbruch failed to perform the proper last step in netting the WGL A&G and Affiliate expenses and comparing these amounts to similar netted amounts for the peer group. Similarly, my corrected amounts in column 3 also shows that WGL-DC's net A&G/Affiliate expenses of $196 per customer also exceed the peer group of net A&G/Affiliate expenses of $61 per customer by an amount of $135 per customer. Thus, A&G/Affiliate expense expenses of WGL and WGL-DC are greater than the peer group, and this supports my adjustment to reduce WGL-DC affiliate expenses.

### *Adjustment BCO-10: Adjust Uncollectible Expense to a Normalized Annual Level (Exhibit OPC (B)-5, Schedule 10)*

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REDUCE UNCOLLECTIBLE EXPENSES TO A NORMALIZED ANNUAL LEVEL?**

A. WGL Adjustment No. 1 proposed to increase uncollectible expense by **BEGIN CONFIDENTIAL***** [redacted] *****END CONFIDENTIAL**

However, WGL's five-year average (for years 2020 to 2024) includes nonrecurring and unusual outlier data for periods 2020 (unusually high charge-offs two to three times the normal annual amounts), and 2021 and 2022 (unusually low charge-offs related to the COVID-19 years), which resulted in the calculation of an unusually high five-year average uncollectibles accrual rate of 2.7046%. I will explain my adjustment after the following table.

[*REMAINDER OF PAGE LEFT BLANK*]

**Table 12 – OPC Adjusted Uncollectible Expense**

**BEGIN CONFIDENTIAL*****

| A | B | C | D | E |
|---|---|---|---|---|
| | | Charge-Off | Revenues | Revenue |
| | Net | Outlier Data | from | Outlier Data |
| Period | Charge-Offs | Removed | Gas Sales | Removed |
| [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] | | | |

*****END CONFIDENTIAL.**

I propose an adjustment to uncollectibles based on data in the above table which **BEGIN CONFIDENTIAL*****[redacted]

[redacted] ***END CONFIDENTIAL.

OPC Data Request No. 10-15[191] asked WGL the reasons for some of the unusual fluctuations in uncollectibles from year-to-year and WGL provided some of this information. Also, WGL provided requested information used in my adjustment calculation.

The Commission should accept my adjustment to WGL's uncollectible expense.

***Adjustment BCO-11: Adjust Call Center Expense (Exhibit OPC (B)-5, Schedule 11)***

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REDUCE CALL CENTER EXPENSES.**

A. WGL does not propose an adjustment to increase or decrease Call Center expenses, I identified this concern from WGL's responses to various data request. I have reduced Call Center expenses.

I have adjusted the test year ended March 31, 2024, Call Center expense to the Call Center expense balance **BEGIN CONFIDENTIAL***** [redacted] ***END CONFIDENTIAL.

[191] WGL Response to OPC Data Request No. 10-15 (Exhibit OPC (B)-58).

WGL provided the amount of Call Center expense for calendar years 2021 to 2023, and test year ended March 31, 2024, in its response to Confidential Data Request No. 18-10,[192] and provided other requested information in response to this data request. I do not believe WGL's response adequately explained the reasons for the changes in Call Center expense.

OPC Data Request No. 6-1[193] requested WGL's Business Plans/Budgets and the Company's response provided Confidential WGL Budgets for 2020, 2021, 2022, 2023, and 2024. WGL's 2023 Budget states the following regarding Call Center issues, **BEGIN CONFIDENTIAL*****[redacted]

[192] WGL Response to OPC Data Request No. 18-10 (Exhibit OPC (B)-87).

[193] *See* WGL's Confidential and Attorneys' Eyes Only Response to OPC Data Request No. 6-1 (Exhibit OPC (B)-45).

[redacted] *****END CONFIDENTIAL.**[194] If WGL can provide adequate supporting documentation to explain these issues, I am receptive to revising or removing this adjustment. However, at this time, sufficient information exists to justify a reduction in Call Center expenses based on this information.

***Adjustment BCO-12: Adjust Short-Term Incentives (Exhibit OPC (B)-5, Schedule 12)***

**Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO SHORT-TERM INCENTIVES ("STI").**

A. WGL did not propose to remove any STI expenses, although WGL did remove all of long-term incentive expense ("LTI"). My adjustment removes $968,543 of STI expense using a proxy that removes one-third of STI expenses related to financial-related performance metrics – and the Commission has historically disallowed financial performance metrics for STI and LTI. WGL states that none of its $2,934,979 of WGL-DC STI expenses are related to financial-related metrics, but I disagree. The AltaGas 2024 Management Information Circular includes a significant number of references to STI being driven by financial performance. Thus, there is a substantial disconnect between WGL witnesses in this rate case that assert there are no financial-related performance metrics included in the STI versus the AltaGas Management Information Circular which includes numerous references to the STI being driven by financial performance metrics. In this case, I will choose to believe the more objective AltaGas Management Information Circular issued to

---

194 *See* WGL's Confidential and Attorneys' Eyes Only Response to OPC Data Request No. 6-1 (Exhibit OPC (B)-45) at page 178 of 233.

shareholders because it does not have a vested interest in swaying opinion in a regulatory proceeding.

**Q. WHAT IS THE COMMISSION PRECEDENT REGARDING STI AND LTI?**

A. The Commission has historically disallowed STI and LTI expense related to financial-related performance metrics. However, since WGL has switched from its WGL Corporate Scorecard (which had some obvious component of financial metrics) to its current Utilities Value Drivers Scorecard in 2020[195] (which has little or no obvious "written" financial performance metrics), the Commission has allowed most or all of STI to be included in the recovery of rates. This is illustrated by two rate cases noted below.

In Formal Case No. 1137 (Order dated March 3, 2017), the Commission found that the Corporate Scorecard included a non-utility earnings goals and a Unity Return on Equity goal, which either addressed non-utility earnings or was a financial performance metric, and the Commission reduced the STI recovery by 20% as found in the management audit in Formal Case No. 1027.[196]

In a more recent WGL rate case, FC 1169, the Commission removed $200,179 of STI expense due to the poor performance of the Call Center (via the Customer Strategy Value Driver), and accepted the remaining $1,835,284 of STI, removing $26,978 of capitalized STI related to the same issues.[197]

---

[195] WGL's response to OPC Data Request No. 10-6 (Exhibit OPC (B)-56) cites to the transition from the WGL Corporate Scorecard to the Utilities Value Drivers Scorecard format in 2020.

[196] *Formal Cas 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 ¶ 230 rel. February 22, 2024, *Citing Formal Case No. 1137*, Order No. 18712 ¶ 254 rel. March 3, 2017.

[197] *Formal Case No. 1169*, Order No. 21939 at ¶ 231.

**Q. CONTRARY TO WGL'S POSITION IN THIS RATE CASE, HAVE YOU FOUND SUBSTANTIAL CORROBORATING INFORMATION STATING THAT STI INCLUDES FINANCIAL PERFORMANCE METRICS?**

A. Yes. WGL states that its STI plans are not driven by any financial performance metrics,[198] and the information that is publicly available via the current Utilities Value Drivers Scorecard make it difficult to identify specific financial performance metrics.[199]

However, I reviewed the 2024 AltaGas Management Information Circular ("2024 Circular") and this document includes numerous citations stating that the STI plan is driven by financial performance.[200] I will cite to the robust language in the 2024 Circular that indicates STI is clearly driven by financial performance, per the following:

1) The Circular states, "The STI pool is determined to be eligible for funding based on the achievement of a set financial performance target. For 2023, the HRC Committee and the Board set the target based on meeting normalized EBITDA from the 2023 business plan." This is a clear reference to a financial performance metric of "EBITDA" regarding the STI plan.[201]

---

[198] Exhibit WG (F) (Smith) at 10:9-12. Witness Smith states that STI conforms with the Commission decision in Order No. 17132, 18712, and 21939 that approved the inclusion of STI in the cost of service. I believe this is Witness Smith's roundabout way of saying that none of the STI is driven by financial performance metrics, so all amounts are properly included in the cost of service.

[199] The STI Plans were provided in WGL Response to OPC Data Request No. 10-3 (Exhibit OPC (B)-54).

[200] The Management Circular includes a March 7, 2024, letter to shareholders and appears to have been published for use in the Shareholders Meeting of May 2, 2024. https://www.altagas.ca/sites/default/files/inline-files/AltaGas-Ltd_Proxy%20Circular%202024.pdf.

[201] 2024 AltaGas Circular at 65.

2) "Once the STI pool is determined to be funded, the amount of funding is based on the results of divisional and corporate value drivers (objectives). Value drivers are set annually based on a combination of strategic, financial, capital and operational efficiency, corporate social responsibility, and emerging energy ecosystem objectives." This includes a specific citation that "financial" objectives/metrics are part of the STI plan.[202]

3) "In evaluating annual results, the first step is to determine if the set financial performance target is met. If the threshold financial performance target is not met, the STI pool will not fund and no payouts will be made. For 2023, the normalized EBITDA actual results had to meet the threshold of 80% or greater of the financial performance target for the STI pool to be funded, with no STI pool funded if actual results were below 80% of target." This is a strong statement about the importance of the financial metrics of EBITDA in the STI plan.[203]

4) "AltaGas delivered strong financial and operating results in 2023 while advancing its strategic priorities." The value driver scorecard results, with the combination of met (success), not met and exceeds measures resulting in a higher scorecard multiplier for Midstream and Corporate, included some of the following notable accomplishments:[204]

---

[202] 2024 AltaGas Circular at 65.

[203] 2024 AltaGas Circular at 65.

[204] 2024 AltaGas Circular at 66.

- Achieved normalized EBITDA of $1.58 billion for 2023, which was slightly above the mid-point of the 2023 guidance range of $1.5 - $1.6 billion.
- Achieved normalized EPS of $1.90 for 2023, within AltaGas' 2023 EPS guidance range of $1.85 - $2.05.

There are various other citations to financial performance metrics in the 2024 AltaGas Circular.

**Q. IS IT POSSIBLE THE 2024 CIRCULAR IS REFERRING TO AN ALTAGAS STI PLAN THAT DIFFERS FROM THE STI PLAN FOR WGL?**

A. It is possible. However, the Utilities Value Drivers Plan provided in response to OPC Data Request No. 10-3[205] are branded on the front page with the AltaGas name, and the names of WGL, SEMCO Energy, Enstar, and Petrogas, so it would appear that one STI Plan applies to all entities. If there is a separate "AltaGas" Utilities Value Drivers Plan that relies on financial performance metrics, then I have not been provided that information, and I would like to see it. Also, if there is a separate AltaGas Utilities Value Drivers Plan with financial performance metrics, then those AltaGas Officers (and Officers of other affiliate subject to this plan), should at the very minimum have a substantive portion of their STI expense removed from amounts allocated or direct assigned from AltaGas (and other affiliates) to WGL.

**Q. ARE THERE SPECIFIC FINANCIAL PERFORMANCE METRICS IN THE 2023 UTILITIES VALUE DRIVER AND HOW DO YOU USE THESE TO PROPOSE**

[205] WGL Response to OPC Data Request No. 10-3 (Exhibit OPC (B)-54).

**AN OVERALL FINANCIAL METRIC THAT SHOULD BE REMOVED FROM STI EXPENSE?**

A. Yes. The 2023 Utilities Value Driver identifies "Regulatory and Public Policy" with underlying performance metrics based on "Revenue Growth", which is a financial-related metric, and it is designated with a 25% weighting out of a total 100%. Also, the category of "Operations" with an Efficient Deployment of Capital metric (20% weighting) and the category of Business Development - New Markets metric (5%) also incorporates some element of financial performance although it is difficult to determine a specific weighted threshold because of the vagueness of these metrics.[206]

Therefore, I believe a financial-performance metric in the range of 25% to 37% is reasonable (25% Regulatory and Public Policy), plus the 20% (one-half is 10%) for Operations category and 5% (one-half is 2.5%) for Business Development – New Markets category, respectively. The allocated weights of 25%, 10%, and 2.5% is 37.50% - and I have rounded this down to 33%. I believe an equal 3-way split is reasonable between the three primary metrics of the 2023 Utilities Value Driver.

**Q. WHAT ARE THE THREE PRIMARY METRICS YOU HAVE IDENTIFIED?**

A. I propose a three-way split of 33% for each of the three primary metrics categories of: a) financial-related benefits, b) customer-related benefits, and c) other-related benefits (which cannot be identified with financial or customer performance metrics – but includes performance metrics related to corporate social responsibility and others. I do not believe

[206] WGL Response to OPC Data Request No. 10-3 (Exhibit OPC (B)-54 at 3).

corporate social responsibility is a "customer" performance metrics, because the customer receives no known, measurable and meaningful benefit from these individual targets/performance metrics.

**Q. HOW DID YOU CALCULATE YOUR ADJUSTMENT TO REMOVE 33% OF STI EXPENSE FROM THIS RATE CASE?**

A. WGL's response to OPC Data Request No. 11-14[207] included STI expense, but the response to OPC Data Request No. 10-5[208] was deemed to be more accurate. WGL's response to OPC Data Request No. 11-8(a) stated that OPC was using the incorrect STI amounts in the data request question and stated the correct amount of WGL STI expense at March 31, 2024, was $15,076,522.[209] After reviewing this amount, it appears to include amounts included in non-expense accounts (such as gas plant, accounts receivable/payable, etc.). However, after being told that OPC was using the wrong amount of STI expense, I am using WGL's proposed amount – although I believe it is in error. I used the WGL-DC portion of $15,076,522 which is $2,934,979, and I multiplied this by 33% to arrive at an adjustment of $968,543.

**Q. DO YOU AGREE WITH WGL'S OPINIONS REGARDING THEIR UTILITIES VALUE DRIVERS?**

207 WGL Response to OPC Data Request No. 11-14 (Exhibit OPC (B)-69).

208 WGL Response to OPC Data Request No. 10-5 (Exhibit OPC (B)-55).

209 WGL Response to OPC Data Request No. 11-8 (Exhibit OPC (B)-64 at 2-3).

A. No. I do not agree with WGL's responses to OPC Data Request Nos. 11-15, 11-17 and 11-18.[210] WGL is unable to establish the validity of its Utilities Value Drivers or explain how these amounts support the reasonableness of WGL's rates in this rate case.

**Q. IS WGL WITNESS BURGUM ABLE TO SUPPORT HIS STATEMENTS THAT WGL'S STI IS COMPETITIVE AND REASONABLE WITH ACTUAL REPUTABLE AND OBJECTIVE EXTERNAL COMPENSATION STUDIES?**

A. No. I previously addressed this issue in my testimony.

### *Adjustment BCO-13: Adjust Cash Working Capital (Exhibit OPC (B)-5, Schedule 13)*

**Q. HAVE YOU ADJUSTED WORKING CAPITAL TO REFLECT YOUR UPDATED EXPENSES FOR THE LEAD/LAG STUDY?**

A. No, I will true-up this adjustment when I file my surrebuttal testimony. This does not have any material impact upon my revenue requirement calculation. I do not oppose WGL's lead/lag study and cash working capital approach, and I will use this for my calculations when I file surrebuttal testimony.[211]

### *Adjustment BCO-14: Credit/Debit Card Fees (Exhibit OPC (B)-5, Schedule 14)*

**Q. DOES OPC OPPOSE WGL'S ADJUSTMENT TO REMOVE CREDIT/DEBIT CARD FEES FROM OPERATING EXPENSES?**

---

[210] WGL Response to OPC Data Request Nos. 11-15, 11-17, 11-18 (Exhibit Nos. OPC (B)-70, 71, 72).

[211] Similarly, I will true up my interest synchronization adjustment (BCO-15) (Exhibit No. OPC (B)-5, Schedule 15) in my surrebuttal testimony.

A. No. OPC Witness David E. Dismukes addresses this issue and states he does not oppose the Company's proposal to directly assign processing fees to customers who leverage credit or debit cards to pay their bills.[212] Therefore, no adjustment is proposed for this issue.

## V. CONCLUSION

**Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?**

A. Yes, it does. However, I am continuing to review existing proposed adjustments and reserve the ability to address additional concerns and adjustments.

[212] Exhibit OPC (A) (Dismukes) at page 39.

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

| | | |
|---|---|---|
| **In the Matter of** | § | |
| | § | |
| **THE APPLICATION OF** | § | |
| **WASHINGTON GAS LIGHT** | § | |
| **COMPANY FOR AUTHORITY** | § | **Formal Case No. 1180** |
| **TO INCREASE EXISTING RATES** | § | |
| **AND CHARGES FOR GAS** | § | |
| **SERVICE** | | |

**AFFIDAVIT**

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

Brian Ostrander

Date: 1/21/2025

Subscribed and sworn to before me

This 21st day of January, ~~2024.~~ 2025

State of Kansas

County of Shawnee

Cynthia L Moore
Notary Public

My Commission expires: 4-3-2028

Cynthia L. Moore
NOTARY PUBLIC
STATE OF KANSAS
MY APPT EXP: 4-3-2028

# Curriculum Vitae (CV) of Bion C. Ostrander

# Bion C. Ostrander – Curriculum Vitae

I am an independent regulatory consultant with forty-six years of total regulatory and accounting experience working for Certified Public Accounting (CPA) firms, regulatory agencies, and my regulatory consulting business, including thirty-four years as an independent consultant with my own firm. I have been providing continuous consulting services since 1990 and have addressed more than 250 cases in numerous U.S. and international jurisdictions.[1]

I have addressed a broad range of energy and telecom accounting and policy issues in my career, including rate case/revenue requirement accounting adjustments, affiliate transaction (Cost Allocation Manual) reviews, capital asset infrastructure/modernization, affordable rates/universal service, tariff design, models that calculate the levelized cost of electricity for renewable energy options (PV solar, wind, biogas, etc.) for purposes of setting feed-in/renewable energy rider tariffs, compensation, depreciation, merger/acquisitions, cross-subsidization, complex income tax issues, service quality, retail and wholesale cost studies, competition, and many others.

My experience is summarized below:

- ✓ **Bion C. Ostrander (dba Ostrander Consulting)**: Principal/Owner - October 1990 to current.
- ✓ **Kansas Corporation Commission**: Chief of Telecommunications – 1986-1990.
- ✓ **Kansas Corporation Commission**: Chief Auditor (gas, electric, telephone & transport.) – 1983-1986.
- ✓ **Mize Houser Mehlinger & Kimes (now Mize CPA, Inc.)**: Auditor in audit section of regional CPA firm – 1981-1983.
- ✓ **Deloitte Haskins and Sells (now Deloitte)**: Auditor for international CPA firm – 1978-1981.

[1] Mr. Ostrander maintained a permit to practice as a CPA for most years he was providing consulting services, the permit was maintained primarily for credential purposes. However, because he no longer provides any attestation or related services that require a permit to practice, he no longer maintains the permit – although he retains membership in CPA organizations.

| Client Summary | |
|---|---|
| ***Consumer Advocates/Attorney General*** | ***Public Service Commissions*** |
| District of Columbia - OPC | Arizona |
| Indiana UCC | Georgia |
| Florida OPC | Kansas |
| Kansas CURB | Maryland |
| Kentucky AG | Minnesota |
| Michigan AG | North Dakota |
| Maine OPA | Oklahoma |
| Maine AARP | ***Other*** |
| Maryland OPC | Alaska Competitive Local Exchange Carrier |
| Michigan AG | Maryland - Montgomery County |
| Minnesota DPS | Cities of Hampton & North Hampton - New Hampshire |
| Nevada AG | Virginia - CWA |
| New Hampshire OCA | Kansas Counties (911 implementation issues) |
| Ohio OCC | ***International*** |
| Oklahoma AG | Fair Trading Commission - Barbados |
| Utah OCS | Eastern Caribbean Telecomm. Authority (ECTEL - |
| Vermont DPS | St. Lucia, St. Kitts/Nevis, St. Vincent, Grenada, Dominica) |
| Washington AG | Armenia - USAID |
| Wyoming | Russia/Ukraine Energy Utility Training |
| | Saudi Arabia |

## Work History – Ostrander:

### Bion C. Ostrander – Consulting Firm (1990 to present):

Principal

Mr. Ostrander principally addresses regulatory issues on behalf of governments and regulatory agencies, including U.S. and international regulatory agencies. Services include those related to revenue requirement issues, renewal energy issues, price caps or alternative regulation plans, competition assessment, costing/pricing, interconnection/local loop unbundling, universal service, management audits and other matters.

### Kansas Corporation Commission (1983 – 1990):

Chief of Telecommunications

Supervised staff and directed all telecommunications-related matters including assessment of rate cases of SWBT, United/Sprint and rural LECs. Also, directed actions regarding alternative regulation plans, establishing access charge policy, transition to intrastate competition, depreciation filings, establishment of the Kansas Relay Center for speech and hearing impaired citizens in Kansas, filings with the FCC, billing standards, quality of service, consumer complaints, staff training and over one hundred docketed regulatory matters per year. Mr. Ostrander was the lead witness on all major telecommunications matters.

Chief Auditor

Directed rate cases of gas, electric and telecom companies prior to promotion to Chief of Telecommunications.

**Mize, Houser, Mehlinger and Kimes:**

Auditor – CPA firm

Performed auditing, tax and special projects for various industries.

**Deloitte, Haskins and Sells – (International CPA/Audit Firm):**

Auditor – CPA firm

Performed auditing, tax and special projects in industries such as utilities, savings and loan, manufacturing, retail, construction, real estate, insurance, banking and not-for-profit.

**Education:**

University of Kansas - B.S. Business Administration with a Major in Accounting, 1978.

| Utility | State | Client/Agency | Docket/Case | Product | Summary of Issues |
|---|---|---|---|---|---|
| Tampa Electric Company | FL. | Office of Public Counsel | Docket No. 20240026-EI | Testimony | Revenue Requirement issues |
| Washington Gas Light Company | MD. | Maryland Commission Staff | Case No. 9704 | Testimony | Revenue requirement issues |
| Potomac Edison Company | MD. | Maryland Commission Staff | Case No. 9695 | In progress | Revenue requirement issues |
| Central Maine Power Company | Maine | Maine Office of the Public Advocate | Docket No. 2022-00152 | Testimony | Revenue requirement issues |
| Washington Gas Light Company | D.C. | Office of the People's Counsel for D.C. | Formal Case No. 1169 | Testimony | Revenue requirement issues |
| Summit Natural Gas Company | Maine | Maine Office of the Public Advocate | Docket No. 2022-00025 | Testimony | Revenue requirement, rate design, and policy issues |
| Aquarion Water Company | NH. | Hampton & North Hampton | Docket No. DW 20-184 | Testimony | Revenue requirement issues |
| Columbia Gas of Ohio | OH. | Office of the Ohio Consumers' Counsel | Case No. 21-637-GA-AIR | Testimony | Revenue requirement issues |
| Washington Gas Light Company | D.C. | Office of the People's Counsel for D.C. | Formal Case No. 1162 | Testimony | Revenue requirement issues |
| Delta Natural Gas Company | KY. | Kentucky Office of Attorney General | Case No. 2021-00185 | Testimony | Revenue requirement issues |
| Renewable Energy Plan | MD. | Fair Trading Commission | N/A | Report | Prepare levelized cost of electricity (LCOE) models to propose<br>feed-in tariffs for all renewable energy options (solar centr.<br>and distributed, wind on-shore, wind off-shore, WTE)<br>and determine the potential impact on customer rates |
| Liberty Utilities | MD. | New Hampshire OCA | Docket No. DE 19-064 | Testimony | Revenue requirement |
| Washington Gas Light Company | MD. | Maryland Commission Staff | Case No. 9481 | Testimony | Revenue requirement and CAM |
| Potomac Electric Power Co. | MD. | Maryland Commission Staff | Case No. 9418 | Testimony | Revenue requirement, rate base and operating expenses |
| None - operational audit | OK. | Oklahoma Commission Staff | No docket | Testimony | Operational audit of Oklahoma Universal Service Fund |
| Carbon Emery Tel. Co. | UT. | Utah Office of Consumer Services | Dkt. No. 15-2302-01 | Testimony | Revenue requirement/CAM |
| Emery Tel. Co. | UT. | Utah Office of Consumer Services | Dkt. No. 15-042-01 | Report | Revenue requirement/CAM - case settled |
| Strata Tel. Co. | UT. | Utah Office of Consumer Services | Dkt. No. 15-053-01 | Testimony | Revenue requirement/CAM - case settled |
| Beehive Tel. Co. | UT. | Utah Office of Consumer Services | Dkt. No. 14-051-01 | Testimony | Revenue requirement/CAM - case withdrawn |
| FairPoint Comm., Inc. | MN. | Maine Office of Public Advocate | 2013-00340 | Testimony | Revenue requirement/CAM |
| Bangor Gas Company | MN. | Maine Office of Public Advocate | 2012-00598 | Testimony | Revenue requirement/CAM and evaluate a new Alt. Reg. |
| Potomac Electric Power Co. | MD. | Montgomery County | Case No. 9336 | Testimony | Revenue requirement, rate base and operating expenses |
| Hanksville Telecom, Inc. | Utah | Utah Office of Consumer Services | Dkt. No. 14-2303-01 | Testimony | Request for Univ. Service Funding, revenue requirement/CAM |
| Big Rivers Electric Corp. | KY | Kentucky Office of Attorney General | CN 2013-00199 | Testimony | TIER rev. req., operating expenses, payroll and policy<br>This rate case was filed while the prior rate case was still<br>pending. |
| Atmos Energy Corp. | KY | Kentucky Office of Attorney General | CN 2013-00148 | Testimony | Revenue requirement/rate case |
| Manti Telephone Company | UT. | Utah Office of Consumer Services | Dkt. No. 13-046-01 | Testimony | Phase II issues, revenue requirement/CAM |
| Delmarva Power & Light Co. | MD. | Maryland Office of People's Counsel | Case No. 9317 | Testimony | Revenue requirement, rate base, and operating expenses |
| Century Link | KS | Citizen's Utility Ratepayer Board | 13-GIMT-473-MIS | Consultation | Review of price cap plan renewal and CAM |
| Generic | KS | Citizen's Utility Ratepayer Board | 13-GIMT-597-GIT | Multiple testimonies | Address Kansas Lifeline issues |
| Big Rivers Electric Corp. | KY | Kentucky Office of Attorney General | CN 2012-00535 | Assist with negotation | TIER rev. req., operating expenses, payroll and policy |
| Potomac Electric Power Co. | MD. | Montgomery County | Case No. 9311 | Comments | Revenue requirement, rate base and operating expenses |
| Cable & Wireless - Caribbean | Note 1 | Eastern Caribbean Telecomm. Authority (EC | not applicable | Testimony<br>Multiple testimonies | Review EAM/CAM telecom cost study and evaluate<br>profitability by service and revise EAM allocations |
| Baltimore Gas & Electric Co. | MD. | Maryland Office of People's Counsel | Case No. 9299 | Report | Revenue requirement, rate base, and operating expenses |

| Utility | State | Client/Agency | Docket/Case | Product | Summary of Issues |
|---|---|---|---|---|---|
| Annual Ks. USF review | KS | Citizen's Utility Ratepayer Board | 13-GIMT-130-GIT | Review | Annual review of Ks. USF funding and assessment. Mr. Ostrander has reviewed these filings for the past 15 years of the Ks. USF existence |
| Manti Telephone Company | UT. | Utah Office of Consumer Services | Dkt. No. 08-046-01 | Testimony | Revenue requirements/CAM and and policy on universal service fund. |
| Generic review | UT. | Utah Office of Consumer Services | No docket | Testimony | Review and assessment of Utah telephone companies |
| Potomac Electric Power Co. | MD. | Maryland Office of People's Counsel | Case No. 9286 | Testimony | Overall revenue requirement and operating expenses |
| Delmarva Power & Light Co. | MD. | Maryland Office of People's Counsel | Case No. 9285 | Report | Overall revenue requirement and operating expenses |
| Annual Ks. USF review | KS | Citizen's Utility Ratepayer Board | 12-GIMT-168-GIT | Multiple testimonies | Annual review of Ks. USF funding, assessment, policies |
| Telecom industry | KS | Citizen's Utility Ratepayer Board | 12-GIMT-170-GIT | Multiple testimonies Review/monitor Comments and | Address implications of FCC changes/policy regarding ICC, Broadband, FUSF policies and other upon changes to policy for Ks. USF and carriers |
| PacifiCorp - Pacific Power | WA. | Washington Attorney General - Public Counsel Section | Dkt. UE-111190 | Reply Comments | Rate case - rate base, revenues, expenses, affiliate transactions, MEHC affiliate management fee, outsourcing of services to Adecco, |
| Washington Gas Light | MD. | Maryland Office of People's Counsel | Case No. 9267 | Testimony | Rate case - rate base, revenues, expenses, affiliate transactions, complex issues regarding outsourcing of services to Accenture, compensation issues, other |
| Telecom industry | KS | Citizen's Utility Ratepayer Board | 11-GIMT-420-GIT | Multiple testimonies | General proceeding to address changes in policy and review of cost studies/CAM to determine cost-based Ks. Univ. Service Fund support for price capped telcos. |
| Washington Elec. Coop. | Vt. | Vt. Dept. of Public Service | Dkt. No. 7691 | Testimony | Rate case - rate base, revenues, expenses, affiliate transactions, other matters. |
| Telecom industry | KS | Citizen's Utility Ratepayer Board | 11-GIMT-842-GIT | Draft testimony & negotiate settlement | Method to identify and report prepaid wireless revenue for Ks. USF. |
| Cable & Wireless | Note 1 | Eastern Caribbean Telecom Authority (ECTEL) | There is no Docket No. | Client advice/review | Review earnings, EAM/CAM, competition, cost studies, assessment of duopoly market, implement new price caps plan. |
| Pioneer Tel. Assoc. | KS | Citizen's Utility Ratepayer Board | Dkt. 11-PNRT-315-KSF | Review | Monitored this case regarding Pioneer's request for increased Ks. USF support, reviewed rate case issues and monitored settlement of issues. |
| Telecom industry | KS | Citizen's Utility Ratepayer Board | 08-GIMT-1023-GIT | Review/monitor | Address Sprint's petition to reduce access charges of CenturyLink, statute issues, policy and calculations. |
| Rural Telcos | KS | Citizen's Utility Ratepayer Board | 10-GIMT-188-GIT | Testimony | Review update of rural telco update of intrastate access charges requires every 2 years by statute |
| Annual Ks. USF review | KS | Citizen's Utility Ratepayer Board | 11-GIMT-201-GIT | Review - no hearings held | Annual review of Ks. USF funding, assessment, policies and carrier data |

| Utility | State | Client/Agency | Docket/Case | Product | Summary of Issues |
|---|---|---|---|---|---|
| Telecom industry | Armenia | USAID and AED - Armenia assessment of Dept. of Public Services Armenia | not applicable | Review/monitor | Telecom sector strategic analysis - legal/regulatory assessment, human & institutional capacity, govt. plan for IT sector development, market structure, performance gaps, telecom law, and other universal service and compliance. |
| Kansas City Power & Light | KS | Citizen's Utility Ratepayer Board | 09-KCPE-246-RTS | Testimony | How to treat common plant costs for CWIP for major upgrades to coal-fired energy plant |
| Annual Ks. USF review | KS | Citizen's Utility Ratepayer Board | 09-GIMT-272-GIT | Review | Annual review of Ks. USF funding, assessment, policies and carrier data |
| Michigan - Verizon | MI | Michigan Attorney General | Dkt. 15210 | Review/monitor | Address CAM, TSLRIC & TELRIC cost studies of Verizon |
| Maryland - Verizon | MD | Maryland Office of People's Counsel | Case No. 9133 | Testimony | Address price caps, competition service quality, and CAM |
| Maryland - Verizon | MD | Maryland Office of People's Counsel | Case No. 9121 | Testimony | Address expanded local calling for Verizon customers |
| Cable & Wireless | Note 2 | Fair Trading Commission of Barbados | No docket | Testimony | Address C&W EAM/CAM costs/profits for regulated & deregulated services, and address 2nd price caps plan |
| Generic | KS. | Citizen's Utility Ratepayer Board | Dkt. No. 07-GIMT-1353 | Comments | Address Lifeline hold harmless plan |
| Generic | KS. | Citizen's Utility Ratepayer Board | Dkt. 06-SCCC-200-MIS | Comments | Address on-going compliance of Embarq with requirements of spin-off stipulation |
| Annual Ks. USF review | KS | Citizen's Utility Ratepayer Board | 08-GIMT-315-GIT | Review | Annual review of Ks. USF funding, assessment, policies and carrier data |
| Virginia - Verizon | VA. | CWA | PUC-2007-0008 | Testimony | Competition/deregulation/detariffing and CAM |
| Embarq - Nevada | NV | BCP of Attorney General - Nevada | Dkt. 06-11016 | Testimony | Address UNEs, CAM, and competition related to Embarq |
| Embarq - Nevada | NV | BCP of Attorney General - Nevada | Dkt. 06-11016 | Testimony | Competition/deregulation/flexibility legislation |
| Embarq - Ks. & | KS. | Citizens' Utility Ratepayers Board | Dkt. 07-GIMT-782-MIS | Stipulated | Address price cap factors and CAM |
| AT&T - Kansas | | Citizens' Utility Ratepayers Board | Dkt. 07-GIMT-782-MIS | Consulting | Address price cap factors for AT&T and CAM |
| Verizon - Michigan | MI. | Michigan Attorney General | Dkt. 15312 | Stipulated | Address reasonableness of Verizon local rates, plus CAM review |
| Generic | KS. | Citizen's Utility Ratepayer Board | Dkt. 08-GIMT-315-GIT | Stipulated | 12th Year assessment Ks. Universal Serv. Fund |
| AT&T | KS. | Citizens' Utility Ratepayers Board | not docketed | Consulting | Assist with advice on 2007 legislative session |
| Generic | KS. | Citizen's Utility Ratepayer Board | | Consulting | 11th Year assessment Ks. Universal Serv. Fund |
| Generic | KS. | Citizen's Utility Ratepayer Board | Dkt. 06-GIMT-332-GIT | Consulting | 10th Year assessment Ks. Universal Serv. Fund |
| Generic | KS. | Citizen's Utility Ratepayer Board | Dkt. 06-GIMT-446-GIT | Consulting | Addressing requirements for ETCs |
| AT&T | KS. | Citizen's Utility Ratepayer Board | Dkt. 07-SWBT-277-MIS | Consulting | AT&T/SWBT annual price cap filing and CAM review |
| Generic | KS. | Citizen's Utility Ratepayer Board | Dkt. 06-GIMT-332-GIT | Comments | 10th Year assessment Ks. Universal Serv. Fund |
| Generic | KS. | Citizen's Utility Ratepayer Board | Dkt. 06-GIMT-390-GIT | Consulting | Ks. Univ. Service neutrality issues |
| Rural Tel. - Kansas | KS. | Citizen's Utility Ratepayer Board | Dkt. 06-RRLT-963-COC | Consulting | Rural Tel. purchase of exchanges from Embarq |
| Embarq - Kansas | KS. | Citizen's Utility Ratepayer Board | Dkt. 06-SCCC-200-MIS | Consulting | Monitor dividends and EQ spin-off |
| Embarq - Kansas | KS. | Citizen's Utility Ratepayer Board | Dkt. 06-UTDT-962-CCS | Stipulation | Embarq sale of exchanges to Rural Tel. |
| Generic | KS. | Citizens' Utility Ratepayers Board | Dkt. 06-GIMT-943-GIT | Consulting | |
| Maine - Verizon | ME. | AARP | Dkt. 2005-155 | Stipulation | Yellow Pages, affiliate transactions, AFOR |
| Sprint - Nevada | NV. | Bureau of Consumer Protection | Dkt. 05-8032 | Consulting | Sprint/Nextel change of control/LTD spin-off |
| Sprint - Kansas | KS. | Citizen's Utility Ratepayer Board | Dkt. 06-SCCC-200-MIS | Testimony | Sprint/Nextel change of control/LTD spin-off |
| SWBT-Kansas | KS. | Citizen's Utility Ratepayer Board | Dkt. 05-SWBT-907-PDR | Settlement | SWBT application for deregulation |
| Sprint - Kansas | KS. | Citizen's Utility Ratepayer Board | 06-UTDT-115-CCS | In progress | Sprint/United sale of exchanges to Twin Valley |

| Utility | State | Client/Agency | Docket/Case | Product | Summary of Issues |
|---|---|---|---|---|---|
| Twin Valley - Kansas | KS. | Citizen's Utility Ratepayer Board | 06-TWVT-116-COC | Consulting | Sprint/United sale of exchanges to Twin Valley |
| Saudi Telecom | | Saudi Arabia Communications & | No docket | Stipulation | Report on Accounting Separation and recommendations for |
| | | Information Technology Commission | | Stipulation | changes to CAM |
| SWBT-Ks. | KS. | Citizens' Utility Ratepayer Board | 01-SWBT-1099-IAT | Report | Address SWBT/Sage interconn. Agreement |
| Sprint/United & | KS. | Citizens' Utility Ratepayer Board | 04-UTDT-781-CCS | | Sale of exchanges from Sprint/United to |
| Blue Valley | | | 04-BVTT-780-COC | Comments | Blue Valley Tel. |
| Generic | KS. | Citizens' Utility Ratepayer Board | 04-GIMT-653-GIT | Stipulation | Address lifeline payment policy |
| Generic | KS. | Citizens' Utility Ratepayer Board | 04-GIMT-1080-GIT | | Policy on KUSF audits/tariff filings |
| Verizon, Bell South | FL. | Florida Office of Public Counsel | Dockets 030867-TL, | Comments | Impact of access rate rebalancing, rate design, |
| & Sprint | | | 030869-TL, 030961-TL | Comments | and universal service, plus review of CAM |
| SWBT-Ks. | Ks. | Citizens' Utility Ratepayer Board | 98-SWBT-677-GIT | Testimony | SWBT's failure to comply with provision of DSL |
| Generic | KS. | Citizens' Utility Ratepayer Board | 03-GIMT-932-GIT | | Ks. Universal Service Fund policies |
| Kansas - generic | KS. | Citizens' Utility Ratepayer Board | 03-GIMT-284-GIT | Testimony | Review KUSF assessment |
| Maryland Verizon | MD. | Maryland People's Counsel | Case No. 8918 | Comments | Review of earnings, price cap & deregulation issues. |
| Verizon Maine | ME. | Maine Office of Public Advoc. | 2000-849 | Testimony | Verizon's 271 filing |
| Ameritech | MI. | Michigan Attorney General | Case No. 12320 | Testimony | Ameritech's 271 filing |
| Verizon Vermont | VT | Dept. of Public Service | Docket 6533 | Testimony | Verizon's 271 filing |
| Sprint Nevada | NV. | Nevada Attorney General | Docket 01-12047 | Comments | Review of earnings, CAM, rate design and affiliate issues |
| Western/KP&L | KS. | Citizens' Utility Ratepayer Board | 01-WSRE-436-RTS | Testimony | Review allocation of costs between regulated |
| | | | | | & nonregulated operations/CAM, review of aircraft logs, |
| | | | | | and analysis of compensation benefits. |
| Southern Ks. | KS. | Citizens' Utility Ratepayer Board | 02-SNKT-1014-EAS | Testimony | Review of Southern Ks. EAS applic. |
| SWBT, Sprint/United | KS. | Citizens' Utility Ratepayer Board | 02-GIMT-272-MIS | Testimony | Price cap formula of LECs, plus CAM |
| Gen. Invest. | KS. | Citizens' Utility Ratepayer Board | 01-GIMT-082-GIT | Testimony | Access charges, afford. rates and misc. |
| Verizon | MI. | Michigan Attorney General | U-12682 | Testimony | Review earnings, CAM, universal service regarding |
| | | | | Testimony | Verizon's request to restructure basic local rates |
| Ks. Rural LECs | KS. | Citizens' Utility Ratepayer Board | 02-GIMT-068-KSF | Comments | Rural LECs KUSF, affordable rates & access |
| Ameritech | MI. | Michigan Attorney General | U-12622 | | Review policy for use of shared transport for |
| | | | | Testimony | intraLATA toll traffic over AM's network |
| Generic | KS. | Citizens' Utility Ratepayer Board | 00-GIMT-910-GIT | Briefs | Methods to improve Lifeline |
| Ameritech | MI. | Michigan Attorney General | U-12598 | | Evaluate Ameritech's service quality problems, |
| | | | | Comments | service quality standards and customer credits |
| | | | | Testimony | to be paid to customers |
| Ameritech & Verizon | MI. | Michigan Attorney General | U-12528 | | Evaluate earnings of Ameritech and Verizon |
| | | | | | in regards to expanded local calling and removal |
| Bell Atlantic | VT. | Vermont Department of | Docket No. 6167 | Testimony | Addressing earnings of Bell Atlantic, CAM, rate |
| | | Public Service | | | design and alternative regulation plan |
| Sprint | NV. | Nevada Attorney General - Bureau of | Docket No. 99-2024 | Testimony | Address earnings of Sprint Nevada, CAM and related |
| | | Consumer Protection | | | policy issues |

| Utility | State | Client/Agency | Docket/Case | Product | Summary of Issues |
|---|---|---|---|---|---|
| Ameritech | MI. | Michigan Attorney General | U-12287 | Testimony | Review of Ameritech's earnings and CAM in regards to |
| | | | | | addressing access charges and in-state EUCL |
| Verizon | MI. | Michigan Attorney General | U-12321 | Testimony | Review of Verizon's earnings and CAM in regards to |
| | | | | | addressing access charges and in-state EUCL |
| Generic | KS. | Citizens' Utility Ratepayer Board | 99-GIMT-326-GIT | Testimony | Address generic universal service costing |
| | | | | | methods, adjustment of Kansas Universal |
| | | | | Filed comments | Service Fund, geographic deaveraging, etc. |
| GTE | MI. | Michigan Attorney General | U-11759 | and testimony | Address GTE's request for intrastate PICC |
| | | | | Phase I | charge and address related cost study issues |
| Southwestern Bell | KS. | Citizens' Utility Ratepayer Board | 98-SWBT-677-GIT | Comments/ | Address SWBT's cost of local service, KUSF |
| Telephone | | | | Testimony | levels and policy issues, plus CAM review |
| | | | | Testimony on | Universal Service Fund |
| ILEC's | MI. | Michigan Attorney General | U-11899 | Stipulation | Address universal service fund for ILECs |
| Ameritech | MI. | Michigan Attorney General | U-11660 | | Address Ameritech's request for intrastate |
| | | | | Briefs | PICC charge and related cost study issues |
| Generic Investigation | KS. | Citizens' Utility Ratepayer Board | 94-GIMT-478-GIT | Comments/ | Performed the first audit of the KUSF, reviewing |
| | | | | Testimony | first two years of actual operations and third |
| | | | | Testimony/ | year projections, addressing cellular issues, |
| | | | | Comments | excessive assessment and per line charges |
| Ameritech | MI. | Michigan Attorney General | U-11635 | | Address Ameritech cost studies for |
| UNEs | | | | | deaveraging issues |
| Generic Investigation | KS. | Citizens' Utility Ratepayer Board | 96-LEGT-670-LEG | Comments | Address increased Lifeline Support measures |
| | | | | briefs | |
| Generic Investigation | KS. | Citizens' Utility Ratepayer Board | 194, 734-U | Comments | Address industry billing standards |
| Ameritech | MI. | Michigan Attorney General | U-11743 | | Address problems with Ameritech's position on |
| | | | | Comments | intraLATA dialing parity and 55% access |
| | | | | Testimony | discount and previous Court case |
| Southwestern Bell | KS. | Citizens' Utility Ratepayer Board | 98-SWBT-380-MIS | | Address problems with SWBT's price cap plan |
| | | | | | and various components/calculations |
| Southwestern Bell | KS. | Citizens' Utility Ratepayer Board | 97-SCCC-411-GIT | Comments | Address SWBT's 271 application in Kansas |
| | | | | | and level of competition, Track A and B, |
| | | | | Testimony | long distance rates, joint marketing, FCC issues |
| BellSouth | GA. | Georgia Public Service Commission | 7061-U | | Address BellSouth and Hatfield cost studies |
| | | | | | for unbundled elements and policy issues |
| Generic Investigation | KS. | Citizens' Utility Ratepayer Board | 194,734-U | Assistance on | Deregulation/detariffing of CLECs/LECs |
| Generic Investigation | KS. | Citizens' Utility Ratepayer Board | 97-SCCC-149-GIT | case | Review of cost study methodology of Hatfield, |
| | | | | Comments | BCPM (Sprint) and Southwestern Bell for |
| | | | | Testimony, | unbundled elements |
| AT&T, Sprint & | ND. | North Dakota Public Service Comm. | PU-453-96-82 | along with | Address proposed deregulation of AT&T, |
| U S WEST | | | and PU-987-96-389 | comments | Sprint and U S WEST |

| Utility | State | Client/Agency | Docket/Case | Product | Summary of Issues |
|---|---|---|---|---|---|
| Rulemaking into Interconnection & Unbundling | WY. | Wyoming Public Service Commission | Gen. Order No. 76 | Case assistance<br>Comments | Comments supporting proposed rules for interconnection, dialing parity, pricing, privacy and other competition issues |
| SWBT/Generic | KS. | Citizens' Utility Ratepayer Board | Cases before Ks. Court of Appeals & Supreme Court | Assistance | Address issues regarding non-cost basis of Kansas Universal Service Fund and problems with revenue neutrality end user charges |
| Ameritech | MI. | Michigan Attorney General | Case No. U-11155, U-11156 and U-11280 | | Review retail/wholesale cost studies of Ameritech |
| GTE | MI. | Michigan Attorney General | Case No. U-11207 | Comments and assistance | Review cost studies of GTE |
| Generic Rulemakings | GA. | Georgia Public Service Commission | Various dockets | Comments and assistance | Assisted GPSC with various rulemakings on competition, universal service and conducted workshop for number portability |
| General Investigation into Competition | KS. | Citizens' Utility Ratepayer Board | 190,492-U<br>94-GIMT-478-GIT | Assistance and analysis<br>Testimony | Address SWBT retail cost study for local service, universal service fund, universal service policy issues, alternative regulation and other matters |
| General Presentation | N/A | Russian/Ukrainian Regulatory Agency and Utilities | Misc. | | Provide presentations and analysis for Russian/ Ukrainian executives in Moscow and Kansas |
| U S WEST | WY. | Wyoming Consumer Advocate Staff | 70000-TR-95-238 | Presentations/ analysis | Address USW's rate/price plan, competition issues, rate design for access charges, and CAM |
| Generic Invest. into Access Charges | KS. | Citizens' Utility Ratepayer Board | 190,383-U | Testimony | Address access charge plan for Kansas and related issues |
| General Investigation into Competition | KS. | Citizens' Utility Ratepayer Board | 190,492-U<br>94-GIMT-478-GIT | Testimony | Address competition issues, alternative regulation, universal service issues, costing methods and related issues |
| United Tel. of Kansas | KS. | Citizens' Utility Ratepayer Board | 189-150-U | Testimony, Suppl. and Rebuttal Testimony/ report | Review quality of service via show-cause and address service standards, modernization schedule and customer complaints |
| U S WEST | MN. | Minnesota Dept. of Public Service | P421/EI-89-860 | Address revenue req. for alternative reg. plan for period 1990 - 1993 | Key issues include management salaries, fringe benefits, short/long-term incentive compensation plans, work force reduction issues, space-utilization, Bellcore expenses, software expense, CAM, rent expense and affiliate transactions |
| Southwestern Bell Tel. | KS. | Citizen's Utility Ratepayer Board (CURB) | 183,522-U | | FASB 106 and issues related to alternative rate plan |
| Michigan | MI. | Michigan Dept. of Attorney | U-10138 | Testimony | IntraLATA equal access competition |
| Northern States Power Company | N.D. | North Dakota Public Service Commission | PU-400-92-399 | Testimony | Compensation issues (salaries, wages and incentive compensatiion) |
| U.S. WEST | MN. | Minnesota Dept. of Public | P421/DI-92-168 | Oversight | Management salaries, fringe benefits, CAM, |

| Utility | State | Client/Agency | Docket/Case | Product | Summary of Issues |
|---|---|---|---|---|---|
| | | Service | | and Review | force reduction and costs, pensions, |
| | | | | Formal report | training, maintenance expense, |
| | | | | on various | leasing and affiliate relations |
| Southwestern Bell Telephone | KS. | Kansas Counties/Cities - Harvey, Douglas, Butler, Riley, Crawford, Dodge City, Jackson and Pottawatomie | 92-SWBT-143-TAR | regulatory issues Comments | 911 service issues - recurring and nonrecurring rates for trunk/circuit and ALI/ANI, data base unbundling, cost studies and dedicated/public provision |
| Michigan LECs and IXCs | MI. | Michigan Dept. of Attorney General | U-10063 | | Establishment of quality of service standards for LECs/IXCs |
| Michigan LECs and IXCs | MI. | Michigan Dept. of Attorney General | U-10064 | Comments | Establishment of the procedures and format for the filing of tariffs |
| Southwestern Bell Telephone | KS. | City of Wichita - subcontracting with law firm of Woodard, Blaylock Hernandez, Pilgreen & Roth | 90-1342-C U.S. District Court for the District of Ks. | Comments<br><br>Affidavit | Lawsuit by City of Wichita vs. SWBT regarding violation of franchise agreement |
| U.S. WEST | AZ. | Arizona Corporation Commission | E-1051-91-004 | | Toll/access revenues, income taxes and misc., plus CAM |
| Indiana Bell Telephone | IN. | Indiana Utility Consumer Counselor | Cause No. 39017 | Rate case subcontract | Rate base, operations, affiliate transactions & misc. |
| Southwestern Bell Telephone | OK. | Oklahoma Attorney General | PUD 000662 | Rate case subcontract | Royalty fee, affiliate transactions and misc. |
| JBN Telephone Co., Inc. | KS. | Kansas Corporation Commission | 171,826-U | Rate case subcontract | Rate base, operations, capital structure acquisition issues, rate design and CAM |
| AT&T Comm. of the Southwest | KS. | Citizens' Utility Ratepayers Board | 91-AT&T-90 | Rate case | Directory assistance rates and call allowances, costs studies and misc. |
| Kansas LECs and IXCs | KS.# | Kansas Corporation Commission | 127,140-U | Comments<br><br>Testimony - | Generic investigation into access charges- access charge policy, rate design and revenue requirements |
| Kansas LECs and IXCs | KS. # | Kansas Corporation Commission | 148,200-U | Access policy witness<br>Formal | Initiated generic investigation into affiliated transactions and established policies |
| Kansas LECs and IXCs | KS. # | Kansas Corporation Commission | 168,334-U | recomm. to Comm.<br>Formal recomm. | Initiated generic docket and established policies to implement Dual Party Relay Service for persons whom are hearing and speech impaired. The Center opened in 1990. |
| AT&T Comm. of the Southwest | KS. # | Kansas Corporation Commission | 167,493-U | to Comm.<br><br>Testimony - | Rate case/regulatory flexibility - Competition, policy, regulatory flexibility, rate design and CAM |

| Utility | State | Client/Agency | Docket/Case | Product | Summary of Issues |
|---|---|---|---|---|---|
| Southwestern Bell Telephone | KS. # | Kansas Corporation Commission | 166,856-U | Chief witness<br>Testimony - Chief witness | Rate case/regulatory flexibility - Rate base, operations, capital structure, CAM, rate design, policy, regulatory flexibility, affiliated transactions, modernization issues, depreciation and misc. |
| Pioneer Tel. Co. | KS. # | Kansas Corporation Commission | 89-PNRT-350-CON | | Promoted introduction of two-way interactive video services in rural areas by introduction of economic develop. rates |
| United Telephone Company | KS. # | Kansas Corporation Commission | 162,044-U | Formal recomm. to Comm.<br>Testimony - Chief witness | Rate case - Yellow pages, royalty fee, rate base, CAM, operations, capital structure, rate design, policy, penalties, affiliated transactions revenue adjustments, misc. |
| United Telephone Long Distance | OH. # | Office of the Consumers' Counsel | 86-2173-TP-ACE | | Royalty fee, Part X, affiliate transactions, cross-subsidization |
| Continental Tel. Co. | KS. # | Kansas Corporation Commission | 157,053-U | Testimony | Reserve deficiency - settled reserve deficiency issue with protections for local ratepayers |
| Continental Tel. Co. | KS. # | Kansas Corporation Commission | 157,052-U | Formal recomm. to Comm. | Tax Reform Act - Reduced rates permanently and collected refunds |
| AT&T Comm. of the Southwest | KS. # | Kansas Corporation Commission | 156,655-U | Formal recomm. to Comm. | Tax Reform Act - Obtained rate reductions and rate refunds |
| Southwestern Bell Telephone | KS. # | Kansas Corporation Commission | 156,655-U | Formal recomm. to Comm. | Tax Reform Act - Obtained rate refunds. Offset Comm. approved dollar shift to local rates from access charges with TRA savings to avoid increases in local rates |
| United Telephone Long Distance | KS. # | Kansas Corporation Commission | 154,728-U | Formal recomm. to Comm. | UTLD/United required to make a formal request for affiliate loan per statutes per findings in Docket 153,655-U |
| United Tel. Co. | KS. # | Kansas Corporation Commission | 154,610-U | Formal recomm. to Comm. | Reserve deficiency - set precedent requiring deficiencies resulting from uneconomic plant placement go below the line |
| United Tel. Co. | KS. # | Kansas Corporation Commission | 153,662-U | Formal recomm. to Comm. | Request by United to deregulate billing and collection is denied upon recommendation |
| United Tel. Long Distance | KS. # | Kansas Corporation Commission | 153, 655-U | Formal recomm. to Comm. | Royalty fee, affiliate transactions, cross-subsidization and affiliate loans |
| Southwestern Bell Telephone | KS. # | Kansas Corporation Commission | 151,488-U | Testimony - Chief witness | Reserve deficiency - settled deficiency with protections for local ratepayers |

| Utility | State | Client/Agency | Docket/Case | Product | Summary of Issues |
|---|---|---|---|---|---|
| Kansas Gas & Electric Company | KS. # | Kansas Corporation Commission | 142,098-U | Formal recomm. to Comm.<br>Testimony - Chief witness | Company Regulatory Plan - Gross-of-tax/net-of-tax deferred carrying costs analysis, FAS 71 and 90 - impact on imprudence disallowance and physical/ economic excess capacity, life insurance financing and policy issues |
| Kansas Electric Power Coop, Inc. | KS. # | Kansas Corporation Commission | 151,191-U | Testimony - | Rate case - deferred carrying charges, present value depreciation, FAS 71 implications, operations and misc. |
| United Tel. Co. | KS. # | Kansas Corporation Commission | 149,685-U | Chief witness<br>Motion - Chief auditor | Rate case - United withdrew rate case as a result of findings regarding significant overstatement of payroll expenses and understatement of lease revenues due from other affiliates |
| Kansas State Tel. Co. of Ks. | KS. # | Kansas Corporation Commission | 147,585-U | | Rate case - excess plant capacity, rate base, operations, capital structure and misc. |
| AT&T Comm. of the Southwest | KS. # | Kansas Corporation Commission | 145,718-U | Testimony | Rate case - rate base and operations |
| Elkhart Tel. Co. | KS. # | Kansas Corporation Commission | 144,087-U | Testimony | Rate case - rate base, operations, capital structure and loans |
| Continental Tel. Co. of Ks. | KS. # | Kansas Corporation Commission | 143, 565-U | Testimony | Rate case - rate base, operations and capital structure |
| Kansas LECs and IXCs | KS. # | Kansas Corporation Commission | 144,299-U | Testimony | General investigation - intraLATA operator services, duplication of services and misc. |
| Kansas Power & Light Co. | KS. # | Kansas Corporation Commission | 140,015-U | Testimony<br>Testimony | Rate case - revenue/sales annualization, purchased gas cost, nonrecurring expenses unfunded deferred taxes and misc. |
| United Tel. Co. | KS. # | Kansas Corporation Commission | 138,500-U | | Rate case - rate base and operations, plus CAM |
| Greyhound Lines, Inc. | KS. # | Kansas Corporation Commission | 137,873-U | Testimony | Rate case - rate base and operations |
| Southwestern Bell Telephone | KS. # | Kansas Corporation Commission | 137, 534-U | Testimony | Rate case - rate base and operating income, plus CAM review |
| The Gas Service Co. | KS. # | Kansas Corporation Commission | 136, 850-U | Testimony<br>Testimony | Rate case - revenue annualization/weather normalization, purchased gas cost, rate base, operations and capital structure |
| Kansas Power & Light Co. | KS. # | Kansas Corporation Commission | 136,381-U | Testimony | Rate case - review of Jeffrey Energy #3 construction costs and contracts, rate base and misc. |
| DS&O Rural Electr. Coop | KS. # | Kansas Corporation Commission | 136,249-U | Testimony | Rate case - rate base, operations and capital structure |

# Work performed while employed by the Kansas Corporation Commission.

Note 1: ECTEL - Performed for island nations of St. Lucia, Dominica, St. Kitts & Nevis, Grenada, and St. Vincent & the Grenadines.

# Ratemaking Results and Revenue Requirement

Washington Gas Light Company
District of Columbia Jurisdiction

Revenue Requirement Calculation
Test Year Ended March 31, 2024

Exhibit OPC (B)-2
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version

| Line | Description | WGL Proposed | OPC Proposed |
|---|---|---|---|
| | A | B | C |
| 1 | Adjusted Rate Base | $ 760,992,964 | $ 710,587,581 |
| 2 | Proposed Rate of Return ("ROR") (Note 1) | 7.87% | 6.58% |
| 3 | Required Net Operating Income | $ 53,892,132 | $ 46,756,663 |
| 4 | | | |
| 5 | Adjusted Net Operating before AFUDC | 27,756,328 | 40,106,856 |
| 6 | AFUDC | | |
| 7 | Adjusted Net Operating Income before Increase | $ 27,756,328 | $ 40,106,856 |
| 8 | | | |
| 9 | Net Operating Income Deficiency (Excess) | 32,162,165 | 6,649,806 |
| 10 | D.C. Income Tax | 3,660,691 | 756,880 |
| 11 | Federal Income Tax | 8,549,377 | 1,767,658 |
| 12 | Total Revenue Deficiency (Excess) before Uncollectibles | 44,372,011 | 9,174,298 |
| 13 | Allowance for Uncollectibles | 1,200,085 | 248,128 |
| 14 | Total Revenue Deficiency (Excess) | $ 45,572,097 | $ 9,422,426 |
| 15 | Per WGL | | |
| 17 | | | |
| 18 | D.C. Income Tax Rate | 8.250% | 8.250% |
| 19 | Federal Income Tax Rate | 19.268% | 19.268% |
| 20 | Composite Income Taxe Rate | 27.518% | 27.518% |
| 21 | Compliment of Composite Tax Rate | 72.4830% | 72.4830% |
| 23 | Uncollectibles (Note 1) | 2.7046% | 2.7046% |
| 24 | | | |
| 25 | | | |
| 26 | Source: | Exhibit WG(D)-1, p. 3 | Exhibit OPC (B)-3 |
| 27 | Note 1: The OPC capital structure and cost of capital are sponsored by OPC Witness Aaron Rothschild. | | |

# Summary of WGL and OPC Adjustments

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-3
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version

OPC Detailed Revenue Requirement and Adjustments
Test Year Ended March 31, 2024

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| Line No. | Description | WGL Proposed | OPC Proposed | Adj. | Explanation - OPC Adjustments | OPC Adjustments | Account |
| 1 | WGL Per Books Net Rate Base | $ 812,206,690 | | | **OPC Operating Income Adjustments:** | | |
| 2 | WGL Distrib. Adjs. | $ (16,030,199) | | | (Negative) amounts = decrease in expense or increase in revenue | | |
| 3 | Subtotal | $ 796,176,491 | $ 760,992,964 | BCO-2 | Adjust deprec. expense on PROJECT*pipes* to 13-mo. avg. | $ (231,158) | Deprec. & Amort. |
| 4 | WGL/OPC Ratemaking Adjs. | $ (35,183,527) | **$ (50,405,383)** | BCO-2 | Adjust deprec. expense - revise WGL proposed deprec. rates | $ (7,385,773) | Deprec. & Amort. |
| 5 | WGL/OPC Adjusted Rate Base | $ 760,992,964 | $ 710,587,581 | BCO-4 | Adjust pay raises | $ (944,860) | O&M |
| 6 | ROR | 7.87% | 6.58% | BCO-5 | Reduce payroll for Phase 2 employee reduction | $ (2,991,405) | O&M |
| 7 | Required Return | $ 59,918,493 | $ 46,756,663 | BCO-6 | Remove amort. of costs incurred to implement involuntary separation | $ (271,011) | O&M |
| 8 | | | | BCO-7 | Adjust overtime to normalized level | $ (777,580) | O&M |
| 9 | Operating Net Income per Books | $ 34,283,145 | | BCO-8 | Remove WGL's non-labor inflation adjustment | $ (1,043,643) | O&M |
| 10 | WGL Distrib. Adjs. | $ (13,284,032) | | BCO-9 | Adjust A&G/affiliate costs | $ (1,223,267) | O&M |
| 11 | Net | $ 20,999,113 | $ 27,756,328 | BCO-10 | **Adjust uncolletibles - Confidential** | | O&M |
| 12 | WGL/OPC Ratemaking Adjs. | $ 6,757,215 | **$ 12,350,528** | BCO-11 | **Reduce Call Center expense - Confidential** | | O&M |
| 13 | **Adjusted Net Income** | $ 27,756,328 | $ 40,106,856 | BCO-12 | Adjust short-term incentives | $ (968,543) | O&M |
| 14 | | | | | Adjust AFUDC Income | | |
| 15 | **Adjusted Operating Net Income** | $ 27,756,328 | $ 40,106,856 | | **OPC Adjs. to Operating Revenues and Expenses** | **$ (17,233,301)** | |
| 16 | Return Deficiency (Surplus) | $ 32,162,165 | $ 6,649,806 | | | | |
| 17 | DC Income Taxes | $ 3,660,691 | $ 756,880 | | **Tax Calculation:** | | |
| 18 | Federal Income Taxes | $ 8,549,377 | $ 1,767,658 | | State and Federal Income Tax Rate | 27.5175% | |
| 19 | Revenue Deficiency | $ 44,372,011 | $ 9,174,298 | | | | |
| 20 | Allowance for Uncollectibles | $ 1,200,085 | $ 248,128 | | State and Federal Income Taxes | $ 4,742,174 | |
| 21 | **Total Revenue Deficiency** | **$ 45,572,097** | **$ 9,422,426** | | Int. syn. total tax increase | | |
| 22 | WGL Filed Revenue Deficiency | $ 45,572,411 | | BCO-3 | Increase tax expense for NOLC PLR | $ 140,599 | |
| 23 | DC Tax Rate | 8.250% | 8.250% | | **Total State and Federal Taxes** | **$ 4,882,773** | |
| 24 | Federal Tax Rate | 19.268% | 19.268% | | **Adjust Net Income** | **$ 12,350,528** | |
| 25 | | 27.5175% | 27.5175% | | | | |
| 26 | Complement of Composite Tax Rat | 72.4830% | 72.4830% | | **OPC Rate Base Adjustments:** | | |
| 27 | Uncollectible Rate (Note 1) | 2.7046% | 2.7046% | | | | |
| 28 | | | | BCO-1 | Remove all PROJECT*pipes* CWIP | $ (6,884,576) | CWIP |
| 29 | | Note 1 | | BCO-1 | Adjust PROJECT*pipes* plant in service from end-of-period to 13-mo. avg. | $ (38,267,939) | Plant in Service |
| 30 | | | | BCO-1 | Adjust PROJECT*pipes* deprec. reserve from end-of-period to 13-mo. avg. | $ 1,589,836 | Deprec. Reserve |
| 31 | Note 1 - The source for the WGL column C is WGL's August 5, 2024 | | | BCO-1 | Adjust PROJECT*pipes* ADIT from end-of-period to 13-mo. avg. | $ 8,035,220 | ADIT |
| 32 | Application, Exhibit WG (D)-1 | | | BCO-1 | Adjust PROJECT*pipes* COR from end-of-period to 13-mo. avg. | $ 2,092,125 | Cost of Removal |
| 33 | | | | BCO-3 | Remove WGL NOLC Private Letter Ruling adjustment | $ (26,370,613) | NOLC |
| 34 | | | | BCO-2 | Adjust deprec. reserve - revise WGL's proposed deprec. rates | $ 7,385,773 | Deprec. Reserve |
| 35 | | | | BCO-2 | Adjust ADIT - revise WGL's proposed deprec. rates | $ 2,014,791 | ADIT |
| 36 | | | | BCO-14 | Reduce CWC | | Other rate base |
| 37 | | | | | **OPC Adjs. to Rate Base** | **$ (50,405,383)** | |

# Revenue Requirement of OPC Adjustments at OPC Recommended ROR

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-4
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version

Rate of Return Per OPC
Test Year Ended March 31, 2024

| Line | Description | Capital Structure | Cost Rates | Weighted Cost Rates |
|---|---|---|---|---|
| | A | B | C | D |
| 1 | Long-Term Debt | 46% | 4.84% | 2.21% |
| 2 | Short-Term Debt | 5% | 6.20% | 0.29% |
| 3 | Common Equity | 50% | 8.22% | 4.09% |
| 4 | OPC Recommended Rate of Return | 100% | | **6.58%** |
| 5 | | | | Note 1 |
| 6 | The OPC capital structure and cost of capital are sponsored by OPC Witness Aaron Rothschild. | | | |
| 7 | Note 1 - Included at Exhibits OPC (B)-2 and OPC (B)-3. | | | |

# Schedules on Individual Adjustments to Rate Base and Net Operating Income

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 1


Adjustment BCO-1
Adjust CWIP, Plant-In-Service and Related Rate Base Accounts
Test Year Ended March 31, 2024

| Ln | Description | Rate Base Adjustments | Source |
|---|---|---|---|
| | A | B | C |
| 1 | **Construction Work in Progress:** | | |
| 2 | Remove PROJECT*pipes* at WGL's March 31, 2024, end-of-period balance | $ (6,884,576) | Exh. WG (D)-5, Adj. No. 3, page 3 of 3 and Exhibit WG (D)-1, page 2 of 4 |
| 3 | Other Plant in Service CWIP - These balances properly removed by WGL | $ - | Exh. WG (D)-5, Adj. No. 2, page 1 of 3 and Exhibit WG (D)-2, page 2 of 3 |
| 4 | OPC Adjustment - Remove PROJECT*pipes* CWIP | **$ (6,884,576)** | Decrease rate base |
| 5 | | | |
| 6 | **Plant in Service:** | | |
| 7 | PROJECT*pipes* - Adjust from WGL's end-of-period to 13-mo. average | $ (27,107,163) | Exh. WG (D)-5, Adj. No. 3, page 3 of 3 and Exhibit WG (D)-2, page 2 of 3 |
| 8 | Other Plant in Service - WGL properly reflected at 13-mo. average | $ - | |
| 9 | Other Plant in Service - Sponsored by OPC Witness Colin Fitzhenry | $ (11,160,776) | Sch. 1, p. 2, column C, line 27 |
| 10 | OPC Adjustment - Reduce PROJECT*pipes* Plant in Service | **$ (38,267,939)** | Decrease rate base |
| 11 | | | |
| 12 | **Depreciation Reserve ("DR"):** | | |
| 13 | Project*pipes* - Adjust from WGL's end-of-period to 13-mo. average | $ 1,589,836 | Exh. WG (D)-5, Adj. No. 3, page 3 of 3 and Exhibit WG (D)-2, page 2 of 3 |
| 14 | Plant in Service - WGL properly reflected at 13-mo. average | $ - | |
| 15 | OPC Adjustment - Reduce PROJECT*pipes* DR | **1,589,836** | Increase rate base |
| 16 | | | |
| 17 | **Accumulated Deferred Taxes (ADIT):** | | |
| 18 | PROJECT*pipes* ADIT - Adjust from WGL's end-of-period to 13-mo. average | $ 8,035,220 | Exh. WG (D)-5, Adj. No. 3, page 3 of 3 and Exhibit WG (D)-2, page 2 of 3 |
| 19 | Plant in Service - WGL properly reflected at 13-mo. average | $ - | |
| 20 | OPC Adjustment - Reduce PROJECT*pipes* ADIT | **$ 8,035,220** | Increase rate base |
| 21 | | | |
| 22 | **Cost of Removal (COR):** | | |
| 23 | PROJECT*pipes* COR - Adjust from WGL's end-of-period to 13-mo. average | $ 2,092,125 | Exh. WG (D)-5, Adj. No. 3, page 3 of 3 and Exhibit WG (D)-2, page 2 of 3 |
| 24 | OPC Adjustment - Reduce PROJECT*pipes* COR | **$ 2,092,125** | Increase rate base |
| 25 | | | |
| 26 | **Adjustment BCO-1 to Rate Base** | **$ (33,435,334)** | |

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment BCO-1
Adjust Plant-In-Service and Related Rate Base Accounts - OPC Witness Fitzhenry
Test Year Ended March 31, 2024

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 1
Page 2 of 2

| Ln | Description | Supporting Information | Rate Base Adjustments | Depreciation Impact |
|---|---|---|---|---|
| | A | B | C | D |
| 1 | **PPROJEC*Tpipes* Expenditure Capital Disallowances** | | | |
| 2 | | | | |
| 3 | FERC Account | Proposed Expenditures | Disallowance | |
| 4 | 376200 - Distr - Mains - Plastic | $53,508,049 | $ (13,377,012) | |
| 5 | 376100 - Distr - Mains - Steel | $1,332,157 | $ (333,039) | |
| 6 | 380200 - Distr - Services - Plastic | $12,504,112 | $ (3,000,987) | |
| 7 | **Subtotal** | **$67,344,318** | **$ (16,711,038)** | |
| 8 | Convert to 13-month average by conservatively using 50% allocation | | 50% | |
| 9 | Subtotal Adjustment BCO-1 to Rate Base (Recommendation of OPC Witness Fitzhenry) | | **$ (8,355,519)** | |
| 10 | | | | |
| 11 | | | | |
| 12 | **Non-PIPES Capital Expenditure Disallowances** | | | |
| 13 | | | | Depreciation |
| 14 | Project | FERC Account | Disallowance | Expense Calc. |
| 15 | DC AOP - Penn. Ave SE & Minn. Ave SE Intersection - Ward 7 | 376200 - Distr - Mains - Plastic | $ (2,254,303) | |
| 16 | AOP - Cleveland Park Streetscape - G007NW - Ward 3 | 376100 - Distr - Mains - Steel | $ (1,071,222) | |
| 17 | DC AOP - Reconstruction of Florida Ave NW - Ward 1 | 376200 - Distr - Mains - Plastic | $ (59,423) | |
| 18 | DC INT - Aspen St NW - A013NW - Ward 4 (Related to BCA287799 & 283129) | 376200 - Distr - Mains - Plastic | $ (241,664) | |
| 19 | ABAND GAS SERV AT MAIN === 705 4TH | 380200 - Distr - Services - Plastic | $ (98,882) | $ (1,862,747) |
| 20 | ILI Readiness - Strip 24 - Launcher | 369003 - Trans-Meas Reg Sta Loop | $ (926,027) | |
| 21 | Strip 7 Valve 8 | 369003 - Trans-Meas Reg Sta Loop | $ (366,745) | $ (646,386) |
| 22 | Tools Field Ops | 394000 - General - Tool,Shop,Gar Eq | $ (330,809) | $ (165,405) |
| 23 | Strip 12 TIMP Dig | 367100 - Trans - Mains - Loop | $ (261,439) | $ (130,720) |
| 24 | **Subtotal** | | **$ (5,610,514)** | |
| 25 | Convert to 13-month average by conservatively using 50% allocation | | 50% | |
| 26 | Subtotal Adjustment BCO-1 to Rate Base (Recommendation of OPC Witness Fitzhenry) | | **$ (2,805,257)** | $ (2,805,257) |
| 27 | **Adjustment BCO-1 to Rate Base (OPC Witness Fitzhenry)** | | **$ (11,160,776)** | |
| 28 | | | Sch. 1, page 1, column B, line 9 | |
| 29 | | | | |
| 30 | | Adjustment to ADIT | Note 2 | |
| 31 | | Adjustment to Cost ofRemoval | Note 2 | |
| 32 | | | | |
| 33 | Note 1 - All of the plant adjustment amounts in this schedule are supported by the Direct Testimony of OPC Witness Fitzhenry | | | |
| 34 | Note 2 - OPC Witness Ostrander will make any applicable corresponding adjustments to ADIT and Cost of Removal in subsequent surrebuttal testimony. | | | |

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 2

Adjustment BCO-2
Revision WGL's Proposed Depreciation Rates
Test Year Ended March 31, 2024

| Ln | Description | Adjustment Depreciation & Rate Base | Source |
|---|---|---|---|
| | A | B | C |
| | **Depreciation Expense:** | | |
| 1 | Project*pipes* - Adjust from end-of-period to 13-mo. average | $ (231,158) | Ex. WG (D)-2, p. 1 and Exh. WG (D)-5, Adj. No. 3 |
| 2 | Adjust WGL's proposed depreciation rates to OPC rates | $ (7,385,773) | Note 2 - Also, see Adjustment BCO-2, Workpaper 1 |
| 3 | **Adjustment BCO-1 to Depreciation Expense** | **$ (7,616,931)** | |
| 4 | | | |
| 5 | **Income Tax Impact:** | | |
| 6 | OPC Adjustment to D.C. income tax expense | **$ 628,397** | |
| 7 | OPC Adjustment to Federal income tax expense | **$ 1,467,630** | |
| 8 | | | |
| 9 | **Impact on Rate Base:** | | |
| 10 | Depreciation Reserve - Adjust WGL's proposed deprec. rates | $ 7,385,773 | Note 2 - Also, see Adjustment BCO-2, Workpaper 1 |
| 11 | ADIT - Adjust WGL's proposed deprec. rates | $ 2,014,791 | Note 2 - Also, see Adjustment BCO-2, Workpaper 1 |
| 12 | **Adjustment BCO-2 to Rate Base - Revise WGL's Deprec. Rates** | **$ 9,400,564** | Increase to Rate Base |
| 13 | | | |
| 14 | Note 1 - The depreciation expense adjustment above also reflects the reduction in Projectpipes and General Plant GPIS per OPC Witness Fitzhenry. | | |
| 15 | Note 2 - Ex. WG (D)-2, p. 1 and Exh. WG (D)-5, Adj. No. 4, page 1 | | |

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 3

Adjustment BCO-3
Reverse WGL's NOLC Tax Sharing Agreement Adjustment
Test Year Ended March 31, 2024

| Description | Adjustments | Source |
|---|---|---|
| A | B | C |
| **NOLC Rate Base Adjustment:** | | |
| Decrease to DC DTA NOLC | $ 878,155 | a |
| Increase to Federal DTA NOLC | $ (27,248,768) | a |
| **Adjustment BCO-3 - NOLC/Rate Base** | **$ (26,370,613)** | |
| | | |
| **NOLC Income Statement Adjustment:** | | |
| NOLC - Income Tax Expense | $ 140,599 | b |
| OPC Adjustment - Increase Income Tax Expense | **$ 140,599** | b |

Source:
(a) - Exhibit WG (D)-5, Adj. No. 32, page 1 of 10, and WGL Witness Tuoriniemi Direct Testimony Replacement Page (Exhibit WG (D), page 98), filed November 6, 2024. OPC Data Request No. 12-2(iii) (Exhibit OPC (B)-76) first identified the discrepancy in WGL's NOLC Adjustment No. 32 at testimony and exhibits. Witness Tuoriniemi's Direct Testimony (98:10) showed a Federal DTA NOLC of $24,088,259, although Exhibit WG (D)-2, page 2 of 3, showed a different amount for Adjustment No. 32 Federal DTA NOLC of $27,248,768. WGL subsequent filed the Replacement Page for Witness Tuoriniemi's Direct Testimony showing a corrected amount of $27,248,768. However, OPC continues to review all of WGL's Adjustment No. 32 impacts and calculations related to the NOLC PLR issue and related impacts on rate base and income tax expense, and additional adjustments may be necessary.

(b) - Witness Tuoriniemi Direct Testimony (98:13) and Replacement Page (Exhibit WG (D), page 98) filed November 6, 2024, both show the same income tax expense adjustment of $140,599, and also per WGL Adjustment No. 10D and 31, Exhibit WG (D)-5, page 1 of 8.

Adjustment BCO-4
Adjust Pay Raises and Reflect May to November 2024 Employee Reductions
Test Year Ended March 31, 2024

| | A | B |
|---|---|---|
| Lne | Description | Adjustment |
| 1 | **Adjustment BCO-4 to Pay Raises** | **$ (944,860)** |
| 2 | | |
| 3 | **Income Tax Impact:** | |
| 4 | OPC Adjustment to D.C. income tax expense | **$ 77,951** |
| 5 | OPC Adjustment to Federal income tax expense | **$ 182,056** |

6 Sources: See supportion calculations at Schedule 4, page 2 of 2.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment BCO-4
Adjust Pay Raises (Reflect May to November 2024 Employee Reductions in Payroll Cost Calculation)
Test Year Ended March 31, 2024

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 4
Page 2 of 2

| | A | B | C | D | E |
|---|---|---|---|---|---|
| Ln | Description | WGL Payroll Adj. 5 | Source | OPC Direct - Disallow Union Post-Test Period Pay Raise and All Management Pay Raises | OPC Potential Surrebuttal - Adjusted with May- Nov. Headcount but limited pay increase to 3%, allow some post-test period raises |
| 1 | Gross Payroll (Exp. & Capit.) | 168,372,853 | Note 2 | | |
| 2 | Gross Short-Term Incentives in Payroll | 15,804,177 | (a) | | |
| 3 | | 184,177,030 | | | |
| 4 | Remove April 2024 Management Invol. Sep. Payroll Costs | 9,945,883 | (a) | | |
| 5 | Gross Payroll Before Removal of Invol. Sep. Costs | 194,122,913 | | 184,177,030 | 184,177,030 |
| 6 | Remove Invol. Separation Program Payroll Costs | (9,945,883) | | - | (17,579,454) |
| 7 | Gross Payroll Used as Starting Point for Payroll Adj. | 184,177,030 | (a) (b) | 184,177,030 | 166,597,576 |
| 8 | | | | | |
| 9 | The pay raises to be removed for Phase 2 separation beginning May 1 and through November 2024, with most taking place in Sept. 2024 | | | | |
| 10 | | | | | |
| 11 | Union Increase of 3% for 2023, no change OPC | 370,949 | (f) | 370,949 | 370,949 |
| 12 | Union increase of 3% for 2024, no change OPC | 1,960,796 | (f) | - | 1,960,796 |
| 13 | Subtotal Union Pay Increase | 2,331,745 | (f) | 370,949 | 2,331,745 |
| 14 | | | | | |
| 15 | Management Increase at Jan. 2024 is 3.97% per WGL and 3% per OPC | 3,138,466 | (f) | - | 2,216,923 |
| 16 | Management Increase at Jan. 2025 is 4.97% per WGL and 3% per OPC | 1,362,578 | (f) | - | 681,256 |
| 17 | Subtotal Management Pay Increase | 4,501,044 | (f) | - | 2,898,179 |
| 18 | | | | | |
| 19 | Union and Management Payroll Change | 6,832,789 | | 370,949 | 5,229,924 |
| 20 | | | | | |
| 21 | O&M Allocation Factor | 75.5276% | | 75.5276% | 75.53% |
| 22 | Adjusted Gross Payroll Expense | 5,160,642 | | 280,169 | 3,950,036 |
| 23 | DC Allocation Factor | 19.36% | | 19.36% | 19.36% |
| 24 | Adjustment for Payroll Increases | 999,100 | | 54,241 | 764,727 |
| 25 | Adjustment for Ratification Bonus | 1,957 | | 1,957 | 1,957 |
| 26 | **Total Adjustment to Payroll** | 1,001,057 | | 56,198 | 766,684 |
| 27 | **Adjustment BCO-4 to Pay Raises** | | | **(944,860)** | **(234,373)** |
| 28 | | | | | |
| 29 | **Reconciliation to Compliance Filing for TYE March 31, 2024:** | | | | |
| 30 | Gross Payroll | 194,122,913.00 | (a) | | |
| 31 | Gross STI | (15,804,177.00) | (a) | | |
| 32 | Amounts Charged to Affiliates | (1,967,152.00) | (a) | | |
| 33 | Gross Payroll per WGL Filing | 176,351,584.00 | (a) | | |
| 34 | | | | | |
| 35 | **Determination of O&M Factor Calculation for TYE March 31, 2024:** | | | | |
| 36 | Gross Payroll (WGL Adj. 5, page 1) | 184,177,030.00 | (h) | | |
| 37 | Involuntary Separation Program Costs (WGL Adj. 13) | 9,945,883.00 | (h) | | |
| 38 | Total Gross Payroll | 194,122,913.00 | (h) | | |
| 39 | Paid Time Off Included in Payroll | (24,908,341.00) | (h) | | |
| 40 | Short-Term Incentives included in Payroll | (15,804,177.00) | (h) | | |
| 41 | Other Differences | 173,701.00 | (h) | | |
| 42 | Gross Payroll for O&M Calculation | 153,584,096.00 | | | |
| 43 | Note - The above payroll costs for calculating the O&M percentage is | | | | |
| 44 | direct payroll for productive time only. | | | | |
| 45 | | | | | |
| 46 | (a) - OPC Follow-Up Data Request No. 11-10 and Exh. WG (D)-5, Adjustment No. 5, p. 15 of 15. | | | | |
| 47 | (b) - Exh. WG (D)-5, Adj. 5, p. 1 and p. 14. | | | | |
| 48 | (c) - OPC Follow-Up Data Request No. 10-5, Attach. 1 | | | | |
| 49 | (d) - Exh. WG (D)-5, Adj. 13, p. 1 - includes a reduction for all "Rate Year Labor Expenses" except life insurance. | | | | |
| 50 | (e) - The difference between WGL conflicting STI amounts of $15,804,177 and $15,076,521 is $727,656, which is deducted from Gross Payroll. | | | | |
| 51 | (f) - Exh. WG (D)-5, Adj. 5, pp. 1, 2, and 3. | | | | |
| 52 | (g) -Exh. WG (D)-5, p. 1. | | | | |
| 53 | (h) - OPC Data Request No. 11-8. | | | | |
| 54 | | | | | |
| 55 | Note 1 - WGL Adj. 5 payroll adjustment excludes LTI costs to begin with, so no reduction is necessary. | | | | |
| 56 | Note 2 - OPC Witness Ostrander backed into this by deducting STI from Gross Payroll before deduction of involuntary separation costs | | | | |
| 57 | Note 3 - See Exhibit OPC (B)-65 for WGL Response to OPC Follow Up Data Request No. 11-10; Exhibit OPC (B)-55 for WGL Response to OPC Follow Up Data Request No. 10-5; and Exhibit OPC (B)-64 for WGL Response to OPC Data Request No. 11-8 | | | | |

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 5


Adjustment BCO-5
Adjust Payroll Expense for Additional May to November 2024 Employee Reductions
Not Disclosed or Addressed by WGL
Test Year Ended March 31, 2024

| | A | B |
|---|---|---|
| Lne | Description | Adjustment |
| 1 | **Adjustment BCO-5 for May to November 2024 Employee Reductions** | **$ (2,991,405)** |
| 2 | | |
| 3 | **Income Tax Impact:** | |
| 4 | OPC Adjustment to D.C. income tax expense | **$ 246,791** |
| 5 | OPC Adjustment to Federal income tax expense | **$ 576,384** |

6 Sources: See supportion calculations at following pages of Schedule 5.
7 Note 1 - Only management payroll costs have been reduced for the May to November 2024 employee reductions, but
8 further reductions may be necessry for Union employees that were also terminated.
9 Note 2 - WGL proposed adjustment No. 13 to remove payroll costs of management employees terminated April 2024
10 but did not disclose or address the subsequent Phase 2 reductions for both management and union employees from May to November 2024.

Adjustment BCO-5
Adjust Payroll Expense for Additional May to November 2024
Employee Reductions Not Disclosed or Addressed by WGL
Test Year Ended March 31, 2024

| Ln | A<br>Description | B<br>Exh. OPC (B)-5, Sch. 5, p. 3 | C<br>OPC Misc. Adjustment | D<br>OPC Payroll Expense Adjustment | E<br>OPC Total Adjustment |
|---|---|---|---|---|---|
| 1 | Reduction in Management Employees May to Nov. 2024 (below) | | (92.50) | (92.50) | |
| 2 | Avg. Man. Payroll Expense Excluding Incentives (Exh. OPC(B)-5, Sch. 5, p. 3) | | $ 105,677 | $ 105,677 | |
| 3 | **Management Employee Reduction May to November 2024** | | **$ (9,775,082)** | **$ (9,775,082)** | |
| 4 | | | | | |
| 5 | Misc. Man. Separation Costs (% of Payroll Reduction): | | | | |
| 6 | Reduce short-term incentives | 13.64% | $ (1,333,321) | | |
| 7 | Reduce medical plans | 10.10% | $ (987,283) | | |
| 8 | Reduce 401(k) | 7.69% | $ (751,704) | | |
| 9 | Reduce payroll taxes | 9.64% | $ (942,318) | | |
| 10 | Reduce life insurance | 17.00% | $ (1,661,764) | | |
| 11 | Misc. Man. Reduction Costs | | $ (5,676,390) | | |
| 12 | Adjust to Gross (Expense & Capital) Costs (Exh. OPC(B)-5, Sch. 5, p. 3 | | 72.73% | | |
| 13 | Gross Misc. Man. & Payroll Separation Costs | | $ (7,804,371) | $ (9,775,082) | $ (17,579,454) |
| 14 | O&M Factor | | 72.7335% | not applic. | |
| 15 | Expensed Misc. Man. Separation Costs | | $ (5,676,390) | $ (9,775,082) | $ (15,451,473) |
| 16 | DC Labor Factor | | 19.36% | 19.36% | 19.36% |
| 17 | **OPC Adjustment BCO-5 - Management Employee Reduction May to Nov. 2024** | | $ (1,098,949) | $ (1,892,456) | **$ (2,991,405)** |
| 18 | | | | | |

| Ln | | A | B | C | D | E | F |
|---|---|---|---|---|---|---|---|
| 20 | | Employee Headcount Reduction per OPC Data Request No. 11-12, Attachment 1, page 1 of 7 | | | | | |
| 21 | | | Management | | Union | | Total |
| 22 | | | Employees | Change | Employees | Change | Change |
| 23 | | Mar-24 | 806.25 | | 695 | | |
| 24 | Involuntary Separation Plan | Apr-24 | 732.75 | **(73.5)** | 690 | (5.0) | (78.5) |
| 25 | Additional employee elimination not | May-24 | 726.75 | (6.0) | 688 | (2.0) | (8.0) |
| 26 | explained by WGL for months | Jun-24 | 733.75 | 7.0 | 686 | (2.0) | 5.0 |
| 27 | May to November 2024, and | Jul-24 | 729.75 | (4.0) | 689 | 3.0 | (1.0) |
| 28 | not identified as an additional | Aug-24 | 721.75 | (8.0) | 687 | (2.0) | (10.0) |
| 29 | formal separation plan for | Sep-24 | 652.25 | **(69.5)** | 685 | (2.0) | (71.5) |
| 30 | management or union employees | Oct-24 | 650.25 | (2.0) | 683 | (2.0) | (4.0) |
| 31 | in WGL responses to OPC discovery | Nov-24 | 640.25 | (10.0) | 677 | (6.0) | (16.0) |
| 32 | | | | | | | |
| 33 | Employee Reduction May to November 2024 | | | **(92.5)** | | **(13.0)** | **(105.5)** |
| 34 | Management Headcount Reduction - From April 2024 of 732.75 to November 2024 of 640.25 | | | **(92.50)** | | | |
| 35 | | | | | | | |

36 Note 1 - WGL's response to OPC Data Request No. 6-19 states that 70 management employees were eliminated in April 2024 related to an
37 involuntary separation plan with no reduction in Union employees, although the total reduction in management employees shown above and per
38 OPC Data Request No. 11-12 in April 2024 appears to be 73.5. See also Exhibit WG (F) (Smith) at 19:8-10; Exhibit WG (A) (Steffes) at 13:14-18 (discussing the elimination of these positions).
39 Note 2 - See Exhibit OPC (B)-52 for WGL Confidential Response to OPC Data Request No. 6-19; and Exhibit OPC (B)-67 for WGL Response to OPC Data Request No. 11-12

| | |
|---|---|
| Washington Gas Light Company | Exhibit OPC (B)-5 |
| District of Columbia Jurisdiction | Formal Case No. 1180 |
| | Direct Testimony of Bion Ostrander |
| Adjustment BCO-5 | Public Version |
| Reduce Payroll Costs for Additional May to November 2024 | Schedule 5 |
| Reduction in Management Employees | Page 3 of 3 |
| Test Year Ended March 31, 2024 | |

| | | A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2023 Payroll Costs | | | Note 4 | 2024 Payroll Costs | | Note 4 | Average | Annualized |
| Ln | Period | August | September | October | November | December | January | February | March | Payroll/Month | Payroll |
| | December 2023 and March 24 Excluded | | | | | Excluded | | | Excluded | | |
| 1 | Total Gross Payroll (Note 3) | | $ 12,853,458 | $ 12,971,920 | $ 13,192,164 | $ 19,821,951 | $ 13,699,721 | $ 13,969,398 | $ 28,022,124 | | |
| 2 | | | | | | | | | | | |
| 3 | Executive (Note 3) | | $ 430,130 | $ 454,901 | $ 453,208 | $ 670,898 | $ 436,543 | $ 439,045 | $ 2,813,302 | | |
| 4 | Non-Exec. Management (Note 3) | | $ 7,411,431 | $ 7,424,563 | $ 7,447,139 | $ 11,093,306 | $ 7,563,582 | $ 7,607,771 | $ 19,286,224 | | |
| 5 | Non-Exec. Management (excluded) | | $ (686,787) | $ (691,040) | $ (686,220) | $ (1,022,844) | $ (691,121) | $ (698,700) | $ (1,909,986) | | |
| 6 | Management Total Expensed Payroll | | $ 7,154,774 | $ 7,188,424 | $ 7,214,127 | $ 10,741,360 | $ 7,309,004 | $ 7,348,116 | $ 20,189,540 | | |
| 7 | | | | | | | | | | | |
| 8 | Man. Headcount (Note 5) | 819 | 824 | 829 | 823 | 824 | 820 | 813 | 808 | | |
| 9 | Avg. Monthly Headcount (Note 5) | | 822 | 827 | 826 | 824 | 822 | 817 | 811 | | |
| 10 | | | | | | | | | | | |
| 11 | Union Total Gross Payroll (Expense & Capital) | | $ 5,698,684 | $ 5,783,496 | $ 5,978,037 | $ 9,080,591 | $ 6,390,717 | $ 6,621,282 | $ 7,832,584 | | |
| 12 | | | | | | | | | | | |
| 13 | Union Headcount (Note 5) | 691 | 689 | 695 | 695 | 694 | 694 | 693 | 695 | | |
| 14 | Avg. Monthly Headcount (Note 5) | | 690 | 692 | 695 | 695 | 694 | 694 | 694 | | |
| 15 | | | | | | | | | | Note 4 | Note 4 |
| 16 | Man. Avg. Payroll Expense per Employee | | $ 8,709 | $ 8,697 | $ 8,734 | $ 13,044 | $ 8,892 | $ 9,000 | $ 24,910 | $ 8,806 | $ 105,677 |
| 17 | Union Avg. Gross Payroll per Employee | | $ 8,259 | $ 8,358 | $ 8,601 | $ 13,075 | $ 9,209 | $ 9,548 | $ 11,286 | $ 8,795 | $ 105,538 |

| Ln | | | | | | | |
|---|---|---|---|---|---|---|---|
| 18 | | | | | | | Management |
| 19 | WGL Adjustment 13 - Remove Management Employees Involuntary Separation Labor O&M Costs from Payroll (for 70 Management Employees Eliminated) - See Note 1 | | | | | | Payroll Cost |
| 20 | | Percent of | Payroll Expense | Management | Average O&M | **Union employee payroll reduction estimate:** | above taken |
| 21 | | Costs to | Eliminated | Employees | Expense per | $1,371,997.05 | to |
| 22 | | Salaries | | Eliminated | Employee | 75.53% | Exh. OPC(B)-5, |
| 23 | Reduce salaries | | 7,233,986 | 70 | 103,343 | 19.36% | Sch. 5, p. 2 |
| 24 | Reduce short-term incentives | 13.64% | 986,995 | 70 | 14,100 | **$ 200,622** | |
| 25 | Reduce medical plans | 10.10% | 730,291 | 70 | 10,433 | | |
| 26 | Reduce 401(k) | 7.69% | 556,223 | 70 | 7,946 | | |
| 27 | Reduce payroll taxes | 9.64% | 697,386 | 70 | 9,963 | | |
| 28 | Reduce life insurance | 0.17% | 12,492 | 70 | 178 | | |
| 29 | Reduction in Payroll Expenses | 41.24% | 10,217,373 | | | | |
| 30 | Adjust to Gross (Expense & Capital) Costs | | 72.733% | | | | |
| 31 | Gross Man. Separation Costs | | 14,047,691 | | | | |
| 32 | O&M Factor | | 72.73% | | | | |
| 33 | Expenseed Man. Separation Costs | | 10,217,373 | | | | |
| 34 | DC Labor Factor | | 19.36% | | | | |
| 35 | WGL Adjustment No. 13 - Involuntary Sep. Costs | | **1,978,083** | | | | |
| 36 | | | | | | | |
| 37 | | | | % of expense | % gross to | | |
| 38 | Ratio of Expensed to Gross (Expense & Capital) Separation Costs: | | | to gross | expense | | |
| 39 | Total expensed payroll separation costs | | 7,233,986 | 72.733% | 1.37488281 | | |
| 40 | Total expense & capital misc. and payroll separation costs | | 9,945,883 | | | | |
| 41 | Per above, it appears that only some portion of Management short-term incentives are capitalized, remaining Management payroll costs are expensed. | | | | | | |
| 42 | It is not clear why some portion of Management incentives are capitalized if Management base payroll costs are all expensed. | | | | | | |
| 43 | | | | | | | |
| 44 | Sources: | | | | | | |
| 45 | WGL Adjustment No. 13 - Exhibit WG (D)-05, Adjustment 13, pp. 1 and 2 | | | | | | |
| 46 | Note 1 - Per WGL response to OPC DR 6-19, Attachment 1, all involuntary separation costs above were incurred in April 2024 through October 2024, so | | | | | | |
| 47 | none of these costs were in the actual test period end March 31, 2024. | | | | | | |
| 48 | Note 2 - Per above, WGL's response to OPC DR 6-19 confirms 70 management employees eliminated via the involuntary separation program. | | | | | | |
| 49 | Note 3 - Source for payroll costs is Exhibit WG (D)-5, Adjustment No. 5, page 14 of 15. | | | | | | |
| 50 | Note 4 - OPC Witness Ostrander calculation of average union and management payroll costs did not include either December 2023 or March 2024 | | | | | | |
| 51 | monthly payroll costs because these amounts include significant portions of short-term incentive costs that could not be separately | | | | | | |
| 52 | identified and removed from the calculation. | | | | | | |
| 53 | Note 5 - Headcount is from OPC Data Request No. 11-12 (Exhibit OPC (B)-67). See Exhibit OPC (B)-5, Sch. 2, p. 2 for detailed information. | | | | | | |

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 6

Adjustment BCO-6
Remove Amortization of Costs Incurred to Implement
April 2024 Management Involuntary Separation Program
Test Year Ended March 31, 2024

| | A | B |
|---|---|---|
| Ln | Description | Amortization of Implementation Costs |
| 1 | Total Costs per WGL in Adj. 14 | (6,998,583) |
| 2 | WGL 5 Year Amortization | 5 |
| 3 | WGL Proposed Amortization Expense | (1,399,717) |
| 4 | DC Labor Factor | 19.3619% |
| 5 | **Adjustment BCO-6 to Remove WGL Amortization** | **(271,011)** |
| 6 | | |
| 7 | **Income Tax Impact:** | |
| 8 | OPC Adjustment to D.C. income tax expense | **$ 22,358** |
| 9 | OPC Adjustment to Federal income tax expense | **$ 52,218** |
| 10 | | |
| 11 | Source and Notes: | |
| 12 | (a) - Exhibit WG (D)-5, Adjustment No. 14, page 1 of 5. | |

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 7

Adjustment BCO-7
Adjust Overtime Expense to Normalized Level
Test Year Ended March 31, 2024

| | A | B | |
|---|---|---|---|
| Ln | Period | Overtime Costs | |
| 1 | Calendar 2020 | $ | 71,873,434 |
| 2 | Calendar 2021 | $ | 72,617,537 |
| 3 | Calendar 2022 | $ | 74,338,367 |
| 4 | Test Year End March 2024 | $ | 80,033,317 |
| 5 | Total Overtime Costs | $ | 298,862,655 |
| 6 | Divide by Four Years | | 4.0 |
| 7 | Four-Year Average | $ | 74,715,664 |
| 8 | Test Year Excess Four-Year Average OT | $ | (5,317,653) |
| 9 | O&M Expense Allocation Factor | | 75.53% |
| 10 | DC Allocation Factor | | 19.36% |
| 11 | Normalize Test Year to Four-Year Average | $ | (777,580) |
| 12 | **Adjustment No. 7 - Overtime Expense** | **$** | **(777,580)** |
| 13 | | | |
| 14 | **Income Tax Impact:** | | |
| 15 | OPC Adjustment to D.C. income tax expense | **$** | **64,150** |
| 16 | OPC Adjustment to Federal income tax expense | **$** | **149,824** |
| 17 | | | |
| 18 | Source: OPC Data Request No. 11-13 (Exhibit OPC (B)-68). | | |

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 8

Adjustment BCO-8
Remove WGL's Non-Labor Inflation Adjustment
Test Year Ended March 31, 2024

| Ln | Description | Non-Labor Inflation Expense |
|---|---|---|
| | A | B |
| 1 | **Adjustment BCO-8 - Non-Labor Inflation** | **$ (1,043,643)** |
| 2 | | |
| 3 | **Income Tax Impact:** | |
| 4 | OPC Adjustment to D.C. income tax expense | **$ 86,101** |
| 5 | OPC Adjustment to Federal income tax expense | **$ 201,089** |
| 6 | | |
| 7 | Source: Exhibit WG (D)-5, Adjustment No. 21, pages 1 to 22. | |

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment BCO-9
Adjust A&G and/or Expenses Allocated from AltaGas and Affiliates to WGL
Test Year Ended March 31, 2024

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 9
Pages 1 of 3

| | A | B | C | D | E |
|---|---|---|---|---|---|
| Ln | Description | WGL | WGL-DC | Adjustment | Source |
| 1 | President/CEO One-Time Bonus/Significant Increase | | | | Exh. OPC (B)-5, Sch. 9, p. 3 of 3 |
| 2 | | | | | |
| 3 | Adjust Affiliate Expense to Reasonable Level | | | | Exh. OPC (B)-5, Sch. 9, p. 2 of 3 |
| 4 | **Adjustment BCO-9 to Affiliate Expenses** | | | **$ (1,223,267)** | |
| 5 | | | | | |
| 6 | OPC Adjustment to D.C. income tax expense | | | **$ 100,920** | |
| 7 | OPC Adjustment to Federal income tax expense | | | **$ 235,699** | |

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment BCO-9
Adjust A&G and/or Expenses Allocated from AltaGas and Affiliates to WGL
Test Year Ended March 31, 2024

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 9
Page 2 of 3

**Expenses Allocated to WGL by AltaGas/ASUS - WGL Amounts (Not WGL-DC) - OPC Data Request No. 4-10**

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| Ln | Function | CY2019 | CY2020 | CY2021 | CY2022 | TYE March 31, 2024 | | |
| 1 | Accounting and Tax | | | | | | | |
| 2 | Board of Directors | | | | | | | |
| 3 | Exec Mgmt | | | | | | | |
| 4 | Finance | | | | | | | |
| 5 | HR | | | | | | | |
| 6 | IT | | | | | | | |
| 7 | Legal and Compliance | | | | | | | |
| 8 | Supply Chain | | | | | | | |
| 9 | Cost-To-Achieve (Note 1) | | | | | | | |
| 10 | **Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | $ - | $ - |
| 11 | | | | | | | | |
| 12 | **Annual Change $** | | | | | | | |
| 13 | **Annual Change %** | | | | | | | |
| 14 | | | | WGL-DC Allocation Factor | | | | |
| 15 | | | | **Adjustment BCO-9 to Affiliate Expenses** | | | | **$ -** |
| 16 | | | | The above adjustment is carried forward to Exhibit OPC(B)-5, Sch. 9, p. 1. | | | | |

17 Source:
18 OPC Data Request No. 4-10 is the source for the above table. The WGL TYE 2024 amount of $26,051,443 agrees to Tuoriniemi Direct Testimony (D)
19 at page 33, line 8 and 18.
20 WGL-DC Allocation Factor - Tuoriniemi Direct Testimony (D), at p. 35, lines 1 and 2.

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment BCO-9
Adjust A&G and/or Expenses Allocated from AltaGas and Affiliates to WGL
Test Year Ended March 31, 2024

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 9
Page 3 of 3

**CONFIDENTIAL - ATTORNEY EYES ONLY - Per OPC Data Request No. 4-14 - Attachment No. 3 (Exhibit OPC (B)-11)**

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| Lne | Position | Total AltaGas Compensation and Amount Allocated to WGL | Calendar 2020 | Calender 2021 | Calendar 2022 | TYE March 31, 2024 | | |
| 1 | | Canada Conversion Factor | | | | | | |
| 2 | President/CEO | AltaGas/Affiliate Total | $ - | $ - | $ - | $ - | | |
| 3 | President/CEO | WGL-DC | | | | | | |
| 4 | | $ Annual Change - WGL-DC | | $ - | $ - | $ - | | |
| 5 | | % AnnualChange - WGL-DC | | | | | | |
| 6 | | | | | | | | |
| 7 | Other Officers | Total Comp. | $ - | $ - | $ - | $ - | | |
| 8 | Other Officers | WGL-DC Allocated | | | | | | |
| 9 | | $ Annual Change - WGL-DC | | $ - | $ - | $ - | | |
| 10 | | % AnnualChange - WGL-DC | | | | | | |
| 11 | | | | | | | | |
| 12 | Total of Above | Total Comp. | $ - | $ - | $ - | $ - | | |
| 13 | Total of Above | WGL-DC Allocated | | | | | | |
| 14 | | | | | | | | |
| 15 | Total Officers Each Year | | | | | | | |
| 16 | President/CEO as % of Other Officers | | | | | | | |
| 17 | | | | | | | | |
| 18 | **Adjustment BCO-9 - Adjust President/CEO Compensation** | | | | | | | **$ -** |
| 19 | The above adjustment is carried forward to Exhibit OPC(B)-5, Sch. 9, p. 1. | | | | | | | |
| 20 | Note: | | | | | | | |
| 21 | 1) Total Compensation includes salaries, short-term incentives, bonuses, and benefits | | | | | | | |
| 22 | 2) "Total" amounts above converted from Canadian $ to US $. The WGL-DC amounts do not need to be converted, | | | | | | | |
| 23 | already expressed in US $. | | | | | | | |
| 24 | | | | | | | | |
| 25 | | | | | | | | |
| 26 | | | | | | | | |
| 27 | | | | | | | | |
| 28 | | | | | | | | |

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment BCO-10
Adjust Uncollectible Expense
Test Year Ended March 31, 2024

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 10

| Lne | A<br>Period | B<br>Net Charge-Offs | C<br>Charge-Off Outlier Data Removed | D<br>Revenues from Gas Sales | E<br>Revenue Outlier Data Removed | F<br>Source |
|---|---|---|---|---|---|---|
| 1 | Calendar 2018 | | | | | (b) |
| 2 | Calendar 2019 | | | | | (b) |
| 3 | Calendar 2020 | | | | | (b) |
| 4 | TME March 2020 | | | | | (a) |
| 5 | TME March 2021 | | | | | (a) |
| 6 | TME March 2022 | | | | | (a) |
| 7 | TME March 2023 | | | | | (a) |
| 8 | TME March 2024 | | | | | (a) |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | Ratemaking Sales and Revenues | | | | | (a) |
| 13 | Uncollect. Accrual Rate | | | | | |
| 14 | OPC Adjusted Uncollectble Expense | $ - | | | | |
| 15 | WGL Proposed Uncoll. Expense | | | | | (a) |
| 16 | **Adjustment BCO-10** | | | | | |
| 17 | | | | | | |
| 18 | **Income Tax Impact:** | | | | | |
| 19 | OPC Adjustment to D.C. income tax expense | | | | | |
| 20 | OPC Adjustment to Federal income tax expense | | | | | |
| 21 | | | | | | |
| 22 | Source: | | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 11

Adjustment BCO-11
Reduce Call Center Expense
Test Year Ended March 31, 2024

| Ln | Description | WGL-DC Call Center Expense |
|---|---|---|
| | A | B |
| 1 | Call Center Expense TYE March 31, 2024 | |
| 2 | Call Center Expense Calendar Year 2023 | |
| 3 | **Adjustment BCO-11 to Call Center Expense** | **$ -** |
| 4 | | |
| 5 | **Income Tax Impact:** | |
| 6 | OPC Adjustment to D.C. income tax expense | **$ -** |
| 7 | OPC Adjustment to Federal income tax expense | **$ -** |
| 8 | | |
| 9 | Source: Call Center Expense amounts amounts above are per WGL's Confidential | |
| 10 | response to OPC Data Request No. 18-10, Attachment 1 (Exhibit OPC (B)-87). | |

Adjustment BCO-12
Reduce Short-Term Incentive (STI) Expense
Test Year Ended March 31, 2024

| Ln | Description | Incentive Expense |
|---|---|---|
| | A | B |
| 1 | **Adjustment BCO-12 to Short-Term Incentive Expense** | **$ (968,543)** |
| 2 | | |
| 3 | OPC Adjustment to D.C. income tax expense | $ 79,905 |
| 4 | OPC Adjustment to Federal income tax expense | $ 186,619 |
| 5 | | |
| 6 | Note: See adjustment supporting calculations at Exhibit OPC (B)-5, Schedule 12, page 2 of 2. | |

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment BCO-12
Reduce Short-Term Incentive (STI) Expense
Test Year Ended March 31, 2024



| | | | | Short-Term Incentive by Period | | | |
|---|---|---|---|---|---|---|---|
| | | | | Calender Year | | | Test Year End |
| Lne | Account | Description | 2019 | 2020 | 2021 | 2022 | March 31, 2024. |
| | A | B | C | D | E | F | G |
| | **WGL STI Amounts** | | | | | | |
| 1 | 920401 | Exec IncentiveProgram-Gross | 5,615,327 | 4,157,877 | 660,812 | - | - |
| 2 | 920402 | Exec Incentive Progr-Distr | (877,563) | (78,471) | (76,406) | - | - |
| 3 | 920431 | Employee Incentive - ROE Gross | 6,581,604 | 7,746,302 | 9,111,833 | 17,114,369 | 11,612,309 |
| 4 | 920431 | Employee Incentive - ROE Gross - SEMCO | - | - | 144,885 | 169,251 | 63,991 |
| 5 | 920432 | Empl Incentive-ROE Distr | (1,934,068) | (1,260,608) | (1,809,490) | (3,876,150) | (2,656,847) |
| 6 | 920441 | ABP Union Utility Gross | - | - | 2,211,710 | 1,612,614 | 3,373,243 |
| 7 | 417902 | Incentives (Utility Other) | 74,840 | 11,360 | 27,220 | 12,056 | 10,391 |
| 8 | 107100 | Gas Plant | 1,238,529 | 1,040,945 | 1,612,266 | 3,498,358 | 2,416,185 |
| 9 | 146000 | Interunit-Receiv/Payable-Net | 1,498,263 | 286,774 | 246,410 | 365,735 | 257,249 |
| 10 | | | 12,196,931 | 11,904,179 | 12,129,240 | 18,896,234 | 15,076,522 |
| 11 | | | | | | | Note 2 |
| 12 | Expense Allocaiton Factor (Comp A&G) | | 19.27% | 21.01% | 19.73% | 18.45% | 19.54% |
| 13 | Capital Allocation Factor (Net Rate Base) | | 17.60% | 17.98% | 18.19% | 18.32% | 19.08% |
| 14 | | | | | | | |
| 15 | **WGL-DC STI Amounts** | | | | | | |
| 16 | 920401 | Executive STI (Gross) | 1,082,299 | 873,379 | 130,393 | - | - |
| 17 | 920402 | Executive STI (Distribution) | (169,142) | (16,483) | (15,076) | - | - |
| 18 | 920431 | Employee Incentive - ROE Gross | 1,268,539 | 1,627,142 | 1,797,965 | 3,157,464 | 2,269,140 |
| 19 | 920431 | Employee Incentive - ROE Gross - SEMCO | - | - | 28,589 | 31,225 | 12,504 |
| 20 | 920432 | Non Executive STI (Distribution) | (372,773) | (254,796) | (357,052) | (715,119) | (519,170) |
| 21 | 920441 | ABP Union Utility Gross | - | - | 436,419 | 297,514 | 659,159 |
| 22 | 417902 | Incentives (Utility Other) | 14,425 | 2,386 | 5,371 | 2,224 | 2,031 |
| 23 | 107100 | Gas Plant | 217,949 | 187,208 | 293,234 | 640,915 | 461,046 |
| 24 | 146000 | Interunit-Receiv/Payable-Net | 288,775 | 60,238 | 48,622 | 67,475 | 50,269 |
| 25 | Total Per Book O&M STI Expense (DC) | | $ 2,330,072 | $ 2,229,242 | $ 2,368,465 | $ 3,481,698 | $ 2,934,979 |
| 26 | Remove one-third of STI expense as related to financial performance metrics (Note 3) | | | | | | 33% |
| 27 | **Adjustment BCO-12 - Short-Term Incentive Expense** | | | | | | **$ (968,543)** |
| 28 | | | | | | | |

29 Note 1 - All amounts above are from OPC Data Request No. 10-5, Attachment 1
30 Note 2 - WGL's response to OPC Data Request 11-8(a) stated that OPC used the incorrect STI amounts in the data request and
31 the correct amount of STI expense at March 31, 2024, was $15,076,522 at the response to OPC Data Request No. 10-5.
32 Atlhough OPC Data Request No. 10-5, Attachment 1 appears to indicate that the STI amount of $15,076,522 includes amounts
33 that are expensed, capitalized, and included in accounts receivable, WGL's response to OPC Data Request No. 11-8 states
34 this same STI amount is the correct expense amount at March 31, 2024.
35 I will rely on WGL's response to OPC Data Request Nos. 10-5 and 11-8 that $15,076,522 is the correct STI expense amount.
36 Note 3 - OPC Witness Ostrander's Direct Testimony allocates equal one-third parts of STI expense to: 1) financial-related metrics;
37 2) customer-related metrics; and 3) non-specific metrics (diversity, etc.)
38 Note 4: *See* Exhibit OPC (B)-55 for WGL's Response to OPC Data Request No. 10-5; and Exhibit OPC (B)-64 for WGL
39 Response to OPC Data Request No. 11-8

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 13

Adjustment BCO-13
True-Up Cash Working Capital ("CWC")
Test Year Ended March 31, 2024

| Line | Description | Amount |
|---|---|---|
| | A | B |
| | **Cash Working Capital:** | Amount |
| 1 | WGL CWC | |
| 2 | OPC Proposed CWC | |
| 3 | **Adjustment BCO-13 - True-Up CWC** | |
| 4 | | Note 1 |
| 5 | Note 1: | |
| 6 | This adjustment will be trued-up in OPC Witness Ostrander's subsequent Surrebuttal Testimony. | |

Washington Gas Light Company
District of Columbia Jurisdiction

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 14

Adjustment BCO-14
Adjustment to Credit/Debit Card Fees
Test Year Ended March 31, 2024

| Ln | Description | |
|---|---|---|
| | A | B |
| 1 | **Adjustment BCO-14 - Credit/Debit Card Fees** | **$ -** |
| 2 | | |
| 3 | **Income Tax Impact:** | |
| 4 | OPC Adjustment to D.C. income tax expense | $ - |
| 5 | OPC Adjustment to Federal income tax expense | $ - |
| 6 | | |
| 7 | Note 1:  OPC does not propose any adjustments to WGL's | |
| 8 | proposed Credit/Debit card fees adjustment per the | |
| 9 | Direct Testimony of OPC Witness Dismukes. | |

Washington Gas Light Company
District of Columbia Jurisdiction

Adjustment BCO-15
True-Up Interest Synchonization
Test Year Ended March 31, 2024

Exhibit OPC (B)-5
Formal Case No. 1180
Direct Testimony of Bion Ostrander
Public Version
Schedule 15

| Line | Description | Amount |
|---|---|---|
| | A | B |
| | **Interest Synchronization:** | |
| 1 | WGL Interest on Debt | |
| 2 | OPC Proposed Interest on Debt | |
| 3 | OPC Adjustment - Revised Interest Synchronization | **$ -** |
| 4 | | |
| 5 | **Interest Synchronization Tax Impact:** | |
| 6 | OPC Adjustment to D.C. income tax expense | $ - |
| 7 | OPC Adjustment to Federal income tax expense | $ - |
| 8 | Total | **$ -** |
| 9 | | |
| 10 | | |

| Line | Description | WGL Interest Synchon. Adj. | OPC Interest Synchron. Adj. |
|---|---|---|---|
| 14 | A | B | C |
| 15 | **Interest on Total Debt** | | |
| 16 | Net Rate Base | | |
| 17 | | | |
| 18 | Weighted Average Cost of Debt | | |
| 19 | | | |
| 20 | Interest on Debt | $ - | $ - |
| 21 | | | |
| 22 | Per Books Interest Expense | | |
| 23 | | | |
| 24 | Adjustment to Interest Expense | $ - | $ - |
| 25 | | Note 1 | |
| 26 | **Income Tax Impact:** | | |
| 27 | OPC Adjustment to D.C. income tax expense | | $ - |
| 28 | OPC Adjustment to Federal income tax expense | | $ - |
| 29 | **Adjustment BCO-15 - Interest Synchronization Adjustment** | | **$ -** |
| 30 | | | |
| 31 | Note 1: | | |
| 32 | This adjustment will be trued-up in OPC Witness Ostrander's subsequent Surrebuttal Testimony. | | |

Exhibit OPC (B)-6
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-5

**Q.** **ALA and WGL Corporate Costs Charged to WGL.** Witness Block's Direct Testimony addresses ASUS Corporate Service Costs allocated to WGL at a high level. Also, in the prior rate case FC 1169, the OPC's data request 11-1 requested a side-by-side comparison of "ALA Allocated Corporate Costs" and "WG Corporate/Shared Service Costs" allocated/assigned to WGL (before allocation to the WGL-DC jurisdiction), and it appears that WGL provided this information for pre-merger prior years 2014 to 2016 and post-merger years 2019, 2020, and 2021, showing all allocated amounts by ALA Service Category/Functions (Accounting and Taxes, Finance, Human Resources, Legal, etc.) and WG Corporate/Shared Service Category/Functions (Corporate Communications, Chief Revenue Officer, Corporate Public Policy and some of the same ALA Service Categories). These allocated amounts were also shown by FERC account number (and account description) – all apparently provided in an Excel spreadsheet pivot table format. Address the following for the related test year end March 31, 2024 and prior calendar years 2019 to 2022:

a. Provide this same information described in the above preamble (provided by WGL to OPC in the prior rate case FC 1169 in OPC data request 11-1) showing ALA and WG Corporate/Shared costs (in separate side-by-side columns for each period/year) allocated/assigned to WGL by Service Category/Functions (Accounting and Taxes, Finance, Human Resources, Legal, Corporate Communications, Corporate Public Policy, etc. per the ASUS/WGL Centralized Service Agreement and the WGL Service Agreement), and in the same working Excel spreadsheet format - showing amounts by underlying FERC account number and description. However, provide this information for the test year end March 31, 2024, and prior calendar years 2019 to 2022.

b. Regarding (a) above, show all expenses by primary account number and reconcile to the related A&G expense account for the related year/periods.

c. Regarding (a) above, for each ALA and WG Allocated/Shared Corporate cost charged to WGL (in separate side-by-side columns for each of the related periods/years) for each of the Service Category/Functions (Accounting and Taxes, Finance, Corporate Communications, etc.), provide these expenses separately identified between the following (unless this detailed information has already been provided in the response to (a) above, showing amounts by FERC account):

   i) Labor/payroll expense and break out these labor expenses between compensation/salary, long-term incentives, short-term incentives, benefits (including Pension and OPEB), and payroll taxes.
   ii) Outside consulting/contracting services expense.
   iii) Depreciation expense.
   iv) Rent expense.
   v) Training expense.
   vi) Regulatory fees and assessments.
   vii) Charitable contributions expense.
   viii) Dues and subscriptions.
   ix) Lobbying expense.
   x) Insurance expense.
   xi) And all other "functional" accounts.

d. Regarding (a) above, for each ALA allocated expense by service Category/Function, explain the reason for annual changes in these amounts (for each of the calendar years 2019 to 2022, and for the test year end March 31, 2024) – for all annual changes in these expenses that equal or exceed $500,000 plus all other annual changes that equal to or exceed 10% (with a minimum annual change that equals or exceeds $250,000). Provide supporting documentation and calculations to support the annual changes described above.

e. Regarding (a) above, for each ALA and WG allocated service cost Category/Function (Accounting and Taxes, Finance, Corporate Communications, Corporate Public Policy, etc.), identify the type of allocation method (e.g., Modified Massachusetts Formula (MMF) or others) and the specific allocation factor percentage used to allocate these costs to WGL, and/or the primary cost pool used for allocating these expenses, the related allocation method, and the allocation factor percentage.

f. Regarding (a) above, for each ALA and WG Service Category/Function (Accounting and Taxes, Finance, Human Resources, Corporate Communications, etc.) for each of the periods requested (calendar years 2019 to 2022, plus test year end March 31, 2024), provide or explain as applicable, the factors that should be multiplied by the WGL amounts to arrive at the WGL-DC jurisdictional amount for each Service

Category/Function or if total ALA and WGL Service Category/Function expenses that are allocated to WGL are multiplied by an overall factor, such as the 19.5408% factor referenced in Witness Tuoriniemi's Direct Testimony (35:1-2) to determine the expenses allocated/assigned to WGL-DC (and if so, specify the overall factor). Provide all supporting documentation and calculations for the factors used to allocate/assign costs from WGL to WGL-DC for each of the related periods/years.

g. Regarding the ALA and WG Corporate allocated service costs by Service Category/Function for each of the periods, explain if any of these expenses have been offset by WGL expenses allocated or direct assigned to ALA or WGL, and if so, then provide the gross amounts before offsets and the related offset amount by affiliate (along with a description of the Service Category/Function of the offset amounts by FERC account number and description), and provide all supporting documentation and calculations.

h. Reconcile the ALA and WG Corporate allocated service costs provided with this data request to affiliate amounts for test year end March 31, 2024, at Witness Tuoriniemi's Direct Testimony (32:15 – 35:16) and to affiliate amounts at Witness Quenum's Confidential Exhibits WG (J)-3 and WG (J)-5 (ACOSS/study for test year end March 31, 2024).

i. Confirm that all ALA and WG Corporate allocated service costs are expenses or otherwise identify all capital costs that are converted to expenses (or allocated as capital cost amounts) and also allocated via ALA and WG Corporate service costs to WGL, and provide all supporting calculations to show the conversion of capital amounts to expense amounts for each of the related periods (by type of ALA and Corporate/Shared Service Category/Function).

**WASHINGTON GAS'S OBJECTION** 11/1/2024

Washington Gas objects to this request to the extent it requires a special study which the Company has not performed. Washington Gas files annual side-by side analyses pursuant to Formal Case No 1142, Order No. 19396, Appendix A, Commitment 26. To the extent studies have been prepared from 2018 to 2023, Washington Gas will provide those studies.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Please refer to the Commission website for Formal Case No. 1142. The side-by-side analyses filed for each of the years included in the Merger Commitment Matrix for Commitment 26 for all available periods.

https://dcpsc.org/FC1142AtlasGas-WGLMerger

CY2019 (Corrected)
https://edocket.dcpsc.org/public/search/details/fc1142/612

CY2020
https://edocket.dcpsc.org/public/search/details/fc1142/733

FY2021
https://edocket.dcpsc.org/public/search/details/fc1142/815

CY2022
https://edocket.dcpsc.org/public/search/details/fc1142/905

CY2023
https://edocket.dcpsc.org/public/search/details/fc1142/983

b. See part a.

c. ALA corporate costs are provided at the Service Category/Function level as agreed in service agreement PUR-2017-00177 and updated PUR-2023-00164.

ALA does not use the FERC chart of accounts.

d. 2019 vs 2020

Overall, the AltaGas corporate service costs allocated to Washington Gas in 2020 was $2.9 million higher than in 2019. Below is an explanation of change by group / functions:

- The $0.1 million increase in allocation of Board of directors cost from 2019 to 2020 was due to higher professional and consultant costs, partially offset by lower travel-related costs.
- During 2019, the charging of transitional services cost to TriSummit Utilities Inc.("TSU"), which acquired AltaGas' Canadian utilities business in 2018, reduced the allocation of Executive management cost in 2019. The transitional services to TSU ended in 2020, resulting in the $0.4 million increase in allocation of Executive management cost in 2020.
- The $2.4 million increase in allocation of Accounting & Tax cost from 2019 to 2020 was the result of severance incurred at ASUS during 2020, higher professional and consultant cost and higher salaries and wages incurred at ASUS.
- The $0.6 million increase in allocation of Legal & Compliance cost from 2019 to 2020 was due to higher environmental, health and safety compliance cost.

- The $0.3 million reduction in allocation of HR cost from 2019 to 2020 was due to lower severance payment incurred.
- The $0.3 million reduction in allocation of IT cost from 2019 to 2020 was due to lower employee costs. The contracting of IT maintenance and support services to third party vendors results in a reduction in the labor component of IT costs and a corresponding increase in the non-labor component of IT costs.
- The $0.1 million increase in allocation of Supply Chain cost from 2019 to 2020 was due to higher cost incurred for the subscription of reference materials.

<u>2020 vs 2021</u>
Overall, the AltaGas corporate service costs allocated to Washington Gas in 2021 was $0.6 million lower than in 2020. Below is an explanation of change by group / functions:

- The $0.1 million reduction in allocation of Board of directors cost from 2021 to 2020 was mainly due to lower professional and consultant costs.
- The $0.9 million increase in allocation of Executive management cost in 2021 from 2020 was the result of reclassification of costs incurred at ASUS from Accounting & Tax to Executive Management in 2021. Cost was reclassified to more appropriately reflect the nature of the costs. This increase in allocation of Executive management cost is offset by reduction in the allocation of Accounting & Tax cost, as described below.
- The $1.5 million reduction in allocation of Accounting & Tax cost from 2021 to 2020 was the result of the reclassification of costs incurred at ASUS from Accounting & Tax to Executive Management, lower professional and consulting costs, and partially offset by higher cost incurred for tax matters relating to ASUS.
- The $0.5 million increase in allocation of Finance cost in 2021 from 2020 was due to higher director and officer insurance (“D&O insurance”) cost, higher professional and consultant cost and allocation of charges from WGL
- The $0.8 million increase in allocation of Legal and Compliance cost in 2021 from 2020 was due to higher cost incurred for sustainability, corporate compliance and stakeholder relations.
- The $1.4 million reduction in allocation of HR costs in 2021 from 2020 was due to lower severance payment.
- The $0.1 million increase in allocation of Supply Chain cost in 2021 from 2020 was due to higher cost incurred for the subscription of reference materials.

<u>2021 vs 2022</u>
Overall, the AltaGas corporate service costs allocated to Washington Gas in 2022 was $1 million higher than in 2021. Below is an explanation of change by group / functions.

- The $0.4 million reduction in Accounting & Tax function from 2021 to 2022 was due to lower STIP expense.

- The $1.6 million increase in HR from 2021 to 2022 is due to STIP, SW&B, and severance (severance for all corporate functions are captured in HR to maintain confidentiality).
- The $0.8 million increase in IT from 2021 to 2022 is primarily due to increased salary and wages, contractors, and reference material costs.
- The $0.7 million reduction in Finance from 2021 to 2022 is primarily due to lower costs are Bank Service Costs and Contract Software Maintenance.

<u>2022 vs 2023</u>
Overall, the AltaGas corporate service costs allocated to Washington Gas in 2023 was $6.3 million higher than in 2022. Below is an explanation of change by group / functions

- The $1.9 million increase for Accounting & Tax function is primarily due to the shift of corporate risk services from Legal to Accounting & Tax as well as increased salary and wages, audit fees, and tax consulting.
- The $0.7 million increase for Board of Directors from 2022 to 2023 is primarily due to executive restructuring costs.
- The $0.8 million increase in Executive Management from 2022 to 2023. This is due to increase in executive restructuring and shareholder communication partially offset by compensation costs.
- The $0.2 million increase in HR from 2022 to 2023 is due to increased consulting and labor costs partially offset by reduced corporate severance.
- The $2.2 million increase in IT from 2022 to 2023 is primarily from Salaries & Wages, cloud related services and contractor costs.
- The $0.3 million increase in Legal, Compliance, & EHS from 2022 to 2023 is due to higher general legal, consulting, and filing costs.
- The $0.1 million increase in Supply Chain function is due to higher Salary & Wages partially offset by lower contractor and reference material costs.

e. Eligible corporate costs are allocated using the MMF method. The calculation for this percentage allocation is explained in response 4-7-e and 4-7-f. This percentage is used for all categories of allocable costs.

f. Please refer to WGL's response for OPC DR 4-10.a, which is for the allocation of ALA corporate shared costs to WGL.

g. WGL expenses allocated or direct assigned to ALA are not offset.

h. Please refer to WGL's response to OPC DR 3-3.

i. No capital costs are included in ALA corporate allocation.

Washington Gas
(Part a. b. and g. and h.)
SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

AltaGas
(Parts c.-f. and i.)
SPONSOR: Eric Block
Vice President and Controller

Exhibit OPC (B)-7
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-7

**Q.** **Allocations from AltaGas to ASUS and Canadian Businesses.** Witness Block's Direct Testimony states (13:19-14:5) that AltaGas (after applying the exclusion of certain corporate costs) allocates Corporate Service costs (as one pool) to: 1) ASUS (the holding company of AltaGas's U.S. business) using the AltaGas MMF factor; and 2) AltaGas's Canadian businesses using the AltaGas MMF factor. Address the following regarding allocations from AltaGas to ASUS and its Canadian businesses using the MMF for the test year end March 31, 2024, and prior calendar years 2019 to 2023.

a. Using a top-down approach, provide: (1) the total amount of AltaGas expenses subject to being allocated to ASUS and Canadian businesses; (2) the amount of corporate costs that are excluded from any subsequent allocation to ASUS and Canadian businesses; and (3) the net amount of AltaGas expenses to be allocated to ASUS and Canadian businesses for the test year end March 31, 2024, and prior calendar years 2019 to 2023 – show all expenses in the three categories above (total, exclusions, and net) by account number and account description, including all applicable expense Categories/Functions from the ASUS/WGL Centralized Corporate Service Agreement for expense categories such as Board of Directors, Accounting and Tax, Legal, Compliance, etc. Also, show all expenses by labor and non-labor components.

b. Regarding (a) above, reconcile these expense amounts that are subject to allocation to ASUS and AltaGas Canadian businesses (and the amounts excluded from allocation) to the AltaGas Annual Report for each of the calendar years 2019 to 2023.

c. Regarding (a) above, explain why these three categories of expenses ((1) total amount of AltaGas expenses subject to being allocated to ASUS and Canadian businesses; (2) amount of corporate costs that are excluded from any subsequent allocation to ASUS and Canadian businesses; and (3) net amount of AltaGas expenses to be allocated to ASUS and Canadian

Page **2** of **11**

businesses) vary from year-to-year for the prior calendar years 2019 to 2023 and for test year end March 31, 2024, and provide all supporting documentation and calculations to support these fluctuating expense levels.

d. Explain how the category of "corporate costs that are excluded from any subsequent allocation" is determined and identify the criteria that are used to determine those costs that will not be allocated to ASUS and AltaGas Canadian businesses (and identify the related account numbers and names).

e. Explain why AltaGas uses only one common cost pool that it allocates using a single allocation method (MMF factor) for purposes of allocating AltaGas expenses to ASUS and Canadian affiliates. Explain why different types of AltaGas expenses are not allocated using different types of allocation methods besides the MMF method.

f. Provide the amount and percent of AltaGas expenses allocated to each U.S. affiliate and each Canadian affiliate using the MMF factor (and identify the three allocation factor drivers/bases for allocating) for calendar years 2019 to 2023 and test year end March 31, 2024.

g. Provide the MMF factor percentages (and underlying calculations for the different cost-allocator bases of earnings before interest, tax and depreciation (EBITDA), relative payroll costs, and relative property – along with the averaging of these factors) used to allocate AltaGas expenses to: 1) ASUS; and 2) Canadian affiliates for the calendar years 2019 to 2023, and test year end March 31, 2024 - and explain the reasons for changes in these allocation factor percentages for each of these periods.

h. Regarding (g) above, provide the numerator and denominator of each MMF allocation factor for each affiliate (along with the total MMF allocation factor used for all affiliates subject to allocation), and the underlying financial amounts for each of the three allocator-bases (EBITDA, relative payroll costs, and relative property), that are used to allocate expenses to: 1) ASUS (and each U.S. company in ASUS); and to 2) Canadian affiliates (and each Canadian business/affiliate) for the calendar years 2019 to 2023, and test year end March 31, 2024. Provide all supporting documentation and calculations for all MMF allocation factor calculations, including summary financial data for each U.S. and Canadian affiliate to which expenses are allocated using the MMF.

i. Regarding (g) and (h) above, translate the above MMF allocation factor information to the quarterly MMF factors calculation used for allocating expenses (Witness Quenum, 9:8-9). Explain the period of data to which any MMF allocation factor component is applied, including if it is used in arrears. For example, explain if the MMF allocation factors used for the March 31,

Page **3** of **11**

2024, test period are all based on financial inputs/data ending March 31, 2024, or if the factors are a combination of actual and historical (or projected data) inputs/data, such as using actual information for April 2023 to December 31, 2023 and using estimated or historical data in place of actual March 31, 2024 actual data.

j. Regarding (g) and (h) above, provide the names of each of the U.S. and Canadian businesses to which AltaGas expenses are allocated using the MMF, and provide the following:

(i) A general description of each affiliate's type of business that is conducted with AltaGas affiliates and with non-affiliate third parties – and state the reason for the existence of the business.
(ii) Identify the year when each affiliate was created and if it has operated as a going concern for all years through test year end March 31, 2024.
(iii) Explain if each affiliate is a profit center for AltaGas, or otherwise explain the purposes of the affiliate if not for generating profits for AltaGas.
(iv) Explain if each affiliate is any of the following: a "capital intensive" business with substantial fixed plant investment on the balance sheet that is used to provide services and generate revenues; a "service-providing" company that is not capital intensive; or a mix of capital intensive and service-related. Explain the basis and provide supporting documentation for your response.
(v) Identify each affiliate that has and has not generated a profit for each year (calendar years 2019 to 2023 and test year end March 31, 2024).

k. Explain if and why the MMF cost allocator bases of: 1) EBITDA; 2) relative payroll costs; and 3) relative property are the most reasonable and appropriate allocation factors to use for each of the U.S. and Canadian affiliates.

l. Identify all U.S. and Canadian affiliates/businesses that do not receive an allocation of expenses from AltaGas for each of the periods (calendar years 2019 to 2023, and test year end March 2024) and explain why this is the case. Provide supporting documentation for your response.

**WASHINGTON GAS'S OBJECTION** 11/1/2024

Washington Gas objects to this request on relevance grounds, as it relates to excluded costs that are not recovered in rates.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Below is a walk from readily available total gross corporate costs (see reconciliation to annual financial statements in DR 4-7-b) to ASUS allocation:

| Gross Corporate Costs $CAD | 2019 | 2020 | 2021 | 2022 | 2023 | Q1, 2024 | Q2, 2023 → Q1, 2024 |
|---|---|---|---|---|---|---|---|
| Accounting & Tax | $ 11,467,143 | $ 10,132,257 | $ 12,077,249 | $ 13,170,619 | $ 13,675,063 | $ 4,123,168 | $ 14,379,751 |
| Board of Directors | $ 1,802,378 | $ 1,862,994 | $ 1,684,040 | $ 1,771,147 | $ 3,165,071 | $ 275,247 | $ 2,160,009 |
| HR | $ 36,354,022 | $ 24,067,544 | $ 38,585,627 | $ 35,473,365 | $ 42,651,007 | $ 21,657,422 | $ 54,980,016 |
| IT | $ 31,830,430 | $ 33,080,418 | $ 34,954,986 | $ 35,887,298 | $ 34,454,690 | $ 8,101,995 | $ 34,201,469 |
| Legal, Compliance & EHS | $ 7,528,535 | $ 7,701,258 | $ 10,295,360 | $ 11,704,703 | $ 13,877,547 | $ 3,899,354 | $ 14,379,365 |
| Supply Chain | $ 2,105,951 | $ 2,646,665 | $ 3,151,979 | $ 3,109,715 | $ 3,048,339 | $ 770,000 | $ 3,027,979 |
| Other | $ 2,349,729 | $ 7,388,533 | $ 3,557,624 | $ 4,060,061 | $ 5,029,989 | $ 2,712,969 | $ 7,057,557 |
| Executive Management | $ 9,381,129 | $ 9,077,676 | $ 26,157,965 | $ 18,248,750 | $ 16,279,322 | $ 5,609,624 | $ 17,044,476 |
| Finance | $ 7,543,162 | $ 5,969,556 | $ 7,159,312 | $ 7,096,985 | $ 17,468,909 | $ 2,738,683 | $ 6,292,078 |
| **Grand Total** | **$ 110,362,481** | **$ 101,926,902** | **$ 137,624,142** | **$ 130,522,645** | **$ 149,649,938** | **$ 49,888,463** | **$ 153,522,700** |

| Less: Exclusions $CAD | 2019 | 2020 | 2021 | 2022 | 2023 | Q1, 2024 | Q2, 2023 → Q1, 2024 |
|---|---|---|---|---|---|---|---|
| Accounting & Tax | $ (2,184,636) | $ 3,976,282 | $ (1,496,114) | $ (2,510,733) | $ (2,866,198) | $ (933,707) | $ (3,489,035) |
| Board of Directors | $ (145,390) | $ (215,459) | $ (239,952) | $ (93,759) | $ (101,229) | $ - | $ (65,802) |
| HR | $ (28,059,555) | $ (17,503,136) | $ (35,154,912) | $ (27,865,867) | $ (35,485,088) | $ (17,998,769) | $ (46,133,694) |
| IT | $ (19,952,658) | $ (21,504,254) | $ (23,478,362) | $ (20,781,557) | $ (16,290,140) | $ (3,352,200) | $ (15,466,897) |
| Legal, Compliance & EHS | $ (94,335) | $ (261,943) | $ (107,348) | $ (97,857) | $ (1,535,611) | $ (731,361) | $ (1,997,241) |
| Supply Chain | $ (1,361,648) | $ (1,773,195) | $ (2,074,820) | $ (2,294,407) | $ (2,182,585) | $ (398,262) | $ (2,589,568) |
| Other | $ (2,349,729) | $ (7,388,533) | $ (3,557,624) | $ (4,060,061) | $ (5,029,989) | $ (2,712,969) | $ (7,057,557) |
| Executive Management | $ (5,417,339) | $ (4,439,242) | $ (18,874,945) | $ (9,792,091) | $ (8,380,858) | $ (2,794,274) | $ (8,430,906) |
| Finance | $ (1,419,191) | $ (1,234,424) | $ (657,419) | $ (1,242,435) | $ (13,166,344) | $ (1,206,026) | $ (1,893,136) |
| **Grand Total** | **$ (60,984,481)** | **$ (50,343,903)** | **$ (85,641,497)** | **$ (68,738,766)** | **$ (85,038,041)** | **$ (30,127,567)** | **$ (87,123,836)** |

| Regulatory Cost Pool $CAD | 2019 | 2020 | 2021 | 2022 | 2023 | Q1, 2024 | Q2, 2023 → Q1, 2024 |
|---|---|---|---|---|---|---|---|
| Accounting & Tax | $ 9,282,507 | $ 14,108,539 | $ 10,581,134 | $ 10,659,886 | $ 10,808,865 | $ 3,189,461 | $ 10,890,717 |
| Board of Directors | $ 1,656,989 | $ 1,647,535 | $ 1,444,087 | $ 1,677,389 | $ 3,063,843 | $ 275,247 | $ 2,094,207 |
| HR | $ 8,294,467 | $ 6,564,408 | $ 3,430,715 | $ 7,607,498 | $ 7,165,919 | $ 3,658,653 | $ 8,846,322 |
| IT | $ 11,877,773 | $ 11,576,165 | $ 11,476,624 | $ 15,105,741 | $ 18,164,550 | $ 4,749,795 | $ 18,734,572 |
| Legal, Compliance & EHS | $ 7,434,200 | $ 7,439,315 | $ 10,188,011 | $ 11,606,847 | $ 12,341,937 | $ 3,167,993 | $ 12,382,124 |
| Supply Chain | $ 744,303 | $ 873,471 | $ 1,077,160 | $ 815,308 | $ 865,754 | $ 371,739 | $ 438,411 |
| Other | | | $ - | $ - | $ - | $ - | $ - |
| Executive Management | $ 3,963,790 | $ 4,638,434 | $ 7,283,020 | $ 8,456,660 | $ 7,898,465 | $ 2,815,350 | $ 8,613,570 |
| Finance | $ 6,123,972 | $ 4,735,133 | $ 6,501,893 | $ 5,854,550 | $ 4,302,565 | $ 1,532,658 | $ 4,398,942 |
| **Grand Total** | **$ 49,378,000** | **$ 51,582,998** | **$ 51,982,645** | **$ 61,783,879** | **$ 64,611,897** | **$ 19,760,896** | **$ 66,398,864** |

| Less: Midstream Allocation $CAD | 2019 | 2020 | 2021 | 2022 | 2023 | Q1, 2024 | Q2, 2023 → Q1, 2024 |
|---|---|---|---|---|---|---|---|
| Accounting & Tax | $ (1,625,897) | $ (3,237,844) | $ (3,365,755) | $ (3,337,727) | $ (3,243,194) | $ (1,039,459) | $ (3,362,927) |
| Board of Directors | $ (290,233) | $ (375,712) | $ (459,746) | $ (519,808) | $ (917,215) | $ (89,704) | $ (638,484) |
| HR | $ (1,452,835) | $ (1,523,956) | $ (1,091,070) | $ (2,350,754) | $ (2,150,601) | $ (1,192,370) | $ (2,757,490) |
| IT | $ (2,080,476) | $ (2,667,841) | $ (3,651,851) | $ (4,758,064) | $ (5,456,249) | $ (1,547,978) | $ (5,767,185) |
| Legal, Compliance & EHS | $ (1,302,153) | $ (1,707,447) | $ (3,243,283) | $ (3,621,361) | $ (3,705,606) | $ (1,032,462) | $ (3,812,365) |
| Supply Chain | $ (130,370) | $ (198,983) | $ (342,676) | $ (253,902) | $ (256,611) | $ (121,151) | $ (141,266) |
| Other | $- | $- | $ - | $ - | $ - | $ - | $ - |
| Executive Management | $ (694,286) | $ (1,080,181) | $ (2,315,275) | $ (2,676,044) | $ (2,370,909) | $ (917,534) | $ (2,666,857) |
| Finance | $ (1,072,657) | $ (1,090,965) | $ (2,068,847) | $ (1,857,971) | $ (1,289,838) | $ (499,499) | $ (1,364,258) |
| **Grand Total** | **$ (8,648,909)** | **$ (11,882,929)** | **$ (16,538,503)** | **$ (19,375,631)** | **$ (19,390,223)** | **$ (6,440,158)** | **$ (20,510,832)** |

| ASUS Allocation $CAD | 2019 | 2020 | 2021 | 2022 | 2023 | Q1, 2024 | Q2, 2023 → Q1, 2024 |
|---|---|---|---|---|---|---|---|
| Accounting & Tax | $ 7,656,610 | $ 10,870,695 | $ 7,215,379 | $ 7,322,159 | $ 7,565,671 | $ 2,150,003 | $ 7,527,789 |
| Board of Directors | $ 1,366,755 | $ 1,271,823 | $ 984,341 | $ 1,157,581 | $ 2,146,628 | $ 185,543 | $ 1,455,722 |
| HR | $ 6,841,632 | $ 5,040,452 | $ 2,339,644 | $ 5,256,743 | $ 5,015,318 | $ 2,466,283 | $ 6,088,832 |
| IT | $ 9,797,296 | $ 8,908,323 | $ 7,824,773 | $ 10,347,678 | $ 12,708,301 | $ 3,201,817 | $ 12,967,387 |
| Legal, Compliance & EHS | $ 6,132,047 | $ 5,731,868 | $ 6,944,729 | $ 7,985,486 | $ 8,636,331 | $ 2,135,531 | $ 8,569,758 |
| Supply Chain | $ 613,933 | $ 674,488 | $ 734,484 | $ 561,406 | $ 609,143 | $ 250,587 | $ 297,145 |
| Other | $- | $- | $ - | $ - | $ - | $ - | $ - |
| Executive Management | $ 3,269,504 | $ 3,558,253 | $ 4,967,745 | $ 5,780,616 | $ 5,527,555 | $ 1,897,816 | $ 5,946,713 |
| Finance | $ 5,051,314 | $ 3,644,168 | $ 4,433,046 | $ 3,996,580 | $ 3,012,727 | $ 1,033,158 | $ 3,034,685 |
| Grand Total | $ 40,729,091 | $ 39,700,069 | $ 35,444,141 | $ 42,408,248 | $ 45,221,674 | $ 13,320,738 | $ 45,888,031 |

b. The table below reconciles gross corporate costs (before reductions and exclusions – see response to DR 4-7-a) to reported operating and administrative costs reported on annual financial statements.

Page 5 of 11

| Gross Corporate Costs Reconciliation to Annual Financial Statements ($CAD 000's) | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| Operating and administrative reported on annual financial statements | (126,395) | (71,285) | (94,532) | (83,788) | (96,454) |
| Less: Power and non-G&A items | 85,903 | 39,974 | 25,645 | 23,074 | 25,425 |
| Administrative & General | (40,491) | (31,310) | (68,888) | (60,714) | (71,029) |
| | | | | | |
| Add: Allocation and recovery exclusions | (57,889) | (57,205) | (55,188) | (58,101) | (70,387) |
| Add: DD&A | (11,982) | (13,412) | (13,548) | (11,709) | (8,225) |
| Other: | - | - | - | 1 | (9) |
| Gross Corporate Costs | (110,362) | (101,927) | (137,624) | (130,523) | (149,650) |

c. Key variances from 2019 to 2020 are as follows:

- Total corporate cost pool (gross) decreased by $8.4 million from 2019 to 2020 due to reduction in Short-Term Incentive ("STI") and Long-Term Incentive ("LTI") partially offset by increases in other direct charges from Utilities.
- Exclusions decreased by $10.6 million from 2019 to 2020 primarily due to reduced Long-Term Incentive expenses.
- Regulatory pool (net) increased by $2.2 million from 2019 to 2020 due to higher severance, professional and consulting.

Key variances from 2020 to 2021 are as follows:

- Total corporate cost pool (gross) increased by $35.7 million from 2020 to 2021 primarily due to Long-Term Incentive expenses.
- Exclusions increased by $35.3 million from 2020 to 2021 due to Increased Long-Term Incentive expenses.
- Regulatory pool (net) increased by $0.4 million from 2020 to 2021 due to director & officer insurance and direct charges from the utility partially offset by lower severance.

Key variances from 2021 to 2022 are as follows:

- Total corporate cost pool (gross) decreased by $7.1 million from 2021 to 2022 primarily due to reductions in Executive Management expenses (severance, STI, LTI)
- Exclusions increased by $16.9 million from 2021 to 2022 due to increased LTI, Airfare and Deferred Share Units ("DSU") expenses.
- Regulatory pool (net) increased by $9.8 million from 2021 to 2022 due to increased salaries and contractor expenses in IT and STI.

Key variances from 2022 to 2023 are as follows:

- Total corporate cost pool (gross) increased by $19.1 million from 2022 to 2023 primarily due to LTI, DSU, SERP, Cloud Services and Consulting.
- Exclusions increased by $16.3 million from 2022 to 2023 primarily due to increased LTI, DSU and SERP.
- Regulatory pool (net) increased by $2.8 million from 2022 to 2023 primarily due to increased Cloud Services and Consulting.

Key variances from 2023 to test year ended March 31, 2024 (Q1 2023 vs Q1 2024) are as follows:

- Total corporate cost pool (gross) increased by $3.9 million from 2023 to 2024 due to LTI and increased cloud computing expenses.

Page **6** of **11**

- Exclusions increased by $2.1 million from 2023 to 2024 primarily due to LTI expense.
- Regulatory pool (net) increased by $1.8 million from 2023 to 2024 primarily due to increased cloud computing expenses.

d. The inclusion of corporate costs are reviewed each budget cycle to determine if they provide benefits to all operating businesses and must have the following characteristics:

- Strategic in nature
- Focused on business oversight
- Development and exercise of corporate governance and stewardship
- Ensuring businesses have appropriate access to capital

Costs that do not meet the above criteria are excluded from eligibility in the MMF. Accounts that have been excluded from the allocable cost pool for regulatory purposes include the following:

- 70135 - Long Term Incentive Plan
- 70136 - Deferred Share Units Plan
- 70150 - Stock Options
- 70155 - Vehicle Allowance
- 70172 - Supplemental Exec Retire Plan
- 70325 - Vehicle Lease - Tax Deductible
- 70335 - Vehicle Operating Expense
- 70345 - Vehicle License & Registration
- 70551 - Charter Flights
- 70590 - Social Events
- 70590.100 - Christmas Party
- 70595 - Employee Recognition
- 70740 - Advertising
- 70925 - Non-Deductible Dues and Fees
- 70930 - Promotional Goods
- 70935 - Customer Events
- 70940 - Tradeshows and Conferences
- 70945 - Charity Events
- 70950 - Charitable Donations
- 70955 - Donations - Non-Receipt

e. AltaGas uses one common cost pool and a single allocation method for accounting efficiency. Different types of expenses are not allocated using different allocation methods as it would be unduly burdensome. The existing factors used in the allocation calculation are acceptable proxies of overall business activity levels as pointed out in response to FC 1180 DR 4-15-a, f-h.

f. For amount and percent of AltaGas expenses allocated to Canadian Affiliates and ASUS, please refer to WGL's response in 4-7.a above; for amount and percent

Page **7** of **11**

of AltaGas expenses allocated to each US Affiliate, please refer to WGL's responses in OPC DR 4-8.a and OPC DR 4-10.a.

g.

| Millions of $ CAD | 2019 | | | | 2020 | | | | 2021 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Factor | Mid | Power | ASUS | Total | Mid | Power | ASUS | Total | Mid | Power | ASUS | Total |
| Property | 2,292 | 88 | 8,674 | 11,054 | 2,742 | - | 7,719 | 10,461 | 3,949 | - | 7,888 | 11,837 |
| | *20.74%* | *0.80%* | *78.47%* | *100.00%* | *26.21%* | *0.00%* | *73.79%* | *100.00%* | *33.36%* | *0.00%* | *66.64%* | *100.00%* |
| Payroll | 44 | 1 | 376 | 420 | 59 | 3 | 318 | 380 | 96 | - | 292 | 388 |
| | *10.36%* | *0.30%* | *89.34%* | *100.00%* | *15.65%* | *0.69%* | *83.66%* | *100.00%* | *24.73%* | *0.00%* | *75.27%* | *100.00%* |
| EBITDA | 220 | 12 | 843 | 1,075 | 407 | 2 | 913 | 1,322 | 533 | 2 | 897 | 1,432 |
| | *20.48%* | *1.14%* | *78.38%* | *100.00%* | *30.79%* | *0.13%* | *69.08%* | *100.00%* | *37.24%* | *0.12%* | *62.64%* | *100.00%* |
| Average | 17.19% | 0.75% | 82.06% | 100.00% | 24.22% | 0.27% | 75.51% | 100.00% | 31.78% | 0.04% | 68.18% | 100.00% |

| Millions of $ CAD | 2022 | | | | 2023 | | | | 2024 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Factor | Mid | Power | ASUS | Total | Mid | Power | ASUS | Total | Mid | Power | ASUS | Total |
| Property | 3,405 | - | 8,334 | 11,739 | 3,299 | - | 9,354 | 12,653 | 3,987 | - | 9,580 | 13,567 |
| | *29.01%* | *0.00%* | *70.99%* | *100.00%* | *26.07%* | *0.00%* | *73.93%* | *100.00%* | *29.39%* | *0.00%* | *70.61%* | *100.00%* |
| Payroll | 69 | - | 298 | 367 | 82 | - | 261 | 343 | 110 | - | 284 | 394 |
| | *18.86%* | *0.00%* | *81.14%* | *100.00%* | *23.91%* | *0.00%* | *76.09%* | *100.00%* | *27.92%* | *0.00%* | *72.08%* | *100.00%* |
| EBITDA | 619 | - | 795 | 1,414 | 614 | - | 902 | 1,516 | 649 | - | 956 | 1,605 |
| | *43.78%* | *0.00%* | *56.22%* | *100.00%* | *40.50%* | *0.00%* | *59.50%* | *100.00%* | *40.44%* | *0.00%* | *59.56%* | *100.00%* |
| Average | 30.55% | 0.00% | 69.45% | 100.00% | 30.16% | 0.00% | 69.84% | 100.00% | 32.58% | 0.00% | 67.42% | 100.00% |

Key variances from 2019 to 2020 are as follows:

- Midstream increase due to increased Payroll costs associated with asset investment driving additional earnings.
- Power decrease due to disposal of power assets in Canada operations resulting in lower EBITDA
- ASUS decrease due to decreased payroll in ASUS associated with asset disposals and increased EBITDA

Key variances from 2020 to 2021 are as follows:

- Midstream increase due to acquisition of PetroGas assets resulting in increased asset base, payroll and EBITDA
- Power decrease due to lower proportion of overall total of all factors
- ASUS decrease due to reduced relative share of overall assets, decreased payroll and reduced EBITDA

Key variances from 2021 to 2022 are as follows:

- Midstream decrease due to adjustment to acquired PetroGas assets resulting in decreased property and payroll factors.
- ASUS increase due to increased capital deployed in Utilities and increased payroll costs

Key variances from 2022 to 2023 are as follows:

- Midstream decrease due to disposal of Aiken assets
- ASUS increase due to increased capital deployed in utilities and $US exchange rate

Page **8** of **11**

Key variances from 2023 to 2024 are as follows:

- Midstream increase due to Pipestone acquisition and associated payroll increases
- ASUS Decrease due to ENSTAR sale in 2023 and higher capital deployed to Midstream vs Utilities

h. The table provided in response to DR 4-7-g provides the allocator factors used to determine the percentage of costs for ASUS and Midstream. Midstream receives its allocation into general operating expenses and a breakdown of each U.S company in ASUS is provided in response to DR 4-7-f.

i. The MMF allocator is calculated annually in arrears using prior year financial data. The factor is applied consistently each quarter and not recalculated unless a material acquisition or divestiture occurs.

j. (i.) See below from the 2023 Annual Information Form ("AIF") page 6. A further listing of midstream businesses can be found in the AIF pages 26-44 [https://www.altagas.ca/invest/financials] for convenience I have provided below:

AltaGas is a leading North American energy infrastructure company that connects customers and markets to affordable and reliable sources of energy. The Company operates a diversified, lower-risk, high-growth energy infrastructure business that is focused on delivering resilient and durable value for its stakeholders.

AltaGas' operating segments include the following:
▪ Utilities, which owns and operates franchised, cost-of-service, rate regulated natural gas distribution and storage utilities that focus on providing safe, reliable, and affordable energy to approximately 1.6 million residential and commercial customers. This includes operating two utilities that operate across four major U.S. jurisdictions with a rate base of approximately US$5.1 billion. The Utilities business also includes storage facilities and contracts for interstate natural gas transportation and storage services, as well as WGL Energy Services, an affiliated retail energy marketing business, which sells natural gas and electricity directly to residential, commercial, and industrial customers located in Maryland, Virginia, Delaware, Pennsylvania, Ohio, and the District of Columbia; and

▪ Midstream, which is a leading North American platform that connects customers and markets from wellhead to tidewater. The three pillars of the Midstream business include:
1) global exports, which includes AltaGas' two operational LPG export terminals and one prospective development terminal
2) natural gas gathering, processing, and extraction
3) fractionation and liquids handling. AltaGas' Midstream segment also includes its natural gas and NGL marketing businesses, domestic logistics, trucking and rail terminals, and liquid and natural gas storage capability.

Page **9** of **11**

- AltaGas' Corporate/Other segment consists of the Company's corporate activities and a small portfolio of gas-fired power generation and distribution assets capable of generating 508 MW of power primarily in California.

(ii.) Midstream has existed in AltaGas since the creation of the company. It has operated as a going concern since inception. The following description of the Midstream business is taken from the Annual Information Form ("AIF") for the year ended December 31, 2023:

AltaGas' Midstream segment is a leading North American platform that connects customers and markets. From wellhead to tidewater, the Company is focused on providing its customers with safe and reliable service and connectivity that facilitates the best outcomes for their businesses. This includes global market access for North American LPGs, which provides North American producers and aggregators with attractive netbacks for propane and butane while delivering diversity of supply and supporting stronger energy security in Asia to AltaGas' downstream customers. Throughout AltaGas' Midstream operations, the Company is playing a vital role within the larger energy ecosystem that keeps the global economy moving forward in a safe, reliable, and affordable manner.

AltaGas' Midstream platform is heavily focused on the Montney and Deep Basin resource plays and centers around global exports, which is where the Company believes the market is headed for Canadian resource development over the Longterm. AltaGas also operates a broader set of midstream infrastructure assets across the WCSB and select regions in the U.S., which are all focused on connecting customers and markets in the most efficient manner possible. There are three core pillars to AltaGas' Midstream platform that are integral to each other and facilitate the Company's wellhead to tidewater value chain. These include:Global Exports, which includes AltaGas' two operational LPG export terminals where the Company has capacity to export up to 150,000 Bbl/d of propane and butane to key markets in Asia; Natural Gas Gathering, Processing and Extraction, which includes 1.2 Bcf/d of extraction processing capacity and approximately 1.2 Bcf/d of raw field gas processing capacity, which is heavily focused on the Montney and Deep Basin; and Fractionation and Liquids Handling, which includes 85 MBbl/d of fractionation capacity and a sizable liquid handling footprint.

(iii.) Each affiliate described above is a profit center for AltaGas.

(iv.) Each affiliate is capital intensive as evidenced in the Property factor of the allocator calculation as shown in response to DR 4-7-g. The equal weighting of 33% to capital intensive (property factor) and 33% to labour (payroll factor) are designed to ensure both "service-providing" and "capital intensive" companies receive a fair allocation.

(v.) Affiliates have been profitable over the stated periods.

k) The factors used to determine the three-part factor for allocation of corporate costs are reasonable. All three are measures of business activity, and that is the point of the three-part or Modified Massachusetts Method (MMF). A three-part factor is used as the cost drivers are not easily identified or tracked. A three-part factor will allocate costs based on business activity versus an identified and tracked cost driver. Please also reference the Company's response to Question 15, subpart a of this data request set.

l) There are no businesses or affiliates that do not receive an allocation of expenses from AltaGas for the stated periods, all operating entities receive an allocation.

SPONSOR: Eric Block
Vice President and Controller

**OPC FOLLOW-UP REQUEST** **11/22/2024**

**Q.** In the portion of the table that WGL provides in response to OPC 4-7(a) labeled "ASUS Allocation $CAD" WGL shows the amount of AltaGas expenses allocated to ASUS (after deduction of "exclusions" and the "Midstream allocation"), with ASUS test year end March 31, 2024, allocated expenses of $45.90M, 2023 of $45.20M, 2022 of $42.40M, 2021 of $35.40M, 2020 of $39.70M, and 2019 of $40.70M. It is not clear if any WGL response to other OPC data requests in the Fourth Series provides a reconciliation from the ASUS amounts above (for years 2019 to 2023 and test year end March 31, 2024) to the amounts allocated to WGL and each U.S. affiliate. Please address the following:

a. Regarding the expenses allocated from AltaGas to ASUS in the table above ((after deduction of "exclusions" and the "Midstream allocation") for the years 2019 to 2023, and test year end March 31, 2024, reconcile these expenses for each year/period to expenses allocated from ASUS to WGL and U.S. affiliates at OPC Data Request Nos. 4-5, 4-8, 4-10 and all other data requests in the Fourth Series of data requests. If no reconciling information has been previously cited in Data Request Nos. 4-5, 4-8, 4-10, then provide a reconciliation beginning with the ASUS amounts in the table above (such as $45.90M for test year March 31, 2024, $45.20M for 2023, etc.) and show the portion of these amounts allocated to WGL and each U.S. affiliate for the related years/periods. Also explain where the remaining ASUS expenses in the above table are allocated (such as to Canadian affiliates or to other entities) and identify these affiliates and entities for each of the years/periods. Provide all supporting documentation and calculations associated with the response.

**WASHINGTON GAS' FOLLOW-UP RESPONSE 12/02/2024**

**A.**

a. See the table below.

| Reconciliation of ASUS Allocation CAD Actuals to ASUS Allocation USD Accounting Entries Amount | | | | | | |
|---|---|---|---|---|---|---|
| | **2019** | **2020** | **2021** | **2022** | **2023** | **Q2, 2023 → Q1, 2024** |
| ASUS Allocation CAD Yearly Actuals<br>*See reference table in response to OPC 4-7(a)* | **$ 40,729,091** | **$ 39,700,069** | **$ 35,444,141** | **$ 42,408,248** | **$ 45,221,674** | **$ 45,888,031** |
| Adjusted for Invoice timing (quarterly lag of true-up invoice) (CAD) | $ 810,265 | $ 1,802,587 | $ (274,322) | $ (4,122,947) | $ 2,922,118 | $ (2,433,238) |
| ASUS Allocation CAD Yearly Actuals Adjusted for timing | **$ 41,539,356** | **$ 41,502,656** | **$ 35,169,820** | **$ 38,285,301** | **$ 48,143,792** | **$ 43,454,793** |
| Adjusted Amount translated to USD | **$ 32,254,199** | **$ 30,432,322** | **$ 28,673,587** | **$ 29,424,170** | **$ 35,529,166** | **$ 33,442,392** |
| **Add Back** | | | | | | |
| Cost-To-Achieve (IT) (USD) | $ 2,246,892 | $ 936,381 | $ 646,228 | $ 107,965 | $ - | $ - |
| Cross-border Markup (USD) | $ 1,101,815 | $ 1,395,739 | $ 1,759,189 | $ 1,771,928 | $ 2,131,750 | $ 2,006,544 |
| **Accounting entry (USD)** | **$ 35,602,907** | **$ 32,764,442** | **$ 31,079,004** | **$ 31,304,063** | **$ 37,660,916** | **$ 35,448,935** |

SPONSOR: Eric Block,
Vice President and Controller

Exhibit OPC (B)-8
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-8

**Q.** **Allocations from ASUS to WGL.** Witness Block's Direct Testimony states (14:10-11) that AltaGas allocates Corporate Service costs to ASUS and AltaGas Canadian affiliates, and the ASUS costs are then allocated to U.S. affiliates. Address the following regarding allocations from ASUS to WGL and U.S. affiliates using the MMF and other allocation factors for the test year end March 31, 2024, and prior calendar years 2019 to 2023:

a. Provide the amount and percent of expenses by type of ALA Corporate expense (e.g., Executive Management, Finance, Accounting and Tax, etc.) allocated from ASUS to WGL and each U.S. affiliate for each type of allocation factor method (including MMF and other methods) for calendar years 2019 to 2023, and test year end March 31, 2024.

b. Regarding (a) above, if the amount and percent of expense allocated to WGL and each U.S. affiliate for each type of allocation factor method (including MMF and other allocation methods, including those identified at Witness Quenum's testimony at 9:6-16) cannot be provided by "type of ALA Corporate expense" (Finance, Accounting and Tax, etc.), then provide the amount and percent allocated to WGL and each U.S. affiliate by each type of "cost pool" for each type of allocation factor method – and describe and identify the costs included in each cost pool. This should include (but not be limited to), cost pool allocation calculations for Overheads (Common Services, Payroll, Executive, Other, Building, Telephone and Software per the December 2023 CAM (pages 39-41) and per Quenum Exhibit (WG (J)-5 Parts A, B, and C). Also, reconcile these allocated expense amounts to the allocated amount of expenses by type of ALA Corporate expense (Finance, Accounting and Tax, etc.) for calendar years 2019 to 2023, and test year end March 31, 2024.

c. Regarding (a) and (b) above, provide the numerator and denominator of each allocation factor (including MMF and other allocation methods, including those identified at Witness Quenum's testimony 9:6-16)) for

WGL and each U.S. affiliate (along with the total allocation factor used for all affiliates subject to allocation), and provide the related underlying financial and other inputs to the allocation factors (including inputs of EBITDA, relative payroll costs, and relative property for the MMF), that are used to allocate expenses to WGL and each U.S. affiliate for calendar years 2019 to 2023, and test year end March 31, 2024. Provide all supporting documentation and calculations for all allocation factor calculations, including all inputs and summary financial data for each U.S. affiliate to which expenses are allocated using the allocation factors.

d. Regarding (b) and (c) above, provide a citation to Service Agreements and provide copies of other documentation which identify and describe each allocation factor method and how it is calculated.

e. Regarding (b) and (c) above, translate the above MMF allocation factor (and all other applicable allocation factors) information to the quarterly MMF factors calculation used for allocating expenses (Witness Quenum, 9:8-9), and provide this same calculation for other allocation factor methods that are used. Explain if any MMF allocation factor component (or other allocation factor methods) is used in arrears and the period of data to which the allocation factor is applied. For example, explain if the MMF allocation factors used for the March 31, 2024, test period are all based on financial inputs/data ending March 31, 2024, or if the factors are a combination of actual and historical (or projected data) inputs/data, such as using actual information for April 2023 to December 31, 2023 and using estimated or historical data in place of actual March 31, 2024 actual data.

f. Regarding (c) above, provide the names of each of the U.S. affiliates to which ASUS expenses are allocated using the various allocation factors (including the MMF), and provide the following:

(i) A general description of each U.S. affiliate's type of business that is conducted with AltaGas affiliates and with non-affiliated third parties – and state the reason for the existence of the business.
(ii) Identify the year when each U.S. affiliate was created and if it has operated as a going concern for all years through test year end March 31, 2024.
(iii) Explain if each U.S. affiliate is a profit center for AltaGas or WGL, or otherwise explain the purposes of the affiliate if not for generating profits for AltaGas and WGL (or for other entities).
(iv) Explain if each U.S. affiliate is any of the following: a "capital intensive" business with substantial fixed plant investment on the balance sheet that is used to provide services and generate revenues; a "service-providing" company that is not capital

intensive; or a mix of capital intensive and service-related. Explain the basis and provide supporting documentation for your response.

(v) Identify each U.S. affiliate that has and has not generated a profit for each year (calendar years 2019 to 2023 and test year end March 31, 2024).

g. Explain if and why each of the cost allocation factors (including the MMF) are the best and most reasonable allocation factors to use for allocating the related expenses or cost pools to WGL and each of the U.S. affiliates. Explain how each of the cost allocation methods used for each expense or cost pool is a reasonable driver of the related expenses, how it supports cost-causation, and if and how it is measurable, objective, stable and predictable, and consistent. Identify those cost allocation methods that do not meet these criteria.

h. Identify all U.S. affiliates/businesses that do not receive an allocation of expenses from ASUS for each of the periods (calendar years 2019 to 2023, and test year end March 2024) and explain why this is the case. Provide supporting documentation for your response.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. As stated on Page 21 of the 2023 DC Cost Allocation and Inter-company Pricing Manual (CAM), "*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*."
Please find attached the allocation of AltaGas corporate shared costs by function from ASUS to its each of its direct US Affiliates. AltaGas corporate shared costs allocations from WGL Holdings to WGL and each of its pre-merger Affiliates will be addressed in WGL's Responses to OPC DR 4-10.

b. Please refer to WGL's Response for 4-8.a.

c. ASUS used Washington Gas' MMF to allocate corporate shared services costs to WGL and US Affiliates. The three factors used in the computation of the MMF are 1) Average Invested Capital (AIC), 2) Adjusted Net Revenue, and 3) Direct & Assigned Labor.

**Average Invested Capital (AIC)** = Capitalization (Sum of Common Stock includes RE) + Net Income (Current Year before closing RE) + Total Long-term debt + Notes Payable & Pref Stock & LT Due in 1 Year + Money Pool Borrowings - Investment in Subs.

**Adjusted Net Revenue** = Operating Revenue – Cost of Sales – Revenue Taxes

**Direct & Assigned Labor** = Productive Labor + Non-Productive Labor

The MMF ratio is a simple average of the three factors for each affiliate.

Average Invested Capital of affiliate / Total Average Invested Capital
Adjusted Net Revenue of the Affiliate / Total Adjusted Revenue
Direct & Assigned Labor of the Affiliate / Total Direct & Assigned Labor

d. The Annual Cost Allocation Manual (CAM) filed with the commission 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.

e. The MMF calculation is based on actuals from historical financial statements data as of the prior quarter; it does not include projections or estimates.

   Quarterly MMF factors calculation worksheets from 2019 to March 31, 2024, are attached.

f. Please refer to the 2023 DC CAM
   (i) Please refer to Page 25 of the 2023 DC CAM.
   (ii) Please refer to Page 25 of the 2023 DC CAM.
   (iii) Each affiliate is a profit center for AltaGas.
   (iv) Please refer to WGL's Responses to OPC DR 4-8.e and OPC DR 4-7.j.
   (v) Affiliates have been profitable over the stated periods.

g. Please refer to WGL's Responses to OPC DR 4-15.

h. All operating affiliates receive an allocation.

SPONSOR: Ghislaine (Celine) Quenum
Manager, Corporate Accounting

# Excerpted Attachments from WGL Response to OPC Data Request No. 4-8

**AltaGas Corporate Services Costs Allocated from ASUS to Direct US Affiliates**

| Function | CY2019 | CY2020 | CY2021 | CY2022 | CY2023 | TME MARCH 2024 | Grand Total |
|---|---|---|---|---|---|---|---|
| **WGL Holdings, Inc** | | | | | | | |
| Accounting and Tax | $ 4,019,383 | $ 6,277,182 | $ 4,499,416 | $ 3,936,209 | $ 5,925,731 | $ 5,720,165 | $ 30,378,087 |
| Board of Directors | 664,140 | 734,402 | 604,072 | 616,956 | 1,389,430 | 1,341,230 | 5,350,230 |
| Exec Mgmt | 1,849,316 | 2,054,680 | 3,061,294 | 2,757,520 | 3,586,216 | 3,461,809 | 16,770,835 |
| Finance | 2,464,523 | 2,104,291 | 2,723,401 | 1,908,609 | 1,949,462 | 1,881,834 | 13,032,120 |
| HR | 3,626,626 | 2,910,562 | 1,331,083 | 3,033,943 | 3,230,246 | 3,118,188 | 17,250,648 |
| IT | 6,248,826 | 5,134,823 | 5,190,038 | 5,916,203 | 8,235,473 | 7,949,781 | 38,675,143 |
| Legal and Compliance | 2,968,285 | 3,309,814 | 4,264,022 | 4,290,003 | 4,564,388 | 4,406,048 | 23,802,560 |
| Supply Chain | 304,376 | 389,477 | 451,305 | 300,694 | 393,200 | 379,560 | 2,218,612 |
| Cost-To-Achieve (IT) | 1,557,265 | 705,006 | 488,955 | 83,500 | - | - | 2,834,726 |
| **Total** | **$ 23,702,740** | **$ 23,620,237** | **$ 22,613,587** | **$ 22,843,636** | **$ 29,274,147** | **$ 28,258,615** | **$ 150,312,961** |
| **AltaGas Power Holdings (U.S.) - (APHUS)** | | | | | | | |
| Accounting and Tax | $ 625,959 | $ 466,847 | $ 236,365 | $ 193,187 | $ 275,153 | $ 252,626 | $ 2,050,135 |
| Board of Directors | 103,430 | 54,619 | 31,733 | 30,280 | 64,516 | 59,234 | 343,812 |
| Exec Mgmt | 288,003 | 152,811 | 160,817 | 135,337 | 166,521 | 152,887 | 1,056,376 |
| Finance | 383,813 | 156,500 | 143,066 | 93,673 | 90,521 | 83,109 | 950,683 |
| HR | 564,793 | 216,464 | 69,925 | 148,904 | 149,992 | 137,712 | 1,287,790 |
| IT | 973,161 | 381,887 | 272,644 | 290,363 | 382,403 | 351,095 | 2,651,553 |
| Legal and Compliance | 462,266 | 246,157 | 223,999 | 210,551 | 211,941 | 194,589 | 1,549,503 |
| Supply Chain | 47,402 | 28,966 | 23,708 | 14,758 | 18,258 | 16,763 | 149,855 |
| Cost-To-Achieve (IT) | 242,552 | 48,420 | 28,169 | 4,265 | - | - | 323,405 |
| **Total** | **$ 3,691,379** | **$ 1,752,671** | **$ 1,190,426** | **$ 1,121,317** | **$ 1,359,304** | **$ 1,248,015** | **$ 10,363,112** |
| **SEMCO Energy, Inc** | | | | | | | |
| Accounting and Tax | $ 1,208,765 | $ 1,592,314 | $ 1,095,476 | $ 959,312 | $ 991,001 | $ 796,685 | $ 6,643,553 |
| Board of Directors | 199,729 | 186,294 | 147,074 | 150,361 | 232,364 | 186,802 | 1,102,624 |
| Exec Mgmt | 556,152 | 521,205 | 745,335 | 672,048 | 599,747 | 482,149 | 3,576,637 |
| Finance | 741,166 | 533,789 | 663,068 | 465,156 | 326,022 | 262,095 | 2,991,297 |
| HR | 1,090,650 | 738,314 | 324,080 | 739,417 | 540,216 | 434,290 | 3,866,966 |
| IT | 1,879,235 | 1,302,536 | 1,263,622 | 1,441,866 | 1,377,274 | 1,107,218 | 8,371,750 |
| Legal and Compliance | 892,664 | 839,591 | 1,038,164 | 1,045,537 | 763,334 | 613,659 | 5,192,949 |
| Supply Chain | 91,536 | 98,797 | 109,880 | 73,283 | 65,758 | 52,864 | 492,118 |
| Cost-To-Achieve (IT) | 447,075 | 182,956 | 129,104 | 20,200 | - | - | 779,335 |
| **Total** | **$ 7,106,972** | **$ 5,995,796** | **$ 5,515,803** | **$ 5,567,182** | **$ 4,895,715** | **$ 3,935,762** | **$ 33,017,230** |
| **AltaGas Services (U.S.), Inc - (ASUS)** | | | | | | | |
| Cross-border Markup | $ 1,101,815 | $ 1,395,739 | $ 1,759,189 | $ 1,771,928 | $ 2,131,750 | $ 2,006,544 | $ 10,166,965 |
| | - | - | - | - | - | - | - |
| **Total** | **$ 1,101,815** | **$ 1,395,739** | **$ 1,759,189** | **$ 1,771,928** | **$ 2,131,750** | **$ 2,006,544** | **$ 10,166,965** |
| **Grand Total** | **$ 35,602,907** | **$ 32,764,442** | **$ 31,079,004** | **$ 31,304,063** | **$ 37,660,916** | **$ 35,448,935** | **$ 203,860,267** |

**AltaGas Corporate Services Costs Allocated from ASUS to Direct US Affiliates**

| Function | CY2019 | CY2020 | CY2021 | CY2022 | CY2023 | TME MARCH 2024 | Grand Total |
|---|---|---|---|---|---|---|---|
| **WGL Holdings, Inc** | | | | | | | |
| Accounting and Tax | 11% | 19% | 14% | 13% | 16% | 16% | 15% |
| Board of Directors | 2% | 2% | 2% | 2% | 4% | 4% | 3% |
| Exec Mgmt | 5% | 6% | 10% | 9% | 10% | 10% | 8% |
| Finance | 7% | 6% | 9% | 6% | 5% | 5% | 6% |
| HR | 10% | 9% | 4% | 10% | 9% | 9% | 8% |
| IT | 18% | 16% | 17% | 19% | 22% | 22% | 19% |
| Legal and Compliance | 8% | 10% | 14% | 14% | 12% | 12% | 12% |
| Supply Chain | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| Cost-To-Achieve (IT) | 4% | 2% | 2% | 0% | 0% | 0% | 1% |
| **Total** | **67%** | **72%** | **73%** | **73%** | **78%** | **80%** | **74%** |
| **AltaGas Power Holdings (U.S.) - (APHUS)** | | | | | | | |
| Accounting and Tax | 2% | 1% | 1% | 1% | 1% | 1% | 1% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 1% | 0% | 1% | 0% | 0% | 0% | 1% |
| Finance | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| HR | 2% | 1% | 0% | 0% | 0% | 0% | 1% |
| IT | 3% | 1% | 1% | 1% | 1% | 1% | 1% |
| Legal and Compliance | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **10%** | **5%** | **4%** | **4%** | **4%** | **4%** | **5%** |
| **SEMCO Energy, Inc** | | | | | | | |
| Accounting and Tax | 3% | 5% | 4% | 3% | 3% | 2% | 3% |
| Board of Directors | 1% | 1% | 0% | 0% | 1% | 1% | 1% |
| Exec Mgmt | 2% | 2% | 2% | 2% | 2% | 1% | 2% |
| Finance | 2% | 2% | 2% | 1% | 1% | 1% | 1% |
| HR | 3% | 2% | 1% | 2% | 1% | 1% | 2% |
| IT | 5% | 4% | 4% | 5% | 4% | 3% | 4% |
| Legal and Compliance | 3% | 3% | 3% | 3% | 2% | 2% | 3% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 1% | 1% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **20%** | **18%** | **18%** | **18%** | **13%** | **11%** | **16%** |
| **AltaGas Services (U.S.), Inc - (ASUS)** | | | | | | | |
| Cross-border Markup | 3% | 4% | 6% | 6% | 6% | 6% | 5% |
| | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **3%** | **4%** | **6%** | **6%** | **6%** | **6%** | **5%** |
| | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** |

**Item 4-8.e**
**OPC Data Request 4**
**MMF - Q4 CY2021**
**Attachment 1**

**MMF -ASUS Allocation to Direct US Affiliates**

As of September 30 2021
For Q4 CY21

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass | AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|---|---|---|---|---|
| WGLH | 72.638% | 75.2843% | 83.899% | 77.2738% | 4,073,123,910 | (957,525,873) | 167,187,726 |
| APHUS | 4.9889% | 4.6975% | 2.1238% | **3.9367%** | 279,747,641 | (59,746,467) | 4,232,133 |
| SEMCO | 22.3727% | 20.0182% | 13.9774% | **18.7894%** | 1,254,523,127 | (254,607,416) | 27,853,226 |
| Total | **100.000%** | **100.000%** | **100.000%** | **100.000%** | **5,607,394,679** | **(1,271,879,756)** | **199,273,084** |

**MMF - WGLH Allocation to WGL and Pre-merger US Affiliates**

As of September 30 2021
For Q4 CY21

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass | AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|---|---|---|---|---|
| 00 WGLH | | | | | | | |
| 01 WGL | 86.1211% | 88.2697% | 92.2287% | **88.8732%** | 3,507,820,842 | (845,204,784) | 154,195,039 |
| 07 Hampshire Gas | 0.4975% | 0.8640% | 0.8268% | **0.7294%** | 20,265,206 | (8,272,898) | 1,382,293 |
| 15 WGES | 0.9198% | 10.8664% | 6.8904% | **6.2255%** | 37,466,608 | (104,048,191) | 11,519,850 |
| 16 WG Resources | 1.6683% | 0.0000% | 0.0538% | **0.5740%** | 67,953,013 | - | 89,914 |
| 28 Midstream MVP | 10.7931% | 0.0000% | 0.0004% | **3.5978%** | 439,618,242 | - | 630 |
| Total | **100.000%** | **100.000%** | **100.000%** | **100.000%** | **4,073,123,910** | **(957,525,873)** | **167,187,726** |

**Item 4-8.e**
**OPC Data Request 4**
**MMF - AIC Factor Calculation - Q4 CY2021**
**Attachment 2**

| QTR | AGA Definition Categories | BU [01] WGL | BU [07] Hampshire | BU [15] WGLE Services | BU [16] WGI Resources | BU [28] Midstream MVP | 305 ltaGas Power Holdings (U.S | 312 Blythe Energy, Inc. | 320 AltaGas Brush Energy Inc. | 326 ltaGas Blythe Operations In | 400 SEMCO | BALANCE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Sep_2020* | Capitalization (Sum of Corp's Stock includes RE) | 1,679,787,417.13 | 22,586,882.67 | 267,914,054.30 | 812,478,829.68 | 29,351,395.95 | (151,746,824.36) | 312,412,333.01 | 8,443,647.87 | (5,774.59) | 622,482,221.00 | 3,603,704,182.66 |
| | Net Income (Current Year before closing RE) | 76,544,089.04 | 1,406,712.28 | 22,827,535.95 | 45,168,369.04 | 19,584,832.93 | 20,878,666.78 | 18,691,349.62 | 17,829.24 | (9,077.90) | 80,447,173.85 | 285,557,480.83 |
| | Total Long Term Debt | 1,431,389,570 | | | | 147,289,111.11 | | | | | 495,959,182.69 | 2,074,637,863.96 |
| | Notes Payable & LTD Due in 1 Year | 169,958,524 | - | - | - | - | - | - | - | - | 35,685,714 | 205,644,237.61 |
| | Money Pool Borrowings | - | (5,003,672.75) | (245,916,443.14) | 12,325,519.63 | 234,697,402.72 | (70,970,042.99) | (36,812,815.18) | - | 3,965,000.21 | - | (107,715,051.50) |
| | Less: Investment in Subs | - | - | - | (821,880,598.28) | - | 188,654,870.36 | - | - | - | 0.55 | (633,225,727.37) |
| | **Total Sep 2020** | **$ 3,357,679,599.94** | **$ 18,989,922.20** | **$ 44,825,147.11** | **$ 48,092,120.07** | **$ 430,922,742.71** | **$ (13,183,330.21)** | **$ 294,290,867.45** | **$ 8,461,477.11** | **$ 3,950,147.72** | **$ 1,234,574,292.09** | **$ 5,428,602,986.19** |
| *Dec_2020* | Capitalization (Sum of Corp's Stock includes RE) | 1,724,044,014.70 | 22,586,882.67 | 267,914,054.30 | 844,743,170.46 | 29,351,395.95 | (151,746,824.36) | 312,412,333.01 | 8,443,647.87 | (5,774.59) | 612,020,130.00 | 3,669,763,030.01 |
| | Net Income (Current Year before closing RE) | 131,880,944.24 | 1,902,859.74 | 20,718,461.16 | 77,316,946.80 | 28,226,909.91 | 39,216,259.45 | 33,412,706.95 | 377,718.93 | 1,762.50 | 128,133,256.81 | 461,187,826.49 |
| | Total Long Term Debt | 1,547,202,259 | | | | 147,289,111.11 | | | | | 496,006,106.00 | 2,190,497,476.41 |
| | Notes Payable & LTD Due in 1 Year | 185,039,833 | - | - | - | - | - | - | - | - | 67,685,714 | 252,725,546.76 |
| | Money Pool Borrowings | - | (4,859,661.41) | (245,835,276.94) | 12,493,336.70 | 237,563,698.79 | (71,797,204.85) | (39,926,425.76) | - | 4,830,755.05 | - | (107,530,778.42) |
| | Less: Investment in Subs | - | - | - | (854,144,939.06) | - | 175,053,712.60 | - | - | - | 0.05 | (679,091,226.41) |
| | **Total Dec 2020** | **$ 3,588,167,051.00** | **$ 19,630,081.00** | **$ 42,797,238.52** | **$ 80,408,514.90** | **$ 442,431,115.76** | **$ (9,274,057.16)** | **$ 305,898,614.20** | **$ 8,821,366.80** | **$ 4,826,742.96** | **$ 1,303,845,206.86** | **$ 5,787,551,874.84** |
| *Mar_2021* | Capitalization (Sum of Corp's Stock includes RE) | 1,831,946,858.19 | 24,489,742.41 | 283,632,515.46 | 909,291,743.52 | 57,578,305.86 | (112,530,564.91) | 345,825,039.96 | 8,821,366.80 | (4,012.09) | 677,561,327.00 | 4,026,612,322.20 |
| | Net Income (Current Year before closing RE) | 133,613,740.20 | 628,512.53 | 10,391,509.28 | 69,948,761.44 | (2,099,683.67) | 1,369,833.73 | 3,650,422.87 | 491,856.57 | (634.48) | 67,606,001.00 | 285,600,319.47 |
| | Total Long Term Debt | 1,519,986,202.98 | - | - | - | 147,289,111.11 | | | | | 493,388,502.00 | 2,160,663,816.09 |
| | Notes Payable & LTD Due in 1 Year | 177,745 | - | - | - | - | - | - | - | - | 8,685,714 | 8,863,458.53 |
| | Money Pool Borrowings | - | (3,407,791.77) | (217,234,104.97) | 12,447,677.69 | 240,443,791.81 | (109,286,737.79) | (44,755,499.99) | - | 1,579,414.13 | - | (120,213,250.89) |
| | Less: Investment in Subs | - | - | - | (919,186,703.40) | - | 171,058,452.76 | - | - | - | 0.05 | (748,128,250.59) |
| | **Total Mar 2021** | **$ 3,485,724,545.90** | **$ 21,710,463.17** | **$ 76,789,919.77** | **$ 72,501,479.25** | **$ 443,211,525.11** | **$ (49,389,016.21)** | **$ 304,719,962.84** | **$ 9,313,223.37** | **$ 1,574,767.56** | **$ 1,247,241,544.05** | **$ 5,613,398,414.81** |
| *Jun_2021* | Capitalization (Sum of Corp's Stock includes RE) | 1,806,958,670.77 | 24,489,742.41 | 278,632,515.46 | 928,149,706.55 | 57,578,305.86 | (112,530,564.91) | 345,825,039.96 | 8,821,366.80 | (4,012.09) | 661,865,564.00 | 3,999,786,334.81 |
| | Net Income (Current Year before closing RE) | 121,162,260.94 | 1,265,005.43 | 41,392,736.83 | 41,250,099.80 | (4,135,164.82) | 5,766,189.33 | 9,614,904.98 | 779,480.54 | (1,745.34) | 79,509,338.19 | 296,603,105.88 |
| | Total Long Term Debt | 1,545,102,300.97 | - | - | - | 147,289,111.11 | - | - | - | - | 498,151,764.00 | 2,190,543,176.08 |
| | Notes Payable & LTD Due in 1 Year | 423,537 | - | - | - | - | - | - | - | - | 5,105,799 | 5,529,335.57 |
| | Money Pool Borrowings | - | (5,174,370.08) | (270,165,553.53) | (244,503,745.21) | 243,185,580.07 | (103,969,007.33) | (49,389,409.51) | - | 1,757,393.24 | - | (428,259,112.35) |
| | Less: Investment in Subs | - | - | - | (684,065,413.45) | - | 164,791,809.75 | - | - | - | 0.05 | (519,273,603.65) |
| | **Total Jun 2021** | **$ 3,473,646,769.25** | **$ 20,580,377.76** | **$ 49,859,698.76** | **$ 40,830,647.69** | **$ 443,917,832.22** | **$ (45,941,573.16)** | **$ 306,050,535.43** | **$ 9,600,847.34** | **$ 1,751,635.81** | **$ 1,244,632,465.24** | **$ 5,544,929,236.34** |
| *Sep_2021* | Capitalization (Sum of Corp's Stock includes RE) | 1,781,916,376.98 | 24,489,742.41 | 273,632,515.46 | 985,981,652.67 | 57,578,305.86 | (112,530,564.91) | 345,825,039.96 | 8,821,366.80 | (4,012.09) | 660,692,551.00 | 4,026,402,974.14 |
| | Net Income (Current Year before closing RE) | 90,233,740.65 | 1,878,223.92 | 111,937,016.29 | 100,715,925.75 | (13,167,046.50) | 8,092,673.65 | 15,158,176.19 | 1,100,571.61 | (3,369.97) | 80,861,099.00 | 396,807,010.59 |
| | Total Long Term Debt | 1,548,372,482.53 | - | - | - | 147,289,111.11 | - | - | - | - | 495,666,506.00 | 2,191,328,099.64 |
| | Notes Payable & LTD Due in 1 Year | 213,363,642 | - | - | - | - | - | - | - | - | 5,101,973 | 218,465,615.28 |
| | Money Pool Borrowings | - | (5,952,780.86) | (412,508,498.37) | (246,867,913.63) | 245,907,622.67 | (101,676,815.65) | (68,170,210.58) | - | 2,218,599.66 | - | (587,049,996.76) |
| | Less: Investment in Subs | - | - | - | (741,897,359.57) | - | 158,434,537.95 | - | - | - | 0.05 | (583,462,821.57) |
| | **Total Sep 2021** | **$ 3,633,886,242.44** | **$ 20,415,185.47** | **$ (26,938,966.62)** | **$ 97,932,305.22** | **$ 437,607,993.14** | **$ (47,680,168.96)** | **$ 292,813,005.57** | **$ 9,921,938.41** | **$ 2,211,217.60** | **$ 1,242,322,129.05** | **$ 5,662,490,881.32** |
| | **Total 5 Qtrs** | $ 17,539,104,208.52 | $ 101,326,029.60 | $ 187,333,037.55 | $ 339,765,067.13 | $ 2,198,091,208.94 | $ (165,468,145.70) | $ 1,503,772,985.51 | $ 46,118,853.03 | $ 14,314,511.65 | $ 6,272,615,637.29 | $ 28,036,973,393.51 |
| | **Average 5 Qtrs** | $ 3,507,820,841.70 | $ 20,265,205.92 | $ 37,466,607.51 | $ 67,953,013.43 | $ 439,618,241.79 | $ (33,093,629.14) | $ 300,754,597.10 | $ 9,223,770.61 | $ 2,862,902.33 | $ 1,254,523,127.46 | $ 5,607,394,678.70 |
| | **Allocation Factor** | 0.63 | 0.00 | 0.01 | 0.01 | 0.08 | (0.01) | 0.05 | 0.00 | 0.00 | 0.22 | 1.00 |
| | **Allocation Percentages** | 62.5571% | 0.3614% | 0.6682% | 1.2118% | 7.8400% | -0.5902% | 5.3635% | 0.1645% | 0.0511% | 22.3727% | 1.00 |

**Item 4-8.e**
**OPC Data Request 4**
**MMF - Q4 CY2022**
**Attachment 1**

## MMF -ASUS Allocation to Direct US Affiliates

As of September 30, 2022
For Q4 CY22

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass | AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|---|---|---|---|---|
| WGLH | 74.122% | 76.6521% | 84.712% | 78.4955% | 4,272,347,032 | (1,053,731,070) | 173,818,655 |
| APHUS | 4.6942% | 4.4146% | 2.0592% | **3.7227%** | 270,571,122 | (60,687,689) | 4,225,132 |
| SEMCO | 21.1833% | 18.9333% | 13.2289% | **17.7818%** | 1,220,983,846 | (260,274,812) | 27,144,161 |
| Total | **100.000%** | **100.000%** | **100.000%** | **100.000%** | **5,763,902,000** | **(1,374,693,571)** | **205,187,948** |

## MMF - WGLH Allocation to WGL and Pre-merger US Affiliates

As of September 30, 2022
For Q4 CY22

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass | AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|---|---|---|---|---|
| 00 WGLH | | | | | - | - | - |
| 01 WGL | 90.3499% | 89.3236% | 92.5515% | **90.7417%** | 3,860,061,734 | (941,230,671) | 160,871,688 |
| 07 Hampshire Gas | 0.5479% | 1.2414% | 0.7805% | **0.8566%** | 23,410,317 | (13,081,378) | 1,356,614 |
| 15 WGES | -0.0100% | 9.4350% | 6.6678% | **5.3643%** | (427,164) | (99,419,020) | 11,589,916 |
| 28 Midstream MVP | 9.1121% | 0.0000% | 0.0003% | **3.0375%** | 389,302,145 | - | 437 |
| Total | **100.000%** | **100.000%** | **100.000%** | **100.000%** | **4,272,347,032** | **(1,053,731,070)** | **173,818,655** |

**Item 4-8.e**
**OPC Data Request 4**
**MMF - AIC Factor Calculation - Q4 CY2022**
**Attachment 2**

| QTR | AGA Definition Categories | BU [01] WGL | BU [07] Hampshire | BU [15] WGLE Services | BU [28] Midstream MVP | 305 AltaGas Power Holdings (U.S.) | 312 Blythe Energy, Inc. | 320 AltaGas Brush Energy Inc. | 326 AltaGas Blythe Operations Inc | 400 SEMCO | BALANCE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Sep_2021* | Capitalization (Sum of Corp's Stock includes RE) | 1,781,916,376.98 | 24,489,742.41 | 273,632,515.46 | 57,578,305.86 | (112,530,564.91) | 345,825,039.96 | 8,821,366.80 | (4,012.09) | 622,033,229.00 | 3,001,761,999.48 |
| | Total Long Term Debt | 1,548,372,482.53 | - | - | 147,289,111.11 | - | - | - | - | 495,666,506.00 | 2,191,328,099.64 |
| | Notes Payable & LTD Due in 1 Year | 213,363,642 | - | - | - | - | - | - | - | 5,101,973 | 218,465,615.28 |
| | Money Pool Borrowings | - | (5,952,780.86) | (412,508,498.37) | 245,907,622.67 | (101,676,815.65) | (68,170,210.58) | - | 2,218,599.66 | - | (340,182,083.13) |
| | Less: Investment in Subs | - | - | - | - | 158,434,537.95 | - | - | - | 0.05 | 158,434,538.00 |
| | **Total Sep 2021 $** | **3,633,886,242.44 $** | **20,415,185.47 $** | **(26,938,966.62) $** | **437,607,993.14 $** | **(47,680,168.96) $** | **292,813,005.57 $** | **9,921,938.41 $** | **2,211,217.60 $** | **1,203,662,807.05 $** | **5,525,899,254.10** |
| *Dec_2021* | Capitalization (Sum of Corp's Stock includes RE) | 1,866,316,760.11 | 24,489,742.41 | 268,632,515.46 | 57,578,305.86 | (112,530,564.91) | 345,825,039.96 | 8,821,366.80 | (4,012.09) | 586,799,931.00 | 3,045,929,084.61 |
| | Total Long Term Debt | 1,747,645,145.57 | - | - | 147,289,111.11 | - | - | - | - | 495,347,376.00 | 2,390,281,632.68 |
| | Notes Payable & LTD Due in 1 Year | 127,431,370 | - | - | - | - | - | - | - | 4,913,911 | 132,345,280.68 |
| | Money Pool Borrowings | - | (3,516,001.73) | (218,514,064.90) | 246,275,006.40 | (93,413,705.57) | (83,603,275.83) | - | 2,720,260.91 | - | (150,051,780.72) |
| | Less: Investment in Subs | - | - | - | - | 154,147,611.85 | - | - | - | 0.05 | 154,147,611.90 |
| | **Total Dec 2021 $** | **3,906,434,361.88 $** | **23,503,786.95 $** | **109,881,296.35 $** | **435,905,375.02 $** | **(39,638,456.13) $** | **286,646,843.66 $** | **10,233,849.83 $** | **2,711,937.12 $** | **1,209,239,637.05 $** | **5,944,918,631.73** |
| *Mar_2022* | Capitalization (Sum of Corp's Stock includes RE) | 1,997,251,872.66 | 27,019,788.68 | 323,395,361.25 | (34,907,129.49) | (100,372,362.41) | 370,250,119.49 | 10,233,849.83 | (8,323.79) | 672,675,930.00 | 3,265,539,106.23 |
| | Total Long Term Debt | 1,710,910,769.31 | - | - | 147,289,111.11 | - | - | - | - | 492,603,894.00 | 2,350,803,774.42 |
| | Notes Payable & LTD Due in 1 Year | 20,550,077 | - | - | - | - | - | - | - | 4,913,004 | 25,463,081.15 |
| | Money Pool Borrowings | - | (2,775,352.53) | (299,487,543.58) | 248,982,655.09 | (104,431,578.41) | (85,400,238.63) | - | 3,200,474.46 | - | (239,911,583.60) |
| | Less: Investment in Subs | - | - | - | - | 152,340,639.85 | - | - | - | 0.05 | 152,340,639.90 |
| | **Total Mar 2022 $** | **3,869,823,588.37 $** | **25,061,219.59 $** | **90,398,372.92 $** | **359,311,623.41 $** | **(46,905,442.39) $** | **286,338,599.45 $** | **10,546,472.56 $** | **3,191,100.09 $** | **1,243,091,997.05 $** | **5,840,857,531.05** |
| *Jun_2022* | Capitalization (Sum of Corp's Stock includes RE) | 1,972,241,450.83 | 27,019,788.68 | 318,395,361.25 | (34,907,129.49) | (100,372,362.41) | 370,250,119.49 | (547,511.41) | (8,323.79) | 688,668,407.03 | 3,240,739,800.19 |
| | Total Long Term Debt | 1,728,108,070 | - | - | 147,289,111 | - | - | - | - | 450,111,157.00 | 2,325,508,338.37 |
| | Notes Payable & LTD Due in 1 Year | 25,459,876 | - | - | - | - | - | - | - | 100,780.00 | 25,560,655.70 |
| | Money Pool Borrowings | - | (4,328,353.79) | (551,285,207.46) | 247,257,253.29 | (84,046,398.57) | (89,714,951.92) | - | 3,497,847.76 | - | (478,619,810.69) |
| | Less: Investment in Subs | - | - | - | - | 158,275,571.10 | - | - | - | 0.05 | 158,275,571.15 |
| | **Total June 2022 $** | **3,844,567,936.63 $** | **24,301,962.53 $** | **(169,271,648.06) $** | **356,215,884.40 $** | **(14,663,997.93) $** | **286,636,653.06 $** | **(0.00) $** | **3,487,433.51 $** | **1,223,804,986.05 $** | **5,555,079,210.20** |
| *Sep_2022* | Capitalization (Sum of Corp's Stock includes RE) | 1,947,234,682.82 | 27,019,788.68 | 313,395,361.25 | (34,907,129.49) | (60,027,066.85) | 370,250,119.49 | (517,888.51) | (8,323.79) | 685,436,255.40 | 3,247,875,799.00 |
| | Total Long Term Debt | 1,728,712,816 | - | - | 147,289,111 | - | - | - | - | 447,955,264.00 | 2,323,957,191.53 |
| | Notes Payable & LTD Due in 1 Year | 258,679,615 | - | - | - | - | - | - | - | 99,955.00 | 258,779,569.53 |
| | Money Pool Borrowings | - | (5,706,168.47) | (411,508,998.60) | 250,048,358.51 | (86,559,469.77) | (108,242,705.23) | - | 3,830,891.91 | - | (358,138,091.65) |
| | Less: Investment in Subs | - | - | - | - | 150,807,840.18 | - | - | - | 0.05 | 150,807,840.23 |
| | **Total Sep 2022 $** | **4,045,596,540.26 $** | **23,769,428.96 $** | **(6,204,872.38) $** | **357,469,848.37 $** | **27,600,750.36 $** | **275,594,774.63 $** | **(0.00) $** | **3,809,097.08 $** | **1,225,119,804.05 $** | **5,952,755,371.33** |
| | **Total 5 Qtrs** $ | 19,300,308,669.57 $ | 117,051,583.50 $ | (2,135,817.78) $ | 1,946,510,724.34 $ | (121,287,315.05) $ | 1,428,029,876.39 $ | 30,702,260.80 $ | 15,410,785.40 $ | 6,104,919,231.25 $ | 28,819,509,998.42 |
| | **Average 5 Qtrs** $ | 3,860,061,733.91 $ | 23,410,316.70 $ | (427,163.56) $ | 389,302,144.87 $ | (24,257,463.01) $ | 285,605,975.28 $ | 6,140,452.16 $ | 3,082,157.08 $ | 1,220,983,846.25 $ | 5,763,901,999.68 |
| | **Allocation Factor** | 0.67 | 0.00 | (0.00) | 0.07 | (0.00) | 0.05 | 0.00 | 0.00 | 0.21 | 1.00 |
| | **Allocation Percentages** | 66.9696% | 0.4062% | -0.0074% | 6.7541% | -0.4209% | 4.9551% | 0.1065% | 0.0535% | 21.1833% | 1.00 |

**Item 4-8.e**
**OPC Data Request 4**
**MMF - Q1 CY2023**
**Attachment 1**

## MMF -ASUS Allocation to Direct US Affiliates

As of December 31, 2022
For Q1 CY23

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass |
|---|---|---|---|---|
| WGLH | 82.405% | 76.0620% | 85.131% | 81.1993% |
| APHUS | 5.2260% | 4.0063% | 1.9736% | **3.7353%** |
| SEMCO | 12.3690% | 19.9317% | 12.8954% | **15.0654%** |
| **Total** | **100.000%** | **100.000%** | **100.000%** | **100.000%** |

| AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|
| 4,421,770,316 | (1,100,397,923) | 176,057,845 |
| 280,422,663 | (57,958,995) | 4,081,481 |
| 663,708,362 | (288,353,967) | 26,668,824 |
| **5,365,901,341** | **(1,446,710,885)** | **206,808,150** |

## MMF - WGLH Allocation to WGL and Pre-merger US Affiliates

As of December 31, 2022
For Q1 CY23

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass |
|---|---|---|---|---|
| 00 WGLH | | | | |
| 01 WGL | 90.2123% | 89.7915% | 92.7001% | **90.9013%** |
| 07 Hampshire Gas | 0.5493% | 1.1224% | 0.7702% | **0.8140%** |
| 15 WGES | 0.8073% | 9.0860% | 6.5288% | **5.4741%** |
| 28 Midstream MVP | 8.4311% | 0.0000% | 0.0008% | **2.8106%** |
| **Total** | **100.000%** | **100.000%** | **100.000%** | **100.000%** |

| AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|
| - | - | - |
| 3,988,980,699 | (988,063,946) | 163,205,861 |
| 24,289,242 | (12,351,283) | 1,356,080 |
| 35,697,624 | (99,982,694) | 11,494,501 |
| 372,802,751 | - | 1,402 |
| **4,421,770,316** | **(1,100,397,923)** | **176,057,845** |

Exhibit OPC (B)-8
Formal Case No. 1180
Witness: Bion C. Ostrander
Page 12 of 26

Formal Case No. 1180
OPC Data Request No. 4-8.e
Attachment 2
1 of 1

**Item 4-8.e**
**OPC Data Request 4**
**MMF - AIC Factor Calculation - Q1 CY2023**
**Attachment 2**

| QTR | AGA Definition Categories | BU [01] WGL | BU [07] Hampshire | BU [15] WGLE Services | BU [28] Midstream MVP | 305 AltaGas Power Holdings (U.S.) | 312 Blythe Energy, Inc. | 320 AltaGas Brush Energy Inc. | 326 AltaGas Blythe Operations Inc | 400 SEMCO | BALANCE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Dec_2021*** | Capitalization (Sum of Corp's Stock includes RE) | 1,866,316,760.11 | 24,489,742.41 | 268,632,515.46 | 57,578,305.86 | (112,530,564.91) | 345,825,039.96 | 8,821,366.80 | (4,012.09) | 586,799,931.00 | 3,045,929,084.61 |
| | Total Long Term Debt | 1,747,645,145.57 | - | - | 147,289,111.11 | - | - | - | - | 495,347,376.00 | 2,390,281,632.68 |
| | Notes Payable & LTD Due in 1 Year | 127,431,370 | - | - | - | - | - | - | - | 4,913,911 | 132,345,280.68 |
| | Money Pool Borrowings | - | (3,516,001.73) | (218,514,064.90) | 246,275,006.40 | (93,413,705.57) | (83,603,275.83) | - | 2,720,260.91 | - | (150,051,780.72) |
| | Less: Investment in Subs | - | - | - | - | 154,147,611.85 | - | - | - | 0.05 | 154,147,611.90 |
| | **Total Dec 2021** | **$ 3,906,434,361.88** | **$ 23,503,786.95** | **$ 109,881,296.35** | **$ 435,905,375.02** | **$ (39,638,456.13)** | **$ 286,646,843.66** | **$ 10,233,849.83** | **$ 2,711,937.12** | **$ 1,209,239,637.05** | **$ 5,944,918,631.73** |
| ***Mar_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,997,251,872.66 | 27,019,788.68 | 323,395,361.25 | (34,907,129.49) | (100,372,362.41) | 370,250,119.49 | 10,233,849.83 | (8,323.79) | 672,675,930.00 | 3,265,539,106.23 |
| | Total Long Term Debt | 1,710,910,769.31 | - | - | 147,289,111.11 | - | - | - | - | 492,603,894.00 | 2,350,803,774.42 |
| | Notes Payable & LTD Due in 1 Year | 20,550,077 | - | - | - | - | - | - | - | 4,913,004 | 25,463,081.15 |
| | Money Pool Borrowings | - | (2,775,352.53) | (299,487,543.58) | 248,982,655.09 | (104,431,578.41) | (85,400,238.63) | - | 3,200,474.46 | - | (239,911,583.60) |
| | Less: Investment in Subs | - | - | - | - | 152,340,639.85 | - | - | - | (742,038,681.00) | (589,698,041.16) |
| | **Total Mar 2022** | **$ 3,869,823,588.37** | **$ 25,061,219.59** | **$ 90,398,372.92** | **$ 359,311,623.41** | **$ (46,905,442.39)** | **$ 286,338,599.45** | **$ 10,546,472.56** | **$ 3,191,100.09** | **$ 501,053,316.00** | **$ 5,098,818,850.00** |
| ***Jun_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,972,241,450.83 | 27,019,788.68 | 318,395,361.25 | (34,907,129.49) | (100,372,362.41) | 370,250,119.49 | (547,511.41) | (8,323.79) | 688,668,407.03 | 3,240,739,800.19 |
| | Total Long Term Debt | 1,728,108,070 | - | - | 147,289,111 | - | - | - | - | 450,111,157.00 | 2,325,508,338.37 |
| | Notes Payable & LTD Due in 1 Year | 25,459,876 | - | - | - | - | - | - | - | 100,780.00 | 25,560,655.70 |
| | Money Pool Borrowings | - | (4,328,353.79) | (551,285,207.46) | 247,257,253.29 | (84,046,398.57) | (89,714,951.92) | - | 3,497,847.76 | - | (478,619,810.69) |
| | Less: Investment in Subs | - | - | - | - | 158,275,571.10 | - | - | - | (733,656,787.00) | (575,381,215.90) |
| | **Total June 2022** | **$ 3,844,567,936.63** | **$ 24,301,962.53** | **$ (169,271,648.06)** | **$ 356,215,884.40** | **$ (14,663,997.93)** | **$ 286,636,653.06** | **$ (0.00)** | **$ 3,487,433.51** | **$ 490,148,199.00** | **$ 4,821,422,423.15** |
| ***Sep_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,947,234,682.82 | 27,019,788.68 | 313,395,361.25 | (34,907,129.49) | (60,027,066.85) | 370,250,119.49 | (517,888.51) | (8,323.79) | 685,436,255.40 | 3,247,875,799.00 |
| | Total Long Term Debt | 1,728,712,816 | - | - | 147,289,111 | - | - | - | - | 447,955,264.00 | 2,323,957,191.53 |
| | Notes Payable & LTD Due in 1 Year | 258,679,615 | - | - | - | - | - | - | - | 99,955.00 | 258,779,569.53 |
| | Money Pool Borrowings | - | (5,706,168.47) | (411,508,998.60) | 250,048,358.51 | (86,559,469.77) | (108,242,705.23) | - | 3,830,891.91 | - | (358,138,091.65) |
| | Less: Investment in Subs | - | - | - | - | 150,807,840.18 | - | - | - | (737,131,908.00) | (586,324,067.83) |
| | **Total Sep 2022** | **$ 4,045,596,540.26** | **$ 23,769,428.96** | **$ (6,204,872.38)** | **$ 357,469,848.37** | **$ 27,600,750.36** | **$ 275,594,774.63** | **$ (0.00)** | **$ 3,809,097.08** | **$ 487,987,896.00** | **$ 5,215,623,463.28** |
| ***Dec_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,922,211,089.09 | 27,019,788.68 | 308,395,361.25 | (34,907,129.49) | (61,828,882.86) | 370,250,119.49 | (517,888.51) | (8,323.79) | 646,683,048.13 | 3,177,297,182.00 |
| | Total Long Term Debt | 1,928,669,784 | - | - | 147,289,111 | - | - | - | - | 450,580,059.00 | 2,526,538,954.54 |
| | Notes Payable & LTD Due in 1 Year | 237,817,345 | - | - | - | - | - | - | - | 139,600,025.00 | 377,417,369.58 |
| | Money Pool Borrowings | - | (5,404,859.07) | (180,128,935.82) | 249,848,820.09 | (85,854,108.53) | (111,424,026.26) | - | 4,275,081.95 | - | (128,688,027.64) |
| | Less: Investment in Subs | - | - | - | - | 146,397,340.23 | - | - | - | (747,345,098.00) | (600,947,757.78) |
| | **Total Dec 2022** | **$ 4,278,481,067.36** | **$ 24,809,811.51** | **$ 153,684,970.31** | **$ 355,111,024.78** | **$ 25,446,285.67** | **$ 276,825,542.61** | **$ (0.00)** | **$ 4,251,873.44** | **$ 630,112,760.00** | **$ 5,748,723,335.68** |
| | **Total 5 Qtrs** | $ 19,944,903,494.49 | $ 121,446,209.54 | $ 178,488,119.15 | $ 1,864,013,755.98 | $ (48,160,860.42) | $ 1,412,042,413.43 | $ 20,780,322.39 | $ 17,451,441.24 | $ 3,318,541,808.05 | $ 26,829,506,703.85 |
| | **Average 5 Qtrs** | $ 3,988,980,698.90 | $ 24,289,241.91 | $ 35,697,623.83 | $ 372,802,751.20 | $ (9,632,172.08) | $ 282,408,482.69 | $ 4,156,064.48 | $ 3,490,288.25 | $ 663,708,361.61 | $ 5,365,901,340.77 |
| | **Allocation Factor** | 0.74 | 0.00 | 0.01 | 0.07 | (0.00) | 0.05 | 0.00 | 0.00 | 0.12 | 1.00 |
| | **Allocation Percentages** | 74.3394% | 0.4527% | 0.6653% | 6.9476% | -0.1795% | 5.2630% | 0.0775% | 0.0650% | 12.3690% | 1.00 |

**Item 4-8.e**
**OPC Data Request 4**
**MMF Q2 CY2023**
**Attachment 1**

## MMF -ASUS Allocation to Direct US Affiliates

As of March 31, 2023
For Q2 CY23

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass | AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|---|---|---|---|---|
| WGLH | 85.276% | 75.1299% | 85.465% | 81.9569% | 4,489,680,903 | (989,394,186) | 178,328,648 |
| APHUS | 5.5007% | 4.3844% | 1.9209% | **3.9353%** | 289,604,587 | (57,738,336) | 4,008,011 |
| SEMCO | 9.2231% | 20.4857% | 12.6146% | **14.1078%** | 485,586,260 | (269,778,562) | 26,321,392 |
| **Total** | **100.000%** | **100.000%** | **100.000%** | **100.000%** | **5,264,871,750** | **(1,316,911,084)** | **208,658,051** |

## MMF - WGLH Allocation to WGL and Pre-merger US Affiliates

As of March 31, 2023
For Q2 CY23

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass | AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|---|---|---|---|---|
| 00 WGLH | | | | | | | |
| 01 WGL | 90.4261% | 92.4808% | 92.4965% | **91.8011%** | 4,059,845,154 | (914,999,850) | 164,947,671 |
| 07 Hampshire Gas | 0.5455% | 1.2713% | 0.7790% | **0.8653%** | 24,491,003 | (12,578,181) | 1,389,163 |
| 15 WGES | 1.0815% | 6.2479% | 6.7238% | **4.6844%** | 48,554,730 | (61,816,155) | 11,990,379 |
| 28 Midstream MVP | 7.9469% | 0.0000% | 0.0008% | **2.6492%** | 356,790,017 | - | 1,434 |
| **Total** | **100.000%** | **100.000%** | **100.000%** | **100.000%** | **4,489,680,903** | **(989,394,186)** | **178,328,648** |

**Item 4-8.e**
**OPC Data Request 4**
**MMF Q2 CY2023**
**Attachment 2**

| QTR | AGA Definition Categories | BU [01] WGL | BU [07] Hampshire | BU [15] WGLE Services | BU [28] Midstream MVP | 305 AltaGas Power Holdings (U.S.) | 312 Blythe Energy, Inc. | 320 AltaGas Brush Energy Inc. | 326 ltaGas Blythe Operations In | 400 SEMCO | BALANCE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Mar_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,997,251,872.66 | 27,019,788.68 | 323,395,361.25 | (34,907,129.49) | (100,372,362.41) | 370,250,119.49 | 10,233,849.83 | (8,323.79) | 672,675,930.00 | 3,265,539,106.23 |
| | Net Income (Current Year before closing RE) | 141,110,869.25 | 816,783.44 | 66,490,555.25 | (2,053,013.30) | 5,557,858.58 | 1,488,718.59 | 312,622.73 | (1,050.58) | 72,899,169.00 | 286,622,512.96 |
| | Total Long Term Debt | 1,710,910,769.31 | - | - | 147,289,111.11 | - | - | - | - | 492,603,894.00 | 2,350,803,774.42 |
| | Notes Payable & LTD Due in 1 Year | 20,550,077 | - | - | - | - | - | - | - | 4,913,004 | 25,463,081.15 |
| | Money Pool Borrowings | - | (2,775,352.53) | (299,487,543.58) | 248,982,655.09 | (104,431,578.41) | (85,400,238.63) | - | 3,200,474.46 | - | (239,911,583.60) |
| | Less: Investment in Subs | - | - | - | - | 152,340,639.85 | - | - | - | (742,038,681.00) | (589,698,041.16) |
| | **Total Mar 2022** | **$ 3,869,823,588.37** | **$ 25,061,219.59** | **$ 90,398,372.92** | **$ 359,311,623.41** | **$ (46,905,442.39)** | **$ 286,338,599.45** | **$ 10,546,472.56** | **$ 3,191,100.09** | **$ 501,053,316.00** | **$ 5,098,818,850.00** |
| ***Jun_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,972,241,450.83 | 27,019,788.68 | 318,395,361.25 | (34,907,129.49) | (100,372,362.41) | 370,250,119.49 | (547,511.41) | (8,323.79) | 688,668,407.03 | 3,240,739,800.19 |
| | Net Income (Current Year before closing RE) | 118,758,539.84 | 1,610,527.64 | 63,618,198.15 | (3,423,350.51) | 11,479,191.95 | 6,101,485.49 | 547,511.41 | (2,090.46) | 84,924,641.97 | 283,614,655.48 |
| | Total Long Term Debt | 1,728,108,070 | - | - | 147,289,111 | - | - | - | - | 450,111,157.00 | 2,325,508,338.37 |
| | Notes Payable & LTD Due in 1 Year | 25,459,876 | - | - | - | - | - | - | - | 100,780.00 | 25,560,655.70 |
| | Money Pool Borrowings | - | (4,328,353.79) | (551,285,207.46) | 247,257,253.29 | (84,046,398.57) | (89,714,951.92) | - | 3,497,847.76 | - | (478,619,810.69) |
| | Less: Investment in Subs | - | - | - | - | 158,275,571.10 | - | - | - | (733,656,787.00) | (575,381,215.90) |
| | **Total June 2022** | **$ 3,844,567,936.63** | **$ 24,301,962.53** | **$ (169,271,648.06)** | **$ 356,215,884.40** | **$ (14,663,997.93)** | **$ 286,636,653.06** | **$ (0.00)** | **$ 3,487,433.51** | **$ 490,148,199.00** | **$ 4,821,422,423.15** |
| ***Sep_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,947,234,682.82 | 27,019,788.68 | 313,395,361.25 | (34,907,129.49) | (60,027,066.85) | 370,250,119.49 | (517,888.51) | (8,323.79) | 685,436,255.40 | 3,247,875,799.00 |
| | Net Income (Current Year before closing RE) | 110,969,426.49 | 2,455,808.75 | 91,908,764.97 | (4,960,491.76) | 23,379,446.81 | 13,587,360.37 | 517,888.51 | (13,471.04) | 91,628,329.60 | 329,473,062.70 |
| | Total Long Term Debt | 1,728,712,816 | - | - | 147,289,111 | - | - | - | - | 447,955,264.00 | 2,323,957,191.53 |
| | Notes Payable & LTD Due in 1 Year | 258,679,615 | - | - | - | - | - | - | - | 99,955.00 | 258,779,569.53 |
| | Money Pool Borrowings | - | (5,706,168.47) | (411,508,998.60) | 250,048,358.51 | (86,559,469.77) | (108,242,705.23) | - | 3,830,891.91 | - | (358,138,091.65) |
| | Less: Investment in Subs | - | - | - | - | 150,807,840.18 | - | - | - | (737,131,908.00) | (586,324,067.83) |
| | **Total Sep 2022** | **$ 4,045,596,540.26** | **$ 23,769,428.96** | **$ (6,204,872.38)** | **$ 357,469,848.37** | **$ 27,600,750.36** | **$ 275,594,774.63** | **$ (0.00)** | **$ 3,809,097.08** | **$ 487,987,896.00** | **$ 5,215,623,463.28** |
| ***Dec_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,922,211,089.09 | 27,019,788.68 | 308,395,361.25 | (34,907,129.49) | (61,828,882.86) | 370,250,119.49 | (517,888.51) | (8,323.79) | 646,683,048.13 | 3,177,297,182.00 |
| | Net Income (Current Year before closing RE) | 189,782,849.26 | 3,194,881.90 | 25,418,544.88 | (7,119,776.93) | 26,731,936.83 | 17,999,449.38 | 517,888.51 | (14,884.72) | 140,594,725.87 | 397,105,614.98 |
| | Total Long Term Debt | 1,928,669,784 | - | - | 147,289,111 | - | - | - | - | 450,580,059.00 | 2,526,538,954.54 |
| | Notes Payable & LTD Due in 1 Year | 237,817,345 | - | - | - | - | - | - | - | 139,600,025.00 | 377,417,369.58 |
| | Money Pool Borrowings | - | (5,404,859.07) | (180,128,935.82) | 249,848,820.09 | (85,854,108.53) | (111,424,026.26) | - | 4,275,081.95 | - | (128,688,027.64) |
| | Less: Investment in Subs | - | - | - | - | 146,397,340.23 | - | - | - | (747,345,098.00) | (600,947,757.78) |
| | **Total Dec 2022** | **$ 4,278,481,067.36** | **$ 24,809,811.51** | **$ 153,684,970.31** | **$ 355,111,024.78** | **$ 25,446,285.67** | **$ 276,825,542.61** | **$ (0.00)** | **$ 4,251,873.44** | **$ 630,112,760.00** | **$ 5,748,723,335.68** |
| ***Mar_2023*** | Capitalization (Sum of Corp's Stock includes RE) | 2,086,948,118.89 | 30,214,670.58 | 329,388,940.17 | (42,026,906.42) | (35,096,946.03) | 388,249,568.87 | - | (23,208.51) | 150,379,454.96 | 2,908,033,692.52 |
| | Net Income (Current Year before closing RE) | 175,000,230.02 | 985,846.86 | (53,824,122.82) | (1,580,813.87) | 8,318,313.51 | 1,931,307.86 | (95.00) | (1,238.35) | 356,771,456.04 | 487,600,884.25 |
| | Total Long Term Debt | 1,929,573,357 | - | | 147,289,111 | | | | | 492,603,894.00 | 2,569,466,362.45 |
| | Notes Payable & LTD Due in 1 Year | 69,234,932 | - | - | - | - | - | - | - | 60,913,004.00 | 130,147,935.80 |
| | Money Pool Borrowings | - | (6,687,926.42) | (101,397,990.02) | 252,160,311.28 | (97,375,294.31) | (109,445,402.14) | - | 4,842,183.20 | - | (57,904,118.41) |
| | Less: Investment in Subs | - | - | - | - | 144,464,601.73 | - | - | - | (742,038,681.00) | (597,574,079.28) |
| | **Total Mar 2023** | **$ 4,260,756,638.05** | **$ 24,512,591.02** | **$ 174,166,827.33** | **$ 355,841,702.10** | **$ 20,310,674.90** | **$ 280,735,474.59** | **$ (95.00)** | **$ 4,817,736.34** | **$ 318,629,128.00** | **$ 5,439,770,677.33** |
| | **Total 5 Qtrs** | $ 20,299,225,771 | $ 122,455,014 | $ 242,773,650 | $ 1,783,950,083 | $ 11,788,271 | $ 1,406,131,044 | $ 10,546,378 | $ 19,557,240 | $ 2,427,931,299 | $ 26,324,358,749 |
| | **Average 5 Qtrs** | $ 4,059,845,154 | $ 24,491,003 | $ 48,554,730 | $ 356,790,017 | $ 2,357,654 | $ 281,226,209 | $ 2,109,276 | $ 3,911,448 | $ 485,586,260 | $ 5,264,871,750 |
| | **Allocation Factor** | 0.77 | 0.00 | 0.01 | 0.07 | 0.00 | 0.05 | 0.00 | 0.00 | 0.09 | 1.00 |
| | **Allocation Percentages** | 77.112% | 0.465% | 0.922% | 6.777% | 0.045% | 5.342% | 0.040% | 0.074% | 9.223% | 100.000% |

**Item 4-8.e**
**OPC Data Request 4**
**MMF Q3 CY2023**
**Attachment 1**

## MMF -ASUS Allocation to Direct US Affiliates

As of June 30, 2023
For Q3 CY23

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass |
|---|---|---|---|---|
| WGLH | 84.309% | 78.3335% | 86.358% | 83.0003% |
| APHUS | 5.5635% | 3.9957% | 1.9185% | **3.8259%** |
| SEMCO | 10.1273% | 17.6708% | 11.7232% | **13.1738%** |
| **Total** | **100.000%** | **100.000%** | **100.000%** | **100.000%** |

| AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|
| 4,555,620,053 | (1,092,508,232) | 179,496,160 |
| 300,623,285 | (55,727,136) | 3,987,640 |
| 547,225,975 | (246,453,268) | 24,366,810 |
| **5,403,469,312** | **(1,394,688,636)** | **207,850,610** |

## MMF - WGLH Allocation to WGL and Pre-merger US Affiliates

-

As of June 30, 2023
For Q3 CY23

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass |
|---|---|---|---|---|
| 00 WGLH | | | | |
| 01 WGL | 91.1694% | 93.3662% | 92.6936% | **92.4097%** |
| 07 Hampshire Gas | 0.5321% | 1.0646% | 0.7844% | **0.7937%** |
| 15 WGES | 1.1108% | 5.5693% | 6.5214% | **4.4005%** |
| 28 Midstream MVP | 7.1877% | 0.0000% | 0.0006% | **2.3961%** |
| **Total** | **100.000%** | **100.000%** | **100.000%** | **100.000%** |

| AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|
| | | |
| 4,153,331,908 | (1,020,033,227) | 166,381,504 |
| 24,238,372 | (11,630,473) | 1,407,970 |
| 50,604,196 | (60,844,533) | 11,705,591 |
| 327,445,577 | - | 1,094 |
| **4,555,620,053** | **(1,092,508,232)** | **179,496,160** |

**Item 4-8.e**
**OPC Data Request 4**
**MMF Q3 CY2023**
**Attachment 2**

| QTR | AGA Definition Categories | BU [01] WGL | BU [07] Hampshire | BU [15] WGLE Services | BU [28] Midstream MVP | 305 AltaGas Power Holdings (U.S.) | 312 Blythe Energy, Inc. | 320 AltaGas Brush Energy Inc. | 326 ltaGas Blythe Operations In | 400 SEMCO | BALANCE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Jun_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,972,241,450.83 | 27,019,788.68 | 318,395,361.25 | (34,907,129.49) | (100,372,362.41) | 370,250,119.49 | (547,511.41) | (8,323.79) | 688,668,407.03 | 3,240,739,800.19 |
| | Net Income (Current Year before closing RE) | 118,758,539.84 | 1,610,527.64 | 63,618,198.15 | (3,423,350.51) | 11,479,191.95 | 6,101,485.49 | 547,511.41 | (2,090.46) | 84,924,641.97 | 283,614,655.48 |
| | Total Long Term Debt | 1,728,108,070 | - | - | 147,289,111 | - | - | - | - | 450,111,157.00 | 2,325,508,338.37 |
| | Notes Payable & LTD Due in 1 Year | 25,459,876 | - | - | - | - | - | - | - | 100,780.00 | 25,560,655.70 |
| | Money Pool Borrowings | - | (4,328,353.79) | (551,285,207.46) | 247,257,253.29 | (84,046,398.57) | (89,714,951.92) | - | 3,497,847.76 | - | (478,619,810.69) |
| | Less: Investment in Subs | - | - | - | - | 158,275,571.10 | - | - | - | (733,656,787.00) | (575,381,215.90) |
| | **Total June 2022** | **$ 3,844,567,936.63** | **$ 24,301,962.53** | **$ (169,271,648.06)** | **$ 356,215,884.40** | **$ (14,663,997.93)** | **$ 286,636,653.06** | **$ (0.00)** | **$ 3,487,433.51** | **$ 490,148,199.00** | **$ 4,821,422,423.15** |
| ***Sep_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,947,234,682.82 | 27,019,788.68 | 313,395,361.25 | (34,907,129.49) | (60,027,066.85) | 370,250,119.49 | (517,888.51) | (8,323.79) | 685,436,255.40 | 3,247,875,799.00 |
| | Net Income (Current Year before closing RE) | 110,969,426.49 | 2,455,808.75 | 91,908,764.97 | (4,960,491.76) | 23,379,446.81 | 13,587,360.37 | 517,888.51 | (13,471.04) | 91,628,329.60 | 329,473,062.70 |
| | Total Long Term Debt | 1,728,712,816 | - | - | 147,289,111 | - | - | - | - | 447,955,264.00 | 2,323,957,191.53 |
| | Notes Payable & LTD Due in 1 Year | 258,679,615 | - | - | - | - | - | - | - | 99,955.00 | 258,779,569.53 |
| | Money Pool Borrowings | - | (5,706,168.47) | (411,508,998.60) | 250,048,358.51 | (86,559,469.77) | (108,242,705.23) | - | 3,830,891.91 | - | (358,138,091.65) |
| | Less: Investment in Subs | - | - | - | - | 150,807,840.18 | - | - | - | (737,131,908.00) | (586,324,067.83) |
| | **Total Sep 2022** | **$ 4,045,596,540.26** | **$ 23,769,428.96** | **$ (6,204,872.38)** | **$ 357,469,848.37** | **$ 27,600,750.36** | **$ 275,594,774.63** | **$ (0.00)** | **$ 3,809,097.08** | **$ 487,987,896.00** | **$ 5,215,623,463.28** |
| ***Dec_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,922,211,089.09 | 27,019,788.68 | 308,395,361.25 | (34,907,129.49) | (61,828,882.86) | 370,250,119.49 | (517,888.51) | (8,323.79) | 646,683,048.13 | 3,177,297,182.00 |
| | Net Income (Current Year before closing RE) | 189,782,849.26 | 3,194,881.90 | 25,418,544.88 | (7,119,776.93) | 26,731,936.83 | 17,999,449.38 | 517,888.51 | (14,884.72) | 140,594,725.87 | 397,105,614.98 |
| | Total Long Term Debt | 1,928,669,784 | - | - | 147,289,111 | - | - | - | - | 450,580,059.00 | 2,526,538,954.54 |
| | Notes Payable & LTD Due in 1 Year | 237,817,345 | - | - | - | - | - | - | - | 139,600,025.00 | 377,417,369.58 |
| | Money Pool Borrowings | - | (5,404,859.07) | (180,128,935.82) | 249,848,820.09 | (85,854,108.53) | (111,424,026.26) | - | 4,275,081.95 | - | (128,688,027.64) |
| | Less: Investment in Subs | - | - | - | - | 146,397,340.23 | - | - | - | (747,345,098.00) | (600,947,757.78) |
| | **Total Dec 2022** | **$ 4,278,481,067.36** | **$ 24,809,811.51** | **$ 153,684,970.31** | **$ 355,111,024.78** | **$ 25,446,285.67** | **$ 276,825,542.61** | **$ (0.00)** | **$ 4,251,873.44** | **$ 630,112,760.00** | **$ 5,748,723,335.68** |
| ***Mar_2023*** | Capitalization (Sum of Corp's Stock includes RE) | 2,086,948,118.89 | 30,214,670.58 | 329,388,940.17 | (42,026,906.42) | (35,096,946.03) | 388,249,568.87 | - | (23,208.51) | 150,379,454.96 | 2,908,033,692.52 |
| | Net Income (Current Year before closing RE) | 175,000,230.02 | 985,846.86 | (53,824,122.82) | (1,580,813.87) | 8,318,313.51 | 1,931,307.86 | (95.00) | (1,238.35) | 356,771,456.04 | 487,600,884.25 |
| | Total Long Term Debt | 1,929,573,357 | - | | 147,289,111 | | | | | 492,603,894.00 | 2,569,466,362.45 |
| | Notes Payable & LTD Due in 1 Year | 69,234,932 | - | - | - | - | - | - | - | 60,913,004.00 | 130,147,935.80 |
| | Money Pool Borrowings | - | (6,687,926.42) | (101,397,990.02) | 252,160,311.28 | (97,375,294.31) | (109,445,402.14) | - | 4,842,183.20 | - | (57,904,118.41) |
| | Less: Investment in Subs | - | - | - | - | 144,464,601.73 | - | - | - | (742,038,681.00) | (597,574,079.28) |
| | **Total Mar 2023** | **$ 4,260,756,638.05** | **$ 24,512,591.02** | **$ 174,166,827.33** | **$ 355,841,702.10** | **$ 20,310,674.90** | **$ 280,735,474.59** | **$ (95.00)** | **$ 4,817,736.34** | **$ 318,629,128.00** | **$ 5,439,770,677.33** |
| ***Jun_2023*** | Capitalization (Sum of Corp's Stock includes RE) | 2,061,901,186.92 | 30,214,670.58 | 324,650,547.98 | (42,026,906.42) | (35,096,946.02) | 388,249,568.87 | - | (23,208.51) | 146,643,337.88 | 2,874,512,251.28 |
| | Net Income (Current Year before closing RE) | 197,147,051.02 | 1,889,331.61 | (40,192,586.78) | 202,835.14 | 11,101,196.27 | 5,373,664.96 | (405.00) | (2,819.49) | 364,687,014.12 | 540,205,281.85 |
| | Total Long Term Debt | 1,931,452,879 | - | - | - | - | - | - | - | 297,839,242.00 | 2,229,292,121.13 |
| | Notes Payable & LTD Due in 1 Year | 146,756,238 | - | - | - | - | - | - | - | 82,297.00 | 146,838,535.38 |
| | Money Pool Borrowings | - | (8,305,934.22) | (183,812,259.39) | 254,413,497.02 | (105,489,691.53) | (102,012,415.73) | - | 5,140,830.79 | - | (140,065,973.06) |
| | Less: Investment in Subs | - | - | - | - | 141,024,445.76 | - | - | - | - | 141,024,445.76 |
| | **Total Jun 2023** | **$ 4,337,257,355.45** | **$ 23,798,067.97** | **$ 100,645,701.81** | **$ 212,589,425.74** | **$ 11,539,004.47** | **$ 291,610,818.10** | **$ (405.00)** | **$ 5,114,802.79** | **$ 809,251,891.00** | **$ 5,791,806,662.33** |
| | **Total 5 Qtrs** | $ 20,766,659,538 | $ 121,191,862 | $ 253,020,979 | $ 1,637,227,885 | $ 70,232,717 | $ 1,411,403,263 | $ (500) | $ 21,480,943 | $ 2,736,129,874 | $ 27,017,346,562 |
| | **Average 5 Qtrs** | $ 4,153,331,908 | $ 24,238,372 | $ 50,604,196 | $ 327,445,577 | $ 14,046,543 | $ 282,280,653 | $ (100) | $ 4,296,189 | $ 547,225,975 | $ 5,403,469,312 |
| | **Allocation Factor** | 0.77 | 0.00 | 0.01 | 0.06 | 0.00 | 0.05 | (0.00) | 0.00 | 0.10 | 1.00 |
| | **Allocation Percentages** | 76.864% | 0.449% | 0.937% | 6.060% | 0.260% | 5.224% | 0.000% | 0.080% | 10.127% | 100.000% |

**Item 4-8.e**
**OPC Data Request 4**
**MMF Q4 CY2023**
**Attachment 1**

## MMF -ASUS Allocation to Direct US Affiliates

As of September 30, 2023
For Q4 CY23

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass | AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|---|---|---|---|---|
| WGLH | 86.801% | 79.3549% | 86.664% | 84.2733% | 4,756,696,977 | (1,078,537,101) | 182,236,684 |
| APHUS | 5.6090% | 3.9767% | 1.8606% | **3.8154%** | 307,375,249 | (54,048,568) | 3,912,430 |
| SEMCO | 7.5904% | 16.6684% | 11.4750% | **11.9113%** | 415,957,050 | (226,545,752) | 24,129,540 |
| Total | **100.000%** | **100.000%** | **100.000%** | **100.000%** | **5,480,029,276** | **(1,359,131,421)** | **210,278,654** |

## MMF - WGLH Allocation to WGL and Pre-merger US Affiliates

As of September 30, 2023
For Q4 CY23

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass | AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|---|---|---|---|---|
| 00 WGLH | | | | | | | |
| 01 WGL | 89.8126% | 93.3641% | 92.7335% | **91.9700%** | 4,272,111,053 | (1,006,966,149) | 168,994,492 |
| 07 Hampshire Gas | 0.5070% | 1.0649% | 0.7884% | **0.7868%** | 24,115,033 | (11,485,239) | 1,436,811 |
| 15 WGES | 2.1147% | 5.5710% | 6.4767% | **4.7208%** | 100,590,944 | (60,085,713) | 11,802,997 |
| 28 Midstream MVP | 7.5658% | 0.0000% | 0.0013% | **2.5224%** | 359,879,947 | - | 2,384 |
| Total | **100.000%** | **100.000%** | **100.000%** | **100.000%** | **4,756,696,977** | **(1,078,537,101)** | **182,236,684** |

**Item 4-8.e**
**OPC Data Request 4**
**MMF Q4 CY2023**
**Attachment 2**

| | | BU [01] | BU [07] | BU [15] | BU [28] | 305 | 312 | 320 | 326 | 400 | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| QTR | AGA Definition Categories | WGL | Hampshire | WGLE Services | Midstream MVP | AltaGas Power Holdings (U.S.) | Blythe Energy, Inc. | AltaGas Brush Energy Inc. | ltaGas Blythe Operations In | SEMCO | BALANCE |
| *Sep_2022* | Capitalization (Sum of Corp's Stock includes RE) | 1,947,234,682.82 | 27,019,788.68 | 313,395,361.25 | (34,907,129.49) | (60,027,066.85) | 370,250,119.49 | (517,888.51) | (8,323.79) | 685,436,255.40 | 3,247,875,799.00 |
| | Net Income (Current Year before closing RE) | 110,969,426.49 | 2,455,808.75 | 91,908,764.97 | (4,960,491.76) | 23,379,446.81 | 13,587,360.37 | 517,888.51 | (13,471.04) | 91,628,329.60 | 329,473,062.70 |
| | Total Long Term Debt | 1,728,712,816 | - | - | 147,289,111 | - | - | - | - | 447,955,264.00 | 2,323,957,191.53 |
| | Notes Payable & LTD Due in 1 Year | 258,679,615 | - | - | - | - | - | - | - | 99,955.00 | 258,779,569.53 |
| | Money Pool Borrowings | - | (5,706,168.47) | (411,508,998.60) | 250,048,358.51 | (86,559,469.77) | (108,242,705.23) | - | 3,830,891.91 | - | (358,138,091.65) |
| | Less: Investment in Subs | - | - | - | - | 150,807,840.18 | - | - | - | (737,131,908.00) | (586,324,067.83) |
| | **Total Sep 2022** | **$ 4,045,596,540.26** | **$ 23,769,428.96** | **$ (6,204,872.38)** | **$ 357,469,848.37** | **$ 27,600,750.36** | **$ 275,594,774.63** | **$ (0.00)** | **$ 3,809,097.08** | **$ 487,987,896.00** | **$ 5,215,623,463.28** |
| *Dec_2022* | Capitalization (Sum of Corp's Stock includes RE) | 1,922,211,089.09 | 27,019,788.68 | 308,395,361.25 | (34,907,129.49) | (61,828,882.86) | 370,250,119.49 | (517,888.51) | (8,323.79) | 646,683,048.13 | 3,177,297,182.00 |
| | Net Income (Current Year before closing RE) | 189,782,849.26 | 3,194,881.90 | 25,418,544.88 | (7,119,776.93) | 26,731,936.83 | 17,999,449.38 | 517,888.51 | (14,884.72) | 140,594,725.87 | 397,105,614.98 |
| | Total Long Term Debt | 1,928,669,784 | - | - | 147,289,111 | - | - | - | - | 450,580,059.00 | 2,526,538,954.54 |
| | Notes Payable & LTD Due in 1 Year | 237,817,345 | - | - | - | - | - | - | - | 139,600,025.00 | 377,417,369.58 |
| | Money Pool Borrowings | - | (5,404,859.07) | (180,128,935.82) | 249,848,820.09 | (85,854,108.53) | (111,424,026.26) | - | 4,275,081.95 | - | (128,688,027.64) |
| | Less: Investment in Subs | - | - | - | - | 146,397,340.23 | - | - | - | (747,345,098.00) | (600,947,757.78) |
| | **Total Dec 2022** | **$ 4,278,481,067.36** | **$ 24,809,811.51** | **$ 153,684,970.31** | **$ 355,111,024.78** | **$ 25,446,285.67** | **$ 276,825,542.61** | **$ (0.00)** | **$ 4,251,873.44** | **$ 630,112,760.00** | **$ 5,748,723,335.68** |
| *Mar_2023* | Capitalization (Sum of Corp's Stock includes RE) | 2,086,948,118.89 | 30,214,670.58 | 329,388,940.17 | (42,026,906.42) | (35,096,946.03) | 388,249,568.87 | - | (23,208.51) | 150,379,454.96 | 2,908,033,692.52 |
| | Net Income (Current Year before closing RE) | 175,000,230.02 | 985,846.86 | (53,824,122.82) | (1,580,813.87) | 8,318,313.51 | 1,931,307.86 | (95.00) | (1,238.35) | 356,771,456.04 | 487,600,884.25 |
| | Total Long Term Debt | 1,929,573,357 | - | | 147,289,111 | | | | | 492,603,894.00 | 2,569,466,362.45 |
| | Notes Payable & LTD Due in 1 Year | 69,234,932 | - | - | - | - | - | - | - | 60,913,004.00 | 130,147,935.80 |
| | Money Pool Borrowings | - | (6,687,926.42) | (101,397,990.02) | 252,160,311.28 | (97,375,294.31) | (109,445,402.14) | - | 4,842,183.20 | - | (57,904,118.41) |
| | Less: Investment in Subs | - | - | - | - | 144,464,601.73 | - | - | - | (742,038,681.00) | (597,574,079.28) |
| | **Total Mar 2023** | **$ 4,260,756,638.05** | **$ 24,512,591.02** | **$ 174,166,827.33** | **$ 355,841,702.10** | **$ 20,310,674.90** | **$ 280,735,474.59** | **$ (95.00)** | **$ 4,817,736.34** | **$ 318,629,128.00** | **$ 5,439,770,677.33** |
| *Jun_2023* | Capitalization (Sum of Corp's Stock includes RE) | 2,061,901,186.92 | 30,214,670.58 | 324,650,547.98 | (42,026,906.42) | (35,096,946.02) | 388,249,568.87 | - | (23,208.51) | 146,643,337.88 | 2,874,512,251.28 |
| | Net Income (Current Year before closing RE) | 197,147,051.02 | 1,889,331.61 | (40,192,586.78) | 202,835.14 | 11,101,196.27 | 5,373,664.96 | (405.00) | (2,819.49) | 364,687,014.12 | 540,205,281.85 |
| | Total Long Term Debt | 1,931,452,879 | - | - | - | - | - | - | - | 297,839,242.00 | 2,229,292,121.13 |
| | Notes Payable & LTD Due in 1 Year | 146,756,238 | - | - | 147,289,111 | - | - | - | - | 82,297.00 | 294,127,646.49 |
| | Money Pool Borrowings | - | (8,305,934.22) | (183,812,259.39) | 254,413,497.02 | (105,489,691.53) | (102,012,415.73) | - | 5,140,830.79 | - | (140,065,973.06) |
| | Less: Investment in Subs | - | - | - | - | 141,024,445.76 | - | - | - | (507,798,350.00) | (366,773,904.25) |
| | **Total Jun 2023** | **$ 4,337,257,355.45** | **$ 23,798,067.97** | **$ 100,645,701.81** | **$ 359,878,536.85** | **$ 11,539,004.47** | **$ 291,610,818.10** | **$ (405.00)** | **$ 5,114,802.79** | **$ 301,453,541.00** | **$ 5,431,297,423.44** |
| *Sep_2023* | Capitalization (Sum of Corp's Stock includes RE) | 2,116,868,677.83 | 30,214,670.58 | 319,146,722.07 | (42,026,906.42) | (20,000,838.29) | 388,249,568.87 | - | (23,208.51) | 155,285,850.50 | 2,947,714,536.64 |
| | Net Income (Current Year before closing RE) | 155,808,008.83 | 2,989,412.77 | (9,248,548.53) | 9,180,776.71 | 13,508,105.76 | 9,274,594.68 | - | (3,832.87) | 347,176,908.92 | 528,685,426.27 |
| | Total Long Term Debt | 1,931,916,903 | - | - | **147,289,111.11** | - | - | - | - | 295,445,890.89 | 2,374,651,904.87 |
| | Notes Payable & LTD Due in 1 Year | 233,870,077 | - | - | - | - | - | - | - | 42,625,564.80 | 276,495,641.38 |
| | Money Pool Borrowings | - | (9,518,819.36) | (218,403,826.95) | 256,655,641.63 | (97,746,217.48) | (126,438,184.45) | - | 5,407,300.07 | - | (190,044,106.54) |
| | Less: Investment in Subs | - | - | (10,832,256.06) | - | 136,992,623.04 | - | - | - | (498,932,289.00) | (372,771,922.03) |
| | **Total Sep 2023** | **$ 4,438,463,666.11** | **$ 23,685,263.99** | **$ 80,662,090.53** | **$ 371,098,623.03** | **$ 32,753,673.03** | **$ 271,085,979.10** | **$ -** | **$ 5,380,258.69** | **$ 341,601,926.11** | **$ 5,564,731,480.59** |
| | **Total 5 Qtrs** | $ 21,360,555,267 | $ 120,575,163 | $ 502,954,718 | $ 1,799,399,735 | $ 117,650,388 | $ 1,395,852,589 | $ (500) | $ 23,373,768 | $ 2,079,785,251 | $ 27,400,146,380 |
| | **Average 5 Qtrs** | $ 4,272,111,053 | $ 24,115,033 | $ 100,590,944 | $ 359,879,947 | $ 23,530,078 | $ 279,170,518 | $ (100) | $ 4,674,754 | $ 415,957,050 | $ 5,480,029,276 |
| | **Allocation Factor** | 0.78 | 0.00 | 0.02 | 0.07 | 0.00 | 0.05 | (0.00) | 0.00 | 0.08 | 1.00 |
| | **Allocation Percentages** | 77.958% | 0.440% | 1.836% | 6.567% | 0.429% | 5.094% | 0.000% | 0.085% | 7.590% | 100.000% |

**Item 4-8.e**
**OPC Data Request 4**
**MMF Q1 CY2024**
**Attachment 1**

**MMF -ASUS Allocation to Direct US Affiliates**

As of December 31, 2023
For Q1 CY24

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass |
|---|---|---|---|---|
| WGLH | 87.4386% | 81.4533% | 87.1724% | **85.3548%** |
| APHUS | 5.5579% | 3.9840% | 2.1161% | **3.8860%** |
| SEMCO | 7.0035% | 14.5627% | 10.7115% | **10.7592%** |
| **Total** | **100.000%** | **100.000%** | **100.000%** | **100.000%** |

| AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|
| 4,887,560,605 | (1,087,205,386) | 186,113,091 |
| 310,672,762 | (53,176,525) | 4,517,793 |
| 391,472,603 | (194,377,667) | 22,869,136 |
| **5,589,705,969** | **(1,334,759,578)** | **213,500,020** |

**MMF - WGLH Allocation to WGL and Pre-merger US Affiliates**

As of December 31, 2023
For Q1 CY24

| BU | AIC% | Net Revenue % | Labor % | Average/Mod Mass |
|---|---|---|---|---|
| 00 WGLH | | | | |
| 01 WGL | 89.6270% | 92.0640% | 92.8534% | **91.5148%** |
| 07 Hampshire Gas | 0.5040% | 1.0415% | 0.7940% | **0.7798%** |
| 15 WGES | 2.4120% | 6.8946% | 6.3518% | **5.2195%** |
| 28 Midstream MVP | 7.4570% | 0.0000% | 0.0008% | **2.4859%** |
| **Total** | **100.000%** | **100.000%** | **100.000%** | **100.000%** |

| AIC -$ | Net Revenue- $ | Labor-$ |
|---|---|---|
| | | |
| 4,380,576,380 | (1,000,924,457) | 172,812,400 |
| 24,631,970 | (11,322,921) | 1,477,764 |
| 117,888,285 | (74,958,008) | 11,821,510 |
| 364,463,969 | - | 1,417 |
| **4,887,560,605** | **(1,087,205,386)** | **186,113,091** |

**Item 4-8.e**
**OPC Data Request 4**
**MMF Q1 CY2024**
**Attachment 2**

| | | BU [01] | BU [07] | BU [15] | BU [28] | 305 | 312 | 320 | 326 | 400 | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **QTR** | **AGA Definition Categories** | **WGL** | **Hampshire** | **WGLE Services** | **Midstream MVP** | **AltaGas Power Holdings (U.S.)** | **Blythe Energy, Inc.** | **AltaGas Brush Energy Inc.** | **ltaGas Blythe Operations In** | **SEMCO** | **BALANCE** |
| ***Dec_2022*** | Capitalization (Sum of Corp's Stock includes RE) | 1,922,211,089.09 | 27,019,788.68 | 308,395,361.25 | (34,907,129.49) | (61,828,882.86) | 370,250,119.49 | (517,888.51) | (8,323.79) | 646,683,048.13 | 3,177,297,182.00 |
| | Net Income (Current Year before closing RE) | 189,782,849.26 | 3,194,881.90 | 25,418,544.88 | (7,119,776.93) | 26,731,936.83 | 17,999,449.38 | 517,888.51 | (14,884.72) | 140,594,725.87 | 397,105,614.98 |
| | Total Long Term Debt | 1,928,669,784 | - | - | 147,289,111 | - | - | - | - | 450,580,059.00 | 2,526,538,954.54 |
| | Notes Payable & LTD Due in 1 Year | 237,817,345 | - | - | - | - | - | - | - | 139,600,025.00 | 377,417,369.58 |
| | Money Pool Borrowings | - | (5,404,859.07) | (180,128,935.82) | 249,848,820.09 | (85,854,108.53) | (111,424,026.26) | - | 4,275,081.95 | - | (128,688,027.64) |
| | Less: Investment in Subs | - | - | - | - | 146,397,340.23 | - | - | - | (747,345,098.00) | (600,947,757.78) |
| | **Total Dec 2022** | **$ 4,278,481,067.36** | **$ 24,809,811.51** | **$ 153,684,970.31** | **$ 355,111,024.78** | **$ 25,446,285.67** | **$ 276,825,542.61** | **$ (0.00)** | **$ 4,251,873.44** | **$ 630,112,760.00** | **$ 5,748,723,335.68** |
| ***Mar_2023*** | Capitalization (Sum of Corp's Stock includes RE) | 2,086,948,118.89 | 30,214,670.58 | 329,388,940.17 | (42,026,906.42) | (35,096,946.03) | 388,249,568.87 | - | (23,208.51) | 150,379,454.96 | 2,908,033,692.52 |
| | Net Income (Current Year before closing RE) | 175,000,230.02 | 985,846.86 | (53,824,122.82) | (1,580,813.87) | 8,318,313.51 | 1,931,307.86 | (95.00) | (1,238.35) | 356,771,456.04 | 487,600,884.25 |
| | Total Long Term Debt | 1,929,573,357 | - | | 147,289,111 | | | | | 492,603,894.00 | 2,569,466,362.45 |
| | Notes Payable & LTD Due in 1 Year | 69,234,932 | - | - | - | - | - | - | - | 60,913,004.00 | 130,147,935.80 |
| | Money Pool Borrowings | - | (6,687,926.42) | (101,397,990.02) | 252,160,311.28 | (97,375,294.31) | (109,445,402.14) | - | 4,842,183.20 | - | (57,904,118.41) |
| | Less: Investment in Subs | - | - | - | - | 144,464,601.73 | - | - | - | (742,038,681.00) | (597,574,079.28) |
| | **Total Mar 2023** | **$ 4,260,756,638.05** | **$ 24,512,591.02** | **$ 174,166,827.33** | **$ 355,841,702.10** | **$ 20,310,674.90** | **$ 280,735,474.59** | **$ (95.00)** | **$ 4,817,736.34** | **$ 318,629,128.00** | **$ 5,439,770,677.33** |
| ***Jun_2023*** | Capitalization (Sum of Corp's Stock includes RE) | 2,061,901,186.92 | 30,214,670.58 | 324,650,547.98 | (42,026,906.42) | (35,096,946.02) | 388,249,568.87 | - | (23,208.51) | 146,643,337.88 | 2,874,512,251.28 |
| | Net Income (Current Year before closing RE) | 197,147,051.02 | 1,889,331.61 | (40,192,586.78) | 202,835.14 | 11,101,196.27 | 5,373,664.96 | (405.00) | (2,819.49) | 364,687,014.12 | 540,205,281.85 |
| | Total Long Term Debt | 1,931,452,879 | - | - | - | - | - | - | - | 297,839,242.00 | 2,229,292,121.13 |
| | Notes Payable & LTD Due in 1 Year | 146,756,238 | - | - | 147,289,111 | - | - | - | - | 82,297.00 | 294,127,646.49 |
| | Money Pool Borrowings | - | (8,305,934.22) | (183,812,259.39) | 254,413,497.02 | (105,489,691.53) | (102,012,415.73) | - | 5,140,830.79 | - | (140,065,973.06) |
| | Less: Investment in Subs | - | - | - | - | 141,024,445.76 | - | - | - | (507,798,350.00) | (366,773,904.25) |
| | **Total Jun 2023** | **$ 4,337,257,355.45** | **$ 23,798,067.97** | **$ 100,645,701.81** | **$ 359,878,536.85** | **$ 11,539,004.47** | **$ 291,610,818.10** | **$ (405.00)** | **$ 5,114,802.79** | **$ 301,453,541.00** | **$ 5,431,297,423.44** |
| ***Sep_2023*** | Capitalization (Sum of Corp's Stock includes RE) | 2,116,868,677.83 | 30,214,670.58 | 319,146,722.07 | (42,026,906.42) | (20,000,838.29) | 388,249,568.87 | - | (23,208.51) | 155,285,850.50 | 2,947,714,536.64 |
| | Net Income (Current Year before closing RE) | 155,808,008.83 | 2,989,412.77 | (9,248,548.53) | 9,180,776.71 | 13,508,105.76 | 9,274,594.68 | - | (3,832.87) | 347,176,908.92 | 528,685,426.27 |
| | Total Long Term Debt | 1,931,916,903 | - | - | **147,289,111.11** | - | - | - | - | 295,445,890.89 | 2,374,651,904.87 |
| | Notes Payable & LTD Due in 1 Year | 233,870,077 | - | - | - | - | - | - | - | 42,625,564.80 | 276,495,641.38 |
| | Money Pool Borrowings | - | (9,518,819.36) | (218,403,826.95) | 256,655,641.63 | (97,746,217.48) | (126,438,184.45) | - | 5,407,300.07 | - | (190,044,106.54) |
| | Less: Investment in Subs | - | - | (10,832,256.06) | - | 136,992,623.04 | - | - | - | (498,932,289.00) | (372,771,922.03) |
| | **Total Sep 2023** | **$ 4,438,463,666.11** | **$ 23,685,263.99** | **$ 80,662,090.53** | **$ 371,098,623.03** | **$ 32,753,673.03** | **$ 271,085,979.10** | **$ -** | **$ 5,380,258.69** | **$ 341,601,926.11** | **$ 5,564,731,480.59** |
| ***Dec_2023*** | Capitalization (Sum of Corp's Stock includes RE) | 2,133,037,128.52 | 30,214,670.58 | 307,692,900.73 | (42,026,906.42) | (20,000,838.28) | 388,249,568.87 | - | (23,208.51) | 144,583,398.81 | 2,941,726,714.30 |
| | Net Income (Current Year before closing RE) | 221,466,180.75 | 3,604,230.85 | (737,107.44) | 16,385,979.22 | 29,476,610.73 | 14,556,458.75 | - | 6,185.22 | 368,997,935.28 | 653,756,473.36 |
| | Total Long Term Debt | 2,132,323,203 | - | - | 147,289,111.11 | - | - | - | - | 295,469,032.00 | 2,575,081,345.92 |
| | Notes Payable & LTD Due in 1 Year | 101,096,663 | - | - | - | - | - | - | - | 66,566,996.22 | 167,663,658.86 |
| | Money Pool Borrowings | - | (7,464,785.75) | (208,636,498.39) | 258,741,774.05 | (100,959,623.48) | (125,481,960.21) | - | 5,968,252.30 | - | (177,832,841.48) |
| | Less: Investment in Subs | - | - | (18,037,458.57) | - | 131,700,740.88 | - | - | - | (510,051,704.00) | (396,388,421.70) |
| | **Total Dec 2023** | **$ 4,587,923,174.72** | **$ 26,354,115.68** | **$ 80,281,836.33** | **$ 380,389,957.96** | **$ 40,216,889.84** | **$ 277,324,067.41** | **$ -** | **$ 5,951,229.01** | **$ 365,565,658.31** | **$ 5,764,006,929.26** |
| | **Total 5 Qtrs** | $ 21,902,881,902 | $ 123,159,850 | $ 589,441,426 | $ 1,822,319,845 | $ 130,266,528 | $ 1,397,581,882 | $ (500) | $ 25,515,900 | $ 1,957,363,013 | $ 27,948,529,846 |
| | **Average 5 Qtrs** | $ 4,380,576,380 | $ 24,631,970 | $ 117,888,285 | $ 364,463,969 | $ 26,053,306 | $ 279,516,376 | $ (100) | $ 5,103,180 | $ 391,472,603 | $ 5,589,705,969 |
| | **Allocation Factor** | 0.78 | 0.00 | 0.02 | 0.07 | 0.00 | 0.05 | (0.00) | 0.00 | 0.07 | 1.00 |
| | **Allocation Percentages** | 78.369% | 0.441% | 2.109% | 6.520% | 0.466% | 5.001% | 0.000% | 0.091% | 7.003% | 100.000% |

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-8

**Q.** **Allocations from ASUS to WGL.** Witness Block's Direct Testimony states (14:10-11) that AltaGas allocates Corporate Service costs to ASUS and AltaGas Canadian affiliates, and the ASUS costs are then allocated to U.S. affiliates. Address the following regarding allocations from ASUS to WGL and U.S. affiliates using the MMF and other allocation factors for the test year end March 31, 2024, and prior calendar years 2019 to 2023:

a. Provide the amount and percent of expenses by type of ALA Corporate expense (e.g., Executive Management, Finance, Accounting and Tax, etc.) allocated from ASUS to WGL and each U.S. affiliate for each type of allocation factor method (including MMF and other methods) for calendar years 2019 to 2023, and test year end March 31, 2024.

b. Regarding (a) above, if the amount and percent of expense allocated to WGL and each U.S. affiliate for each type of allocation factor method (including MMF and other allocation methods, including those identified at Witness Quenum's testimony at 9:6-16) cannot be provided by "type of ALA Corporate expense" (Finance, Accounting and Tax, etc.), then provide the amount and percent allocated to WGL and each U.S. affiliate by each type of "cost pool" for each type of allocation factor method – and describe and identify the costs included in each cost pool. This should include (but not be limited to), cost pool allocation calculations for Overheads (Common Services, Payroll, Executive, Other, Building, Telephone and Software per the December 2023 CAM (pages 39-41) and per Quenum Exhibit (WG (J)-5 Parts A, B, and C). Also, reconcile these allocated expense amounts to the allocated amount of expenses by type of ALA Corporate expense (Finance, Accounting and Tax, etc.) for calendar years 2019 to 2023, and test year end March 31, 2024.

c. Regarding (a) and (b) above, provide the numerator and denominator of each allocation factor (including MMF and other allocation methods, including those identified at Witness Quenum's testimony 9:6-16)) for

WGL and each U.S. affiliate (along with the total allocation factor used for all affiliates subject to allocation), and provide the related underlying financial and other inputs to the allocation factors (including inputs of EBITDA, relative payroll costs, and relative property for the MMF), that are used to allocate expenses to WGL and each U.S. affiliate for calendar years 2019 to 2023, and test year end March 31, 2024. Provide all supporting documentation and calculations for all allocation factor calculations, including all inputs and summary financial data for each U.S. affiliate to which expenses are allocated using the allocation factors.

d. Regarding (b) and (c) above, provide a citation to Service Agreements and provide copies of other documentation which identify and describe each allocation factor method and how it is calculated.

e. Regarding (b) and (c) above, translate the above MMF allocation factor (and all other applicable allocation factors) information to the quarterly MMF factors calculation used for allocating expenses (Witness Quenum, 9:8-9), and provide this same calculation for other allocation factor methods that are used. Explain if any MMF allocation factor component (or other allocation factor methods) is used in arrears and the period of data to which the allocation factor is applied. For example, explain if the MMF allocation factors used for the March 31, 2024, test period are all based on financial inputs/data ending March 31, 2024, or if the factors are a combination of actual and historical (or projected data) inputs/data, such as using actual information for April 2023 to December 31, 2023 and using estimated or historical data in place of actual March 31, 2024 actual data.

f. Regarding (c) above, provide the names of each of the U.S. affiliates to which ASUS expenses are allocated using the various allocation factors (including the MMF), and provide the following:

(i) A general description of each U.S. affiliate's type of business that is conducted with AltaGas affiliates and with non-affiliated third parties – and state the reason for the existence of the business.
(ii) Identify the year when each U.S. affiliate was created and if it has operated as a going concern for all years through test year end March 31, 2024.
(iii) Explain if each U.S. affiliate is a profit center for AltaGas or WGL, or otherwise explain the purposes of the affiliate if not for generating profits for AltaGas and WGL (or for other entities).
(iv) Explain if each U.S. affiliate is any of the following: a "capital intensive" business with substantial fixed plant investment on the balance sheet that is used to provide services and generate revenues; a "service-providing" company that is not capital

intensive; or a mix of capital intensive and service-related. Explain the basis and provide supporting documentation for your response.

(v) Identify each U.S. affiliate that has and has not generated a profit for each year (calendar years 2019 to 2023 and test year end March 31, 2024).

g. Explain if and why each of the cost allocation factors (including the MMF) are the best and most reasonable allocation factors to use for allocating the related expenses or cost pools to WGL and each of the U.S. affiliates. Explain how each of the cost allocation methods used for each expense or cost pool is a reasonable driver of the related expenses, how it supports cost-causation, and if and how it is measurable, objective, stable and predictable, and consistent. Identify those cost allocation methods that do not meet these criteria.

h. Identify all U.S. affiliates/businesses that do not receive an allocation of expenses from ASUS for each of the periods (calendar years 2019 to 2023, and test year end March 2024) and explain why this is the case. Provide supporting documentation for your response.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. As stated on Page 21 of the 2023 DC Cost Allocation and Inter-company Pricing Manual (CAM), "*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*."
Please find attached the allocation of AltaGas corporate shared costs by function from ASUS to its each of its direct US Affiliates. AltaGas corporate shared costs allocations from WGL Holdings to WGL and each of its pre-merger Affiliates will be addressed in WGL's Responses to OPC DR 4-10.

b. Please refer to WGL's Response for 4-8.a.

c. ASUS used Washington Gas' MMF to allocate corporate shared services costs to WGL and US Affiliates. The three factors used in the computation of the MMF are 1) Average Invested Capital (AIC), 2) Adjusted Net Revenue, and 3) Direct & Assigned Labor.

**Average Invested Capital (AIC)** = Capitalization (Sum of Common Stock includes RE) + Net Income (Current Year before closing RE) + Total Long-term debt + Notes Payable & Pref Stock & LT Due in 1 Year + Money Pool Borrowings - Investment in Subs.

**Adjusted Net Revenue** = Operating Revenue – Cost of Sales – Revenue Taxes

**Direct & Assigned Labor** = Productive Labor + Non-Productive Labor

The MMF ratio is a simple average of the three factors for each affiliate.

Average Invested Capital of affiliate / Total Average Invested Capital
Adjusted Net Revenue of the Affiliate / Total Adjusted Revenue
Direct & Assigned Labor of the Affiliate / Total Direct & Assigned Labor

d. The Annual Cost Allocation Manual (CAM) filed with the commission 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.

e. The MMF calculation is based on actuals from historical financial statements data as of the prior quarter; it does not include projections or estimates.

   Quarterly MMF factors calculation worksheets from 2019 to March 31, 2024, are attached.

f. Please refer to the 2023 DC CAM
   (i) Please refer to Page 25 of the 2023 DC CAM.
   (ii) Please refer to Page 25 of the 2023 DC CAM.
   (iii) Each affiliate is a profit center for AltaGas.
   (iv) Please refer to WGL's Responses to OPC DR 4-8.e and OPC DR 4-7.j.
   (v) Affiliates have been profitable over the stated periods.

g. Please refer to WGL's Responses to OPC DR 4-15.

h. All operating affiliates receive an allocation.

SPONSOR: Ghislaine (Celine) Quenum
Manager, Corporate Accounting

**OPC FOLLOW-UP REQUEST** **11/22/2024**

**Q.** WGL's response to OPC 4-8(e), states the MMF calculation is based on actuals from historical financial statements as of the prior quarter; it does not include projections or estimates. Please address the following:

a. Regarding allocations from ASUS to WGL, please clarify if the expense amounts allocated to WGL for the test year end March 31, 2024, were allocated using the MMF factor for the quarter ending December 31, 2023 (which is the quarter prior to March 31, 2024 per the above explanation) – and which is applied to all actual allocated expenses for the test year end March 31, 2024. If not, please explain if each specific quarter for test year end March 31, 2024, uses the prior quarter MMF allocation factor as applied to all actual allocated expenses for test year end March 31, 2024 – for example, the March 31, 2024, allocated expenses would use the prior quarter December 31, 2023, MMF factor, the December 31, 2023, allocated expenses would use the prior quarter September 30, 2023, MMF factor, etc.

b. Confirm that the actual year-end MMF allocation factor for each year (or each test year end, such as March 31, 2024), would not apply the actual year-end factor until the end of the subsequent first quarter of the next year (for example, for year-end December 31, 2023, the actual December 31, 2023, MMF factors would only be applied to allocated expenses in the subsequent quarter ended March 31, 2024, of the subsequent year.

c. Regarding (a) above, explain if this same quarterly allocation factor approach applies to for allocations from AltaGas to ASUS and from WGL to affiliates. If not, please explain the allocation process used for these allocations.

**WASHINGTON GAS'S FOLLOW-UP RESPONSE** **12/02/2024**

**A.**

a. Please see below the MMF Calculations for the test year and the quarterly corporate cost allocations that were applied to compute the expense amounts allocated to WGL.

| | | |
|---|---|---|
| MMF Calculation as of Dec. 31, 2023 | → | Applied to Q1 CY2024 Corporate Costs Allocation |
| MMF Calculation as of Sep. 30, 2023 | → | Applied to Q4 CY2023 Corporate Costs Allocation |
| MMF Calculation as of Jun. 30, 2023 | → | Applied to Q3 CY2023 Corporate Costs Allocation |
| MMF Calculation as of Mar. 31, 2023 | → | Applied to Q2 CY2023 Corporate Costs Allocation |

b. Please see WGL's response to Question (a) above.

c. The same quarterly allocation factor approach in (a) above applies for allocations from AltaGas to ASUS and from WGL to affiliates.

SPONSOR: Ghislaine (Celine) Quenum
Manager, Corporate Accounting

Exhibit OPC (B)-9
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-9

**Q.** **Costs Allocated from WGL to Affiliates.** Witness Tuoriniemi's Direct Testimony identifies (34:4-15) those affiliates to which WGL provides services. Address the following regarding allocations from WGL to U.S. affiliates. Also, in the prior rate case FC 1169, the OPC's data request 11-1 requested a side-by-side comparison including "ALA Allocated Corporate Costs" allocated/assigned to WGL for prior years and this information was provided. However, this data request seeks the amount of expenses allocated from WGL to each affiliate by Service Category/Functions (Accounting and Taxes, Finance, Human Resources, Legal, etc.), and also showing these allocated amounts by FERC account number (and account description) in an Excel spreadsheet pivot table format. Address the following for the related test year end March 31, 2024 and prior calendar years 2019 to 2022:

a. Provide this same information described in the above preamble showing WGL expenses allocated to each affiliate by Service Category/Functions (Accounting and Taxes, Finance, Human Resources, Legal, Corporate Communications, Corporate Public Policy, etc. per related Service Agreements) in a working Excel spreadsheet format – also showing amounts by underlying FERC account number and description. Provide this information for the test year end March 31, 2024, and prior calendar years 2019 to 2022.

b. Regarding (a) above, show all expenses by primary account number and reconcile to the related A&G expense account for the related year/periods.

c. Regarding (a) above, for each WGL Corporate cost allocated to each affiliate by Service Category/Functions (Accounting and Taxes, Finance, Corporate Communications, etc.), provide these expenses separately identified between the following (unless this detailed information has already been provided in the response to (a) above, showing amounts by FERC account):

(i) Labor/payroll expense, and break out these labor expenses between compensation/salary, long-term incentives, short-term incentives, benefits (including Pension and OPEB), and payroll taxes.

(ii) Outside consulting/contracting services expense.

(iii) Depreciation expense.

(iv) Rent expense.

(v) Training expense.

(vi) Regulatory fees and assessments.

(vii) Charitable contributions expense.

(viii) Dues and subscriptions.

(ix) Lobbying expense.

(x) Insurance expense.

(xi) And all other "functional" accounts.

d. Regarding (a) above, for each WGL allocated expense by service Category/Function, explain the reason for annual changes in these amounts (for each of the calendar years 2019 to 2022, and for the test year end March 31, 2024) – for all annual changes in these expenses that equal or exceed $100,000 plus all other annual changes that equal to or exceed 10% (with a minimum annual change that equals or exceeds $50,000). Provide supporting documentation and calculations to support the annual changes described above.

e. Regarding (a) above, for each WGL allocated service cost Category/Function (Accounting and Taxes, Finance, Corporate Communications, Corporate Public Policy, etc.), identify the type of allocation method (MMF, etc.) and the specific allocation factor percentage used to allocate these costs from WGL to the affiliate, or identify the primary cost pool used for allocating these expenses and the related allocation method and the allocation factor percentage.

f. Regarding (a) above, for each WGL Service Category/Function (Accounting and Taxes, Finance, Human Resources, Corporate Communications, etc.) allocated to each affiliate for each of the periods requested (calendar years 2019 to 2022, plus test year end March 31, 2024), provide or explain as applicable, the factors that should be multiplied by the WGL amounts to arrive at the WGL-DC jurisdictional amount allocated for each Service Category/Function or if total WGL Service Category/Function expenses that are allocated to affiliates are multiplied by an overall factor, such as the 19.5408% factor (per Witness Tuoriniemi's Direct Testimony at 35:1-2) to determine the expenses allocated/assigned to WGL-DC (and if so, specify the overall factor). Provide all supporting documentation and calculations for the factors used to calculate the WGL-DC amount allocated to each affiliate.

g. Reconcile the WGL Corporate allocated service costs to affiliates provided with this data request to affiliate amounts for test year end March 31, 2024, at Witness Tuoriniemi's Direct Testimony (34:4-15) and to affiliate amounts at Witness Quenum's Confidential Exhibits WG (J)-3 and WG (J)-5 (ACOSS/study for test year end March 31, 2024).

**WASHINGTON GAS'S OBJECTION** 11/1/2024

Washington Gas objects to this request on grounds that it requires a special study which has not been performed. Without waiving this objection, the Company will provide responsive information that is available.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. The Company allocated costs to affiliates based on the service definitions in its Cost Allocation Manual ("CAM"). See the Company's response to OPC DR 4-4 which provided the service categories for the periods requested.

b. See the Company's response to OPC DR 4-4 which shows the amounts recorded in the Test Year and in CY2021, which is derived from the Affiliate Cost of Service Study and shows the amounts which represent offset to Washington Gas Expenses. The remainder of the costs are recorded to the balance sheet account 146000. Accounts Receivable Affiliates and not captured by type of service.

c. See parts (a) and (b) and the Company's response to OPC DR 4-4. The CAM provides the most detailed description of the services billed.

d. See Attachment 1 for the variations based on the CAM filings for the respective periods. Analysis at the detailed line would provide no further insight not explained by the explanations provided below and would require the preparation of a study that Washington Gas has not performed. See Exhibit WG (J) for a description of these categories.

**Direct Labor:** The continuous decline in Direct Labor from $9.4 million in 2019 to $4.0 million in the test year reflects the decrease in number and scope of Washington Gas affiliates over time requiring fewer services. The significant decline was only slightly offset by the cost of services provided to ALA affiliates over that same period.

**Direct Expenses:** The continuous decline in Direct Expenses from $11.3 million in 2019 and $0.5 million in the test year reflects the decrease in number and scope of Washington Gas affiliates over time requiring fewer services. The significant decline was only slightly offset by the cost of services provided to ALA.

**Allocation of Common Services:** The continuous decline in the Allocation of Common services is Direct Expenses from $1.4 million in 2019 and $0.6 million in the test year reflects the decrease in number and scope of Washington Gas affiliates over time requiring fewer services. The significant decline was only slightly offset by the cost of services provided to ALA affiliates over that same period.

**Overheads:** Overheads are a derivative of Direct Labor and the underlying cost of the cost of the benefits provided. The amount declined from $2.9 million to $0.6 million in the test year. While the amounts declined, due to the decrease in number and scope of Washington Gas affiliates over time requiring fewer services, the greater impact on costs over time related to fluctuations in the cost of the underlying benefits, principally Other Postretirement Benefits and Pensions. The cost of these items can vary year-over-year due to changing interest rates and investment performance. The significant decline was only slightly offset by the cost of services provided to ALA affiliates over that same period.

.

**Other Services:** The continuous decline is Other Services from $9.8 million in 2019 and $3.7 million in the test year reflects the decrease in number and scope of Washington Gas affiliates over time requiring fewer services. This category consists principally of pass-thru amounts and cash payments to/from Affiliates: such as payments for outside service providers for the benefits of affiliates and cash receipts on behalf of the affiliates; these transactions are recorded by Washington Gas as inter-company receivables/payables and have no impact on its operating expenses.

e. See Exhibit WG (J)-3, the Company's Affiliate Cost of Service Study ("ACOSS") where the Company quantified the impact of the allocation factors applied to each type of cost at the levels available. Also see Formal Case No. 1169 for the ACOSS for CY2021. Because Washington Gas has not prepared an ACOSS for any other period, it is unable to quantify the information for other periods.

f. Please refer to the Company's response to OPC DR 4-4. Cost charges to affiliates are not a cost of Washington Gas, not specific to jurisdictions and not allocated to the District of Columbia.

g. Please refer to the Company's response to OPC DR 4-4.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

Washington Gas Light Company
Affiliate Charges
FC1180 Test year and CY2019 to 2022

| Line No. | Description of Services Provided | Test Year | CY2022 | CY2021 | CY2020 | CY2019 |
|---|---|---|---|---|---|---|
| 1 | SERVICES PROVIDED TO AFFILIATES BY WG | | | | | |
| **2** | **DIRECT LABOR** | **3,961,452** | **4,003,883** | **5,204,089** | **5,828,157** | **9,423,340** |
| | DIRECT EXPENSES | | | | | |
| 3 | Computer Software | 50,164 | 461,278 | 688,594 | 1,227,828 | 1,763,347 |
| 4 | Contract Labor | 11,282 | 197,633 | 376,851 | 452,234 | 253,996 |
| 5 | Contract Other | 403 | 267 | 417,067 | 44,822 | 62,000 |
| 6 | Electricity | 1,518 | 7,538 | 9,382 | 9,126 | 6,201 |
| 7 | Material: Non-Stock | 37,296 | 244,724 | 305,253 | 235,072 | 538,270 |
| 8 | Pro Services: Auditing | 744 | 133,279 | 158,633 | 411,278 | 410,675 |
| 9 | Pro Services: Legal | 6,320 | 4,821 | 235,490 | 151,842 | 2,267,184 |
| 10 | Pro Services: Other | 246,131 | 274,231 | 1,557,729 | 1,887,062 | 3,111,886 |
| 11 | Pro Services: Systems / It | 127,147 | 1,033,033 | 1,282,739 | 1,505,331 | 1,569,928 |
| 12 | Rentals & Leases | 8,705 | 94,195 | 151,022 | 125,772 | 151,541 |
| 13 | Telephone: Land Line | 12,674 | 85,004 | 141,251 | 193,754 | 219,849 |
| 14 | Training: Pro. Services | 6,030 | 6,197 | 4,877 | 7,528 | 39,872 |
| 15 | Travel: Other Expenses | 29,353 | 165,304 | 81,952 | 98,431 | 356,218 |
| | **SUB-TOTAL** | **544,017** | **2,707,504** | **5,454,912** | **6,376,726** | **11,260,926** |
| | ALLOCATION OF COMMON SERVICES | | | | | |
| 16 | Support Services - Labor | 285,893 | 335,879 | 526,047 | 616,213 | 1,134,912 |
| 17 | Support Services - Non-Labor | 97,227 | 88,287 | 261,739 | 319,507 | 313,343 |
| 18 | ALA Corp Svcs - Labor | | | | | |
| 19 | ALA Corp Svcs - Non Labor | | | | | |
| 20 | ASUS Allocable - Labor | 51,637 | 182,352 | 58,569 | 105,969 | |
| 21 | ASUS Allocable - Non Labor | 128,183 | 101,226 | 56,309 | 83,261 | |
| | **SUB-TOTAL** | **562,940** | **707,743** | **902,665** | **1,124,950** | **1,448,256** |
| | OVERHEADS | | | | | |
| 22 | Group Insurance | 525,718 | 500,224 | 385,304 | 541,910 | 1,893,372 |
| 23 | Injuries & Damages | 67,044 | 39,424 | 32,370 | 152,693 | 292,731 |
| 24 | Other Post Retirement Benefits | (657,197) | (618,768) | (544,887) | (2,001,482) | (2,474,960) |
| 25 | Payroll Taxes | 256,416 | 234,852 | 251,624 | 411,068 | 1,166,346 |
| 26 | Pension Expense | 64,446 | (210,692) | 24,912 | 904,735 | 1,210,398 |
| 27 | Employee Savings Plan Exp | 245,990 | 249,128 | | | |
| 28 | Medicare | 59,968 | 52,828 | | | |
| 29 | FUTA | 25,861 | 18,216 | 9,755 | 2,905 | 10,528 |
| | **SUB-TOTAL** | **588,246** | **265,213** | **159,078** | **11,830** | **2,099,710** |

Washington Gas Light Company
Affiliate Charges
FC1180 Test year and CY2019 to 2022

| Line No. | Description of Services Provided | Test Year | CY2022 | CY2021 | CY2020 | CY2019 |
|---|---|---|---|---|---|---|
| | OTHER SERVICES | | | | | |
| 30 | Accounts Payable - Misc | 994,083 | 3,663,036 | 41,642 | 6,993 | 104,298 |
| 31 | Building Services Allocation | 705,047 | 607,710 | 802,546 | 1,171,492 | 1,003,259 |
| 32 | Safety Gear Allowance - Union | - | - | - | 1,032 | 505 |
| 33 | Transportation Allowance - Executive | 9,546 | - | - | 215 | 5,268 |
| 34 | Computer Services | 655,154 | 1,418,340 | 1,721,059 | 1,762,963 | 932,395 |
| 35 | Meals On-site | 710 | 1,593 | 3,891 | 2,750 | 9,168 |
| 36 | Emp Reimb - Entertainment | 33,912 | 21,424 | 6,434 | 23,341 | 49,411 |
| 37 | Emp Reimb - Local Meals | 49,883 | 30,801 | 22,377 | 10,409 | 76,700 |
| 38 | Emp Reimb - Mileage(NonPR) | 12,443 | 9,905 | 8,481 | 13,403 | 19,382 |
| 39 | Emp Reimb - Misc Exp(Payroll) | 3,996 | 9,897 | 10,730 | 68,127 | 10,984 |
| 40 | Emp Reimb - Education Refund | - | - | 150 | 365 | 397 |
| 41 | Vehicle Allowance | - | - | - | - | 7 |
| 42 | WGES Fuel Allowance | - | - | 40 | - | - |
| 43 | Settlement of Claims | - | - | 59,782 | - | - |
| 45 | G/L Journals | - | 169,988 | 211,447 | 379,442 | 936,463 |
| 46 | Insurance Premiums & Expense | 519,083 | 1,021,747 | 2,290,902 | 2,777,716 | 3,996,943 |
| 47 | GT Transportation Allocation | - | - | 56,714 | 96,137 | 272,774 |
| 48 | POE Allocation - WG | - | - | 19,557 | 81,124 | 94,060 |
| 49 | Cost of Goods Sold | - | - | 3,016,873 | 81,842 | 466,758 |
| 50 | Regulatory Fees and Assessment | 1,227 | - | 709 | - | 1,732 |
| 51 | Subscriptions, Dues, Registrat | 24,357 | 154,538 | - | 210 | 3,574 |
| 52 | Project Cancellations | - | - | 304,685 | 378,100 | 58,820 |
| 53 | Other Supplies and Expenses | 148,261 | 113,209 | - | - | - |
| 54 | Donations and Gifts | - | - | 137,017 | 145,335 | 378,637 |
| 55 | Bank and Financing Fees | 117,839 | - | 523,411 | 835,446 | 749,080 |
| 56 | Income and General Taxes | - | 1,452 | 1,277,178 | 4,451,456 | 621,070 |
| 57 | Stores Allocation | 49,450 | 71,666 | 42,487 | 17,385 | 22,648 |
| 58 | Postage Used | 7,829 | 8,304 | | | |
| | **SUB-TOTAL** | **3,717,832** | **7,303,610** | **10,558,114** | **12,306,340** | **9,814,336** |
| **59** | **Total Services Provided to Affiliates by WG** | **9,374,487** | **14,987,952** | **22,278,858** | **25,648,002** | **34,046,568** |

Washington Gas Light Company
Affiliate Charges
FC1180 Test year and CY2019 to 2022

| | | Change | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Test Year v. CY2022 | | CY2022 v. CY2021 | | CY2021 v CY2020 | | CY2020v. CY2019 | |
| Line No. | Description of Services Provided | Amount | Percent | Amount | Percent | Amount | Percent | Amount | Percent |
| 1 | SERVICES PROVIDED TO AFFILIATES BY WG | | | | | | | | |
| **2** | **DIRECT LABOR** | **(42,431)** | **-1%** | **(1,200,206)** | **-23%** | **(624,067)** | **-11%** | **(3,595,183)** | **-38%** |
| | DIRECT EXPENSES | | | | | | | | |
| 3 | Computer Software | (411,113) | -89% | (227,316) | -33% | (539,234) | -44% | (535,520) | -30% |
| 4 | Contract Labor | (186,351) | -94% | (179,218) | -48% | (75,383) | -17% | 198,238 | 78% |
| 5 | Contract Other | 136 | 51% | (416,800) | -100% | 372,245 | 830% | (17,178) | -28% |
| 6 | Electricity | (6,019) | -80% | (1,844) | -20% | 256 | 3% | 2,925 | 47% |
| 7 | Material: Non-Stock | (207,428) | -85% | (60,529) | -20% | 70,181 | 30% | (303,197) | -56% |
| 8 | Pro Services: Auditing | (132,535) | -99% | (25,354) | -16% | (252,645) | -61% | 603 | 0% |
| 9 | Pro Services: Legal | 1,499 | 31% | (230,669) | -98% | 83,647 | 55% | (2,115,341) | -93% |
| 10 | Pro Services: Other | (28,100) | -10% | (1,283,498) | -82% | (329,333) | -17% | (1,224,824) | -39% |
| 11 | Pro Services: Systems / It | (905,886) | -88% | (249,707) | -19% | (222,591) | -15% | (64,597) | -4% |
| 12 | Rentals & Leases | (85,490) | -91% | (56,827) | -38% | 25,250 | 20% | (25,769) | -17% |
| 13 | Telephone: Land Line | (72,330) | -85% | (56,247) | -40% | (52,503) | -27% | (26,095) | -12% |
| 14 | Training: Pro. Services | (167) | -3% | 1,320 | 27% | (2,651) | -35% | (32,344) | -81% |
| 15 | Travel: Other Expenses | (135,952) | -82% | 83,353 | 102% | (16,480) | -17% | (257,786) | -72% |
| | **SUB-TOTAL** | **(2,163,487)** | **-80%** | **(2,747,408)** | **-50%** | **(921,814)** | **-14%** | **(4,884,200)** | **-43%** |
| | ALLOCATION OF COMMON SERVICES | | | | | | | | |
| 16 | Support Services - Labor | (49,986) | -15% | (190,169) | -36% | (90,166) | -15% | (518,699) | -46% |
| 17 | Support Services - Non-Labor | 8,940 | 10% | (173,453) | -66% | (57,767) | -18% | 6,163 | 2% |
| 18 | ALA Corp Svcs - Labor | | | | | | | | |
| 19 | ALA Corp Svcs - Non Labor | | | | | | | | |
| 20 | ASUS Allocable - Labor | (130,714) | -72% | 123,782 | 211% | (47,399) | -45% | 105,969 | 0% |
| 21 | ASUS Allocable - Non Labor | 26,957 | 27% | 44,917 | 80% | (26,952) | -32% | 83,261 | 0% |
| | **SUB-TOTAL** | **(144,803)** | **-20%** | **(194,922)** | **-22%** | **(222,284)** | **-20%** | **(323,306)** | **-22%** |
| | OVERHEADS | | | | | | | | |
| 22 | Group Insurance | 25,494 | 5% | 114,920 | 30% | (156,607) | -29% | (1,351,462) | -71% |
| 23 | Injuries & Damages | 27,620 | 70% | 7,054 | 22% | (120,323) | -79% | (140,037) | -48% |
| 24 | Other Post Retirement Benefits | (38,428) | 6% | (73,881) | 14% | 1,456,595 | -73% | 473,478 | -19% |
| 25 | Payroll Taxes | 21,564 | 9% | (16,772) | -7% | (159,444) | -39% | (755,278) | -65% |
| 26 | Pension Expense | 275,138 | -131% | (235,604) | -946% | (879,823) | -97% | (305,662) | -25% |
| 27 | Employee Savings Plan Exp | (3,139) | -1% | 249,128 | | | | | |
| 28 | Medicare | 7,141 | 14% | 52,828 | | | | | |
| 29 | FUTA | 7,644 | 42% | 8,461 | 87% | 6,850 | 236% | (7,623) | -72% |
| | **SUB-TOTAL** | **323,034** | **122%** | **106,135** | **67%** | **147,248** | **1245%** | **(2,087,880)** | **-99%** |

Washington Gas Light Company
Affiliate Charges
FC1180 Test year and CY2019 to 2022

| | | Change | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Test Year v. CY2022 | | CY2022 v. CY2021 | | CY2021 v CY2020 | | CY2020v. CY2019 | |
| Line No. | Description of Services Provided | Amount | Percent | Amount | Percent | Amount | Percent | Amount | Percent |
| | OTHER SERVICES | | | | | | | | |
| 30 | Accounts Payable - Misc | (2,668,954) | -73% | 3,621,394 | 8697% | 34,649 | 495% | (97,305) | -93% |
| 31 | Building Services Allocation | 97,337 | 16% | (194,836) | -24% | (368,946) | -31% | 168,233 | 17% |
| 32 | Safety Gear Allowance - Union | | | - | | (1,032) | -100% | 526 | 104% |
| 33 | Transportation Allowance - Executive | 9,546 | | - | | (215) | -100% | (5,053) | -96% |
| 34 | Computer Services | (763,186) | -54% | (302,719) | -18% | (41,904) | -2% | 830,568 | 89% |
| 35 | Meals On-site | (883) | -55% | (2,298) | -59% | 1,141 | 41% | (6,418) | -70% |
| 36 | Emp Reimb - Entertainment | 12,488 | 58% | 14,990 | 233% | (16,907) | -72% | (26,070) | -53% |
| 37 | Emp Reimb - Local Meals | 19,082 | 62% | 8,423 | 38% | 11,968 | 115% | (66,291) | -86% |
| 38 | Emp Reimb - Mileage(NonPR) | 2,538 | 26% | 1,424 | 17% | (4,922) | -37% | (5,979) | -31% |
| 39 | Emp Reimb - Misc Exp(Payroll) | (5,901) | -60% | (832) | -8% | (57,397) | -84% | 57,143 | 520% |
| 40 | Emp Reimb - Education Refund | | | (150) | -100% | (215) | -59% | (32) | -8% |
| 41 | Vehicle Allowance | | | - | | | | (7) | -100% |
| 42 | WGES Fuel Allowance | | | (40) | -100% | 40 | | | |
| 43 | Settlement of Claims | | | (59,782) | -100% | 59,782 | | | |
| 45 | G/L Journals | (169,988) | -100% | (41,459) | -20% | (167,995) | -44% | (557,021) | -59% |
| 46 | Insurance Premiums & Expense | (502,664) | -49% | (1,269,155) | -55% | (486,814) | -18% | (1,219,227) | -31% |
| 47 | GT Transportation Allocation | | | (56,714) | -100% | (39,422) | -41% | (176,638) | -65% |
| 48 | POE Allocation - WG | | | (19,557) | -100% | (61,568) | -76% | (12,936) | -14% |
| 49 | Cost of Goods Sold | | | (3,016,873) | -100% | 2,935,032 | 3586% | (384,916) | -82% |
| 50 | Regulatory Fees and Assessment | 1,227 | | (709) | -100% | 709 | 0% | (1,732) | -100% |
| 51 | Subscriptions, Dues, Registrat | (130,181) | -84% | 154,538 | 0% | (210) | -100% | (3,365) | -94% |
| 52 | Project Cancellations | - | | (304,685) | -100% | (73,416) | -19% | 319,280 | 543% |
| 53 | Other Supplies and Expenses | 35,052 | 31% | 113,209 | 0% | - | 0% | - | 0% |
| 54 | Donations and Gifts | - | | (137,017) | -100% | (8,318) | -6% | (233,302) | -62% |
| 55 | Bank and Financing Fees | 117,839 | | (523,411) | -100% | (312,035) | -37% | 86,366 | 12% |
| 56 | Income and General Taxes | (1,452) | -100% | (1,275,726) | -100% | (3,174,278) | -71% | 3,830,386 | 617% |
| 57 | Stores Allocation | (22,216) | -31% | 29,178 | 69% | 25,102 | 144% | (5,263) | -23% |
| 58 | Postage Used | (475) | -6% | 8,304 | 0% | - | 0% | - | 0% |
| | **SUB-TOTAL** | **(3,585,778)** | **-49%** | **(3,254,504)** | **-31%** | **(1,748,226)** | **-14%** | **2,492,003** | **25%** |
| **59** | **Total Services Provided to Affiliates by WG** | **(5,613,465)** | **-37%** | **(7,290,906)** | **-33%** | **(3,369,144)** | **-13%** | **(8,398,566)** | **-25%** |

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-9

**Q.** **Costs Allocated from WGL to Affiliates.** Witness Tuoriniemi's Direct Testimony identifies (34:4-15) those affiliates to which WGL provides services. Address the following regarding allocations from WGL to U.S. affiliates. Also, in the prior rate case FC 1169, the OPC's data request 11-1 requested a side-by-side comparison including "ALA Allocated Corporate Costs" allocated/assigned to WGL for prior years and this information was provided. However, this data request seeks the amount of expenses allocated from WGL to each affiliate by Service Category/Functions (Accounting and Taxes, Finance, Human Resources, Legal, etc.), and also showing these allocated amounts by FERC account number (and account description) in an Excel spreadsheet pivot table format. Address the following for the related test year end March 31, 2024 and prior calendar years 2019 to 2022:

a. Provide this same information described in the above preamble showing WGL expenses allocated to each affiliate by Service Category/Functions (Accounting and Taxes, Finance, Human Resources, Legal, Corporate Communications, Corporate Public Policy, etc. per related Service Agreements) in a working Excel spreadsheet format – also showing amounts by underlying FERC account number and description. Provide this information for the test year end March 31, 2024, and prior calendar years 2019 to 2022.

b. Regarding (a) above, show all expenses by primary account number and reconcile to the related A&G expense account for the related year/periods.

c. Regarding (a) above, for each WGL Corporate cost allocated to each affiliate by Service Category/Functions (Accounting and Taxes, Finance, Corporate Communications, etc.), provide these expenses separately identified between the following (unless this detailed information has already been provided in the response to (a) above, showing amounts by FERC account):

(i) Labor/payroll expense, and break out these labor expenses between compensation/salary, long-term incentives, short-term incentives, benefits (including Pension and OPEB), and payroll taxes.

(ii) Outside consulting/contracting services expense.

(iii) Depreciation expense.

(iv) Rent expense.

(v) Training expense.

(vi) Regulatory fees and assessments.

(vii) Charitable contributions expense.

(viii) Dues and subscriptions.

(ix) Lobbying expense.

(x) Insurance expense.

(xi) And all other “functional” accounts.

d. Regarding (a) above, for each WGL allocated expense by service Category/Function, explain the reason for annual changes in these amounts (for each of the calendar years 2019 to 2022, and for the test year end March 31, 2024) – for all annual changes in these expenses that equal or exceed $100,000 plus all other annual changes that equal to or exceed 10% (with a minimum annual change that equals or exceeds $50,000). Provide supporting documentation and calculations to support the annual changes described above.

e. Regarding (a) above, for each WGL allocated service cost Category/Function (Accounting and Taxes, Finance, Corporate Communications, Corporate Public Policy, etc.), identify the type of allocation method (MMF, etc.) and the specific allocation factor percentage used to allocate these costs from WGL to the affiliate, or identify the primary cost pool used for allocating these expenses and the related allocation method and the allocation factor percentage.

f. Regarding (a) above, for each WGL Service Category/Function (Accounting and Taxes, Finance, Human Resources, Corporate Communications, etc.) allocated to each affiliate for each of the periods requested (calendar years 2019 to 2022, plus test year end March 31, 2024), provide or explain as applicable, the factors that should be multiplied by the WGL amounts to arrive at the WGL-DC jurisdictional amount allocated for each Service Category/Function or if total WGL Service Category/Function expenses that are allocated to affiliates are multiplied by an overall factor, such as the 19.5408% factor (per Witness Tuoriniemi's Direct Testimony at 35:1-2) to determine the expenses allocated/assigned to WGL-DC (and if so, specify the overall factor). Provide all supporting documentation and calculations for the factors used to calculate the WGL-DC amount allocated to each affiliate.

g. Reconcile the WGL Corporate allocated service costs to affiliates provided with this data request to affiliate amounts for test year end March 31, 2024, at Witness Tuoriniemi's Direct Testimony (34:4-15) and to affiliate amounts at Witness Quenum's Confidential Exhibits WG (J)-3 and WG (J)-5 (ACOSS/study for test year end March 31, 2024).

**WASHINGTON GAS'S OBJECTION** 11/1/2024

Washington Gas objects to this request on grounds that it requires a special study which has not been performed. Without waiving this objection, the Company will provide responsive information that is available.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. The Company allocated costs to affiliates based on the service definitions in its Cost Allocation Manual ("CAM"). See the Company's response to OPC DR 4-4 which provided the service categories for the periods requested.

b. See the Company's response to OPC DR 4-4 which shows the amounts recorded in the Test Year and in CY2021, which is derived from the Affiliate Cost of Service Study and shows the amounts which represent offset to Washington Gas Expenses. The remainder of the costs are recorded to the balance sheet account 146000. Accounts Receivable Affiliates and not captured by type of service.

c. See parts (a) and (b) and the Company's response to OPC DR 4-4. The CAM provides the most detailed description of the services billed.

d. See Attachment 1 for the variations based on the CAM filings for the respective periods. Analysis at the detailed line would provide no further insight not explained by the explanations provided below and would require the preparation of a study that Washington Gas has not performed. See Exhibit WG (J) for a description of these categories.

**Direct Labor:** The continuous decline in Direct Labor from $9.4 million in 2019 to $4.0 million in the test year reflects the decrease in number and scope of Washington Gas affiliates over time requiring fewer services. The significant decline was only slightly offset by the cost of services provided to ALA affiliates over that same period.

**Direct Expenses:** The continuous decline in Direct Expenses from $11.3 million in 2019 and $0.5 million in the test year reflects the decrease in number and scope of Washington Gas affiliates over time requiring fewer services. The significant decline was only slightly offset by the cost of services provided to ALA.

**Allocation of Common Services:** The continuous decline in the Allocation of Common services is Direct Expenses from $1.4 million in 2019 and $0.6 million in the test year reflects the decrease in number and scope of Washington Gas affiliates over time requiring fewer services. The significant decline was only slightly offset by the cost of services provided to ALA affiliates over that same period.

**Overheads:** Overheads are a derivative of Direct Labor and the underlying cost of the cost of the benefits provided. The amount declined from $2.9 million to $0.6 million in the test year. While the amounts declined, due to the decrease in number and scope of Washington Gas affiliates over time requiring fewer services, the greater impact on costs over time related to fluctuations in the cost of the underlying benefits, principally Other Postretirement Benefits and Pensions. The cost of these items can vary year-over-year due to changing interest rates and investment performance. The significant decline was only slightly offset by the cost of services provided to ALA affiliates over that same period.

.

**Other Services:** The continuous decline is Other Services from $9.8 million in 2019 and $3.7 million in the test year reflects the decrease in number and scope of Washington Gas affiliates over time requiring fewer services. This category consists principally of pass-thru amounts and cash payments to/from Affiliates: such as payments for outside service providers for the benefits of affiliates and cash receipts on behalf of the affiliates; these transactions are recorded by Washington Gas as inter-company receivables/payables and have no impact on its operating expenses.

e. See Exhibit WG (J)-3, the Company's Affiliate Cost of Service Study ("ACOSS") where the Company quantified the impact of the allocation factors applied to each type of cost at the levels available. Also see Formal Case No. 1169 for the ACOSS for CY2021. Because Washington Gas has not prepared an ACOSS for any other period, it is unable to quantify the information for other periods.

f. Please refer to the Company's response to OPC DR 4-4. Cost charges to affiliates are not a cost of Washington Gas, not specific to jurisdictions and not allocated to the District of Columbia.

g. Please refer to the Company's response to OPC DR 4-4.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

**OPC FOLLOW-UP REQUEST** **11/22/2024**

**Q.** WGL's response to OPC 4-9(e) and related Attachment 1 (pages 1 to 4) shows (and states) that Direct Labor allocated by WGL to affiliates declined from $9.40M in 2019 to $4.0M in the test year end March 31, 2024 (a reduction of $5.40M) and that Direct Expense allocated by WGL to affiliates declined from $11.30M in 2019 to $.50M in the test year end March 31, 2024 (a reduction of $10.80M) as two examples. Please address the following:

a. Per the above-cited reduction, explain if it is correct that the reduction in Direct Labor of $5.40M and Direct Expense of $10.80M for these expenses allocated from WGL to affiliates also means that WGL also incurred the same amount of reductions in these expenses on its books for the same time frame. If not, explain if it is correct that there was a reduction in Direct Labor and Direct Expense allocated from WGL to affiliates, but WGL did not incur this same level of reduction in Direct Labor and Direct Expense on its books, and so the amount of Direct Labor and Direct Expense incurred by WGL did not decline, or did not decline as much as the reduction in allocations from WGL to affiliates.

b. Regarding (a) above, for all reduction in expenses allocated by WGL to affiliates in the response to OPC 4-9(e) and Attachment 1 (pages 1 to 4), provide the corresponding amount of reduction of WGL expenses for each of the periods 2019 to test year March 31, 2024, and explain why WGL did not incur the same level of reduction in expenses as the reduction in expenses it allocated to affiliates. Provide supporting documentation and calculations for WGL's position.

c. Regarding (a) and (b) above, explain if the reduction in WGL expenses allocated to affiliates is due to a change in allocation factors or methodology, or any other type of change, and which did not result in a reduction in WGL's expenses on its books for the same type of expense. Provide supporting documentation and calculations for WGL's position.

**WASHINGTON GAS'S FOLLOW-UP RESPONSE 12/02/2024**

**A.** a. No, it is not correct that the reduction in Direct Labor of $5.40M and Direct Expense of $10.80M for these expenses allocated from WGL to affiliates also means that WGL also incurred the same amount of reductions in these expenses on its books for the same time frame.

As discussed in the original response, the decline was due to a decrease in the number and scope of Washington Gas affiliates that, over time, require fewer services. Washington Gas has a pool of resources available to perform work for itself and is available to provide services to affiliates as needed. The labor pool does not shrink on a dollar-for-dollar basis as the services provided to affiliates decrease. Likewise, if services provided to affiliates increase, Washington Gas does not need to add incremental labor to service the need. For example, if an employee charged an affiliate the cost for 80 hours of time annually to a former affiliate, and if that affiliate no longer requires service, the employee hours would either be deployed at Washington Gas to meet its needs or possibly to another affiliate. However, Washington Gas does not track individual employee time in a manner to be able to quantify it in the manner requested that would track how individual response might move.

Washington Gas monitors its staffing level and increases or decreases them as necessary. Washington Gas's Voluntary Severance Plan is the result of such an assessment.

Direct expenses are costs Washington Gas incurs directly for the benefit of the affiliate. A decrease in a direct expense incurred from an affiliate has no impact on Washington Gas's costs because the amounts were incurred for the benefit of the affiliate. If the costs are eliminated, Washington Gas's expenses would remain unchanged.

b. See part a.

c. See part a. As discussed in the original response, the decline was due to a decrease in the number and scope of Washington Gas affiliates over time requiring fewer services, and not due to a change in allocation factors or methodology, or any other type of change.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

Exhibit OPC (B)-10
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential Exhibit Omitted

Exhibit OPC (B)-11
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

Exhibit OPC (B)-11
Formal Case No. 1180
Witness: Bion Ostrander
PUBLIC VERSION

# Confidential and Attorneys' Eyes
# Exhibit Omitted

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-15

**Q.** **Two MMF Allocation Methods.** Witness Block's Direct Testimony states (14:3-9) that the AltaGas MMF uses a simple average of three cost allocator-bases of: (1) relative earnings before interest, tax, and depreciation (EBITDA); (2) relative payroll costs; and (3) relative property (plant and equipment, including construction work in progress, plus material and supplies/inventories and gas inventories) of each business unit. The December 31, 2023, CAM (Exhibit (J)-2 at page 37) states that WGL allocates most of its shared services costs to affiliates using the MMF consisting of the three factors: (1) adjusted net revenues; (2) direct and assigned labor; and (3) average invested capital. Address the following:

(a) Explain if and why AltaGas and WGL use two different types of MMF allocation methods (with different inputs/cost drivers) to allocate some of the same types of costs, one method for allocating costs from AltaGas to affiliates and another method for allocating costs from WGL to affiliates. Provide all studies and documentation to support the reasonableness of these two MMF allocation methods, and cite to all best industry standards that recommend the use of either of these two allocation methods.

(b) Do all ASUS costs that are allocated to WGL (and other affiliates) use the MMF method with factors of: (1) relative earnings before interest, tax, and depreciation (EBITDA); (2) relative payroll costs; and (3) relative property plant and equipment, including construction work in progress, plus material and supplies/inventory and gas inventories? If yes, explain the basis for doing so, including all supporting documentation. If not, identify the other MMF methods used to allocate costs from ASUS to WGL and other affiliates, explain the basis for doing so, and include all supporting documentation.

(c) Do all WGL costs allocated to other affiliates use the other MMF method with factors of (1) adjusted net revenues; (2) direct and assigned labor; and (3) average invested capital. If yes, explain the basis for doing so, including all supporting documentation. If not, identify the other MMF methods used to allocate costs from WGL to each affiliate, explain the basis for doing so, and include all supporting documentation.

(d) Regarding (b) and (c) above, explain which MMF method is used to allocate costs from various other affiliates (besides ASUS) to WGL, including allocations to WGL by SEMCO Energy, Hampshire, and other affiliates. Explain the rationale for the allocation method used and include all supporting documentation.

(e) Explain if AltaGas, ASUS, or WGL have formal written criteria that are used for determining reasonable and accurate “allocation methods and inputs/factors/cost drivers for allocation methods” in its CAM or other documents and provide these criteria and the related supporting documentation identifying these criteria.

(f) Per (a), (b), and (c) above, explain the time period that these two different MMF methods (with different inputs/cost drivers) have been used by AltaGas and WGL.Explain if WGL used different allocation factors prior to the AltaGas merger and, if so, identify the MMF methods and inputs/cost drivers prior to the merger, along with other allocation methods, Also explain if WGL changed its allocation methods after the merger with AltaGas (and identify the MMF methods and inputs/cost drivers used after the merger, along with other allocation methods.

(g) The ASUS MMF method allocates costs to WGL and other affiliates using the inputs/cost drivers of: (1) relative earnings before interest, tax, and depreciation (EBITDA); (2) relative payroll costs; and (3) relative property plant and equipment, including construction work in progress, plus material and supplies/inventory and gas inventories. Explain how each of these cost drivers meets the criteria of cost-causation (and correlation between the cost driver and the costs that it drives/allocates to other affiliates), and if and how the cost drivers are measurable, objective, stable or predictable, and consistent. Explain and show the specific cost-causation impact of changes in EBITDA (and the other drivers of payroll and plant) relative to the changes in the expenses that the cost driver allocates to WGL (and other affiliates) – and show this trend and correlation for calendar years 2021, 2022 and test year end March 31, 2024.

(h) The WGL MMF method allocate costs from WGL to other affiliates using the inputs/cost drivers of: (1) adjusted net revenues; (2) direct and assigned labor; and (3) average invested capital. Explain how each of these cost drivers meet the criteria of cost-causation (and correlation between the cost driver and the costs that it drives/allocates to other affiliates), and if and how the cost drivers are measurable, objective, stable or predictable, and consistent. Explain and show the specific cost-causation impact of changes in average invested capital (and the other drivers of net revenues and labor)

Page **3** of **5**

relative to the changes in the expenses that the cost driver allocates to WGL (and other affiliates) – and show this trend and correlation for calendar years 2021, 2022 and test year end March 31, 2024.

(i) Explain why WGL does not use a traditional Massachusetts Method to allocate expense to affiliates, using inputs/cost drivers of: (1) Operating Revenues; (2) Payroll; and (3) Net Book Value of tangible capital assets plus inventory.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a) AltaGas and WGL have been using their respective MMF factors pre-merger and have consistently used and reported to the commission, the same factors post-merger. Annual Cost Allocation Manual(CAM) filed with DC pre and post-merger includes the description of WGL's MMF factors. Direct Testimony of Alex Patterson, William R. Ford and Todd J. Jirovec filed during the merger case proceeding, Formal Case No. 1142 reflected the MMFs and their justification. The different methodology for ALA has been consistent in adoption pre-merger and post-merger by the Michigan PSC. The methodology used by Washington Gas has been consistently adopted by the Virginia SCC, Maryland PSC, and DC PSC both pre- and post-merger.

To the Company's knowledge, there is no "best" standard for allocation of common costs. A three-part factor is used as the cost drivers are not easily identified nor tracked. The MMF is also discussed in Robert L. Hahne and Gregory E. Aliff, *Accounting for Public Utilities*.[1] *Accounting for Public Utilities* provides a comprehensive discussion of cost allocation. The introduction to common cost allocation is as follows:

> FERC. There are a number of methods used by the utility industry to allocate residual corporate support services that have been accepted as reasonable by state and federal regulatory authorities. Among the cost allocation methodologies that have been accepted by state and federal regulators as reasonable are those that are based on multi-factor formulas representing overall business activity levels of utility companies.
>
> The most commonly used multi-factor formulas approved for use by state and federal regulators include the Kansas-Nebraska Formula

[1] Robert L. Hahne and Gregory E. Aliff, *Accounting for Public Utilities,* Release No, 31, November 2014

(KN formula), the Massachusetts Formula, and the Modified Massachusetts Formula, or Distrigas Formula.[2]

b) ASUS costs that are allocated to WGL (and other affiliates) do not use ALA's MMF component factors but uses WGL's MMF component factors. All ASUS costs allocated use WGL's MMF component factors and no other component factors are being used.

c) Yes. WGL costs allocated to other affiliates use the other MMF method with factors of (1) adjusted net revenues; (2) direct and assigned labor; and (3) average invested capital. As stated in a) that WGL has used this factor consistently pre and post-merger and have included in yearly CAM filings.

d) Apart from AltaGas/ASUS no other entities allocate cost to WGL using MMF factors.

e) Washington Gas's annual CAM paragraph's related to general approach details the cost assignments and allocation methods/factors used by WGL and its affiliates.

f) As stated in a) AltaGas and WGL have been using their respective MMF factors pre-merger and have consistently used and reported to the commission, the same factors post-merger.

g) As noted above, MMF or three-part allocation factors are used when specific cost-causative factors are not identified. They allocate costs based on measures of business activity, not cost drivers.

h) As noted above, MMF or three-part allocation factors are used when specific cost-causative factors are not identified. They allocate costs based on measures of business activity, not cost drivers.

i) WGL has consistently used the current MMF factor pre- and post-merger and included it in the annual CAM filed with the jurisdiction.

[2] Robert L. Hahne and Gregory E. Aliff, *Accounting for Public Utilities* § 19.03[4][d] Allocation of Corporate Overhead Costs (Mathew Bender).

SPONSOR: Eric Block
Vice President and Controller

Exhibit OPC (B)-13
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-16

**Q.** **AltaGas MMF Allocation Factor Calculations.** Witness Block's Direct Testimony states (14:3-9) that for allocating costs from AltaGas to WGL and affiliates, the AltaGas MMF uses a simple average of three cost allocator-bases of: (1) relative earnings before interest, tax, and depreciation (EBITDA); (2) relative payroll costs; and (3) relative property plant and equipment, including construction work in progress, plus material and supplies/inventory and gas inventories. Address the following:

a. For the AltaGas MMF inputs, provide a detailed description of all accounts (identify all account number and account descriptions) included in each of the inputs/cost drivers of: (1) EBITDA; (2) relative payroll costs; and (3) plant and material supplies, and gas inventory for each of the calendar years 2019 to 2022, and test year ended March 31, 2024.

b. Regarding (a) above, explain and address the following:

(i) Explain if the payroll cost input/cost driver includes or excludes short and
long-term incentives, bonuses, payroll taxes, SERP, OPEB, Pensions and identify all payroll cost components included in the cost-driver. Also explain why the inclusion of these payroll cost components is reasonable in the allocation factor.

(ii) Explain why it is reasonable to include long-term incentive expense as a cost-driver when WGL has removed these costs from the rate case.

(iii) Explain if the plant/property input/cost driver is based on gross plant or net plant at year-end or based on 13-month averages, and explain why this is reasonable.

(iv) Explain why the plant input/cost driver includes CWIP, and explain why this is reasonable when WGL has excluded CWIP from recovery in this rate case.

(v) Explain if a working capital component is used in the plant/inventory factor, and explain why.

(vi) Explain if the EBITDA, payroll costs, and plant/inventory input/cost drivers include other costs that have been removed or adjusted by WGL in this rate case (such as certain intangible costs, severance costs, etc.) and explain why it is reasonable to use these amounts in the MMF allocation method calculation.

c. For each affiliate to which ASUS allocates costs (including WGL), for each calendar year 2019 to 2022 and the test year end March 31, 2024, provide the following regarding the calculation of the three MMF input/cost drivers of: (1) EBITDA; (2) relative payroll costs; and (3) plant and material supplies, and gas inventory:

(i) Provide the overall MMF allocation factor percentages and the related numerator and denominator that incorporates all three input/cost drivers (EBITDA, payroll, and plant/inventory), and provide all underlying calculations and supporting documents.

(ii) Provide the: (a) detailed MMF allocation factor percentages for WGL and each affiliate; (b) underlying financial documents and other source documents for each of the numerators and denominators of the three input/cost drivers (EBITDA, payroll and plant/inventory) for WGL and each of the affiliates; (c) the total numerator and denominators for WGL and all affiliates combined; and (d) all underlying calculations and supporting documents for the three input/cost drivers of: (1) EBITDA; (2) relative payroll costs; and (3) plant and material supplies, and gas inventory.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Please see below
EBITDA – the EBITDA factor is derived from the prior year financial results; accounts included are as follows:

1. 50010 - Sales
2. 51000 - Services
3. 52000 - Regulated Operations
4. 53000 - Other (Revenue) Loss

5. 60010 - Cost of Sales
6. 64000 - Operating Expenses
7. 70000 - Administrative & General
8. 80010 - (Inc) Loss Equity Investment
9. 81000 - Other Expenses (Income)

Payroll – The payroll factor is derived from the prior year financial results; accounts included are as follows:

1. 70015 - Salaries & Wages – Regular & 70044 - Labor Manual Adj (Gross S&W)
2. 70020 - Salaries & Wages – Overtime
3. 70045 – Severance
4. 70060 - Vacation Expense
5. 70061 – Statutory Vacation Pay – G&A
6. 70130 – Short Term Incentive Plan
7. 70155 – Vehicle Allowance

Property – The property factor is comprised of PP&E and inventory derived from the prior year financial results and includes the following accounts:

1. 13100 – Product Inventory (gas inventory)
2. 13200 – Other Inventory
3. 21000 - Property, Plant and Equipment
4. 22000 - Accumulated Amortization
5. 25000 – CWIP

b.

(i) Payroll factor includes all accounts itemized in response to DR 4-16-a and included items are deemed reasonable as it is representative of business activity.

(ii) Long-term incentive is not included in the calculation of the payroll factor; only the accounts listed in the response to DR 4-16-a are included in the payroll factor.

(iii) Net plant at year end and is considered reasonable as a representation of business activity.

(iv) CWIP is an important measure of investment and business activity.

(v) Accounts included in the property component are listed in response to DR 4-16-a; working capital component is not included in our definition of the Property factor.

(vi) No costs outside the listed accounts in DR 4-16-a are included in the MMF calculation.

c.

(i) Please refer to WGL's Responses for OPC DR 4-8 and OPC DR 4-17.

(ii) Please refer to WGL's Responses for OPC DR 4-8 and OPC DR 4-17.

SPONSOR:

Part a &b

Eric Block,
Vice President and Controller

Part c
Ghislaine (Celine) Quenum
Manager, Corporate Accounting

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-17

**Q.** **WGL Allocation Factor Calculations.** The CAM (page 39) states that WGL allocates most costs to affiliates use the MMF with the three inputs/cost drivers of: (1) adjusted net revenues; (2) direct & assigned labor; and (3) average invested capital. Address the following:

a. For the AltaGas MMF inputs, provide a detailed description of all accounts (identify all account number and account descriptions) included in each of the inputs/cost drivers of: (1) adjusted net revenues; (2) direct & assigned labor; and (3) average invested capital for each of the calendar years 2019 to 2022, and test year ended March 31, 2024.

b. Regarding (a) above, explain and address the following:

(i) Explain why WGL uses the term "net" revenues and if revenues are net of uncollectibles/bad debt expense. Also explain if uncollectibles/bad debt expense is the amount per books or is the amount calculated using the methodology in the rate case for adjusting uncollectibles expense, and explain the rationale for the methodology used.

(ii) Explain if the direct & assigned labor input/cost driver includes or excludes short and long-term incentives, bonuses, payroll taxes, SERP, OPEB, Pensions; identify all payroll cost components included in the cost-driver; and explain why the inclusion of these payroll cost components is reasonable in the allocation factor.

(iii) Explain how the "direct & assigned labor" input/cost driver differs from WGL payroll costs per books for calendar year 2022 and the test year end March 31, 2024, and provide a reconciliation of these amounts identifying all different cost components.

(iv) Explain why it is reasonable to include long-term incentive expense as a cost-driver when WGL has removed these costs from the rate case.

(v) Explain and identify all underlying components of the “average invested capital” component and explain how this varies from the “plant/inventory” input/cost driver of the MMF method used to allocate costs from AltaGas to WGL and affiliates.

(vi) Explain if the “average invested capital” factor is based on a year-end or 13-month average, and explain if it includes plant/property that is based on gross plant or net plant at year-end or based on 13-month averages. Explain why the approach used by WGL is reasonable.

(vii) If “average” invested capital is used as an input/cost driver for the WGL MMF method (and confirm if this is a 13-month average), then explain why it would be reasonable to use year-end balances in the “property and inventory” input/cost driver of the AltaGas MMF method and if and why doing so is not unreasonably inconsistent.

(viii) Explain if the “average invested capital” factor includes CWIP, and explain why this is reasonable given that WGL has excluded CWIP from recovery in this rate case.

(ix) Explain if a working capital component is used in the “average invested capital” and explain why.

(x) Explain if the net revenue, direct & assigned labor, and average invested capital input/cost drivers include other costs that have been removed or adjusted by WGL in this rate case (such as certain intangible costs, severance costs, etc.) and explain why it is reasonable to use these amounts in the MMF allocation method calculation.

c. For each affiliate to which WGL allocates costs (including WGL), for each calendar year 2019 to 2022 and the test year end March 31, 2024, provide the following regarding the calculation of the three MMF input/cost drivers of: (1) net revenue; (2) direct & assigned labor; and (3) average invested capital:

(i) Provide the overall MMF allocation factor percentages and the related numerator and denominator that incorporates all three input/cost drivers (net revenue, direct/assigned labor, and average invested capital), and provide all underlying calculations and supporting documents.

(ii) Provide the: (a) detailed MMF allocation factor percentages for WGL and each affiliate; (b) underlying financial documents and other source documents for each of the numerators and denominators of the three input/cost drivers (net revenue, direct/assigned labor, and average invested capital) for WGL and each of the affiliates; (c) the total numerator and denominators for WGL and all affiliates combined; and (d) all underlying calculations and supporting documents for the three input/cost drivers of net revenues, direct/assigned labor, and average invested capital.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Please see WGL's Response for OPC DR 4-8 and DR 4-10.

b.

(i) Revenue is not netted of uncollectibles/bad debt expense. Please refer to WGL's Responses in OPC DR 4-8 and DR 4-10, for additional information about MMF three factors' calculation.

(ii) Direct & Assigned Labor does not include short and long-term incentives, bonuses, payroll taxes, SERP, OPEB, Pensions. Please refer to WGL's Responses in OPC DR 4-8 and DR 4-10, for additional information about MMF three factors' calculation.

(iii) Direct and assigned labor is the accumulation of the total gross pay and is a true measure of the business activity related to labor employed by the entity. As such it is independent on how the costs get recorded for accounting purposes. The total direct and assigned labor used in the MMF is nonetheless recorded across Washington Gas's accounts based on the requirement of the Federal Energy Regulatory Commission Uniform System of Account. This includes capital, expense, overhead, and other balance sheet accounts based on the nature of the work performed. Please see the individual quarterly MMF calculations (Labor Tab) provided in response to OPC DR 4-8 which shows the accounts where the direct and assigned labor is charged.

(iv) Please refer to WGL's Response for question 4-17.b(ii) above.

(v) Please refer to WGL's Responses in OPC DR 4-8 and DR 4-15. Also, refer to the 2023 DC Cost Allocation and Inter-company Pricing Manual (CAM).

Page **4** of **4**

(vi) The “average invested capital” is not based on a 13-month average. Please refer to WGL’s Responses in OPC DR 4-8 and DR 4-10, for additional information about MMF three factors’ calculation.

(vii) Property and Inventory balances are not included in the “average invested capital” calculation. Please refer to WGL’s Responses in OPC DR 4-8 and DR 4-10, for additional information about MMF three factors’ calculation.

(viii) Please refer to WGL’s Responses in OPC DR 4-8 and DR 4-10, for information about MMF “average invested capital” components and calculation.

(ix) Please refer to WGL’s Responses in OPC DR 4-8 and DR 4-10, for information about MMF three factors’ components and calculation.

(x) The three factors in the MMF calculation are not adjusted for costs that have been removed or adjusted by WGL in this rate case. To do so would be inappropriate. As discussed earlier these MMF factors are measures of business activities, not a measure or regulatory treatment of costs. The fact that the District of Columbia excludes certain things for determining rates is irrelevant to the business activities the MMF factors measure.

c.

(i) Please refer to WGL’s Responses in OPC DR 4-8 and DR 4-10, for additional information about MMF three factors’ calculation.

(ii) Please refer to WGL’s Responses in OPC DR 4-8 and DR 4-10, for additional information about MMF three factors’ calculation.

SPONSOR: Ghislaine (Celine) Quenum
Manager, Corporate Accounting

Exhibit OPC (B)-15
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential Exhibit Omitted

Exhibit OPC (B)-16
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-21

**Q.** **Witness Baryenbruch Credentials.** Witness Baryenbruch's Direct Testimony (2:21-23 and 3:1-2) refers to the prior review of affiliate charges for: (1) Connecticut Light and Power; (2) Connecticut Natural Gas (now Eversource); (3) General Water Corporation (now Veolia); (4) Philadelphia Suburban Water Company (now Essential Utilities); and (5) Pacific Gas & Electric Company. However, his Exhibit WG (L)-1, page 1 of 1 (showing his list of affiliate transaction-related assignments) does not appear to include the above-listed utilities. Address the following:

a. Explain why Witness Baryenbruch did not include the five above-listed utility clients at Exhibit WG (L)-1, page 1 of 1, and provide an updated document showing all other affiliate-related assignments (in the same level of detail) that have not been included at Exhibit WG (L)-1, page 1 of 1.

b. Regarding (a) above, for those five utilities clients not listed at Exhibit WG (L)-1, page 1 of 1, provide a copy of the Direct Testimony and exhibits (including all related studies and reports if the work product was not provided to the client as testimony) of Witness Baryenbruch related to those engagements - or at the minimum, provide a working link that will allow access to such requested documents.

c. Regarding Exhibit WG (L)-1, page 1 of 1, for the period January 2019 through year-to-date 2024, provide a copy of all testimony and exhibits (including all related studies and reports if the work product was not provided to the client as testimony) of Witness Baryenbruch related to those engagements - or at the minimum, provide a working link that will allow access to such requested documents.

d. Regarding (b) and (c) above for the same time frame, provide a copy of the related state regulatory agency's final Order addressing the testimony (or other work product) of Witness Baryenbruch, or at the minimum, provide a working link that will allow access to such requested documents.

e. Regarding (b) and (c) above for the same time frame, identify those engagements where Witness Baryenbruch provided testimony or a work product to a client addressing either or both of the same issues that he is addressing in Formal CN 1180 regarding: (1) the evaluation of the necessity of services provided by affiliates to the regulated utility; and (2) the reasonableness of the associated affiliate charges for a certain time frame or period.

f. Regarding (b) and (c) above for the same time frame, explain if the client was a utility company, a regulatory agency, or other intervenor (and provide the names of the client), and explain if the engagement was the result of a commission-ordered management or prudence audit (and explain if the utility company or the commission paid his consulting fees).

**WASHINGTON GAS'S PARTIAL OBJECTION** 11/1/2024

**Subparts (c) and (d)**

Washington Gas objects to subparts (c) and (d) of this request on grounds that they are unduly burdensome, as Company Witness Baryenbruch has participated in approximately 40 rate cases since 2019. The Company also objects on grounds that the information is publicly available. The docket numbers that will be provided in response to subpart (c) above can be used to find this information.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. For the five utilities listed above, Mr. Baryenbruch was part of a team that conducted a management audit. The work was performed in the 1980s. The client assignments listed in Exhibit WG (L)-1 are those where he specifically evaluated affiliate transactions and, in many cases, acted as a rate case witness.

b. Mr. Baryenbruch did not prepare testimony for these clients.

c. Shown below are the rate cases in which Mr. Baryenbruch acted as a witness supporting a utility client's affiliate charges during the period 2019 to 2024. Not on the list are a few cases in which Mr. Baryenbruch acted as a rebuttal witness where the scope of his testimony was narrower than the WGL case.

Page **3** of **4**

Docket numbers are provided below for use in finding the requested materials on the regulator's website. Mr. Baryenbruch does not have these links to his specific materials. An objection was raised for "working links" because this is unduly burdensome and the information is public and available to everyone.

| Year | Client | State | Docket # |
|---|---|---|---|
| 2019 | Massanutten Public Service Company | Virginia | PUR-2020-0039 |
| | Missouri American Water | Missouri | WR-2020-0344 |
| | New Jersey American Water | New Jersey | WR19121516 |
| | Water Service CorporationKentucky | Kentucky | 2020-00160 |
| 2020 | Electric Transmission Texas | Texas | 51583 |
| | Iowa American Water | Iowa | RPU-2020-0001 |
| | Kentucky Utilities | Virginia | PUR-2021-00171 |
| | Northern Indiana Public Service | Indiana | 45621 |
| | Southwestern Electric Power | Texas | 51415 |
| | West Virginia American Water | West Virginia | 21-0369-W-42T |
| 2021 | Appalachian Power | Virginia | PUR-2023-00002 |
| | Columbia Gas of Virginia | Virginia | 2022-00036 |
| | Great Basin Water | Nevada | 21-12025 |
| | Illinois American Water | Illinois | 22-0210 |
| | Missouri American Water | Missouri | WR-2022-0303 |
| | New Jersey American Water | New Jersey | WR22010019 |
| | Northern Indiana Public Service | Indiana | 45772 |
| | Virginia-American Water | Virginia | PUR 2021-00255 |
| | Water Service Corporation Kentucky | Kentucky | 2022-00147 |
| 2022 | Electric Transmission Texas | Texas | 54502 |
| | Indiana American Water | Indiana | 45870 |
| | Kentucky American Water | Kentucky | 2023-00191 |
| | Liberty Utilities New York Water | New York | 23-00979 |
| | Northern Indiana Public Service | Indiana | 45967 |
| | West Virginia American Water | West Virginia | 23-0383-W-42T |
| | Wind Energy Transmission Texas | Texas | 55029-1 |
| 2023 | AEP Texas | Texas | 56165 |
| | Appalachian Power | Virginia | PUR-2024-00024 |
| | Appalachian Power | West Virginia | 24-0669-E-42T |
| | Columbia Gas of Virginia | Virginia | PUR-2024-00030 |
| | Illinois American Water | Illinois | 24-0097 |
| | Iowa American Water | Iowa | RPU-2024-0002 |
| | Kentucky Utilities | Virginia | PUR 2024-00052 |
| | Missouri American Water | Missouri | WR-2024-0320 |
| | New Jersey American Water | New Jersey | WR24010056 |
| | Northern Indiana Public Service | Indiana | 45772 |
| | Tennessee American Water | Tennessee | 24-00032 |
| | Virginia-American Water | Virginia | 2023-00194 |

d. This request was objected to as being unduly burdensome. In addition, the information is public and available to everyone. The docket numbers provided in c. above can be used to find this information.

e. See the response to c. above.

f. In all cases, the listed utilities were Mr. Baryenbruch's client. None of these assignments were the result of a commission-ordered management or prudence audit.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-17
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-28

**Q.** **Witness Baryenbruch Affiliate Issues Reviewed**. Witness Baryenbruch's Direct Testimony addresses affiliate studies and related issues. Address the following:

a. Explain if Witness Baryenbruch reviewed and tested the reasonableness of AltaGas, ASUS, and WGL, affiliate allocation methods and related allocation factors (such as the Modified Massachusetts Method and others). If the answer is "yes", then provide a copy of all reports and information provided to WGL, along with all results, recommendations, and supporting documentation and calculations (including all original working Excel documents). Explain if Witness Baryenbruch compared affiliate allocation methods and related allocation factors of AltaGas, ASUS, and WGL to those of other utilities, and provide the related results.

b. Explain if Witness Baryenbruch reviewed and tested the reasonableness of the AltaGas expenses (the starting point for the allocation process) that are subject to allocation to ASUS (and perhaps other service companies), and subsequently to WGL and other affiliates. If the answer is "yes", then provide a copy of all reports and information provided to WGL, along with all results, recommendations, and supporting documentation and calculations (including all original working Excel documents). Explain if Witness Baryenbruch compared the expenses of AltaGas and ASUS that are subject to allocation to WGL and other affiliates, to the Parent Company and Service Company expenses of other utilities that are subject to allocation to their respective affiliates, and provide the related results.

c. Explain if Witness Baryenbruch reviewed and tested the reasonableness of: (i) the number of employees; (ii) the mix of employees by type of service provided; (iii) the efficiency of employees; and (iv) the cost and ratio of Executives/Management employees to all employees of AltaGas, ASUS, and WGL in regards to the employee costs that are subject to allocation to WGL (and other affiliates) via affiliate charges. If the answer is "yes", then provide a copy of all reports and information provided to WGL, along with all results, recommendations, and supporting documentation and calculations (including all original working Excel documents). Explain if Witness Baryenbruch compared this information for AltaGas, ASUS, and WGL to other utility companies, and provide the related results.

d. Identify all other affiliate-related issues and all other issues reviewed by Witness Baryenbruch that are not addressed in his Direct Testimony, and explain why these issues were not addressed in testimony in this proceeding.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Mr. Baryenbruch's scope only covered post-allocation affiliate charges assigned to WGL.

b. Mr. Baryenbruch's scope only covered post-allocation affiliate charges assigned to WGL.

c. Mr. Baryenbruch did not evaluate these non-financial metrics.

d. All of Mr. Baryenbruch's work is reflected in his direct testimony and report.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-18
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-29

**Q.** **Witness Baryenbruch Necessity of Services.** Witness Baryenbruch's Direct Testimony states his study evaluates the "necessity of services" provided by affiliates to WGL (3:14-15) and the support for this statement is supposedly addressed in more detail at "Question 1 – Necessity of Affiliate Services" (5:1 – 8:9) and per Exhibit WG(L)-2. Witness Baryenbruch generally refers to the benefits that WGL receives from affiliates related to Governance, Compliance, Capital Availability, Economics, Continuity of Service, and Enterprise Standards (5:1-22 and 6:21-7:20) for the related Service Categories of Accounting and Taxes, Board of Directors, Compliance, Executive Management, Finance, Human Resources, Information Technology, Legal, Supply Chain, Accounting and Taxes, Accounts Payable, Executive Management, and Human Resources (8:1-9 - Table 1 and Exhibit WG (L-2) - Exhibits 2 and 3 at pages 9 and 10 of 31). Address the following:

a. The benefits to WGL-DC from affiliates WGL, AltaGas and SEMCO cited by Witness Baryenbruch (5:1-21 and 6:21-7:20 and Exhibit WG (L-2), Exhibit 3) appear to be just a general listing of benefits for various services without substantiation or supporting documentation. Provide all studies, analysis and supporting documentation showing the specific measurement of each benefit (for each Service Category) on a quantifiable and qualifiable basis that was prepared by Witness Baryenbruch. Explain and show how Witness Baryenbruch reached a conclusion regarding the related benefits for various service categories without any quantifiable and qualifiable (or tangible and intangible) supporting documentation or analysis – if this is the case.

b. Regarding (a) above, explain if Witness Baryenbruch performed an independent and objective analysis of the benefits of various services or if he primarily relied upon the representation of management of WGL, AltaGas, ASUS, and other affiliates regarding this issue, and provide all supporting documentation pertaining to analyses performed by or relied upon by Witness Baryenbruch.

c. Regarding (a) above, explain how many labor hours were spent evaluating this issue and explain if this issue was evaluated on-site at the premises of WGL, AltaGas, ASUS (or other affiliates) or if this review and evaluation was conducted at Baryenbruch & Company offices.

d. Regarding (a) above, Witness Baryenbruch's Direct Testimony addresses the benefit of "Economies", and states, "[t]he 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 to affiliates." (Exhibit WG (L) at 7:6-9). Provide all supporting documentation, calculations, and studies that Witness Baryenbruch relied upon regarding these statements, and provide: (1) the amount of "cost savings" realized by WGL from purchasing and operating economies of scale from each of WGL, AltaGas and SEMCO (and provide total WGL savings and all allocation factors and calculations used to determine jurisdictional WGL-DC savings); and (2) quantify and provide the better prices for common goods and services and related savings passed on to WGL-DC from WGL, AltaGas and SEMCO (provide the total better prices and related savings for WGL, as well as all allocation factors and calculations used to determine jurisdictional WGL-DC prices and savings).

e. Regarding (a) above, provide copies of Witness Baryenbruch interview notes conducted with employees/executives of WGL, SEMCO, Altagas (and any other affiliates), and explain how these interviews impacted the related conclusions regarding benefits for the various service categories. Provide a list of all employees/executives by job position/company and date that were interviewed as well as the conclusions reached from those interviews.

f. Explain and show how the benefits by service categories of WGL, AltaGas and SEMCO vary from, or compare to, the types of benefits by service categories of affiliate transactions for other utility companies for which Witness Baryenbruch has conducted a similar review. As part of the response, state whether the benefits provided to WGL-DC by its affiliates are the same as, less than, or greater than, the benefits provided to other regulated utility companies by their affiliates, and provide all supporting documentation and calculations to support these conclusions.

g. Explain if Witness Baryenbruch identified any disadvantages, negative impacts, and cost increases to WGL-DC related to the provision of services from WGL, AltaGas and SEMCO. Please identify all of these negative impacts and provide the quantifiable and qualifiable impact. Also provide total WGL impacts and all allocation factors and calculations used to determine jurisdictional WGL-DC impacts.

Page **3** of **5**

**WASHINGTON GAS'S PARTIAL OBJECTION**

11/1/2024

**Subpart (f)**

Washington Gas objects to subpart (f) of this request on grounds that it requires the performance of a special study which has not been performed.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. The association of benefits with service categories is based on Mr. Baryenbruch's review of affiliate services described in service agreements and the CAM, discussions with WGL personnel and his significant hands-on experience carrying out consulting assignments for other utility clients. He has worked as a consultant with many utility client teams to design and implement improvements across many functional areas. His knowledge of the utility industry is not limited to simply performing outside assessments of utility companies.

b. See the response to (a) above.

c. Work to evaluate the necessity of affiliate services was performed over the duration of Mr. Baryenbruch's assignment. It did not start and end over a discrete period. Mr. Baryenbruch's work did not require an on-site presence.

d. Mr. Baryenbruch's work scope did not include calculating specific cost savings from affiliate services. In his other cases, this has never been a requirement to demonstrate the necessity of affiliate services. Besides, this would add greatly to the cost of his work. If the costs of affiliate services are unreasonably high, that would show up in Mr. Baryenbruch's cost comparisons. The results of the cost comparisons are favorable for WGL.

e. Mr. Baryenbruch conducted the following interviews as part of his evaluation:

| 2024 Date | Participant | Job Title | Discussion Topics |
|---|---|---|---|
| May 15 | Tracy Vincent (SEMCO) | Financial Controller | Services provided by SEMCO to WGL; SEMCO vs WGL responsibilities; charge and hour detail |
| May 28 | Duncan Miller (ALA)<br><br>Eric Block (ALA) | Dir. - Finance Bus. Partner<br>VP & Controller | Services provided by ALA to WGL; ALA vs WGL responsibilities; charge and |

| | | | |
|---|---|---|---|
| | Shiraz Khan (ALA) | Sr Financial Data Mgmt Analyst | hour detail |
| Jun 11 | Duncan Miller<br><br>Shiraz Khan | Dir. - Finance Bus. Partner<br>Sr Financial Data Mgmt Analyst | Services provided by ALA to WGL; ALA vs WGL responsibilities; charge and hour detail |
| Jun 18 | Tracy Vincent (SEMCO) | Financial Controller | Services provided by SEMCO to WGL; SEMCO vs WGL responsibilities; charge and hour details; LCM comparison process |
| Jul 8 | Jim Wagner (WGL)<br><br>Al Balow (WGL)<br><br>Colin Bond (WGL)<br>Asav Patel (WGL)<br><br>Ghislaine Quenum (WGL) | AVP – Rates and Reg. Affairs<br>Lead – Reg. Affairs<br>VP & Controller<br>Sr Director, Acct – Utilities<br>Mgr Corporate Accounting | SEMCO and ALA vs WGL<br><br>responsibilities |
| Jul 19 | Duncan Miller (ALA)<br><br>Eric Block (ALA)<br>Colin Bond(WGL)<br>Al Balow (WGL) | Dir. - Finance Bus. Partner<br>VP & Controller<br>VP & Controller<br>Lead – Reg. Affairs | Services provided by ALA to<br><br>WGL; ALA vs WGL responsibilities; LCM comparison results |
| Various | Jim Wagner (WGL) | AVP – Rates & Reg. Affairs | Various matters, including necessity of services |
| Various | Al Balow (WGL) | Lead – Reg. Affairs | Various matters, including necessity of services |

These interviews enabled Mr. Baryenbruch to understand the nature of services provided by affiliates versus functional activities WGL performed with its own staff. This allowed him to conclude on the necessity of affiliate services. Also, the interviews enabled him to develop the data needed to prepare his cost comparisons. Notes were not necessary as Mr. Baryenbruch immediately incorporated information into his draft materials.

f. Please see the objection above.

Page **5** of **5**

g. No. The described assessment was not within Mr. Baryenbruch's work scope.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-19
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-30

**Q.** **Witness Baryenbruch Benefits Categories.** The Direct Testimony of Witness Baryenbruch generally refers to the benefits that WGL receives from affiliates AltaGas and SEMCO for each of the related Service Categories (5:1-22 and 6:21-7:20, p. 8 Table 4, and Exhibit WG (L-2 - Exhibit 3, p. 10 of 31). Address the following:

a. Explain if Witness Baryenbruch identified each of the Benefit Categories of "Governance, Compliance, Capital Availability, Economics, Continuity of Service, and Enterprise Standards" provided by AltaGas and SEMCO to WGL or if WGL, AltaGas, or SEMCO (or other affiliates) identified these specific Benefit Categories of AltaGas and SEMCO, and then provided this information to Witness Baryenbruch. To the extent it was the former, explain Witness Baryenbruch's process for identifying these Benefit Categories. Provide all supporting documentation and analysis prepared by (or relied upon by) Witness Baryenbruch to identify these Benefit Categories of benefits WGL receives fromr AltaGas and SEMCO.

b. Regarding (a) above, please identify other types of Benefit Categories which other regulated public utilities receive from their affiliates based on Witness Baryenbruch prior experience with these affiliate issues(or any analysis performed by Witness Baryenbruch in this regard), and cite to the specific utility and affiliate company and any related docket/case number where this review was performed.

c. Explain if Witness Baryenbruch identified and assigned the Benefit Categories of "Governance, Compliance, Capital Availability, Economics, Continuity of Service, and Enterprise Standards" to each of the related Service Categories of "Accounting and Taxes, Board of Directors, Compliance, Executive Management, Finance, Human Resources, Information Technology, Legal, Supply Chain, Accounting and Taxes, Accounts Payable, Executive Management, and Human Resources" for each affiliate AltaGas and SEMCO or ifWGL, AltaGas, or SEMCO (or other affiliates) identified and provided the assigned Benefit Categories to each of the Service Categories of AltaGas and SEMCO to Witness Baryenbruch. To the extent it was the former, explain Witness Baryenbruch's process for identifying and assigning these Benefit Categories. Provide all supporting documentation and analysis prepared by Witness Baryenbruch or relied upon by Witness Baryenbruch to identify and assign these Benefit Categories for each of the Service Categories for each affiliate, including AltaGas and SEMCO.

d. Regarding (c) above, provide all supporting documentation and calculations to show all statistical or non-statistical sampling of invoices or other documents for each of the Service Categories that were prepared or relied upon to determine the various types of Benefit Category that were included (or not included) in each of these Service Categories for each of the affiliates, including AltaGas and SEMCO. Provide copies of all invoices or other information sampled or reviewed by Witness Baryenbruch as part of this review process, and explain how this information was used to reach conclusions about Benefit Categories for each Service Category.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Mr. Baryenbruch made the benefit category determination based upon interviews listed in OPC Data Request 4-29.e, review of the CAM and Service Agreements and his professional experience and judgment.

b. The referenced Benefit Categories are a standard set used by Mr. Baryenbruch. See OPC Data Request 4-21.c for his previous rate cases and docket numbers.

c. See the response to OPC DR 4-30.a. above.

d. It was not necessary for Mr. Baryenbruch to audit invoices and transactions. Never in the course of his more than 100 rate case assignments have regulators required or expected him to sample and review invoices in his evaluation of affiliate charges.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-20
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-31

**Q.** **Witness Baryenbruch Costs by Benefit and Service.** The Direct Testimony of Witness Baryenbruch generally refers to the benefits that WGL receives from affiliates AltaGas and SEMCO for each of the related Service Categories (5:1-22 and 6:21-7:20, p. 8 Table 4, and Exhibit WG (L-2) at Exhibit 3, p. 10 of 31). Address the following:

a. With respect to the various types of Benefit Category costs that are included in each of the Service Categories at Table 4, page 8, provide the amount of costs for each Service Category (Governance, Compliance, Capital Availability, Economics, Continuity of Service, and Enterprise Standards) included in each Service Category provided by AltaGas and SEMCO to WGL, i.e., "Accounting and Taxes, Board of Directors, Compliance, Executive Management, Finance, Human Resources, Information Technology, Legal, Supply Chain, Accounting and Taxes, Accounts Payable, Executive Management, and Human Resources".

b. Regarding (a) above, explain if WGL, AltaGas, or SEMCO (or other affiliates) identified these specific Benefit Categories of AltaGas and SEMCO, and then provided this information to Witness Baryenbruch. Provide all supporting documentation and analysis prepared by Witness Baryenbruch or relied upon by Witness Baryenbruch to identify these Benefit Categories for AltaGas and SEMCO.

**WASHINGTON GAS'S PARTIAL OBJECTION** 11/1/2024

**Subpart (a)**

Washington Gas objects to subpart (a) of this request on grounds that it requires the performance of a special study which has not been performed.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Mr. Baryenbruch understands this question seeks a break down of costs by Service Category (e.g., Accounting and Taxes) and Benefit Category (e.g., Governance, Compliance, etc.). If that is correct, an objection is raised to this request. It would require a Special Study.

   If this request is asking for costs broken down just by Service Category, that information can be found in Mr. Baryenbruch's Exhibit WG (L)-2, page 13 of 31.

b. See the response to OPC Data Request 4-30.a.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-21
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-32

**Q.** **Witness Baryenbruch Redundant Affiliate Issues.** The Direct Testimony of Witness Baryenbruch states (8:10-16) that his analysis and Exhibit WG (L)-2 at page 7, 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 services to customers, and that affiliate services are not duplicative with WGL's own business processes. Address the following:

a. The responsibility matrix at Exhibit WG (L-2), page 7 appears to be a general listing of services by Function/Category (e.g., Executive Management, Financial Services, Legal, etc.) indicating whether WGL, AltaGas, or SEMCO is either primarily responsible or provides support for the services and does not appear to include substantiation or supporting documentation for a conclusion that indicates there is no redundant affiliate services. Provide all studies, analysis and supporting documentation prepared by (or relied upon by) Witness Baryenbruch showing there are not redundant services for each of the Functions listed at Exhibit WG (L)-2, page 7. Explain and show how Witness Baryenbruch reached a conclusion regarding the absence of redundant services, along with all quantifiable and qualifiable (or tangible and intangible) supporting documentation or analysis supporting this conclusion.

b. Regarding (a) above, explain if Witness Baryenbruch performed an independent and objective analysis to determine there are not any duplicative or redundant services for A&G Functions or if he primarily relied upon the representation of management of WGL, AltaGas, ASUS, and SEMCO (or other affiliates) regarding this issue, and provide all supporting documentation of the analysis conducted or relied upon by Witness Baryenbruch.

c. Regarding (a) above, explain how many labor hours were spent evaluating this issue and explain if this issue was evaluated on-site at the premises of either WGL or any of its affiliates (e.g., AltaGas, ASUS, SEMCO, etc.)) or, if on the other hand, this review and evaluation was conducted at Baryenbruch & Company offices.

d. Regarding (a) above, provide copies of Witness Baryenbruch's interview notes conducted with employees/executives of WGL, SEMCO, Altagas (and any other affiliates), and explain how these interviews impacted the related conclusions regarding the absence of redundant or duplicative services by A&G Function. Provide a list of all employees/executives by job position/company and date that were interviewed and provide the conclusions reached from those interviews.

e. Explain if Witness Baryenbruch, in his experience in the most recent ten-year period with the evaluation of affiliate transactions, has ever identified or determined that an affiliate provided redundant or duplicative services, and provide a citation to the link for the related testimony and docket/case number (or provide a copy of such documents if a link to such testimony is not available). Explain the analysis performed by Witness Baryenbruch and how he was able to reach this conclusion, and provide all supporting documentation and calculations.

f. Reference Witness Baryenbruch's Direct Testimony at page 8, lines 12 - 15 and Exhibit WG (L)-2, page 9 of 31 (Exhibit 2, p. 7), provide a specific definition of the terms "primarily responsible" and "provides support" to explain the level of services performed by A&G Function for each affiliate WGL, AltaGas, and SEMCO. Explain if there is a certain percentage of services by Function provided by those affiliates that are "primarily responsible" for the service, compared to a certain percentage of services by Function provided by those affiliates that "provide support" services. Explain specifically how Witness Baryenbruch determined which affiliates and to which degree they were responsible for A&G services by Function, and provide supporting documentation and calculations.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Mr. Baryenbruch developed the responsibility matrix based upon interviews listed in OPC Data Request 4-29.e, review of the CAM and Service Agreements as well as his professional experience and judgment.

b. Mr. Baryenbruch independently determined that affiliate services are not redundant.

c. Work to evaluate WGL versus affiliate services was performed over the duration of Mr. Baryenbruch's assignment. It did not start and end over a discrete period. Mr. Baryenbruch's work did not require an on-site presence.

Page **3** of **3**

d. The interviews listed in OPC Data Request 4-29.e enabled Mr. Baryenbruch to understand the nature of services provided by affiliates versus functional activities WGL performed with its own staff. This allowed him to conclude on the lack of redundancy in WGL activities and affiliate services. Also, the interviews enabled him to develop the data needed to prepare his cost comparisons. Notes were not necessary as Mr. Baryenbruch immediately incorporated information into his draft materials.

e. During the recent ten-year period, Mr. Baryenbruch has not found an instance of redundancy. This is not surprising because Mr. Baryenbruch finds utility management take action to avoid redundancy, which can create conflict within organizations and lead to accountability issues and higher operating costs. His observation is based on decades of experience working on client utility reviews. This hands-on experience provides a deep understanding of proper utility operations.

f. Primarily Responsible means executive management holds the entity (WGL, ALA or SEMCO) accountable for the successful performance of the function. For instance, WGL is Primarily Responsible for assembling its annual budget. Provides Support means the entity must provide information, review/approval or take other action necessary in support of the Primarily Responsible entity. For instance, ALA and SEMCO must provide WGL with their budgeted charges so the WGL consolidated budget can be compiled.

   There is no formula or algorithm that determine Primarily Responsibility. The determination is more straightforward. It is based on which entity that executive management ultimately holds responsible.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-22
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-33

**Q.** **Witness Block Affiliate Issues.** The Direct Testimony of Witness Baryenbruch generally refers to the benefits that WGL receives from affiliates AltaGas and SEMCO for each of the related Service Categories (5:1-22 and 6:21-7:20, p. 8 Table 4, and Exhibit WG (L-2 - Exhibit 3, p. 10 of 31). Also, the Direct Testimony of Witness Baryenbruch states (8:10-16) that his analysis and Exhibit WG (L)-2, p. 7 (page 9 of 31), 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 services to customers, and that affiliate services are not duplicative with WGL's own business processes. Witness Block explains the Corporate Services provided by AltaGas to WGL (3:1 to 9:8), states such services are necessary (9:9 to 10:2), addresses the benefits of such services (10:3 to 11:20), and states there is no duplication of corporate services provided by AltaGas and WGL (11:21 to 12:25). Address the following:

a. Witness Block reaches the same conclusions as Witness Baryenbruch from the standpoint that affiliates' services are necessary and beneficial, and there is no duplication of such corporate services. Explain if: Witness Block's conclusions regarding these same issues are based on Witness Baryenbruch's analysis and conclusions; if Witness Baryenbruch's conclusions regarding these same issues are based on Witness Block's analysis and conclusions; or if Witness Block and Baryenbruch each reach their respective conclusions based on their own specific analysis and conclusions.

b. Regarding (a) above, provide a copy of all of Witness Block's analysis and related underlying supporting documentation and calculations regarding his conclusions related to affiliate services being necessary, beneficial, and non-duplicative of such corporate services (and provide a copy of all applicable working Excel documents).

c. Regarding (b) above, identify and explain the difference between the type of analysis performed by Witness Block compared to the type of analysis performed by Witness Baryenbruch to reach their same conclusions regarding these affiliate issues.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Mr. Block and Mr. Baryenbruch reached their conclusions independently.

b. Services being necessary, beneficial and non-duplicative has been determined based on Witness Block's involvement in the budget and forecasting process as part of his role leading Financial Planning and Analysis, and on analysis and testimony from FC1169 in which witness Jirovec completed an Activity and Cost Assessment Report for AltaGas and WGL. The nature of services being provided by AltaGas to WGL has not changed since the preparation of that report.

   As part of Witness Block's role as leading financial planning and analysis, he oversees a process where Services being provided are planned and budgeted in a cost-efficient manner and to avoid duplication. These services are determined necessary as they are common activities that are required as part of the ongoing management of a diversified, publicly traded company.

   Please refer to Witness Jirovec testimony from FC1169, in which each AltaGas activity was determined to be necessary, beneficial and non-duplicative based on the study he presented. "I have established that AltaGas and WGL activities are comparable to other service companies, necessary and beneficial, and not overlapping." The conclusions remain accurate today.

c. The direct testimonies of Messrs. Block and Baryenbruch are complementary, presenting evidence of necessity and reasonableness of services provided by affiliates to WGL. Mr. Block's testimony covers: (1) ALA services and their benefits to WGL, (2) distinct, non-duplicative nature of ALA services compared to work activities performed by WGL, (3) management of corporate services expenses and (4) Assignment of corporate services costs to WGL. Mr. Baryenbruch's testimony covers: (1) necessity of ALA and SEMCO services to WGL and its customers, (2) Reasonableness of ALA and SEMCO charges and (3) governance-related practices applied to affiliate charges to WGL.

SPONSOR: Patrick Baryenbruch (a) and (c)
Consultant

SPONSOR: Eric Block (b)
Vice President and Controller

Exhibit OPC (B)-23
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-34

**Q.** **Witness Baryenbruch Other Studies of Lower of Cost or Market.** The Direct Testimony of Witness Baryenbruch (8:17 – 12:25 and Exhibit WG (L)-2, pages 11 to 28 (of 31 pages) indicates his analysis shows that: (1) affiliate services were provided to WGL during TY 2024 at the lower of cost or market value (i.e., affiliate services were less expensive than the cost of outside providers); (2) on average, the hourly rates for outside service providers are 203% higher than comparable hourly rates of affiliates; (3) if all 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 (for outside services of attorneys, certified public accountants, IT professionals, and management consultants); and (4) affiliates charge their actual costs of service (9:12 – 10:18). Address the following:

a. Explain if Witness Baryenbruch has conducted a similar or same "lower of cost or market analysis" for a client in the most recent 10-year period (January 2015 through October 2024) and provide a copy of the related study and supporting documentation, a copy of the related testimony and exhibits supporting such study (or provide a link to such information), and provide the name of the client, docket/case number, and the reasons for performing this analysis.

b. Regarding (a) above, explain why Witness Baryenbruch has never conducted a similar or same "lower of cost market analysis" for a client in the most recent 10-year period – and explain when Witness Baryenbruch last conducted such a similar or same analysis (and provide a link to such information and provide the name of the client, docket/case number, and the reasons for performing this analysis).

c. Regarding (a) above, explain the reasons for the differences in conclusions or outcomes between the lower of cost or market analysis in other jurisdictions/proceedings compared to Witness Baryenbruch's conclusions in this proceeding.

d. Explain if Witness Baryenbruch performed the entirety of the analysis supporting his conclusions regarding the lower of cost or market in this proceeding or if employees of WGL, AltaGas, ASUS, SEMCO or other affiliates assisted in this analysis and the preparation of data. Identify all analysis and information prepared by Witness Baryenbruch compared to all of the analysis and information prepared by WGL and its affiliates. Explain the degree to which results are based on Witness Baryenbruch's analysis or explain the degree to which he relies upon the representation of management of WGL and its affiliates regarding this analysis.

e. Explain how many labor hours were spent by Witness Baryenbruch evaluating the lower of cost or market issue and explain if this issue was evaluated on-site at the premises of WGL, AltaGas, ASUS, and SEMCO (or other affiliates), or if this review was conducted at Baryenbruch & Company offices.

**WASHINGTON GAS'S PARTIAL OBJECTION** 11/1/2024

**Subpart (a)**

Washington Gas objects to subpart (a) of this request on grounds that it is unduly burdensome. This witness includes a lower-of-cost or market comparison in most of his previous testimony and accompanying exhibits. OPC will be provided information to obtain this testimony and exhibits for 2019-2024 in the response to OPC Data Request No. 4-21(c). This information will include a reasonable number of examples from the witness' other rate cases.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. An objection was raised to this request. It is unduly burdensome. Mr. Baryenbruch includes a lower-of-cost-or-market comparison in most all of his previous testimony and accompanying exhibits. OPC is provided with the information to obtain his testimony and exhibits for 2019 to 2024 in response to OPC Data Request 4-21.c.

b. The statement in the Data Request is incorrect in saying that "Witness Baryenbruch has never conducted a similar or same 'lower of cost market analysis' for a client in the most recent 10-year period". In fact, Mr. Baryenbruch prepares such a cost comparison for most all of his rate case assignments.

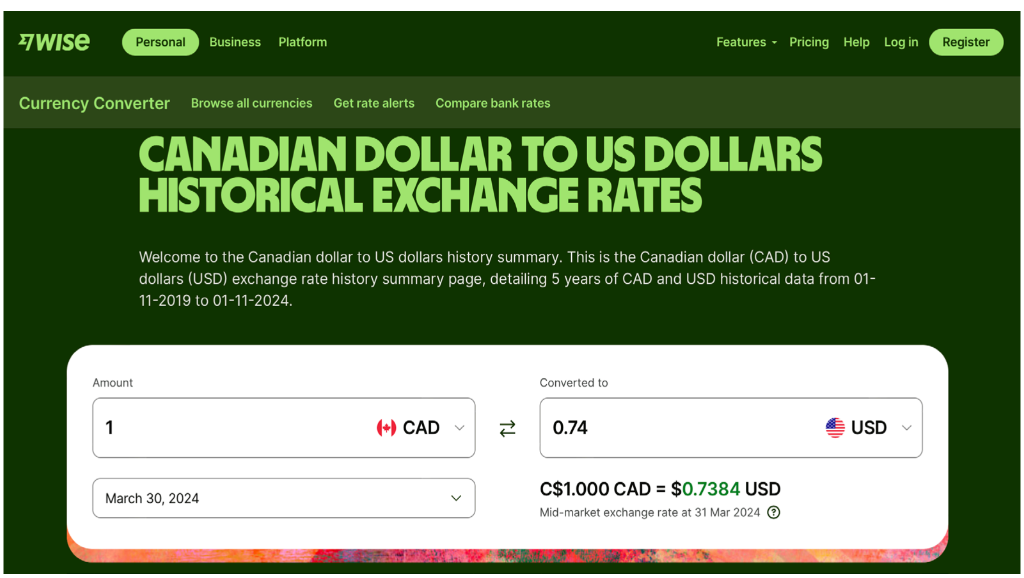
See also the response to a. above.

Page **3** of **4**

c. The cost of outside service providers was found to be 203% higher than WGL's affiliates during TY 2024. This is substantially more favorable than the cost differentials for my other utility clients. For instance, here is a comparison of WGL's savings compared to my 2023 cases:

| Baryenbruch Client | State | Docket Number | OS Providers Higher Than Affiliates |
|---|---|---|---|
| WGL | DC | 1180 | 203% |
| AEP Texas | Texas | 56165 | 58% |
| Appalachian Power | Virginia | PUR-2024-00024 | 58% |
| Appalachian Power | West Virginia | 24-0669-E-42T | 58% |
| Columbia Gas of Virginia | Virginia | PUR-2024-00030 | 58% |
| Illinois American Water | Illinois | 24-0097 | 75% |
| Iowa American Water | Iowa | RPU-2024-0002 | 73% |
| Kentucky Utilities | Virginia | PUR 2024-00052 | 81% |
| Missouri American Water | Missouri | WR-2024-0320 | 59% |
| New Jersey American Water | New Jersey | WR24010056 | 87% |
| Northern Indiana Public Service | Indiana | 45772 | 63% |
| Tennessee American Water | Tennessee | 24-00032 | 73% |
| Virginia-American Water | Virginia | 2023-00194 | 108% |

WGL's favorable position can likely be attributed to the lower-cost locations of WGL's affiliates. ALA is headquartered in Calgary, Alberta and SEMCO in Port Huron, Michigan. Both have a considerably lower cost of living than Washington, DC. Also, the US/Canadian dollar exchange rate is favorable for WGL. At March 31, 2024, the end of Test Year 2024, the Canadian to US dollar exchange rate was 0.74, as shown below (source: Wise.com [https://wise.com/us/currency-converter/cad-to-usd-rate/history/31-03-2024).](https://wise.com/us/currency-converter/cad-to-usd-rate/history/31-03-2024)



d. Mr. Baryenbruch performed entirely his lower-of-cost-or-market comparison using raw data provided by ALA and SEMCO personnel.

e. Work to perform the lower-of-cost-or-market evaluation was performed over the duration of Mr. Baryenbruch's assignment. It did not start and end over a discrete period.

SPONSOR: Patrick Baryenbruch
Consultant

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-35

**Q.** **Witness Baryenbruch Lower of Cost or Market Documentation.** The Direct Testimony of Witness Baryenbruch (8:17 – 12:25 and Exhibit WG (L)-2, pages 11 to 28 (of 31 pages) indicates his analysis shows that: (1) affiliate services were provided to WGL during TY 2024 at the lower of cost or market value (i.e., affiliate services were less expensive than the cost of outside providers). Address the following:

a. Provide copies of all studies, supporting documentation, underlying calculations and other information (in Excel file format where applicable) supporting Witness Baryenbruch's conclusions regarding affiliate services being provided to WGL during TY 2024 at the lower of cost or market. This includes (but is not limited to), documentation and calculations supporting Table 5 (10:1-13), Table 7 (11:17-25), Table 8 (12:9-25), along with the various tables at Exhibit WG (L)-2 per page 12 of 31, page 13 of 31 (Exhibit 4), page 14 of 31 (Exhibit 5), page 15 of 31 (Exhibit 6), page 16 of 31, page 18 of 31 (Exhibit 7), page 19 of 31 (Exhibit 8), page 20 of 31 (Exhibit 9), page 21 of 31 (Exhibit 10), page 22 of 31 (Exhibit 11), page 23 of 31, page 24 of 31, page 25 of 31, page 26 of 31 (Exhibit 12), and page 27 of 31 (Exhibit 13).

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-25
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-36

**Q. Witness Baryenbruch Premise for Comparing Hourly Billing Rates of Affiliates and Outside Providers.** The Direct Testimony of Witness Baryenbruch (8:17 – 12:25 and Exhibit WG (L)-2, pages 11 to 28 (of 31 pages) indicates his analysis shows that affiliate services were less expensive than the cost of outside providers. Also, Table 5 (10:1-13) provides a comparison of WGL Affiliate "Hourly Rates" to those of Outside Providers (external independent vendors) for the four categories of professional services (Attorney, CPA, Management Consultant, and IT Professional). The calculation of hourly billing rates for Attorneys, CPAs, Management Consultants and IT Professionals is addressed and calculated at Exhibit WG (L)-2 (pages 16 to 22 of 31). Address the following:

a. Explain why (and the basis for) the premise of Witness Baryenbruch's analysis of comparing WGL Affiliate employees' hourly rates to outside professional service billing rates is reasonable and relevant for reaching a conclusion that WGL's affiliate charges are at the lower of cost or market and are significantly less than the cost of outside professionals if they were providing these same services.

b. Per (a) above, explain if the premise of Witness Baryenbruch's analysis is only relevant if WGL Affiliates would or could employ "all outside professional vendors" to provide all (or almost all) of its routine and day-to-day internal services provided by its employees that provide similar services as Attorneys, CPAs, Management Consultants and IT Professionals. Please identify all utilities that Witness Baryenbruch is aware of that use all outside independent professional services of Attorneys, CPAs, Management Consultants and IT Professionals to provide all (or almost all) of their routine and day-to-day services that could be provided by their own employees. If no utility uses all outside professionals to provide these services for its internal operations, then explain why Witness Baryenbruch proposes this as a reasonable alternative for purposes of comparing hourly billing rates and costs of WGL Affiliate internal employees to outside professional vendor services.

c. Explain if it is Witness Baryenbruch's understanding that most utilities (and other companies) the size of WGL only use outside professional services when it is required by state/government regulations (CPA audits of financial statements), when the utility/company does not have the specific detailed expertise in-house that an outside professional firm can provide regarding unique or specific services or studies, or when such outside professional firms can provide a service more efficiently than a utility/company can provide in-house. If not, explain why a utility/company would choose to use outside professional firms to provide all of its routine and day-to-day legal, accounting, IT, and management expertise as assumed in Witness Baryenbruch's study and comparison of hourly billing rates between WGL Affiliates and outside professional firms.

d. Explain if Witness Baryenbruch is aware that outside professional consulting firms such as Attorneys, CPAs, Management Consultants and IT Professionals generally use an hourly billing rate that marks-up by multiples of 2 to 4 times (or more) the cost of their consulting employees to recover the actual salary/payroll costs plus additional mark-up to recover overhead costs and to provide a contribution to company profits. If Witness Baryenbruch is not aware, then explain his understanding of how such professional consulting firms bill out the labor time of their employees to clients via hourly billing rates.

e. Regarding (d) above, explain why it is reasonable to compare the marked up employee salary cost (hourly billing rate) of a professional consulting firm to the salary cost of WGL's internal employees (that do not include a mark-up of their salary costs to recover other overhead costs and provide a contribution to company profits). Also explain if WGL and/or AltaGas mark-up employee salary costs to recover overhead costs and/or profits, when allocating these internal employee labor costs to affiliates (and provide the related mark-up amounts by component).

f. Explain how Witness Baryenbruch's analysis and comparison of hourly billing rates between WGL Affiliate internal employees and outside independent professional consulting firm employees (for Attorney, CPA, IT Professional, and Management Consulting services) reflects the increased efficiency of outside professional consulting firm employees which have a greater depth of knowledge and experience across the industry (experience addressing numerous unique and routine issues with many other utilities and other companies). Otherwise, explain if it is Witness Baryenbruch's opinion that outside professional consulting firm employees cannot contribute any efficiencies, economies of scale, or experience advantages over WGL's internal employees.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. The National Association of Regulatory Utility Commissioners (NARUC) recommends that the cost of services provided by affiliates to a regulated utility be priced at the lower of cost or market. Mr. Baryenbruch's work compares WGL's cost-per hour for affiliate services to the hourly billing rates charged by outside providers of those services. This test determines if it would be less expensive to outsource affiliate services. Some states, such as Virginia, require regulated utilities to demonstrate that affiliate services are priced at the lower of cost or market. For these reasons, Mr. Baryenbruch's comparison is reasonable and relevant.

b. Mr. Baryenbruch's analysis is relevant because outside providers are capable of performing many utility functions. No utility outsources "all (or almost all) of their routine day-to-day services." But that is irrelevant to the performance of a lower-of-cost-or-market test, which is meant to demonstrate whether affiliate services are lower than outside providers.

   There are instances of utilities outsourcing ongoing business processes. My client, NiSource, outsourced accounts payable functions to Tata Consultancy Services in 2022 (see attached OPC Data Request 4-36.b workpaper). IT-related functions are often outsourced. For instance, a utility that transitions from one vendor's business application to that of another vendor will often outsource the support of the old application until it is retired.

c. See the response to b. above.

d. Mr. Baryenbruch constructed the cost pools for WGL's affiliates with similar expenses to those of outside providers. In general, his cost pools contain employee compensation (salaries, incentives), payroll taxes, employee benefits, office expenses and rent, IT-related expenses, insurance and other expenses. WGL affiliate cost pools do not include a "contribution to company profits" because their services are provided at cost. However, that is not relevant to Mr. Baryenbruch's analysis, which is meant to demonstrate that affiliate services cost less than outside providers.

e. See the response to d. above.

f. Mr. Baryenbruch's analysis is a straight up comparison of TY 2024 actual charges for affiliate services to those of outside providers. This question makes an automatic assumption that outside providers are more efficient than staff of WGL affiliates. There is no basis for this biased assumption.

SPONSOR: Patrick Baryenbruch
Consultant

**NISOURCENEXT**

A Stronger Foundation for Future Success

# AP Cognizant (Catalyst) to TCS AP (EDMonline)

## Supplier Training Deck

# NiSource Introductions

Adolfo Acevedo
Director
NiSource Business Services

Sandra Brummitt
Vice President
Chief Tax & Procurement Officer

Chris Ludwig
Lead Business Analyst
Procure to Pay Solutions

*We are changing from Cognizant (Catalyst) to TCS AP (EDMonline). NiSource is doing so by pursuing a collaborative outsourcing partnership with IT and Business Services provider Tata Consultancy Services (TCS). This will enable NiSource to build strategic capability that delivers value to NiSource, its employees, and its suppliers.*

# Executive Summary

## Today's topics and decision points

| Topics being presented today for information sharing | Desired Outcomes |
|---|---|
| • Overview: AP Cognizant (Catalyst) to TCS AP (EDMonline) snapshot<br>• Today vs. Tomorrow<br>• Support Matrix<br>• TCS AP (EDMonline)<br>• Q&A<br>• Survey | • Align on approach<br>• Introduce TCS AP<br>• Train on EDMonline |

# AP Cognizant (Catalyst) to TCS AP (EDMonline) Snapshot

## THE TIMING

- Suppliers to begin using TCS AP (EDMonline) in place of Cognizant (Catalyst) for invoice processing on February 28, 2022

## THE CHANGE

- **Application:** Moving from AP Cognizant (Catalyst) to TCS AP (EDMonline) for invoice processing
- **Support:** Cognizant no longer providing employee/vendor support; transition to TCS Procure to Pay Services
- **Contact information:** New address, email, phone

## THE PLAN

- Implement solution with all required features that exist in Catalyst today
- Conduct multiple rounds of communications to suppliers (post, email, and Supplier Site) about change, new application access, training, and new support model
- Deploy training on Supplier Site

# AP Cognizant (Catalyst) to TCS AP (EDMonline) Snapshot

| YOUR ACTION TIMELINE | |
|---|---|
| **EXPECT:** Multichannel updates on project (mail, email, Supplier Site) | Nov 2021 – Feb 2022 |
| **DO:** | Dec 2021 - Feb 2022 |
| ❑ Business Partners to inform suppliers | Dec 2021 - Feb 2022 |
| ❑ Gain access credentials to EDMonline | Feb 2022 |
| ❑ Complete Training* | 17 Feb 2022 |
| ❑ Use EDMonline | 28 Feb 2022 |
| ❑ Seek support from TCS | 28 Feb 2022 |

| | KEYS TO SUCCESS |
|---|---|
| | Focused training plan with a variety of options (live or recorded demos, user guide, functional support guide) |
| | Multi-channel communications approach to ensure message reach, understanding and action (mail, email, Supplier Site) |
| | Precise coordination with Supply Chain to ensure a consistent and clear supplier experience |

# TODAY VS. TOMORROW: AP COGNIZANT (CATALYST) TO TCS AP (EDMONLINE): INVOICE PROCESSING

Phase 2



Evolution of Business Services

| | Today | Service Level Shift | | Tomorrow – February 28, 2022 |
|---|---|---|---|---|
| SUPPORT | • Cognizant performs **WMS vendor registration** in Catalyst<br>• **Email** Cognizant for support @ nisourceap@cognizant.com<br>• **Call** Cognizant for IT support and emergency requests requiring immediate support @ 1-877-357-3911, Option 1 | • Call / Email/Mail<br>• ASAP support<br>• SLAs as defined | • Call/Email/Mail. ASAP ad-hoc support<br>• Agreed Service SLAs<br>• Support by priority of request (2 hr-Urgent, 2 Days – Std.) | • TCS performs **WMS vendor registration** – reach out to your NiSource Business Partner for registration<br>• **Email** the support mailbox for EDMonline queries: nisourceaccountspayable@nisource.com (internal inquiries)<br>• **Call** TCS for emergency requests requiring immediate support @ 1-631-203-2055, Option 1 (M – F: 7:00 a.m. - 7:00 p.m. ET) |

# Support Matrix

| Support Area | Contact Details |
|---|---|
| NiSource Accounts Payable (internal inquiries) | nisourceaccountspayable@nisource.com |
| TCS AP | 1-631-203-2055, Option 1 (7:00 a.m. - 7:00 p.m. ET) |

# EDMonline Training

## WMS Suppliers

# Training Agenda

- EDM-Online Introduction
- How to gain access (New & Existing Suppliers)
- Password management
- Application Features and How to search Remittances
- FAQs

# EDM Online – Introduction & How to gain access

**Introduction:**

**EDM online** replaces **Catalyst** with the same set of features in a simplified way. It will be the repository for your remittance advices dated from 1st Dec 2020 for the invoices paid by NiSource. Suppliers can use this application to download the remittance advices at any point in time.

**Already a NiSource Supplier:**

If you are an existing supplier who has the access to current Catalyst, you need not to raise any request to get the access. We are going to provide access by transferring data from Catalyst to EDM-Online. However, as there is a change in the application, we will provide access and will share the user ID & password credentials to access the application.

**New to NiSource:**

If you are a new supplier or who do not have an access to current Catalyst, please speak to your NiSource Business Contact to raise a request in the system for you to provide access

Once the request is raised and approved, NiSource AP team will give the access and you will be receiving your username and temporary password to access the application.

**Points to note:**

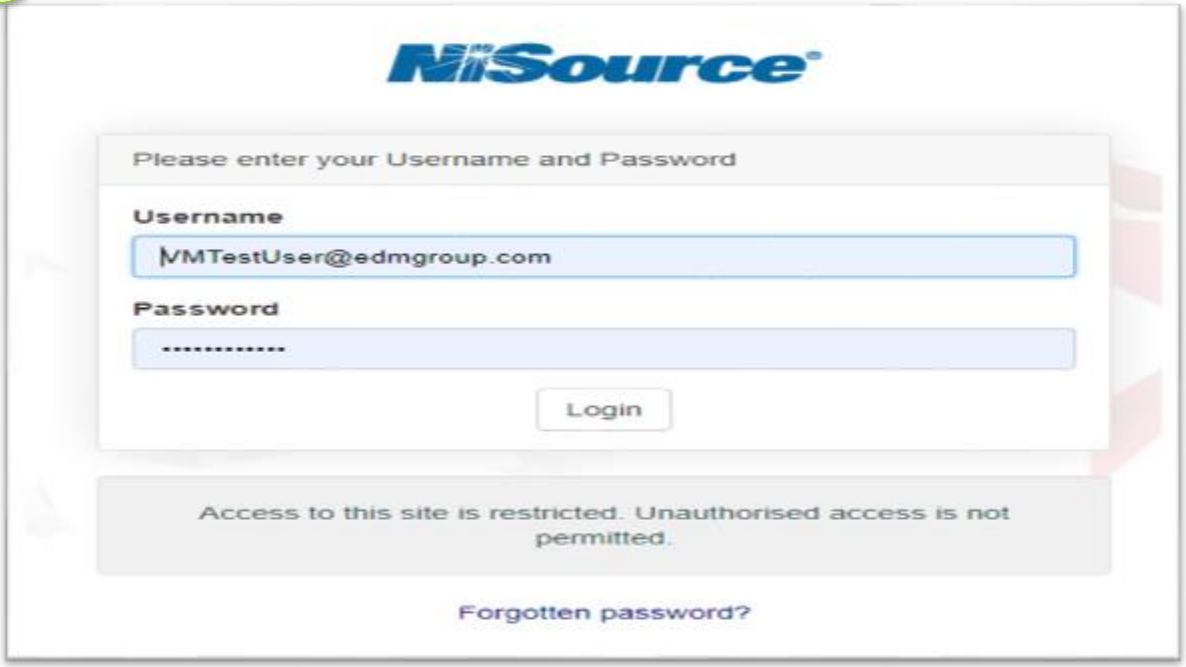
- User need to reset their password on first login
- Password should be alpha numeric and one upper case
- Password will expire in 30 days if you are not resetting your password

**For queries and support required** – Please contact nisourceaccountspayable@nisource.com to get immediate response

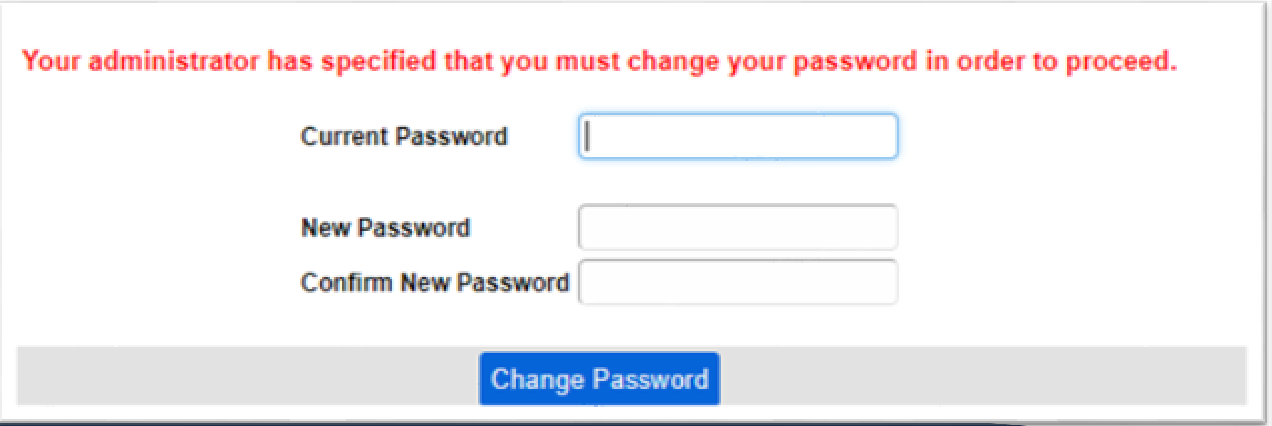
# EDM Online – How to Log-In & Reset Your Password



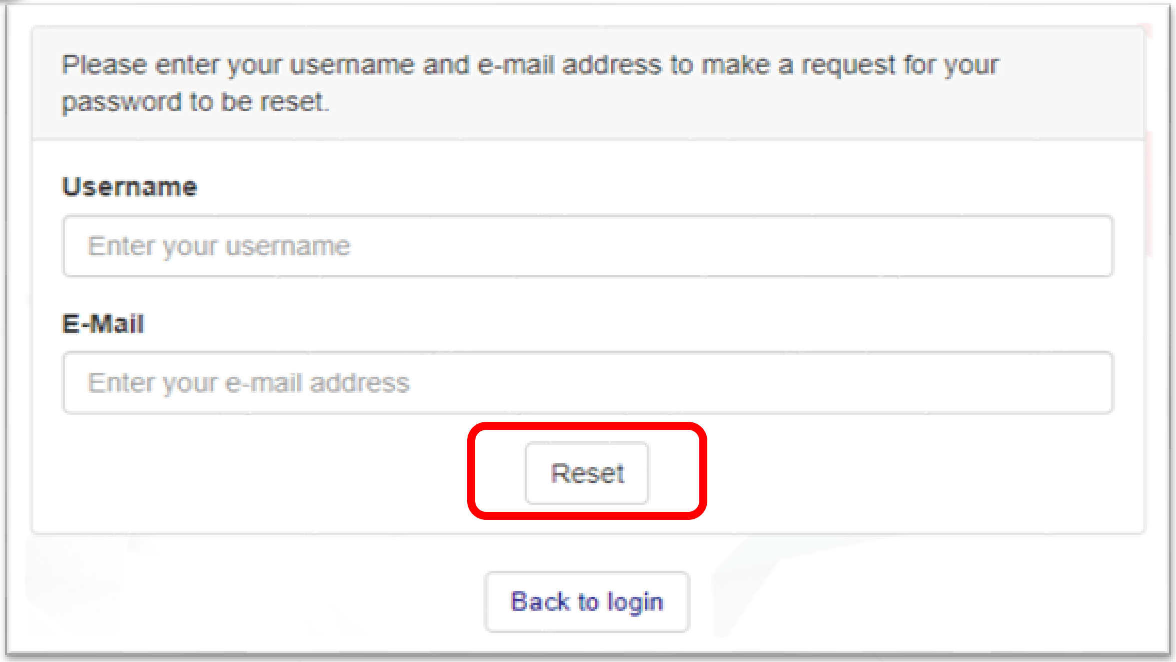
1 Use ID and Temporary Password which will be shared by NiSource




Change your temporary password on 1st Log-in




2 If you forgotten your password and to re-set, click "forgotten Password" in the log-in page and below screen will open




Enter your user ID & Email address and press "Reset"

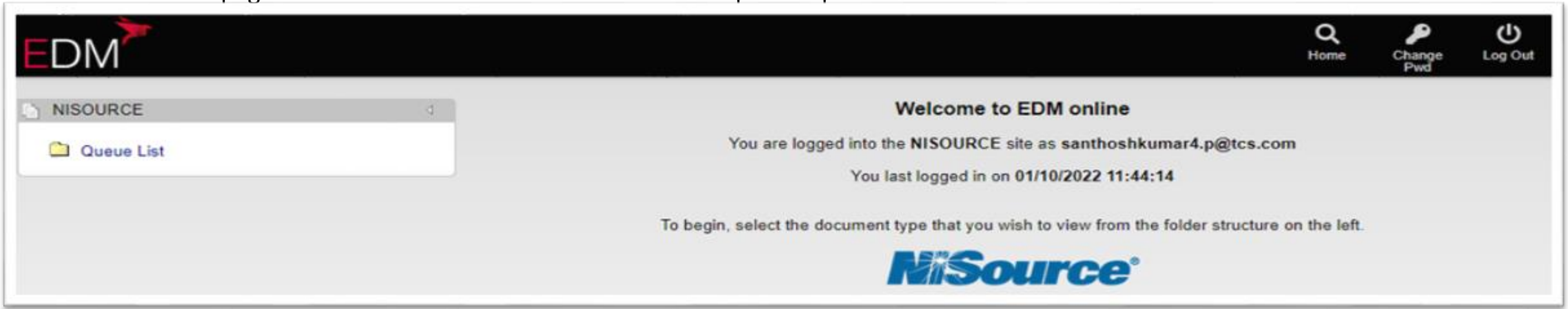
Email will be sent by EDM (our scanning partner) with the temporary password to the email ID given

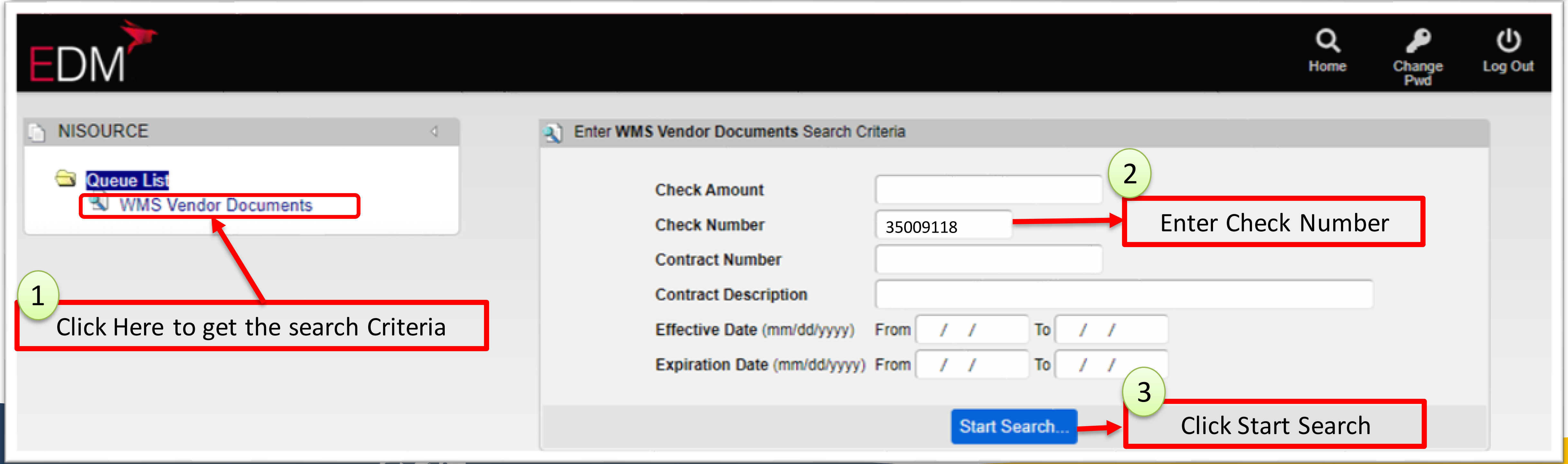
If you are not receiving your temporary password / finding any issues, please contact nisourceaccountspayable@nisource.com

# EDM Online – How to download remittance advice (1)



Below is the home page of EDM-Online where we have all the required options to download the remittance advice






Public

# EDM Online – How to download remittance advice (2)

EDM

Home | Change Pwd | Log Out

NISOURCE

Queue List
WMS Vendor Documents

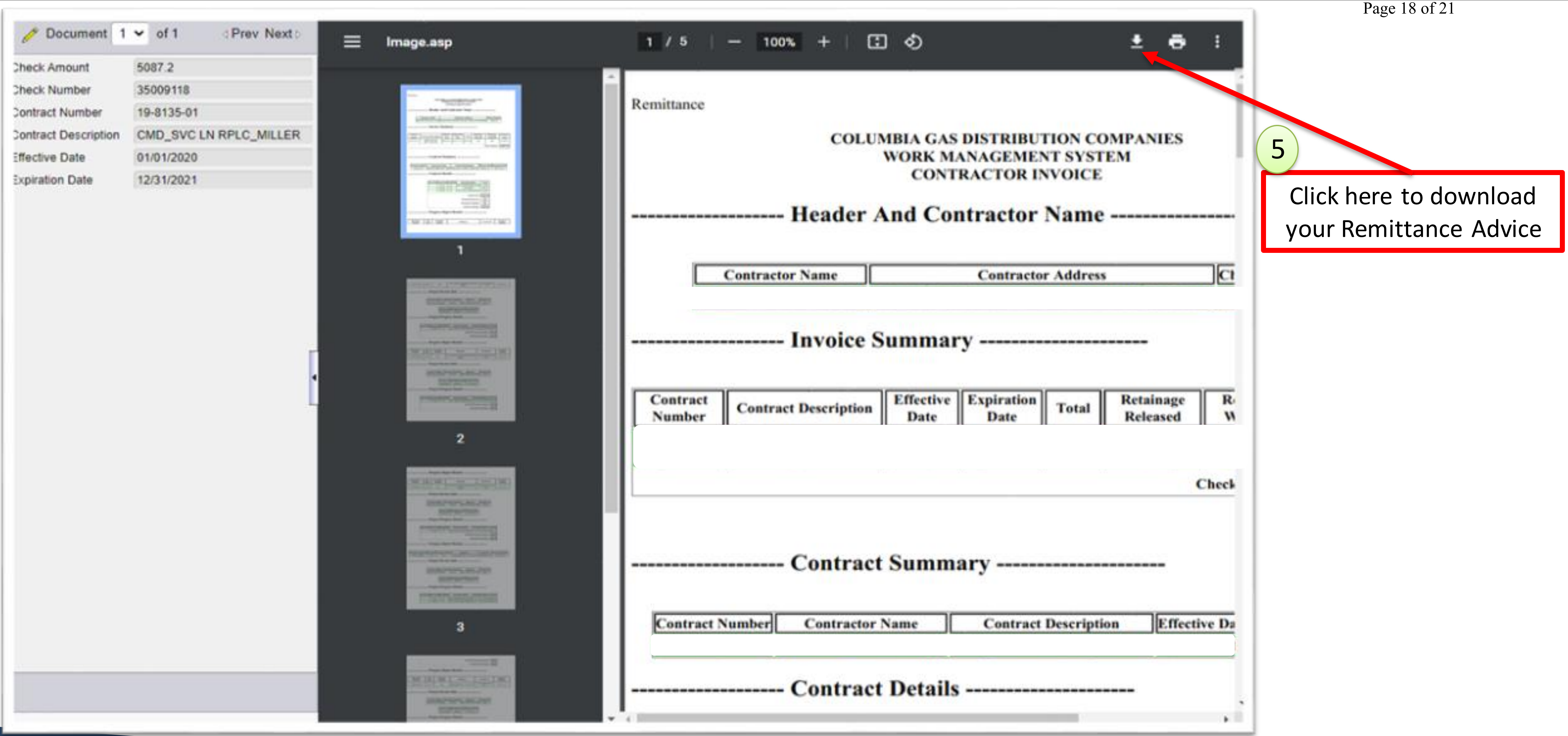
4

Click here to view your Remittance Advice

**WMS Vendor Documents Search Results**

| Check Amount | Check Number | Contract Number | Contract Description | Effective Date | Expiration Date | Option(s) |
|---|---|---|---|---|---|---|
| 5087.2 | 35009118 | 19-8135-01 | CMD_SVC LN RPLC_MILLER | 01/01/2020 | 12/31/2021 | |
| 2309.2 | 37049198 | 20-8242-01 | CPA_VAC EX_MILLER PIPE | 04/01/2020 | 03/31/2022 | |
| 8594.7 | 34059860 | 20-8324-00 | COH_MILLER_TOLEDO 2021 | 01/01/2021 | 01/10/2022 | |
| 8594.7 | 34059860 | 20-8326-00 | COH_MILLER_CBUS_2021 | 01/01/2021 | 01/10/2022 | |
| 8594.7 | 34059860 | 20-8327-00 | COH_MILLER_NPOINT_2021 | 01/01/2021 | 01/04/2022 | |
| 13890.06 | 38028260 | 21-8496-00 | CVA_MILLER PIPE_CENT21 | 01/01/2021 | 12/31/2021 | |

# EDM Online – View Your Remittance



# EDM Online – FAQs



**1. How to gain access:**

Supplier who already have an access to Catalyst – No action required from your end. We are providing access to all suppliers by transferring suppliers details from Catalyst to EDM-Online

Supplier who do not have an access to catalyst or the access got cancelled recently – Speak to your NiSource Business Contact who has to raise a request in the system for you to get the EDM-Online access

**2. How to revoke access:**

If you do not require access, please send an email to nisourceaccountspayable@nisource.com to remove the access

**3. Contact for technical issue:**

You can always reach out to 1-631-203-2055 and select option 1 / (Email – nisourceaccountspayable@nisource.com) to speak to our team to resolve the issue

**4. Options for those who are not attending the scheduled trainings:**

- Please access the FAQs
  https://www.nisource.com/docs/librariesprovider2/supply-chain-documents/supplier-faqs-transition-from-ap-cognizant-(catalyst)-to-edmonline.pdf
  https://www.nisource.com/company/doing-business-with-us/current-suppliers
- User guide is also available within EDM-Online application to understand the features and navigations

# Q&A

# Take 1-Minute to Complete the Survey

**Link: https://www.surveymonkey.com/r/Z52Y76H**

Exhibit OPC (B)-26
Formal Case No. 1180
Direct Testimony of Bion Ostrander

Page **1** of **3**

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-37

**Q.** **Witness Baryenbruch Calculation of WGL Affiliate Hourly Billing Rates and Hours Charged.** The Direct Testimony of Witness Baryenbruch (8:17 – 12:25 and Exhibit WG (L)-2, pages 11 to 28 (of 31 pages) indicates his analysis shows that affiliate services were less expensive than the cost of outside providers. Also, Table 5 (10:1-13) shows WGL Affiliate "Hourly Rates" and "Hours Charged" for the four categories of professional services (provided by attorneys, CPAs, management consultants, and IT professionals) as explained at Exhibit WG (L)-2 (pages 11 and 12 of 31), with the categories of service costs shown by cost pools for TY 2024 (Exhibit WG (L)-2, page 12 of 31) and service category (Exhibit WG (L)-2, page 13 of 31, Exhibit 4), along with related hours shown by service category (Exhibit WG (L)-2, page 14 of 31, Exhibit 5). Address the following:

a. Per Witness Baryenbruch (10:1-13, Table 5), provide all supporting documentation and calculations (in original Excel format as applicable) regarding the determination of the TY 2024 WGL Affiliates "Hourly Rates" for each of the professional services of Attorney, CPA-Accounts Payable, CPA-Other Finance, IT Professional, and Management Consultant.

b. Per Witness Baryenbruch ((10:1-13, Table 5), provide all supporting documentation and calculations (in original Excel format as applicable) regarding the determination of the TY 2024 WGL Affiliates "Hours Charged" for each of the professional services of Attorney, CPA-Accounts Payable, CPA-Other Finance, IT Professional, and Management Consultant. Explain and show how the number of "Hours Charged" is determined from payroll costs, headcount reports, and other supporting documentation, and provide all calculations supporting the determination of "Hours Charged."

c. Regarding (b) above, explain how WGL Affiliates' "Hours Charged" is determined if Executive/Management personnel do not keep specific documentation regarding the specific number of hours they work or the

Page 2 of 3

specific number of hours they work by Service Category (Accounting, Board of Directors, Compliance, etc.).

d. Explain why the TY 2024 WGL costs for each of the professional services (Attorney, CPA-Accounts Payable, CPA-Other Finance, IT Professional, and Management Consultant) by Service Category (Accounting, Accounts Payable, Compliance, etc.) at Exhibit WG (L)-2, page 13 of 31, Exhibit 4, when divided by the related hours at Exhibit WG (L)-2, page 14 of 31, Exhibit 5, does not equal the "WGL Affiliates" billing rates at Witness Baryenbruch testimony (10:1-6, Table 5). For example, Attorney costs of $1,195,122 at Exhibit 4 divided by Attorney hours of 8,577 at Exhibit 5 equals an hourly billing rate of $139.34, which does not equal the WGL Affiliate Attorney hourly billing rate of $101.00 at Witness Baryenbruch testimony (10:3-4, Table 5).

e. Regarding (a) above, provide a reconciliation of the WGL Affiliate billing rates at Witness Baryenbruch testimony (10:1-6, Table 5) to all documentation at Exhibit WG (L)-2, page 13 (Exhibit 4) and page 14 (Exhibit 5), and all other testimony, Exhibits and supporting documentation. Provide additional support for costs, the number of hours, and other documentation as necessary to provide a complete reconciliation to the hourly billing rates at Table 5.

f. Explain why Exhibit 4 shows costs for affiliates providing Management Consultants services related to the Board of Directors category but Exhibit 5 does not show "Company Hours" for these related services. Explain how the absence of "hours" for Board of Directors impacted the calculation of the Management Consultant "hourly billing rate" at Table 5, and explain and show how these Board of Directors costs were reflected in the final hourly billing rate of Management Consultant in the absence of related hours.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers.

b. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers.

c. For ALA, hours are based upon full-time equivalent (FTE) employees associated with supporting WGL. This is determined by applying the percent of WGL charges to total charges for each ALA business unit (BU) times the BU's average FTE count during TY 2024.

For SEMCO, hours are based upon TY 2024 actual hours worked.

The compilation of affiliate hours can be found in Mr. Baryenbruch's workpapers in response to OPC Data Request 4-19.

d. Exhibit 4 on page 13 of 31 represents gross charges by service category and outside provider category. As shown in the table on page 12 of 31, certain charges are excluded from the hourly rate calculation because they are not a cost of the services provided by affiliate personnel. Excluded expense categories are described on pages 11 and 12 of 31. The exclusions are appropriate so affiliate cost pools match the expense recovery associated with outside providers.

e. This information can be found in Mr. Baryenbruch's workpapers in response to OPC Data Request 4-19.

f. A large portion of Board of Directors-related charges are outside directors' fees. They are not ALA employees, thus there are no labor-related expenses. Detailed calculations of affiliate hourly rate can be found in Mr. Baryenbruch's workpapers in response to OPC Data Request 4-19.

SPONSOR: Patrick Baryenbruch
Consultant

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS‘S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE’S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-38

**Q.** **Witness Baryenbruch Calculation of Hourly Rates by Payroll Cost Category.** The Direct Testimony of Witness Baryenbruch Table 5 (10:1-13) compares hourly rates of WGL affiliates to outsider services providers for the four categories of professional services (provided by attorneys, CPAs, management consultants, and IT professionals) as explained at Exhibit WG (L)-2 (pages 11 and 12 of 31), and with the categories of service costs shown by cost pools for TY 2024 (Exhibit WG (L)-2, page 12 of 31) and service category (Exhibit WG (L)-2, page 13 of 31, Exhibit 4). Address the following:

a. Provide the amount of payroll costs by specific category (base salary, incentives, benefits, etc.) for test year 2023 included in the calculation of the WGL Affiliate hourly billing rates for each of the professional services (Attorneys, CPA-Accounts Payable, CPA-Other Finance, IT Professional, and Management Consultant) at Table 5 and reconcile these amounts to the underlying related costs by Service Category at Exhibit 4 (along with all other documentation supporting costs included in the hourly billing rates). For example, for “Attorney” professional service costs of $1,195,122 at Exhibit 4, provide the underlying payroll costs by specific categories (base salary, incentives, benefits, etc.) that are used in calculating the WGL Affiliates hourly billing rate at Table 5. Provide this information for the following payroll cost categories (explain if the costs below are expensed, capitalized, or include both expensed and capitalized):

   i) Base salary.

   ii) Short-term incentives.

   iii) Long-term incentives.

   iv) Other bonuses or incentives.

v) Health/medical insurance.

vi) OPEB.

vii) Pension.

viii) Payroll taxes.

ix) Other benefits.

x) Other payroll costs, overheads, and loadings.

b. If a specific payroll cost category listed in (a) above is not included in the calculation of costs by professional services at Exhibit 4 (and not included in the WGL Affiliate hourly billing rate at Table 5), then please provide this payroll cost to OPC in case it is necessary for OPC to include any of these payroll costs order to make them comparable to the costs of outside providers.

c. Regarding (a) and (b) above, explain why each of the related payroll costs categories are included or excluded from the underlying calculation of the WGL Affiliates hourly billing rate at Table 5, and particularly explain why short and long-term incentives have been included or excluded from such hourly rate calculations.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers, including this charge detail.

b. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers, including his hourly rate calculations.

c. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers, including his hourly rate calculations.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-28
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-39

**Q.** **Witness Baryenbruch Hourly Rate Costs and Hours.** The Direct Testimony of Witness Baryenbruch Table 5 (10:1-13) compares hourly rates of WGL affiliates to outsider services providers for the four categories of professional services (provided by attorneys, CPAs, management consultants, and IT professionals) as explained at Exhibit WG (L)-2 (pages 11 and 12 of 31), the categories of service costs shown by cost pools for TY 2024 (Exhibit WG (L)-2, page 12 of 31) and service category (Exhibit WG (L)-2, page 13 of 31, Exhibit 4), and the related number of hours (Exhibit WG (L)-2, page 14 of 31, Exhibit 5). Address the following:

a. Regarding Exhibit 4, provide the number of full-time equivalent employees (or identify "partial" employee calculations) included in each of the professional service category "Charges/Costs" (Attorney, CPA-Accounts Payable, CPA-Other Finance, IT Professional, and Management Consultant) and for each related Service Category line item (Accounting, Compliance, Human Resources, etc.) and provide all supporting documentation and calculations used to determine the number of employees.
b. Regarding Exhibit 5, provide the number of full-time equivalent employees (or identify "partial" employee calculations) included in each of the professional service category company "Hours" (Attorney, CPA-Accounts Payable, CPA-Other Finance, IT Professional, and Management Consultant) and for each Service Category line item (Accounting, Compliance, Human Resources, etc.) and provide all supporting documentation and calculations used to determine the number of employees.

c. Regarding (a) and (b) above, please explain if the number of employees and the same types of employees are both reflected in Exhibit 4 and Exhibit 5, and explain the reasons for any differences in the number or types of employees between these two exhibits.

d. Regarding (a) and (b) above, please reconcile the number of employees at Exhibit 4 and 5 to existing headcount reports/statistics showing employees by Service Category (Accounting, Compliance, Human Resources, etc.), types of positions (Officers, Management, etc.), along with other headcount statistic documents that are available.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers, including the detail for affiliate charges.

b. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers, including the detailed calculations for affiliate hours.

c. The supporting detail for Exhibit 4 can be found in Mr. Baryenbruch's work papers (OPC Data Request 4-19). They include a breakdown of charges by business unit and account (i.e., resource types such as salaries, employee benefits, incentive plan payments, defined contributions).

   The supporting detail for Exhibit 5 can also be found in Mr. Baryenbruch's workpapers.

d. Exhibit 4 is denominated in dollar charges, not employee hours or headcount.

   Exhibit 5 is based on TY 2024 FTEs by business unit by quarter. Average FTEs are converted into hours by business unit. Business units are associated with service categories and outside providers. These calculations are shown in Mr. Baryenbruch's workpapers at OPC Data Request 4-19.

   The FTE data is not broken down by each and every position for business units. That level of detail is not required for management reporting or any other reason.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-29
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-40

**Q.** **Witness Baryenbruch Comparison of Billing Rates for WGL Affiliates to Outside Providers for CPA Professional Services.** The Direct Testimony of Witness Baryenbruch Table 5 (10:1-13) compares hourly rates of WGL Affiliates to Outside Providers for the professional service categories of CPA-Accounts Payable and CPA-Other Finance. Exhibit WG (L)-2 (pages 16, 19, 20 of 31), generally explains how WGL determined the Hourly Billing Rates for external independent CPAs (outside of WGL Affiliates). Also, the costs used for determining the internal WGL Affiliates' Hourly Billing Rate for CPAs is reflected by cost pools (Exhibit WG (L)-2, page 12 of 31) and by service category (Exhibit WG (L)-2, page 13 of 31, Exhibit 4), and the related number of hours (Exhibit WG (L)-2, page 14 of 31, Exhibit 5). In order to address the correlation and determination of hourly billing rates calculated by Witness Baryenbruch for external independent CPAs (Outside Providers) and internal CPAs of WGL Affiliates, please address the following:

a. Per Exhibit 4, provide the amount of WGL Affiliate costs for CPA-Accounts Payable and CPA-Other Finance (for each of the Service Categories of Accounting, Accounts Payable, Finance, Procurement and Taxes) with the following CPA credentials (and without CPA credentials):

   i) WGL Affiliate employees that have passed the CPA examination but are not licensed and do not have a permit to practice.

   ii) WGL Affiliate employees that have passed the CPA examination and are licensed CPAs, but do not have a permit to practice.

   iii) WGL Affiliate employees that have passed the CPA examination, are licensed CPAs, and have a permit to practice.

iv) WGL Affiliate employees that have previously worked for a CPA firm as a licensed and permit to practice CPA.

v) WGL Affiliate employees that have a college degree in accounting but do not have any CPA credentials (do not meet any of the criteria in items (i) to (iv) above).

vi) WGL Affiliate employees that do not have a degree in accounting (or emphasis in accounting) or any CPA credentials, although the related employee costs have been included in the CPA-Accounts Payable and CPA-Other Finance services category.

b. Per (a) above, for each of the subitems (i) to (vi), provide the amount of WGL Affiliate Costs in a similar format as Exhibit 4 (for CPA-Accounts Payable and CPA-Other Finance for Categories of Accounting, Accounts Payable, Finance, Procurement and Taxes) that are associated with each of the following experience levels identified by Witness Baryenbruch at the table at Exhibit WG (L)-2, page 16 of 31:

(i) Partners/Owners

(ii) Directors (over 10 years of experience)

(iii) Managers (6-10 years of experience)

(iv) Sr Associates (4-5 years of experience)

(v) Associates (1-3 years of experience)

(vi) New Professionals

c. Per (b) above, provide the WGL Affiliates hourly billing rates for CPA-Accounts Payable and CPA-Other Finance for each of the related experience levels of WGL Affiliate employees identified in (b) above, and provide all supporting documentation and calculations.

d. Per Exhibit 5, provide the number of WGL Affiliate hours for CPA-Accounts Payable and CPA-Other Finance (for each of the Service Categories of Accounting, Accounts Payable, Finance, Procurement and Taxes) with the following CPA credentials (and without CPA credentials):

(i) WGL Affiliate employees that have passed the CPA examination, but are not licensed and do not have a permit to practice.

(ii) WGL Affiliate employees that have passed the CPA examination and are licensed CPAs, but do not have a permit to practice.

(i) WGL Affiliate employees that have passed the CPA examination, are licensed CPAs, and have a permit to practice.

(ii) WGL Affiliate employees that have previously worked for a CPA firm as a licensed and permit to practice CPA.

(iii) WGL Affiliate employees that have a college degree in accounting (or an emphasis in accounting) but do not have any CPA credentials (do not meet any of the criteria in items (i) to (iv) above.

(iv) WGL Affiliate employees that do not have a degree in accounting or any CPA credentials, although the related employee hours have been included in the CPA-Accounts Payable and CPA-Other Finance services category.

e. Per (d) above, for each of the subitems (i) to (vi), provide the amount of WGL Affiliate Hours in a similar format as Exhibit 5 (for CPA-Accounts Payable and CPA-Other Finance for Categories of Accounting, Accounts Payable, Finance, Procurement and Taxes) that are associated with each of the following experience levels identified by Witness Bayrenbruch at the table at Exhibit WG (L)-2, page 16 of 31:

(i) Partners/Owners

(ii) Directors (over 10 years of experience)

(iii) Managers (6-10 years of experience)

(iv) Sr Associates (4-5 years of experience)

(v) Associates (1-3 years of experience)

(vi) New Professionals

f. Per (a) and (d) above, for WGL Affiliate employees that have been designated as providing CPA-related services (CPA-Accounts Payable and CPA-Other Finance), but do not have CPA credentials, then explain why it is reasonable to compare these WGL Affiliate employee hourly rates/costs to the billing rates of external independent credentialed CPAs.

g. Regarding (f) above, explain and cite to all precedent and best practices examples where this type of similar study and comparison has been proposed or adopted in regulatory proceedings in other jurisdictions, or has been proposed or adopted for other purposes (outside of regulatory proceedings).

**WASHINGTON GAS'S PARTIAL OBJECTION** 11/1/2024

**Subparts (a) through (f)**

Washington Gas objects to subparts (a) through (f) of this request on grounds that they require the performance of a special study which has not been performed.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. An objection is raised for this request. This information would require a special study.

   The requested ALA information is not available in the format requested. The billing rates for outside providers come from credible sources and are shown to be significantly higher than Mr. Baryenbruch's calculated hourly rate for WGL affiliates. The requested information would not change the outcome of Mr. Baryenbruch's comparison.

b. An objection is raised to this request. It would require a special study. See the response to a. above.

c. An objection is raised to this request. It would require a special study. See the response to a. above.

d. An objection is raised to this request. It would require a special study. See the response to a. above.

e. An objection is raised to this request. It would require a special study. See the response to a. above.

f. An objection is raised to this request. It would require a special study. See the response to a. above.

g. A lower-of-cost-or-market comparison has been performed for the vast majority of Mr. Baryenbruch's 160 rate case assignments before regulators in 22 states. In none of these cases has his methodology been rejected.

The state of Virginia has extensive statutory requirements covering utility-affiliate transactions. Among other things, the Virginia State Corporation Commission (VSCC) requires its regulated utilities to demonstrate that their services from affiliates are priced at the lower of cost or market. Mr. Baryenbruch's methodology has been specifically accepted by the Virginia State Corporation Commission (VSCC), as noted below in its order for case PUE-2002-00375:

*As this Commission has found previously that the methodology of the Baryenbruch study is satisfactory, we decline today to find that the Company failed to meet its burden of proof regarding the reasonableness of the affiliate expenses.*
Order for PUE 2002-00375, page 14. (see attached OPC Data Request 4-40.g workpaper)

Mr. Baryenbruch has performed 34 evaluations of transactions between Virginia utilities and their affiliates. Each of these included a lower-of-cost-or-market comparison. For twenty-one straight years, he evaluated transactions between affiliates and Columbia Gas of Virginia, which includes his report with their annual affiliate transaction report filing with the VSCC. The VSCC staff has recommended that a number of their regulated utilities use Mr. Baryenbruch to evaluate their affiliate transactions. All of this demonstrates solid regulatory acceptance of Mr. Baryenbruch's methodology and the results of his comparisons.

SPONSOR: Patrick Baryenbruch
Consultant

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION



AT RICHMOND, SEPTEMBER 3, 2003

APPLICATION OF

VIRGINIA-AMERICAN WATER COMPANY

CASE NO. PUE-2002-00375

For a general
increase in rates

## ORDER ON HEARING EXAMINER'S REPORT

On June 24, 2002, Virginia-American Water Company ("Virginia-American" or "Company") filed with the State Corporation Commission ("Commission") an Application for a general increase in rates. In its application, Virginia-American sought to increase annual operating revenues for the Hopewell District by $872,320 and for the Alexandria District by $238,349. The Company did not seek an increase for the Prince William District. On July 8, 2002, Virginia-American filed several revised schedules to its application.

By order dated July 18, 2002, the Commission issued its Order for Notice and Hearing in which it directed the Company to publish notice and appointed a Hearing Examiner to conduct all further proceedings in this matter. The Commission's Order also permitted the proposed rates, which were designed to increase annual operating revenues by approximately 3.7%, to become effective November 22, 2002, subject to refund.

On December 18, 2002, a stipulation ("Stipulation") between the Company and Commission Staff ("Staff") was filed which provided for no change in the annual revenues for the Alexandria District.

The City of Hopewell ("City"), the Hopewell Committee for Fair Water Rates ("Committee"),[1] and Prince George County filed notices of participation as respondents. On November 14, 2002, the City filed a Motion for a Continuance, requesting that the evidentiary hearing scheduled for December 11, 2002, be rescheduled to December 20, 2002. On the same day, the Hearing Examiner granted the motion but retained the December 11, 2002, hearing date for the limited purpose of receiving testimony from public witnesses. No public witnesses appeared at the December 11, 2002, hearing.

The evidentiary hearing was convened on December 20, 2002. Richard D. Gary, Esquire, and Renata M. Manzo, Esquire, appeared on behalf of the Company. Edward L. Flippen, Esquire, appeared on behalf of the City. Cliona M. Robb, Esquire, appeared on behalf of the Committee. Wayne N. Smith, Esquire, and Joseph W. Lee, Esquire, appeared as counsel to the Staff. At the close of the evidentiary hearing, counsel for the City was granted permission to file a motion to dismiss the Application.

[1] The Hopewell Committee for Fair Water Rates is comprised of Goldschmidt Chemical Company, Hercules Incorporated, Honeywell, Hopewell Cogeneration Facility, James River Cogeneration, PraxAir, Inc., and Smurfit-Stone Container.

On January 24, 2003, the City filed its Motion to Dismiss, in which it alleged that the Company failed to comply with the Commission's Rules Governing Utility Rate Increase Applications and Annual Informational Filings ("Rate Case Rules")[2] because the Application was inaccurate and incomplete and its workpapers were misleading. The errors in the Application involved the Company's failure to note the impact of the closure of the Dominion Cogeneration facility in Hopewell. On January 27, 2003, the Hearing Examiner directed the parties to respond to the Motion to Dismiss.

On February 10, 2003, post-hearing briefs were filed by the Company, the Staff and the City. The Company's brief included a response to the City's Motion to Dismiss. It also contained a request for a waiver of the Rule 20 VAC 5-200-30 if that rule is deemed to have been violated by the Company.

On February 14, 2003, the City filed its Reply on its Motion to Dismiss. On the same day, the Company filed a Motion to Update the Record that sought to add to the record the actual audited costs of the Hopewell Regional Wastewater Treatment Facility expense. On February 18, 2003, the City filed its objection to the Motion to Update the Record. On February 25,

[2] 5 VAC 5-20-10 et seq.

2003, the Company filed its response to the City's objection to its Motion to Update the Record.

On February 26, 2003, the Hearing Examiner denied the Company's Motion to Update the Record. Also on February 26, 2003, the City and Committee jointly filed a Motion to Reduce Rates and Order Refunds, which alleged that the revised schedules filed by the Company on July 8, 2002, showed that the Hopewell District required a total annual revenue increase of \$853,458, rather than the \$872,320 initially requested in the Application.

On March 3, 2003, the Company filed its Response to the joint Motion to Reduce Rates and Order Refunds and filed an Objection to the Hearing Examiner's ruling denying its Motion to Update the Record.

On May 14, 2003, Hearing Examiner Alexander F. Skirpan, Jr., entered a Report ("Report") summarizing the record and analyzing the evidence and issues in this proceeding. The Examiner made the following findings:

(1) The use of a test year ending December 31, 2001, is proper in this proceeding;

(2) Virginia-American's test year operating revenues, after all adjustments, were \$10,324,640 for the Alexandria District; \$5,253,740 for the Prince William District; and \$8,484,745 for the Hopewell District;

(3) Virginia-American's test year operating revenue deductions, after all adjustments, were \$8,052,612 for the

Alexandria District; $3,909,159 for the Prince William District; and $6,808,550 for the Hopewell District;

(4) Virginia-American's test year adjusted net operating income, after all adjustments were $2,265,285 for the Alexandria District; $1,342,841 for the Prince William District; and $1,672,885 for the Hopewell District;

(5) Virginia-American's current rates produce a return on adjusted rate base of 8.407% for the Alexandria District; 7.785% for the Prince William District; and 6.013% for the Hopewell District;

(6) Virginia-American's current rates produce a return on equity of 10.395% for the Alexandria District; 8.883% for the Prince William District; and 4.573% for the Hopewell District;

(7) Virginia-American's current cost of equity is within a range of 9.3% - 10.3%, and Virginia-American's rates for the Hopewell District should be established based on the 9.8% midpoint of the equity range;

(8) Virginia-American's overall cost of capital, using the midpoint of the equity range and the capital structure as proposed by Staff, is 8.162%;

(9) Virginia-American's adjusted test year rate base is $26,944,433 for the Alexandria District; $17,248,475 for the Prince William District; and $27,821,627 for the Hopewell District;

(10) Based on the record and the Stipulation, Virginia-American requires no additional gross annual revenues to earn a reasonable return on rate base for the Alexandria District and the Prince William District, and $950,444 in additional gross annual revenues for the Hopewell District;

(11) Because the notice for the Hopewell District provided for an increase of $872,320 in additional gross annual revenues, the increase in annual revenues for the Hopewell District is limited to that amount;

(12) In accordance with the Stipulation, the Company shall file a depreciation study for the Alexandria and Prince William Districts with Staff on or before December 31, 2004; and

(13) The interim rates for the Hopewell District should continue and be designated as permanent rates.

The Hearing Examiner also declined to increase rates to levels in excess of the rates noticed by the Company, and did not adjust the rates for the Hopewell District to reflect the loss of billing determinants resulting from the closure of the Dominion Cogeneration facility.

The Hearing Examiner recommended that this Commission enter an order adopting the findings in his report and dismissing the case from the active docket. The Examiner further directed that comments on the Report were to be filed within twenty-one days from the date of the Report, or on or before June 4, 2003. Comments on the Report were filed by the Company, by the Staff, and jointly by the Committee and the City.

NOW THE COMMISSION, having considered the record, the pleadings, the Hearing Examiner's Report, the responses thereto, and the applicable law, is of the opinion and finds that the analysis, findings, and recommendations of the Hearing Examiner's Report are reasonable, supported by the record, and should be adopted, except as stated below.

We are compelled to address three issues in this case: the calculation of the Company's cost of equity; affiliate costs;

and the loss of Dominion Cogeneration as a significant customer of the Company's Hopewell District.[3]

Cost of Equity

Witnesses for the Company, the City, and Staff contend that their cost of equity recommendations satisfy the requirement that "the return to the equity owner should correspond with returns on investments in other businesses having corresponding risks, and the return 'should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.'"[4] As the Hearing Examiner observed, the differences in the cost of equity recommendations advanced by the parties "generally are related to the exercise of professional judgment as to the technical development and interpretation of the various costs of equity models."[5]

The Company contends in its exceptions to the Report that the Hearing Examiner made two errors regarding the cost of capital. First, it asserts that the Hearing Examiner erred in failing to make an upward adjustment to the cost of capital

---

[3] The curtailment of cogeneration operations at the Dominion Cogeneration facility that occurred in early 2002 reduced the billings for the facility's water usage from $336,452 in test year to the minimum charge of $1,000 per month.

[4] Howell v. C & P Tel. Co., 215 Va. 549, 558 (1975) (quoting FPC v. Hope Natural Gas, 320 U.S. 591, 603 (1944)), appeal dismissed, 423 U.S. 805 (1975).

[5] Report at 13.

because Virginia-American is a small company for which the market has demonstrated that investors demand a higher rate of return. The capital asset pricing model used by the Company's witness included an adjustment to reflect Virginia-American's small size. The Hearing Examiner states that "[i]t seems selective or inconsistent to treat Virginia-American as a small company, entitled to a premium, when it is a subsidiary of a large holding company."[6] As City witness James R. Haltiner testified: "To impose a cost of equity premium to ratepayers in Virginia or any other jurisdiction, because each is a smaller part of the entire company is not only unfair, but it goes against financial theory."[7] We concur, although in this case we do not find that the Company's adjustment would be required even if the Company was not affiliated with the holding company and was treated on a stand-alone basis.

Last year this Commission granted approval for Thames Aqua Holdings GmbH ("Thames Holdings") to acquire control of Virginia-American pursuant to a plan of merger involving American Water Works, Inc. (the Company's parent corporation), Thames Holdings, RWE Aktiengesellschaft (Thames Holdings' parent holding company), and Apollo Acquisition Company (a subsidiary of Thames Holdings). In the order approving the transaction

---

[6] Report at 16.

[7] Haltiner, Prefiled Testimony, Exhibit No. 16, at 12.

under the Utility Transfers Act,[8] the Commission observed that Staff concluded that benefits from the transaction include "the financial backing of a large company such as RWE."[9] In that matter the petitioners stated

> that the transaction will provide the American Companies with an enhanced ability to raise capital necessary to enable them to meet the demands placed on them with increasingly stringent water quality and environmental standards while rehabilitating and replacing aging water infrastructure and maintaining a reasonable capital structure. The financial resources and backing of RWE/Thames should enhance the American Companies' access to capital markets.[10]

Second, Virginia-American alleges that the recommended reduction in the Company's authorized return on equity from 10.74% to 9.8% "is an abrupt and drastic reduction that clearly violates the Commission's policy of gradualism."[11] As noted in the Report, however, in an order entered by this Commission in the Company's prior case in February 2002, the benchmark return on equity for future earnings test was set at 10.0%.[12]

---

[8] Chapter 5 (§ 56-88 et seq.) of Title 56 of Code of Virginia.

[9] Joint Petition of American Water Works Company, Inc. and Thames Water Aqua Holdings GmbH, For approval under the Utility Transfers Act, Final Order, Case No. PUA010082 (April 4, 2002), at 7.

[10] Staff Report, Case No. PUA-2001-00082, at 7.

[11] Company's Exceptions to Hearing Examiner's Report at 13.

[12] Application of Virginia-American, For a general increase in rates, Case No. PUE-2001-00312, Final Order, Attachment A, Stipulation ¶ 6 (February 19, 2002).

We agree with the Hearing Examiner that Virginia-American's current cost of equity is within a range of 9.3% and 10.3%, and Virginia-American's revenue requirement should be established based on the midpoint, 9.8%, of the equity range.

Affiliate Charges

The City and Committee contend that the Hearing Examiner erred in finding that the Company's claimed affiliate charges were reasonable.[13] American Water Works Service Company ("Service Company"), which is affiliated with Virginia-American, billed $1,683,895.10 to Virginia-American for services. Company witness Patrick L. Baryenbruch prepared a report that sets out the results of his evaluation of the services provided by Service Company to Virginia-American. His study addresses the economic impact on the Company if it was to outsource all of the services it now receives from Service Company, and whether the services the Company receives from Service Company are necessary. His report concludes that: (i) the Service Company's hourly rates, on average, are 47% less than those of outside providers of similar services; (ii) if all of the Services performed by Service Company had been out-sourced during the test year period, the Company and its ratepayers would incur an additional $777,708 in annual expenses;

[13] Comments of City and Committee to Report of Hearing Examiner at 7, 8.

(iii) Service Company costs do not include any profit mark-up; and (iv) Service Company costs that cannot be charged directly to operating companies are allocated on the basis of the number of customers.

The City asserts that this evidence fails to meet the standard of proof for the reasonableness of affiliate expenses by failing to provide the Service Company's costs and to explain how they are allocated to Virginia-American and ultimately to the Hopewell District. The City further alleges that the Company has failed to comply with the Rate Case Rules.[14]

We do not find that the Company's evidence as to affiliate charges violates the Rate Case Rules. The instructions for Schedule 25 provide:

> Cost records and market analyses supporting all affiliated charges billed to or by the regulated entity/division shall be maintained and made readily available for commission staff review. This shall include supporting detail of costs (including the return component) incurred by the affiliated interest rendering the service and the allocation methodology. In situations when the pricing is required to be the higher (lower) of cost or market and market is unavailable, note each such transactions and have data supporting such a finding available for commission staff review.[15]

[14] City of Hopewell's Post-Hearing Brief at 7, 8.

[15] 20 VAC 5-200-30, Appendix, Schedule 25.

As the Hearing Examiner properly noted, the requirement that cost records and market analyses be maintained and made readily available for Staff review does not render the failure to introduce such information as evidence in the record a violation of Rate Case Rule 20 VAC 5-200-30. There is no showing in this case that the Company failed to maintain, or make readily available for Staff review, such information.

The City also contends that the Company has failed to provide evidence supporting the reasonableness of its affiliate charges, and that such failure should preclude its recovery of those expenses from Hopewell. As this Commission has stated:

> Where it is most economical for the utility to purchase the product or service from the market it should do so. Where it can save money by purchasing from an affiliate at the affiliate's cost, including a reasonable return for the affiliate on the sale, it should do that. Where the Company proposes that the Commission set rates based upon charges from an affiliate, the charges must be based on the affiliate's cost, including a reasonable return, so long as this cost does not exceed the market price.[16]

Virginia Code § 56-78 provides that in a proceeding involving the rates or practices of a public service company:

> the Commission <u>may</u> exclude in whole or in part from the accounts of such public service company any payment or compensation to an affiliated interest for any services

[16] <u>Application of GTE South Incorporated, For revisions to its local exchange, access and intraLATA long distance rates</u>, Case No. PUC-1995-00019, 1997 S.C.C. Ann. Rpt. 216, 218.

> rendered or property or service furnished, as described above, under existing contracts or arrangements with such affiliated interest, if it shall appear and be established upon investigation that such payment or compensation or such contract or arrangement is not consistent with the public interest. In such proceeding any payment or compensation may be disapproved or disallowed by the Commission, in whole or in part, unless satisfactory proof is submitted to the Commission of the cost to the affiliated interest rendering the service or furnishing the property or service above described. (Emphasis added.)

The Commission is therefore permitted, but is not required, to disapprove or disallow such payments. We do not agree with the assertion that this Commission is required to disallow the affiliate charges in this case.

Virginia Code § 56-79 provides:

> No proof shall be satisfactory, within the meaning of [§§ 56-77 and 56-78], unless it includes the original (or verified copies) of the relevant cost records and other relevant accounts of the affiliated interest, or such abstract thereof or summary taken therefrom, as the Commission may deem adequate, properly identified and duly authenticated; provided, however, that the Commission may, where reasonable, approve or disapprove such contracts or arrangements without the submission of such cost records or accounts.

The Commission is again expressly authorized to approve such arrangements without the submission of the described records or accounts. In this case, we will allow the Company's affiliate charges. The methodology of the Baryenbruch study relied on by the Company has been accepted by this Commission in every rate case the Company has filed since 1995.[17] This Commission has previously specifically approved the Service Company's methodology of allocating costs to operating companies based on direct assignment or on the number of customers.[18]

We realize that the Baryenbruch report does not put into evidence the amount of the total costs of the Service Company that are allocated among all affiliated entities, does not state how much of the cost is assigned directly and how much is assigned based on the number of customers, and does not state how the cost allocated to Virginia-American is sub-allocated among its operating districts. There is, however, no evidence this and other information was not available for review as required by our rules. As this Commission has found previously that the methodology of the Baryenbruch study is satisfactory, we decline today to find that the Company failed to meet its burden of proof regarding the reasonableness of the affiliate expenses. Virginia Code § 56-79 provides that we may approve such arrangements where reasonable, and we find that it is reasonable in this case to do so.

---

[17] Case Nos. PUE-1995-00003, PUE-1997-00523, PUE-1999-00677, and PUE-2001-00312.

[18] Application of Virginia-American Water Company, For a general increase in rates, Case No. PUE-1997-00523, 1999 S.C.C. Ann. Rpt. 388, 389.

We find, however, that it would assist in our review of the reasonableness of the Service Company's charges in future cases if the Company provided additional information. Accordingly, we will require, in the future, that the Company provide information in its application itemizing: (i) the total cost to the Service Company of rendering service or furnishing property, and its return thereon; (ii) the total cost of the Service Company assigned to each of the Service Company's affiliated entities; (iii) a breakdown of Virginia-American's assigned cost sub-allocated to each of Virginia-American's operating districts; and (iv) supporting detail for allocation methodologies within Virginia-American.[19]

Also, we reiterate the standard with respect to costs incurred by a regulated utility for services. If the service is purchased from an affiliate, the utility may not collect through rates an amount that exceeds the least of three options: the utility's cost of providing the service in-house, the market

[19] We note also that the Rate Case Rules require that Schedule 25 of an application include a summary of affiliate transactions detailing costs by function for each month of the test period, and show the final Uniform System of Accounts account distribution of all costs billed to or by the regulated entity by month for the test period. See 20 VAC 5-200-30, Appendix, Schedule 25.

price for the service, or the cost to the affiliate of providing the service, including a reasonable return.[20]

Loss of Sales to Dominion Cogeneration

We find that the following facts are relevant to our consideration of the loss of Dominion Cogeneration as a customer of the Company's Hopewell District:

1. In December 2001, the operations manager for the Company's Hopewell District was notified that the Dominion Cogeneration facility would cease cogeneration operations around the end of January 2002.

2. On or about January 15, 2002, Roy L. Ferrell, Director of Rates and Planning for Service Company, working in Charleston, West Virginia, began preparing the Application.

3. As of January 19, 2002, the Dominion Cogeneration facility ceased operations and was placed into cold reserve.

4. On February 21, 2002, Dominion Cogeneration notified the Company that the facility workforce had been reduced and requested that one of its two meters be removed.

5. Commencing in February 2002, the Dominion Cogeneration facility's water usage dropped significantly.

6. Since March 2002, Dominion Cogeneration has been billed the minimum monthly charge of $1,000 per month.

7. The cessation of Dominion Cogeneration facility operations reduces net annual revenue for the Hopewell District by approximately $336,452, or 4% of the test year jurisdictional base rate revenues.

---

[20] See Application of GTE South Incorporated, For revisions to its local exchange, access and intraLATA long distance rates, Case No. PUC-1995-00019, 1997 S.C.C. Ann. Rpt. 216, 218.

8. On June 24, 2002, the Company filed its Application, which did not disclose or address the effect of the closure of the Dominion Cogeneration facility.

9. On July 3, 2002, Staff filed in the Commission Clerk's Office its Memorandum of Completeness/Incompleteness, noting that the Application was complete.

10. On July 8, 2002, the Company filed revised schedules, additional workpapers to be included in a previously filed schedule, and revised pre-filed testimony pertaining to, among other issues, the loss of water sales to Prince George County, but which did not disclose or address the closure of the Dominion Cogeneration facility.

11. In July 2002, Mr. Ferrell learned that Dominion Cogeneration had curtailed its operations earlier in 2002, and some time that month Mr. Ferrell informed Staff by telephone that the Dominion Cogeneration facility had shut down.

12. On October 28, 2002, the City and the Committee prefiled the direct testimony of witnesses. The testimony of D. Wayne Trimble, witness for the City, states that he did not make a revenue adjustment to reflect the loss of sales due to the closing of the cogeneration facility,[21] and acknowledges that the City was notified in November 2001 that the facility was expected to close by the end of March 2002.

13. On November 15, 2002, Staff filed testimony that included adjustments related to the lost sales to Dominion Cogeneration, including the elimination of $336,452 in revenues and reductions in chemical expenses of $15,997 and purchased power expenses of $14,414.

14. The City was advised of the Staff's adjustment for the Dominion Cogeneration facility shutdown at most four weeks before the Staff filed its testimony, and the details related to the shutdown were not made available to the City until the Staff's filing on November 15, 2002.

[21] Pre-filed testimony of Trimble, Exhibit No. 20, at 6.

15. The noticed rates went into effect on an interim basis, subject to refund, on November 22, 2002.

16. At no time did the Company file amendments to the Application that reflect the loss of revenue attributable to the closure of the Dominion Cogeneration facility.

The parties agree that the Application failed to reflect the closing of the Dominion Cogeneration facility and that the Company knew or should have known of the facility's closure prior to filing the Application. However, they disagree as to the implications of the Company's failure to include relevant data in the Application or in any subsequent Company filing.

The City asserts in its Motion to Dismiss that the Company knowingly filed inaccurate and misleading exhibits and schedules, which action clearly violated the Rate Case Rules and arguably constitutes a fraud under Virginia law. The City contends that the Company had actual knowledge of the loss of Dominion Cogeneration as a customer prior to filing the Application. The City further alleges that the Company failed to "verify the accuracy" of its exhibits as required by the Rate Case Rules, and that the Rate Case Rules would be rendered meaningless if a utility can comply with the Rules by merely placing one telephone call to the Staff in order to rectify an application that is materially inaccurate.[22]

---

[22] Reply of the City of Hopewell at 4, 7.

The Company counters that its error does not constitute a violation of the Rate Case Rules because the only party harmed by the omission is the Company; the omission was inadvertent; the Company official responsible for preparing the Application attempted to verify its accuracy; and it is common practice for Staff to make adjustments to a utility's rate case application based on information Staff obtains after the filing of the application. The Company also states that the Commission has the discretion to correct errors made by rate case applicants, and in this case Staff's November 15, 2002, report makes public the data about the effect of the facility's closure. The Company notes that in 2000 the Commission amended its Rate Case Rules to provide that its "rules do not limit the commission staff or parties other than the applicant from raising issues not addressed by the applicant for commission consideration."[23] According to the Company, the Commission's discretion to decide and fix rates that are just and reasonable includes the ability to correct errors made by rate case applicants.

The Company's assertion that it is the only party harmed by the failure to reflect the loss due to the closure of Dominion Cogeneration deserves comment. This assertion is based on Staff's determination that, had information regarding the loss

[23] 20 VAC 5-200-30(A)(10).

of the revenue from this customer been included in the Application, the actual revenue requirements for the Hopewell District would have exceeded the amount originally requested by $78,124.[24] If it had correctly excluded the revenue from the Dominion Cogeneration facility, it is urged, its annual revenue requirement and interim rates would be larger than were requested in the Application.

The City disputes the assertion that it is unharmed by the omission of this information in the Application. The City was advised of the Staff's adjustment for the Dominion Cogeneration shutdown at most four weeks before the Staff filed its testimony. However, details of the adjustment were not made available to the City until the Staff's filing on November 15, 2002. The City asserts that this delay prevented it from challenging the rates that went into effect on an interim basis on November 22, 2002.[25]

In this case, the Company never formally notified the Commission or other parties that the facility had shut down and never amended its schedules to reflect the loss of revenue from the closure of the Dominion Cogeneration facility. More

---

[24] This is the difference between the amount of additional gross annual revenue for the Hopewell District originally requested in the Application ($872,320) and the amount that the Hearing Examiner found, based on the Staff's Report, would be required to earn a reasonable return on rate base ($950,444).

[25] Reply of the City of Hopewell, February 14, 2003, at 2.

importantly, the Company never notified other parties that data to make an adjustment for the closure of the facility was being provided to Staff.

The Hearing Examiner found that, by failing to reflect the loss of Dominion Cogeneration in its Application, the Company violated the Rate Case Rules. However, the Hearing Examiner found that the Company has shown good cause for the Commission to waive its Rate Case Rules regarding the loss of Dominion Cogeneration in this case. The Hearing Examiner properly observed that the holding in Virginia Committee for Fair Utility Rates v. Virginia Electric & Power Co., 243 Va. 320 (1992), is not controlling in this case. In 2000, the Commission's Rate Case Rules were amended to allow the Commission to waive any portion of the Rate Case Rules for good cause shown.[26]

Based on the Staff's report, the Hearing Examiner found that the Company would require $950,444 in additional gross annual revenues to earn a reasonable return on rate base for the Hopewell District. However, since the notice for the Hopewell District provided for $872,320 in additional gross annual revenue, he recommended that the increase in annual revenues for the Hopewell District be limited to the noticed amount.

[26] 20 VAC 5-200-30(A)(11).

The Company states that no party other than Virginia-American has been harmed by the initial omission of the revenue loss adjustment from its Application. The Company's argument is based on the assumption that it would have been able to recover an additional $78,124 through rates if it had not omitted the information from its Application.

We do not agree with the Company, the City and the Committee,[27] or the Hearing Examiner on this issue. First, this is not merely an oversight or a small adjustment that was overlooked and corrected when it was found. The adjustment to the requested increase amounts to more than $300,000 and would have raised the rate request by more than a third. Second, the Company did not notify all parties of the error (or the data needed to make the new adjustment) as soon as those involved in the rate case became aware of the mistake in July. As a result, the City did not have the actual data upon which it could base a response to this adjustment until after the Staff filed its testimony on November 15, 2002. One may conclude that either the Company did not take adequate steps to "verify the accuracy of all data and calculations contained in and pertaining to every exhibit submitted" or, being aware of the loss of the

[27] The Committee and City jointly filed Comments to the Hearing Examiner's Report, in which they take issue with the Hearing Examiner's waiver of the alleged violation by the Company of the Rate Case Rules. Comments of the City and Committee at 1.

customer, chose neither to seek rate relief nor to make appropriate changes to its cost of service study related to the customer loss.

The result of granting a waiver of a violation of the Rate Case Rules, as recommended by the Hearing Examiner, is to allow the Company to convert what would have been an increase of less than \$650,000[28] to an increase of the full \$872,320 originally requested, exclusive of the lost customer issue.[29] As a result, the Company would recover part of the revenue lost because of the closure of the Dominion Cogeneration facility. This cannot be allowed. First, the Protestants did not have an adequate opportunity to respond to the adjustment.[30] Second, while corrections and adjustments may be made as a rate case proceeds through discovery and hearing, the Company cannot directly, or

---

[28] This figure assumes that the original \$872,320 revenue increase requested for the Hopewell District would be reduced to reflect the cost of equity and other adjustments recommended by the Hearing Examiner.

[29] The Hearing Examiner's recommendation did not provide for a decrease in the billing determinants to adjust for the shutdown of the Dominion Cogeneration facility. It should be noted that if the revenues for the Hopewell District before the closure of this facility are compared to the revenues that could be anticipated after implementing the \$872,320 revenue increase recommended by the Hearing Examiner, its actual revenue would increase by less than the recommended \$872,320 increase because the Company would not collect either (i) payments that would have been due from Dominion Cogeneration had it continued full operations or (ii) the portion of the \$872,320 increase that was allocated to Dominion Cogeneration.

[30] It is not clear that granting a continuance in this case in November would have resolved the issue. As the parties had prepared their cases by that date, we cannot arbitrarily grant continuances in order to allow the Company to cure its own mistake, particularly where it failed to provide the necessary data when it became aware of the change.

though Staff, inject a new issue such as this. To do so would allow the Company to present a string of additional adjustments that could be used to support its original request. Also, while the original omission of the loss of most of the customer's consumption may well have been inadvertent, we must assume that the subsequent failure to provide detailed data to other parties in a timely fashion and to amend the application was deliberate. In short, on this issue, the Company will be held to its filing.

In addition, we note that even if this issue had been raised in the original filing, the rate increase related to the loss of a customer is far from automatic.[31] For example, witness Trimble testified that the Company chose not to include a revenue adjustment to reflect the loss of sales due to the closing of the Dominion Cogeneration facility when they filed their case in June, 2002, and added that:

> To include a sales adjustment of this magnitude would render most of the Company's Cost of Service Study, and the tariffs resulting from that Study, not only unreliable, but invalid. The Company's Cost of Service Study clearly identifies this facility . . . as a non-potable

[31] In Commonwealth ex rel. Strock v. B&J Enterprises, we noted that it is not this Commission's responsibility to "ensure that [the Company] conducts its business in a manner that produces net operating income or net revenues." Case No. PUE-2001-00716, Final Order (June 27, 2003) at 31. See also Federal Power Commission v. Hope Natural Gas, 320 U.S. 591, 603 (1944)("regulation does not ensure that the business shall produce net revenues"). As the Supreme Court observed in Market St. Ry. Co. v. Railroad Commission, 324 U.S. 548, 567 (1945), "[t]he due process clause . . . has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces."

customer. As such, the loss in sales of non-potable water just as clearly has no effect to residential and commercial customers.[32]

These issues certainly would need to be addressed. Also, evidence concerning the rate base devoted to the customer, the "benefits" the customer provided to the Company and to the various classes of customers, how long the entity had been a customer, and other facts and considerations should be provided to determine whether the risk of loss of a customer should all be borne by the remaining customers (and, if so, which classes of customers) or whether the stockholders should bear part or all of the risk.

The result in this case is not intended to preclude Staff from making adjustments in other cases where the troublesome facts in this case, including the applicant's knowledge of the customer loss long before it filed the Application, the magnitude of the loss, and the failure to provide relevant data to other parties, are not present.

We find that it is appropriate to limit the increase in gross annual revenues for the Hopewell District to the amount that would have been allowed if the Company's requested revenue requirement for the Hopewell District (including the revised schedules to its Application filed by the Company on July 8,

[32] Trimble, Direct Testimony, Exhibit No. 20, at 6.

2002) had not been adjusted for the lost sales to Dominion Cogeneration, but otherwise had been adjusted to reflect the recommendations regarding the cost of equity and other adjustments in the Hearing Examiner's Report. We will remand this issue, and this issue only, to the Hearing Examiner in order that he determine such amount of additional gross annual revenues for the Hopewell District.

The rates required to recover this amount of additional gross annual revenue will need to be set based on billing determinates without excluding Dominion Cogeneration.

Accordingly, IT IS ORDERED THAT:

(1) The findings and recommendations of the Hearing Examiner, as modified herein, are accepted.

(2) The matter of the amount of additional gross annual revenues for the Hopewell District is hereby remanded to the Hearing Examiner for determination, as discussed herein. In connection therewith, the Hearing Examiner shall determine the Company's: (i) test year operating revenue deductions, after all adjustments, (ii) test year adjusted net operating income, after all adjustments, (iii) the return produced on adjusted rate base by current rates, (iv) return on equity produced by current rates, and (v) adjusted test year rate base, for the Hopewell District.

(3) In accordance with the Stipulation, the Company shall file a depreciation study for the Alexandria and Prince William Districts with Commission's Divisions of Public Utility Accounting and Energy Regulation on or before December 31, 2004. In addition, the Company shall file a depreciation study for the Hopewell District with the Commission's Divisions of Public Utility Accounting and Energy Regulation on or before December 31, 2004.

(4) This matter will be continued generally pending the results of the remand ordered herein.

AN ATTESTED COPY hereof shall be sent by the Clerk of the Commission to: Richard D. Gary, Esquire, and Renata M. Manzo, Esquire, Hunton & Williams, Riverfront Plaza, East Tower, 951 East Byrd Street, Richmond, Virginia 23219-4074; Edward L. Flippen, Esquire, McGuireWoods LLP, One James Center, 901 East Cary Street, Richmond, Virginia 23219-4030; Cliona M. Robb, Esquire, Christian & Barton, L.L.P., 1200 Building, Suite 1200, 909 East Main Street, Richmond, Virginia 23219-3095; H. M. Robertson, Esquire, Prince George County Attorney, P.O. Box 188, Prince George, Virginia 23875; Judith W. Jagdmann, Deputy Attorney General, Office of the Attorney General, 900 East Main Street, Second Floor, Richmond, Virginia 23219; and the Commission's Office of General Counsel and Divisions of Energy Regulation and Public Utility Accounting.

(LASERJET.RES)



```
 ####      #       ##    ####     ###
#    #   ###      # #   #    #   #
#    #     #     #  #   #    #  #
#    #     #     #  #   #    #  ####
#    #     #    ######  #    #  #   #
#    #     #        #   #    #  #   #
#    #     #        #   #    #  #   #
 ####    #####     ###   ####    ###
```

H&W Despooler - Windows NT Server 3.5 - version 1.01

file spooled: 9/5/2003

job number:   1347

Exhibit OPC (B)-30
Formal Case No. 1180
Direct Testimony of Bion Ostrander

Page **1** of **3**

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-41

**Q.** **Witness Baryenbruch Weighting of CPA Experience Levels.** Witness Baryenbruch (Exhibit WG (L)-2, page 16 of 31) includes a table showing (from a 2010 American Institute of Certified Public Accountants (AICPA) survey) the percentage of Virginia CPA firm staffing levels ranging from Partner/Owners to New Professionals. Also, Exhibit WG (L)-2, page 19 of 31, Exhibit 8, shows how Witness Baryenbruch weights the three CPA positions of Paraprofessional, Associate, and Manager for calculating the hourly billing rates for external independent CPAs for the CPA-Accounts Payable positions of WGL Affiliates. Finally, Exhibit WG (L)-2, page 20 of 31, Exhibit 9, shows how Witness Baryenbruch weights the four CPA positions of Staff Accountant, Senior Accountant, Manager, and Partner for calculating the hourly billing rates for external independent CPAs for the CPA-Other Finance position of WGL Affiliates. Address the following:

a. Explain how Witness Baryenbruch uses the weighting of CPA position experience levels per the table at Exhibit WG (L)-2, page 16 of 31(based on the 2010 AICPA survey) to determine the weighting percentages for CPA-Accounts Payable services applied to hourly billing rates at Exhibit WG (L)-2, page 19 of 31, Exhibit 8. Provide all calculations and supporting documentation.

b. Per (a) above, explain why Witness Baryenbruch only used the positions of Paraprofessional, Associate, and Manager for determining CPA hourly billing rates for the CPA-Accounts Payable position, explain if this is because these are the only similar type of experience levels for WGL Affiliate personnel providing these CPA-Accounts Payable services related to the corresponding related CPA-Accounts Payable costs at Exhibit WG (L)-2, page 13 of 31, Exhibit 4.

c. Per (a) and (b) above, provide the "Costs", "Hours", "Number of WGL Affiliate Personnel" and the "WGL Affiliate Hourly Billing Rate" for each of the WGL Affiliate personnel experience levels of Paraprofessional,

Page **2** of **3**

Associate, and Manager (for the CPA-Accounts Payable position), and reconcile all costs, hours, and number of personnel to Exhibit WG (L)-2, page 13 of 31, Exhibit 4 and Exhibit WG (L)-2, page 14 of 31, Exhibit 5 (show costs, hours, and number of personnel by applicable Service Category of Accounts Payable).

d. Explain how Witness Baryenbruch uses the weighting of CPA position experience levels per the table at Exhibit WG (L)-2, page 16 of 31(based on the 2010 AICPA survey) to determine the weighting percentages for CPA-Other Finance services applied to hourly billing rates at Exhibit WG (L)-2, page 20 of 31, Exhibit 9. Provide all calculations and supporting documentation.

e. Per (c) above, explain why Witness Baryenbruch only used the positions of Staff Accountant, Senior Accountant, Manager, and Partner for determining CPA hourly billing rates for the CPA-Other Finance position, explain if this is because these are the only similar type of experience levels for WGL Affiliate personnel providing these CPA-Other Finance services related to the corresponding related CPA-Other Finance costs at Exhibit WG (L)-2, page 13 of 31, Exhibit 4.

f. Per (d) and (e) above, provide the “Costs”, “Hours”, “Number of WGL Affiliate Personnel” and the “WGL Affiliate Hourly Billing Rate” for each of the WGL Affiliate personnel experience levels of Staff Accountant, Senior Accountant, Manager, and Partner for the CPA-Other Finance position), and reconcile all costs, hours, and number of personnel to Exhibit WG (L)-2, page 13 of 31, Exhibit 4 and Exhibit WG (L)-2, page 14 of 31, Exhibit 5 (show costs, hours, and number of personnel by applicable Service Categories of Accounting, Finance, Procurement, and Taxes.

g. Identify other sources or surveys that Witness Baryenbruch is aware that identify the percentage CPA firm staffing levels by position (for Virginia and other jurisdictions) and explain why these sources were not used in his testimony and calculations.

**WASHINGTON GAS’S RESPONSE** 11/15/2024

**A.**

a. The table on page 16 of 31 showing a profile of the percent of Virginia public accounting personnel who hold a CPA certificate is for information only. It is not used to develop the position weightings that appear in Exhibit 8 (page 19 of 31). These position weightings are based upon the SEMCO staff that provides accounts payable services to WGL.

b. See the response for a. above.

c. The majority of this information is available in Mr. Baryenbruch's workpapers. Actual WGL data by person by outside provider experience level is not maintained. That level of detail is not required for management reporting or any other reason.

d. The table on page 16 of 31 showing a profile of the percent of Virginia public accounting personnel who hold a CPA certificate is for information only. It is not used to develop the position weightings that appear in Exhibit 9 (page 20 of 31). These position-weightings are based upon a typical staffing distribution. The vast majority of charges/hours are associated with work performed by ALA personnel.

e. Mr. Baryenbruch typically utilizes this set of positions in building the average hourly rate for public accounting firms. The vast majority of charges/hours to CPA-Other Finance are associated with services provided by ALA.

   The majority of this information is available in Mr. Baryenbruch's workpapers. Actual WGL affiliate data by person by outside provider experience level is not maintained. That level of detail is not required for management reporting or any other reason.

f. See the response to e. above

g. Mr. Baryenbruch is not aware of any other source that shows this information.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-31
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-42

**Q.** **Witness Baryenbruch 2022 AICPA Billing Rates Survey.** Witness Baryenbruch (Exhibit WG (L)-2, page 16 of 31) explains how CPA hourly billing rates for CPA-Accounts Payable and CPA-Other Finance are developed from a bi-annual survey by the AICPA, using 2022 survey rates (which Witness Baryenbruch has escalated to average 2023 rates), with related CPA billing rates shown at Exhibit WG (L)-2, page 19 of 31, Exhibit 8 (for CPA-Accounts Payable) and Exhibit WG (L)-2, page 20 of 31, Exhibit 9 (for CPA-Other Finance). Address the following;

a. Provide a complete copy of the bi-annual AICPA Survey showing 2022 billing rates, and identify the specific billing rates in the Survey (identify the pages and tables) that equal or reconcile to those rates shown at Exhibit WG (L)-2, page 19 of 31, Exhibit 8 (for CPA-Accounts Payable) and Exhibit WG (L)-2, page 20 of 31, Exhibit 9 (for CPA-Other Finance).

b. Regarding the AICPA Survey in (a) above, explain if these CPA billing rates are specifically related solely to Virginia-based CPA firms. If not, explain the applicable billing rates for each state/jurisdiction which Witness Baryenbruch relied upon. Also explain why these billing rates are reasonable and appropriate.

c. Provide the mark-up percentages or multiples used for each CPA firm position in the AICPA Survey. For example, explain if the Partner's billing rate reflects a mark-up or multiple of 2 times (or more) over the salary/payroll cost to arrive at the related billing rate for the Partner.

d. Per (a) above, provide a copy of the most recent updated bi-annual AICPA Survey.

e. Identify other sources or surveys that Witness Baryenbruch is aware that identify current or more recent CPA firm billing rates by position, and explain why these sources were not used in his testimony and calculations.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers.

b. The AICPA's 2022 survey contains national billing rates (see attached OPC Data Request OPC 4-42.b workpaper). Mr. Baryenbruch believes these rates are appropriate for comparison purposes. The vast majority of respondent accounting firms are not large. Eighty-three percent had annual client fees of less than $5 million and one to two equity owners.

c. See the response to OPC Data Request 4-19 for the 2022 AICPA survey.

d. The 2022 survey is the latest available. The AICPA performs its survey every two years. This version was published in 2023. The next will be published in 2025.

e. Mr. Baryenbruch is not aware of any other source that shows this information.

SPONSOR: Patrick Baryenbruch
Consultant

| AICPA PCPS/CPA.com National MAP Survey | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Private and Confidential | | <200K | 200<500K | 500<750K | 750K<1.5M | 1.5<5M | 5<10M | 10M+ |
| Number of Firms | | 151 | 197 | 121 | 183 | 280 | 102 | 83 |
| | | | | | | | | |
| | | | | | | | | |
| Equity Owners in firm | | 1 | 1 | 1 | 2 | 2 | 5 | 9 |
| CPAs in firm | | 1 | 1 | 2 | 3 | 6 | 17 | 42 |
| | | | | | | | | |
| Number with 1-2 Equity Owners in Firm | 932 | | | | | | | |
| Total Respondent Firms | 1117 | | | | | | | |
| Percent with 1-2 Equity Owners in Firm | 83% | | | | | | | |

Exhibit OPC (B)-32
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-44

**Q.** **Witness Baryenbruch Management Consultant.** The Direct Testimony of Witness Baryenbruch determined that outside services provided by "Management Consultants" could be similar to in-house services provided by affiliates (8:21 to 9:8) and per Exhibit WG (L)-2, page 11 of 31, and as shown by the hourly rate comparison at Table 5 (10:1-13) and per the costs of the professional service categories (Attorneys, CPAs, Management Consultants, ITR Professional) by Service Category (Exhibit WG (L)-2, page 13 of 31, Exhibit 4) and the related number of hours (Exhibit WG (L)-2, page 14 of 31, Exhibit 5). Address the following:

a. Per Exhibit 4, explain how Witness Baryenbruch determined that WGL/affiliate employees providing services related to Board of Directors, Compliance, Executive Management and Human Resources were similar or the same as professional services provided by "Management Consultants." Provide all criteria and supporting documentation relied upon by WGL/affiliates to determine that these related WGL/affiliate employees are providing Management Consultant-like services.

b. Explain why "Management Consultant" services were limited to the service categories identified in (a) above at Exhibit 4, and explain why "Management Consultant" services were not associated with other service categories such as Accounting, Accounts Payable, Finance, Information Technology, Legal, Procurement, and Taxes.

c. Provide Witness Baryenbruch's definition of "Management Consultant" and explain the types of services typically provided by Management Consultants. Provide all supporting documentation for these conclusions.

d. Per (a) above, explain if Witness Baryenbruch interviewed employees, reviewed their related curriculum vitae, evaluated job descriptions, considered years of experience, and evaluated prior work experience/jobs as part of determining which WGL/affiliate employees were and were not providing Management Consulting type services. Provide all supporting documentation relied upon.

e. Regarding Exhibit 4 affiliate "Management Consultant" costs for each of the Service Categories of Board of Directors, Compliance, Executive Management, and Human Resources, identify the number of WGL/affiliate employees (by Service Category) that previously worked for a "Management Consultant" firm and provide documentation to show how this was determined.

f. Regarding (a) to (f) above, explain how Mr. Baryenbruch determined that these WGL/affiliate employees would be (or are) capable of providing Management Consultant type services and provide all supporting documentation for this determination. Explain if prior experience with a Management Consulting firm was considered, if only employees with advanced or specialized degrees were considered (MBA, CPA, etc.), and explain if a minimum number of years of experience was required for each employee (or explain if a WGL/affiliate first year new employee could be considered to be providing Management Consultant type services). Provide all supporting documentation.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Mr. Baryenbruch does not make assignments to outside service providers by individual affiliate staff member. The assignment is made at the affiliate business unit level. There are around 100 business units in the ALA corporate group. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers, which document how this is accomplished.

b. See the response to a. above.

c. In general, management consultants provide expert advice and solutions to organizations to help them improve their performance, efficiency and effectiveness. Management consultants provide functional services similar to board of directors, executive management, compliance and human resources.

d. See the response to a. above.

e. See the response to a. above. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers.

f. See the response to a. above. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers.

Page **3** of **3**

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-33
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential Exhibit Omitted

Exhibit OPC (B)-34
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-49

**Q.** **Witness Baryenbruch Weighting of Management Consultant Experience Levels.** Witness Baryenbruch (Exhibit WG (L)-2, page 22 of 31, Exhibit 11) shows the percentage/weighting of firm staffing level positions and related hourly billing rates for Management Consultant positions of Analyst Consultant, Associate, Senior Assoc./Manager, Principal, Partner, Entry-Level Consultant, Associate Consultant, Senior Consultant, Junior Partner, and Senior Partner – with 2023 billing rates from the source Rodenhauser & Company, LLC. Address the following:

a. Explain how Witness Baryenbruch uses the weighting and billing rates of Management Consultant position experience levels from the Rodenhuaser & Company, LLC survey to determine the weightings and assign the billing rates per Exhibit WG (L)-2, page 22 of 31, Exhibit 11. Provide all calculations and supporting documentation.

b. Per (a) above, explain why Witness Baryenbruch only used the Management Consultant positions and related billing rates at Exhibit WG (L)-2, page 22 of 31, Exhibit 11 for application to WGL Affiliate personnel providing Management Consulting type services. Explain if this is because these are the only similar type experience levels for WGL Affiliate personnel providing these Management Consultant type services, per the related WGL Affiliate Management Consultant personnel costs at Exhibit WG (L)-2, page 13 of 31, Exhibit 4 (and the related hours at Exhibit WG (L)-2, page 14 of 31, Exhibit 5.

c. Per (a) and (b) above, provide the "Costs", "Hours", "Number of WGL Affiliate Personnel" and the "WGL Affiliate Hourly Billing Rate" for each of the Management Consultant WGL Affiliate personnel experience levels of Analyst Consultant, Associate, Senior Assoc./Manager, Principal, Partner, Entry-Level Consultant, Associate Consultant, Senior Consultant, Junior Partner, and Senior Partner, and reconcile all costs, hours, and number of personnel to Exhibit WG (L)-2, page 13 of 31, Exhibit 4 and Exhibit WG

(L)-2, page 14 of 31, Exhibit 5 (show costs, hours, and number of personnel by applicable Service Categories of Board of Directors, Compliance, Executive Management, and Human Resources.

d. Identify other sources or surveys that Witness Baryenbruch is aware that identify the percentage of Management Consultant firm staffing levels by position (for Virginia and other jurisdictions) and explain why these sources were not used in his testimony and calculations.

**WASHINGTON GAS'S PARTIAL OBJECTION** 11/1/2024

**Subpart (c)**

Washington Gas objects to subpart (c) of this request on grounds that it requires the performance of a special study which has not been performed.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers.

b. Because management consulting firms are the type of outside service providers to which the specified affiliate services could be outsourced. This assignment is made at the affiliate business unit level. The assignment is not made for individual affiliate staff members.

c. An objection is raised to this request. It would require a special study.

d. Mr. Baryenbruch is not aware of any such source.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-35
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-50

**Q. Witness Baryenbruch 2023 Rodenhauser & Company Billing Rates Survey.** Witness Baryenbruch (Exhibit WG (L)-2, page 17 of 31) explains how hourly billing rates for Management Consultants are developed from the Rodenhauser & Company 2023 survey and shown at Exhibit WG (L)-2, page 22 of 31, Exhibit 11. Address the following:

a. Provide a complete copy of the Rodenhauser & Company 2023 survey showing billing rates by Management Consultant position/experience level, and identify the specific billing rates in the survey (identify the pages and tables) that equal or reconcile to those rates shown at Exhibit WG (L)-2, page 22 of 31, Exhibit 11 by specific position.

b. Regarding the Rodenhauser survey in (a) above, explain if these related billing rates are specifically related to Virginia-based Management Consulting firms or explain the applicable billing rates for each state/jurisdiction which Witness Baryenbruch relied upon – and explain why these billing rates are reasonable and appropriate.

c. Provide the mark-up percentages or multiples used for each Management Consulting firm position in the Rodenhauser Survey. For example, explain if the Partner's billing rate reflects a mark-up or multiple of 2 times (or more) over the salary/payroll cost to arrive at the related billing rate for the Partner.

d. Explain if the Rodenhauser survey only addresses billing rates for Management Consulting services provided by CPA firms (or CPA firms that have a separate Management Consulting department that does require the related consultants to be CPAs), and explain why Management Consulting billing rates used by Witness Baryenbruch were limited to this type of Management Consulting firm.

e. Per (a) above, provide a copy of the most recent updated Rodenhauser survey.

f. Identify other sources or surveys that Witness Baryenbruch is aware that identify current or more recent Management Consulting firm billing rates by position, and explain why these sources were not used in his testimony and calculations.

g. Provide the number of WGL Affiliate personnel identified as providing Management Consultant type services that are located in Virginia, District of Columbia, Maryland, Delaware, Michigan, and Canada (and all other states/jurisdictions) based on the related costs for Management Consultants provided at Exhibit WG (L)-2, pages 13 of 31 (Exhibit 4) and the related hours provided at Exhibit WG (L)-2, page 14 of 31 (Exhibit 5).

**WASHINGTON GAS'S PARTIAL OBJECTION** 11/1/2024

**Subpart (g)**

Washington Gas objects to subpart (g) of this request on grounds that it requires the performance of a special study which has not been performed.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers.

b. The Rodenhauser survey shows national billing rates. Most management consultants do not limit themselves to a certain geographic area, so national billing rates are reasonable and appropriate.

c. Mr. Baryenbruch does not know of a source for such information.

d. The Rodenhauser survey covers 80 various consulting firms that fall into the following three tiers:
   - Tier 2 Firms – 251 to 500 billable consultants
   - Tier 3 Firms – 51 to 250 billable consultants
   - Tier 4 Firms – 50 or less billable consultants

e. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers, including the Rodenhauser survey.

f. Mr. Baryenbruch does not know of a source for such information.

g. An objection is raised to this request. It would require a special study.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-36
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS‘S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE’S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-51

**Q.** **Witness Baryenbruch Weighting of IT Professional Experience Levels.** Witness Baryenbruch addresses IT Professional hourly rates at Exhibit WG (L)-2, page 16 of 31 and Exhibit WG (L)-2, page 21 of 31, Exhibit 10) shows the percentage/weighting of firm staffing level positions and related hourly billing rates for IT Professional positions of Contractor, Senior Contractor, Associate, Manager, and Partner – with 2023 billing rates from the Rodenhauser & Company, LLC survey. Address the following:

a. Explain how Witness Baryenbruch uses the weighting and billing rates of IT position experience levels from the Rodenhuaser & Company, LLC survey to determine the weightings and assign the billing rates per Exhibit WG (L)-2, page 21 of 31, Exhibit 10. Provide all calculations and supporting documentation.

b. Per (a) above, explain why Witness Baryenbruch only used the IT and related billing rates at Exhibit WG (L)-2, page 21 of 31, Exhibit 10 for application to WGL Affiliate personnel providing IT type services. Explain if this is because these are the only similar type of experience levels for WGL Affiliate personnel providing these IT type services, per the related WGL Affiliate IT personnel costs at Exhibit WG (L)-2, page 13 of 31, Exhibit 4 (and the related hours at Exhibit WG (L)-2, page 14 of 31, Exhibit 5).

c. Per (a) and (b) above, provide the “Costs”, “Hours”, “Number of WGL Affiliate Personnel” and the “WGL Affiliate Hourly Billing Rate” for each of the IT Professional WGL Affiliate personnel experience levels of Contractor, Senior Contractor, Associate, Manager, and Partner and reconcile all costs, hours, and number of personnel to Exhibit WG (L)-2, page 13 of 31, Exhibit 4 and Exhibit WG (L)-2, page 14 of 31, Exhibit 5 (show costs, hours, and number of personnel by applicable Service Categories of Information Technology).

d. Identify other sources or surveys that Witness Baryenbruch is aware that identify the percentage of IT consulting firm staffing levels by position (for Virginia and other jurisdictions) and explain why these sources were not used in his testimony and calculations.

**WASHINGTON GAS'S PARTIAL OBJECTION** 11/1/2024

**Subpart (c)**

Washington Gas objects to subpart (c) of this request on grounds that it requires the performance of a special study which has not been performed.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. The weighting for outside IT professionals is based on Mr. Baryenbruch's many years as an IT project manager and management consultant to the chief information officers of Duke Energy and the former Progress Energy.

b. The IT positions shown in Exhibit 10 on page 21 of 31 are representative of the staff required to provide services to a large enterprise such as ALA. This is based on Mr. Baryenbruch's many years as an IT project manager and management consultant to the chief information officers of Duke Energy and the former Progress Energy.

c. An objection is raised to this request. It would require a special study.

d. Mr. Baryenbruch is not aware of other such sources.

SPONSOR: Patrick Baryenbruch
Consultant

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-52

**Q.** **Witness Baryenbruch 2023 Rodenhauser & Company Billing Rates Survey.** Witness Baryenbruch (Exhibit WG (L)-2, page 16 of 31) explains how hourly billing rates for IT Professionals are developed from the Rodenhauser & Company 2023 survey as shown at Exhibit WG (L)-2, page 21 of 31, Exhibit 10. Address the following:

a. Provide a complete copy of the Rodenhauser & Company 2023 survey showing billing rates by IT Professional position/experience level, and identify the specific billing rates in the survey (identify the pages and tables) that equal or reconcile to those rates shown at Exhibit WG (L)-2, page 21 of 31, Exhibit 10 by specific position.

b. Regarding the Rodenhauser survey in (a) above, explain if these related billing rates are specifically related to Virginia-based IT consulting firms or explain the applicable billing rates for each state/jurisdiction which Witness Baryenbruch relied upon – and explain why these billing rates are reasonable and appropriate.

c. Provide the mark-up percentages or multiples used for each IT Professional firm position in the Rodenhauser Survey. For example, explain if the Partner's billing rate reflects a mark-up or multiple of 2 times (or more) over the salary/payroll cost to arrive at the related billing rate for the Partner.

d. Per (a) above, provide a copy of the most recent updated Rodenhauser survey.

e. Identify other sources or surveys that Witness Baryenbruch is aware that identify current or more recent IT consulting firm billing rates by position, and explain why these sources were not used in his testimony and calculations.

f. Provide the number of WGL Affiliate personnel identified as providing IT Professional type services that are located in Virginia, District of Columbia, Maryland, Michigan (and all other states/jurisdictions) based on the related costs for Management Consultants provided at Exhibit WG (L)-2, pages 13 of 31 (Exhibit 4) and the related hours provided at Exhibit WG (L)-2, page 14 of 31 (Exhibit 5).

**WASHINGTON GAS'S PARTIAL OBJECTION** 11/1/2024

**Subpart (f)**

Washington Gas objects to subpart (f) of this request on grounds that it requires the performance of a special study which has not been performed.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers, including the Rodenhauser survey and the calculation of average billing rates used in Exhibit 10 on page 21 of 31.

b. The billing rates for IT consultant positions (associate, manager, partner) are based on Rodenhauser's national survey results. The billing rates for contractor positions (contractor, senior contractor) are the actual rates paid by WGL for IT contractors in 2024.

c. This information is not available in the Rodenhauser survey or in the hourly rate schedule of WGL's IT contractors.

d. See the response to OPC Data Request 4-16 for Mr. Baryenbruch's workpapers, including the Rodenhauser survey.

e. Mr. Baryenbruch is not aware of any such sources.

f. An objection is raised to this request. It would require a special study.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-38
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-53

**Q.** **Witness Baryenbruch Weighting of Legal/Attorney Professional Experience Levels.** Witness Baryenbruch addresses Legal/Attorney hourly rates at Exhibit WG (L)-2, page 16 of 31 and Exhibit WG (L)-2, page 18 of 31. Exhibit 7 shows the hourly rates by practice area for Virginia attorneys. Address the following:

a. Explain why Witness Baryenvruch does not apply specific billing rates to various Attorney levels of experience and related positions (Manager, Partner, etc.) for each specific practice area at Exhibit 7 for purposes of determining a Legal/Attorney hourly billing rate, as he did in other Exhibits included in Exhibit WG (L-2) for calculations of billing rates for other professional positions of CPA, IT Professionals, and Management Consultants. Explain why the departure from this method is reasonable for Legal/Attorney billing rates and explain why it is reasonable to lump all Attorneys into one billing rate regardless of experience level and type of position (Partner, Manager, Associate, Paraprofessional, etc.).

b. Provide the "Costs", "Hours", "Number of WGL Affiliate Personnel" and the "WGL Affiliate Hourly Billing Rate" for each of the Attorney Practice Areas for WGL Affiliate personnel, and reconcile all costs, hours, and number of Attorney personnel to Exhibit WG (L)-2, page 13 of 31, Exhibit 4 and Exhibit WG (L)-2, page 14 of 31, Exhibit 5 (show costs, hours, and number of Attorney personnel by applicable Service Categories of Legal).

c. Identify other sources or surveys that Witness Baryenbruch is aware that identify the percentage of Attorney staffing levels by positions (Partner, Manager, Associate, Paraprofessional, etc.) for Virginia and other jurisdictions, and explain why these sources were not used in his testimony and calculations.

**WASHINGTON GAS'S PARTIAL OBJECTION**

11/1/2024

**Subpart (b)**

Washington Gas objects to subpart (b) of this request on grounds that it requires the performance of a special study which has not been performed.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Hourly rates are not broken out by attorney level in Exhibit 7 on page 18 of 31 because the Clio survey presents only a single average hourly rate for attorneys by practice area. It is likely the Clio's database contains hourly rates for multiple attorney positions and Clio chooses not to report that detail. So, Clio's reported single average hourly rate is, in effect, an average of multiple attorney positions.

b. An objection is raised to this request. It would require a special study.

c. Up until 2022, Mr. Baryenbruch used the Annual Survey of Law Firm Economics, which is published by the National Law Review. He stopped using it because the average hourly rates for 2021 jumped significantly from the previous survey. Mr. Baryenbruch felt the 2021 survey's rates were not reliable and he switched to the Clio survey thereafter. The Clio survey's average hourly billing rates for attorneys have been accepted in every subsequent rate case assignment.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-39
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-54

**Q.** **Witness Baryenbruch 2023 Survey.** Witness Baryenbruch (Exhibit WG (L)-2, page 18 of 31, Exhibit 7 shows hourly billing rates for Attorneys by Practice Area (without any detailed information for billing rates by Attorney experience levels and position) from the 2023 Virginia Themis Solutions Inc. (Clio) source. Address the followingL

a. Provide a complete copy of the Virginia Themis Solutions Inc. (Clio) 2023 survey showing billing rates of Attorneys by Practice Area, and identify the specific billing rates in the survey (identify the pages and tables) that equal or reconcile to those rates shown at Exhibit WG (L)-2, page 18 of 31, Exhibit 7 by specific Practice Area.

b. Regarding the Virginia Themis survey in (a) above, explain if Attorney billing rates are available for other states/jurisdictions at this same survey, and explain why it is reasonable to use only the Virginia-related Attorney billing rates.

c. Provide the mark-up percentages or multiples used for each Attorney/Legal firm position in the Themis Solutions Inc survey of Attorney billing rates. For example, explain if the Partner's billing rate reflects a mark-up or multiple of 2 times (or more) over the salary/payroll cost to arrive at the related billing rate for the Partner.

d. Per (a) above, provide a copy of the most recent updated Themis Solutions Inc. survey for Virginia.

e. Identify other sources or surveys that Witness Baryenbruch is aware that identify current or more recent Attorney billing rates by experience and position (Partner, Manager, Associate, Paraprofessional, etc.), and explain why these sources were not used in his testimony and calculations.

f. For each of the Attorney Practice Areas (and related billing rates) identified at Exhibit WG (L)-2, page 18 of 31, Exhibit 7, identify the number of WGL Affiliate Attorneys providing each of these Practice Area services, provide the related cost of WGL Affiliate Attorneys providing each of these Practice Area services, and provide the related number of hours of WGL

Affiliate Attorneys providing each of these Practice Area services, and reconcile the number of employees, costs, and hours to Exhibit WG (L)-2, page 13 of 31, Exhibit 4 and Exhibit WG (L)-2, page 14 of 31, Exhibit 5.

g. Provide the number of WGL Affiliate personnel identified as providing Attorney/Legal services that are located in Virginia, District of Columbia, Maryland, Michigan (and all other states/jurisdictions) based on the related costs for Attorneys at Exhibit WG (L)-2, pages 13 of 31 (Exhibit 4) and the related hours provided at Exhibit WG (L)-2, page 14 of 31 (Exhibit 5).

**WASHINGTON GAS'S PARTIAL OBJECTION** 11/1/2024

**Subparts (f) and (g)**

Washington Gas objects to subparts (f) and (g) of this request on grounds that the information is not available in the format requested and is beyond the scope of this witness' testimony.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. See the response to OPC Data Request 4-19 for Mr. Baryenbruch's workpapers, including this information. The average hourly rates are taken from Clio's website. Clio also publishes a Legal Trends Report and the 2023 version is included in Mr. Baryenbruch's workpapers. Hourly rates by state are presented at the end of this document.

b. The Clio survey provides hourly rates for many states. Virginia was chosen because of its proximity to WGL and the hypothetical assumption that if ALA legal services to WGL were to be outsourced, it would be to close by law firms.

c. This information is not available in the Clio survey.

d. See the response to a. above.

e. See the response to OPC Data Request 4-53.c.

f. An objection is raised to this request. It would require a special study.

g. An objection is raised to this request. It would require a special study.

SPONSOR: Patrick Baryenbruch
Consultant

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-55

**Q.** **Witness Baryenbruch Support for A&G Expenses per Customer.** Witness Baryenbruch Direct Testimony (10:19 to 13:14) and Exhibit WG (L)-2 address and compare the level of A&G expenses per customer for WGL and other utilities. Address the following:

a. Provide a copy of all supporting documentation and calculations (including original working Excel documents) addressing the comparison of A&G expenses between WGL and other utilities at Witness Baryenbruch Direct Testimony (10:19 to 13:14, including Tables 7 and 8) and Exhibit WG (L)-2, pages 25 to 28 of 31 (including all tables and Exhibits 12 and 13). WGL should provide all information from the related 2023 FERC Form 1 for each utility that Witness Baryenbruch relied upon, and provide all reconciliations from A&G expenses at the FERC Form 1 for each utility to the A&G expenses included in Witness Baryenbruch calculations.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. See the response to OPC Data Request 4-19 for this information.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-41
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-56

**Q.** **Witness Baryenbruch Reasons for Higher Affiliate Charges.** Witness Baryenbruch's Direct Testimony (12:5-25, Table 8) and Exhibit WG (L)-2, page 27 of 31, Exhibit 13, show that WGL's 2023 A&G expenses per customer is $178.00, compared to other utilities. Witness Baryenbruch's Direct Testimony explains (12:6-8) and Table 8 (between lines 15-16) shows that the WGL A&G expense of $178/per customer is in the middle of the third quartile and somewhat above the utility group median, with twelve other utilities having higher costs and eighteen utilities having lower costs. Witness Baryenbruch also states (10:22-24) that WGL's affiliate charges represent a sizeable portion of WGL's A&G expenses, making up 13% of WGL's total A&G expenses. Address the following:

a. Please confirm the Direct Testimony of Witness Baryenbruch concludes that WGL's affiliate charges are the reason for its higher level of A&G expenses compared to other utilities in the comparison group, and explain if Witness Baryenbruch agrees or disagrees with this conclusion. Also explain if WGL agrees or disagrees with this conclusion.

b. Regarding (a) above, if Witness Baryenbruch disagrees with this conclusion, or if WGL disagrees with this conclusion, explain all reasons why WGL's sizeable portion of affiliate charges are not the reason for WGL's higher level of A&G expenses compared to other utilities in the comparison group, and provide all supporting documentation for this position. Also, explain why Witness Baryenbruch's conclusion that WGL's "Affiliate charges represent a sizeable portion of WGL's A&G expenses" is not an accurate statement in this regard.

c. Explain the specific reasons and factors causing Witness Baryenbruch to conclude that WGL's sizeable affiliate charges are the reason for its higher level of A&G expenses relative to comparable utilities. Provide all supporting documentation. Also explain which of the specific reasons below contribute to WGL's sizeable level of affiliate charges (or identify all additional reasons that contribute to this) and provide related supporting documentation for each reason:

i) Certain specific WGL allocation factors contribute to the higher level of affiliate charges, and identify which specific allocation factors contribute to this conclusion.
ii) AltaGas begins with a greater level of expenses (and/or ASUS expenses) subject to allocation to WGL (compared to other utilities) and this contributes to the higher level of affiliate charges, and explain this conclusion.
iii) AltaGas allocates a greater level of affiliate charges to WGL (compared to its allocations to other affiliates) and this contributes to the higher level of affiliate charges, and explain this conclusion.
iv) Other affiliates allocate an unusually greater level of affiliate charges to WGL and this contributes to a higher level of affiliate charges, and explain this conclusion.
v) AltaGas and/or WGL (or other affiliates) allocate or direct assign redundant affiliate charges to WGL and this contributes to a higher level of affiliate charges, and explain this conclusion.
vi) AltaGas and/or WGL (or other affiliates) have a greater number of employees performing the same various services (compared to other utilities) and so AltaGas and/or WGL are less efficient than other utilities and this contributes to a higher level of affiliate charges, and explain this conclusion.
vii) Identify all other reasons causing WGL to have a higher level of affiliate charges, and explain these reasons.

d) If Witness Baryenbruch cannot identify the specific reasons causing WGL's higher level of affiliate charges relative to A&G charges (compared to other utilities in the comparison group), then explain why this does not diminish the importance and credibility of Witness Baryenbruch's testimony regarding affiliate charges.

e) If Witness Baryenbruch cannot identify the specific reasons causing WGL's higher level of affiliate charges relative to A&G charges (compared to other utilities in the comparison group), then explain how Witness Baryenbruch can eliminate the existence of duplicate services as a reason for these higher levels of affiliate charges.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Neither Mr. Baryenbruch nor WGL agrees with this assertion.

b. Affiliate A&G-related charges make 13% of WGL's total A&G expenses. Mr. Baryenbruch's lower-of-cost-or-market comparison showed the cost of affiliate services is dramatically lower than the cost of outside providers of similar services. Also, the magnitude of affiliate charges to WGL is not unusual compared to what other utilities are charged by their affiliates. As calculated below, WGL's TY 2024 affiliate charges per customer were $23.

| | TY 2024 |
|---|---|
| Affiliate Charges | |
| AltaGas | $ 26,781,103 |
| SEMCO | $ 1,556,406 |
| Total Affiliate Charges (A) | $ 28,337,509 |
| Total WGL Customers at 12/31/2023 | 1,226,879 |
| Affiliate A&G Charges per Customer | $ 23 |

Note A: These are all A&G-related

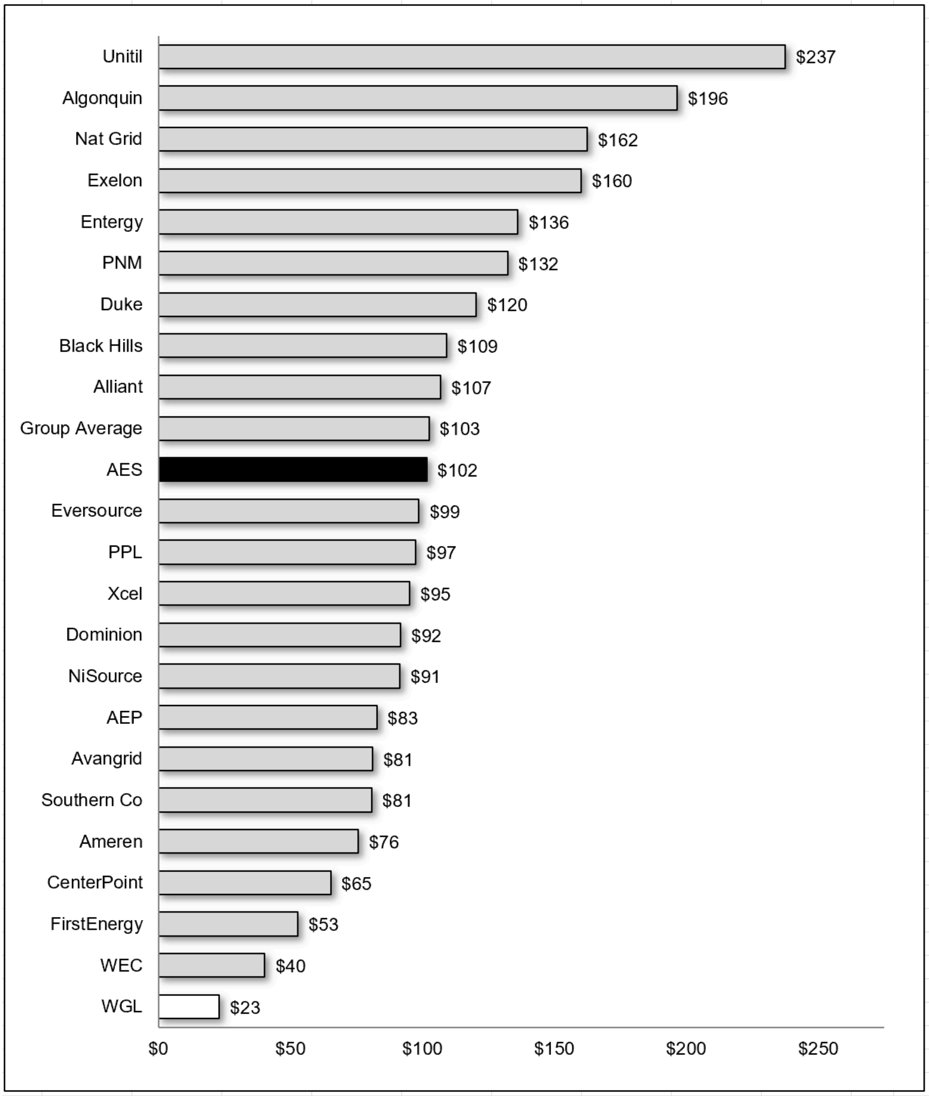
Source: Company information

This level of affiliate charges is not unusual. The table below shows the amount of A&G-related affiliate charges to the regulated utilities of the listed utility holding companies.

| Utility Company | 2023 Regulated Retail Service Company A&G Expenses | Regulated Retail Customers | Cost per Customer |
|---|---|---|---|
| AEP | $463,462,789 | 5,600,000 | $ 83 |
| AES | $107,305,433 | 1,056,000 | $ 102 |
| Algonquin | $235,778,007 | 1,200,000 | $ 196 |
| Alliant | $151,883,338 | 1,420,000 | $ 107 |
| Ameren | $249,624,936 | 3,300,000 | $ 76 |
| Avangrid | $267,637,704 | 3,300,000 | $ 81 |
| Black Hills | $142,009,582 | 1,300,000 | $ 109 |
| CenterPoint | $456,647,843 | 7,000,000 | $ 65 |
| Dominion | $412,743,398 | 4,500,000 | $ 92 |
| Duke | $1,192,398,534 | 9,900,000 | $ 120 |
| Entergy | $436,405,601 | 3,204,000 | $ 136 |
| Eversource | $434,227,112 | 4,400,000 | $ 99 |
| Exelon | $1,682,110,370 | 10,500,000 | $ 160 |
| FirstEnergy | $316,569,517 | 6,000,000 | $ 53 |
| Nat Grid | $1,120,437,236 | 6,900,000 | $ 162 |
| NiSource | $333,537,252 | 3,647,000 | $ 91 |
| PNM | $107,934,202 | 816,000 | $ 132 |
| PPL | $341,090,403 | 3,500,000 | $ 97 |
| Southern Co | $727,044,818 | 9,000,000 | $ 81 |
| Unitil | $46,758,285 | 196,900 | $ 237 |
| WEC | $187,079,034 | 4,643,000 | $ 40 |
| Xcel | $561,477,642 | 5,900,000 | $ 95 |
| Total/Average | $9,974,163,036 | 97,282,900 | $ 103 |

Source: FERC Form 60; Baryenbruch & Company, LLC, analysis

The graph below shows WGL's affiliate charges per customer are lower than all of the comparison group utility companies.



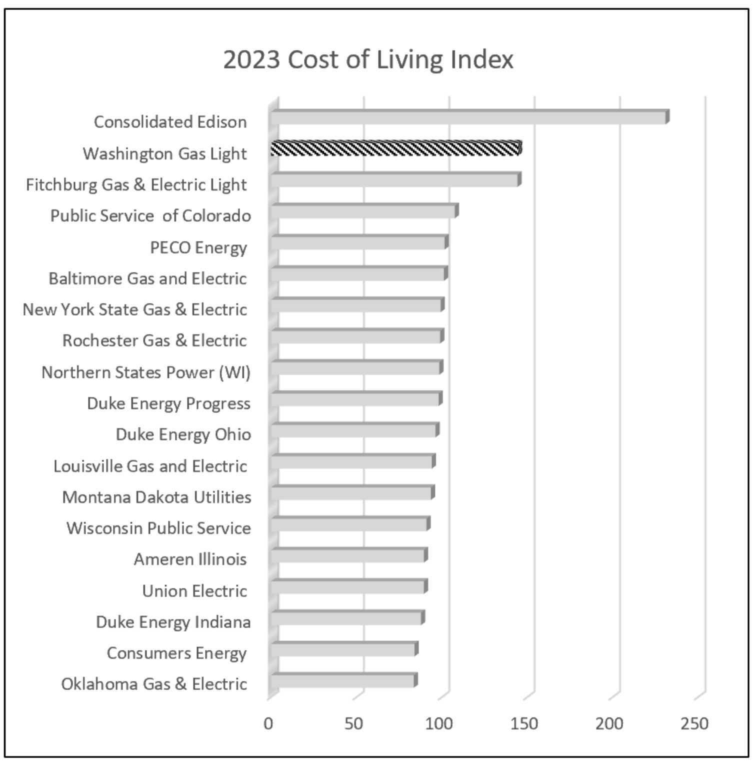

Source: Company information; 2023 FERC Form 60; Baryenbruch & Company, LLC, analysis

The remaining balance (87%) of WGL's total A&G expenses represents expenses that are directly incurred by WGL. Here, the major contributor to WGL's cost differential is the significantly higher cost of living (COL) in Washington, DC. Using data from Exhibit 12 on page 27 of 31, Mr. Baryenbruch gathered the cost-living indices for each utility whose total 2023 A&G expenses per customer are lower than those of WGL for TY 2024. Comparison group cost of living is based on the location of their headquarters office. The table below shows the resultant data set.

| Comparison Group Utilities | Total A&G Expenses Per Customer (A) | Headquarters City | 2023 Cost of Living Index |
|---|---|---|---|
| Washington Gas Light Company | $178 | Washington DC | 144.6 |
| Northern States Power Company (Wisconsin) | $168 | Eau Claire, WI | 98.5 |
| Montana Dakota Utilities, Inc. | $166 | Bismarck, ND | 93.6 |
| Union Electric Company | $160 | St. Louis, MO | 89.5 |
| Fitchburg Gas & Electric Light Company | $159 | Lunenburg, MA | 144.3 |
| Consolidated Edison Company | $148 | New York, NY | 231.0 |
| Duke Energy Progress, LLC | $140 | Raleigh, NC | 98.1 |
| New York State Gas & Electric Company | $134 | Binghamton, NY | 99.3 |
| Baltimore Gas and Electric Company | $131 | Baltimore, MD | 101.2 |
| Louisville Gas and Electric Company | $129 | Louisville, KY | 94.1 |
| Public Service Company of Colorado | $122 | Denver, CO | 107.6 |
| Ameren Illinois Company | $119 | Collinsville, IL | 89.5 |
| Rochester Gas & Electric Company | $119 | Rochester, NY | 99.0 |
| Duke Energy Indiana, LLC | $116 | Plainfield, IN | 87.8 |
| Oklahoma Gas & Electric Company | $115 | Oklahoma City, OK | 83.6 |
| PECO Energy Company | $99 | Philadelphia, PA | 101.6 |
| Wisconsin Public Service Corporation | $86 | Green Bay, WI | 91.0 |
| Consumers Energy Company | $66 | Jackson, MI | 84.0 |
| Duke Energy Ohio, Inc. | $58 | Cincinnati, OH | 96.3 |

Note A: Source is Company information, FERC Form 1 (2023), Baryenbruch & Company, LLC analysis
Note B: Source is Cost of Living Index (2024), Council for Community and Exonomic Research

When you align each utility's cost of living index, as shown in the graph below, it shows WGL's COL index to be the second highest among the 18 utilities with lower total A&G expenses per customer. WGL's significantly higher service territory drives up its cost of A&G salaries, contract services, office rents and other A&G-related expenses. Thus, a higher COL is the major contributor to WGL's relative cost position.




Please see the six (6) attached files for OPC Data Request 56.b.

c. The following statement in this question is absolutely false:

> "… causing Witness Baryenbruch to conclude that WGL's sizeable affiliate charges are the reason for its higher level of A&G expenses relative to comparable utilities."

Mr. Baryenbruch never made this statement.

See the response to b. above for the principal reason for WGL's relative cost position. It was not in Mr. Baryenbruch's work scope to evaluate the allocation methodology for the cost of affiliate services.

d. See the response to b. above for the principal reason for WGL's relative cost position.

e. See the response to b. above for the principal reason for WGL's relative cost position.

SPONSOR: Patrick Baryenbruch
Consultant

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

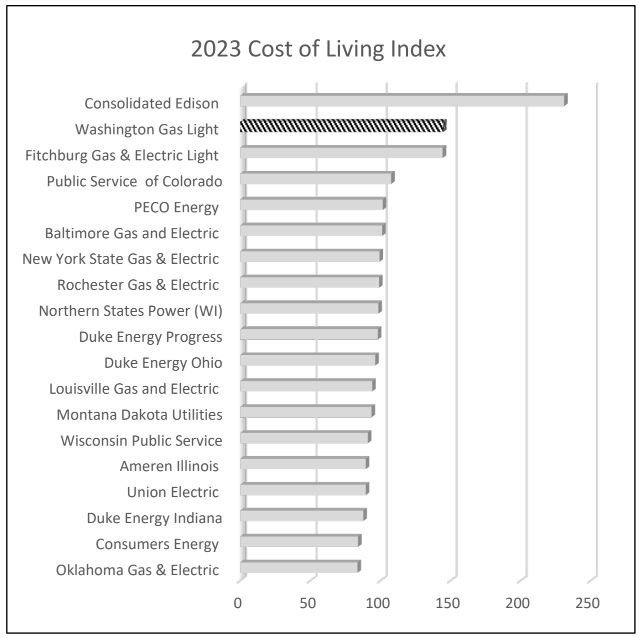
| Comparison Group Utilities | 2023 Total A&G Expenses per Customer | | Quartile | | Headquarters | Cost-of Living Index | |
|---|---|---|---|---|---|---|---|
| San Diego Gas & Electric Company | $918 | | | | | | |
| Pacific Gas & Electric Company | $541 | | | | | | |
| Black Hills Power, Inc. | $432 | | | | | | |
| Northern Indiana Public Service Company | $379 | | 4th | | | | |
| Empire District Electric Company | $292 | | | | | | |
| Central Hudson Gas & Electric Corporation | $258 | | | | | | |
| Southern Indiana Gas and Electric Company | $245 | | | | | | |
| Niagra Mohawk Power Company | $218 | | | 8 | | | |
| 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** | | | | Washington DC | 144.6 | |
| Northern States Power Company (Wisconsin) | $168 | | | | Eau Claire, WI | 98.5 | |
| Montana Dakota Utilities, Inc. | $166 | | | | Bismarck, ND | 93.6 | |
| Union Electric Company | $160 | < median | | 8 | St. Louis, MO | 89.5 | |
| Fitchburg Gas & Electric Light Company | $159 | | | | Lunenburg, MA | 144.3 | |
| Consolidated Edison Company | $148 | | | | New York, NY | 231.0 | |
| Duke Energy Progress, LLC | $140 | | | | Raleigh, NC | 98.1 | |
| New York State Gas & Electric Company | $134 | | 2nd | | Binghamton, NY | 99.3 | NonMetro - Ostego County |
| Baltimore Gas and Electric Company | $131 | | | | Baltimore, MD | 101.2 | |
| Louisville Gas and Electric Company | $129 | | | | Louisville, KY | 94.1 | |
| Public Service Company of Colorado | $122 | | | | Denver, CO | 107.6 | |
| Ameren Illinois Company | $119 | | | 8 | Collinsville, IL | 89.5 | St. Louis, MO |
| Rochester Gas & Electric Company | $119 | | | | Rochester, NY | 99.0 | |
| Duke Energy Indiana, LLC | $116 | | | | Plainfield, IN | 87.8 | Indianapolis, IN |
| Oklahoma Gas & Electric Company | $115 | | | | Oklahoma City, OK | 83.6 | |
| PECO Energy Company | $99 | | 1st | | Philadelphia, PA | 101.6 | |
| Wisconsin Public Service Corporation | $86 | | | | Green Bay, WI | 91.0 | |
| Consumers Energy Company | $66 | | | | Jackson, MI | 84.0 | |
| Duke Energy Ohio, Inc. | $58 | | | 7 | Cincinnati, OH | 96.3 | |

Source: Company information, FERC Form 1 (2023), Baryenbruch & Company, LLC analysis

| Comparison Group Utilities | Total A&G Expenses Per Customer (A) | Headquarters City | 2023 Cost of Living Index | |
|---|---|---|---|---|
| Washington Gas Light Company | $178 | Washington DC | 144.6 | |
| Northern States Power Company (Wisconsin) | $168 | Eau Claire, WI | 98.5 | |
| Montana Dakota Utilities, Inc. | $166 | Bismarck, ND | 93.6 | |
| Union Electric Company | $160 | St. Louis, MO | 89.5 | |
| Fitchburg Gas & Electric Light Company | $159 | Lunenburg, MA | 144.3 | |
| Consolidated Edison Company | $148 | New York, NY | 231.0 | |
| Duke Energy Progress, LLC | $140 | Raleigh, NC | 98.1 | |
| New York State Gas & Electric Company | $134 | Binghamton, NY | 99.3 | NonMetro - Ostego County |
| Baltimore Gas and Electric Company | $131 | Baltimore, MD | 101.2 | |
| Louisville Gas and Electric Company | $129 | Louisville, KY | 94.1 | |
| Public Service Company of Colorado | $122 | Denver, CO | 107.6 | |
| Ameren Illinois Company | $119 | Collinsville, IL | 89.5 | St. Louis, MO |
| Rochester Gas & Electric Company | $119 | Rochester, NY | 99.0 | |
| Duke Energy Indiana, LLC | $116 | Plainfield, IN | 87.8 | Indianapolis, IN |
| Oklahoma Gas & Electric Company | $115 | Oklahoma City, OK | 83.6 | |
| PECO Energy Company | $99 | Philadelphia, PA | 101.6 | |
| Wisconsin Public Service Corporation | $86 | Green Bay, WI | 91.0 | |
| Consumers Energy Company | $66 | Jackson, MI | 84.0 | |
| Duke Energy Ohio, Inc. | $58 | Cincinnati, OH | 96.3 | |

Note A: Source is Company information, FERC Form 1 (2023), Baryenbruch & Company, LLC analysis
Note B: Source is Cost of Living Index (2024), Council for Community and Exonomic Research

| Comparison Group Utilities | COLI |
|---|---|
| Oklahoma Gas & Electric | 83.6 |
| Consumers Energy | 84.0 |
| Duke Energy Indiana | 87.8 |
| Union Electric | 89.5 |
| Ameren Illinois | 89.5 |
| Wisconsin Public Service | 91.0 |
| Montana Dakota Utilities | 93.6 |
| Louisville Gas and Electric | 94.1 |
| Duke Energy Ohio | 96.3 |
| Duke Energy Progress | 98.1 |
| Northern States Power (WI) | 98.5 |
| Rochester Gas & Electric | 99.0 |
| New York State Gas & Electric | 99.3 |
| Baltimore Gas and Electric | 101.2 |
| PECO Energy | 101.6 |
| Public Service of Colorado | 107.6 |
| Fitchburg Gas & Electric Light | 144.3 |
| Washington Gas Light | 144.6 |
| Consolidated Edison | 231.0 |



# Remaining Attachments of WGL Response to OPC Data Request No. 4-56 Excluded

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-56

**Q.** **Witness Baryenbruch Reasons for Higher Affiliate Charges.** Witness Baryenbruch's Direct Testimony (12:5-25, Table 8) and Exhibit WG (L)-2, page 27 of 31, Exhibit 13, show that WGL's 2023 A&G expenses per customer is $178.00, compared to other utilities. Witness Baryenbruch's Direct Testimony explains (12:6-8) and Table 8 (between lines 15-16) shows that the WGL A&G expense of $178/per customer is in the middle of the third quartile and somewhat above the utility group median, with twelve other utilities having higher costs and eighteen utilities having lower costs. Witness Baryenbruch also states (10:22-24) that WGL's affiliate charges represent a sizeable portion of WGL's A&G expenses, making up 13% of WGL's total A&G expenses. Address the following:

a. Please confirm the Direct Testimony of Witness Baryenbruch concludes that WGL's affiliate charges are the reason for its higher level of A&G expenses compared to other utilities in the comparison group, and explain if Witness Baryenbruch agrees or disagrees with this conclusion. Also explain if WGL agrees or disagrees with this conclusion.

b. Regarding (a) above, if Witness Baryenbruch disagrees with this conclusion, or if WGL disagrees with this conclusion, explain all reasons why WGL's sizeable portion of affiliate charges are not the reason for WGL's higher level of A&G expenses compared to other utilities in the comparison group, and provide all supporting documentation for this position. Also, explain why Witness Baryenbruch's conclusion that WGL's "Affiliate charges represent a sizeable portion of WGL's A&G expenses" is not an accurate statement in this regard.

c. Explain the specific reasons and factors causing Witness Baryenbruch to conclude that WGL's sizeable affiliate charges are the reason for its higher level of A&G expenses relative to comparable utilities. Provide all supporting documentation. Also explain which of the specific reasons below contribute to WGL's sizeable level of affiliate charges (or identify all additional reasons that contribute to this) and provide related supporting documentation for each reason:

i) Certain specific WGL allocation factors contribute to the higher level of affiliate charges, and identify which specific allocation factors contribute to this conclusion.
ii) AltaGas begins with a greater level of expenses (and/or ASUS expenses) subject to allocation to WGL (compared to other utilities) and this contributes to the higher level of affiliate charges, and explain this conclusion.
iii) AltaGas allocates a greater level of affiliate charges to WGL (compared to its allocations to other affiliates) and this contributes to the higher level of affiliate charges, and explain this conclusion.
iv) Other affiliates allocate an unusually greater level of affiliate charges to WGL and this contributes to a higher level of affiliate charges, and explain this conclusion.
v) AltaGas and/or WGL (or other affiliates) allocate or direct assign redundant affiliate charges to WGL and this contributes to a higher level of affiliate charges, and explain this conclusion.
vi) AltaGas and/or WGL (or other affiliates) have a greater number of employees performing the same various services (compared to other utilities) and so AltaGas and/or WGL are less efficient than other utilities and this contributes to a higher level of affiliate charges, and explain this conclusion.
vii) Identify all other reasons causing WGL to have a higher level of affiliate charges, and explain these reasons.

d) If Witness Baryenbruch cannot identify the specific reasons causing WGL's higher level of affiliate charges relative to A&G charges (compared to other utilities in the comparison group), then explain why this does not diminish the importance and credibility of Witness Baryenbruch's testimony regarding affiliate charges.

e) If Witness Baryenbruch cannot identify the specific reasons causing WGL's higher level of affiliate charges relative to A&G charges (compared to other utilities in the comparison group), then explain how Witness Baryenbruch can eliminate the existence of duplicate services as a reason for these higher levels of affiliate charges.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. Neither Mr. Baryenbruch nor WGL agrees with this assertion.

b. Affiliate A&G-related charges make 13% of WGL's total A&G expenses. Mr. Baryenbruch's lower-of-cost-or-market comparison showed the cost of affiliate services is dramatically lower than the cost of outside providers of similar services. Also, the magnitude of affiliate charges to WGL is not unusual compared to what other utilities are charged by their affiliates. As calculated below, WGL's TY 2024 affiliate charges per customer were $23.

| | TY 2024 |
|---|---|
| Affiliate Charges | |
| AltaGas | $ 26,781,103 |
| SEMCO | $ 1,556,406 |
| Total Affiliate Charges (A) | $ 28,337,509 |
| Total WGL Customers at 12/31/2023 | 1,226,879 |
| Affiliate A&G Charges per Customer | $ 23 |

Note A: These are all A&G-related

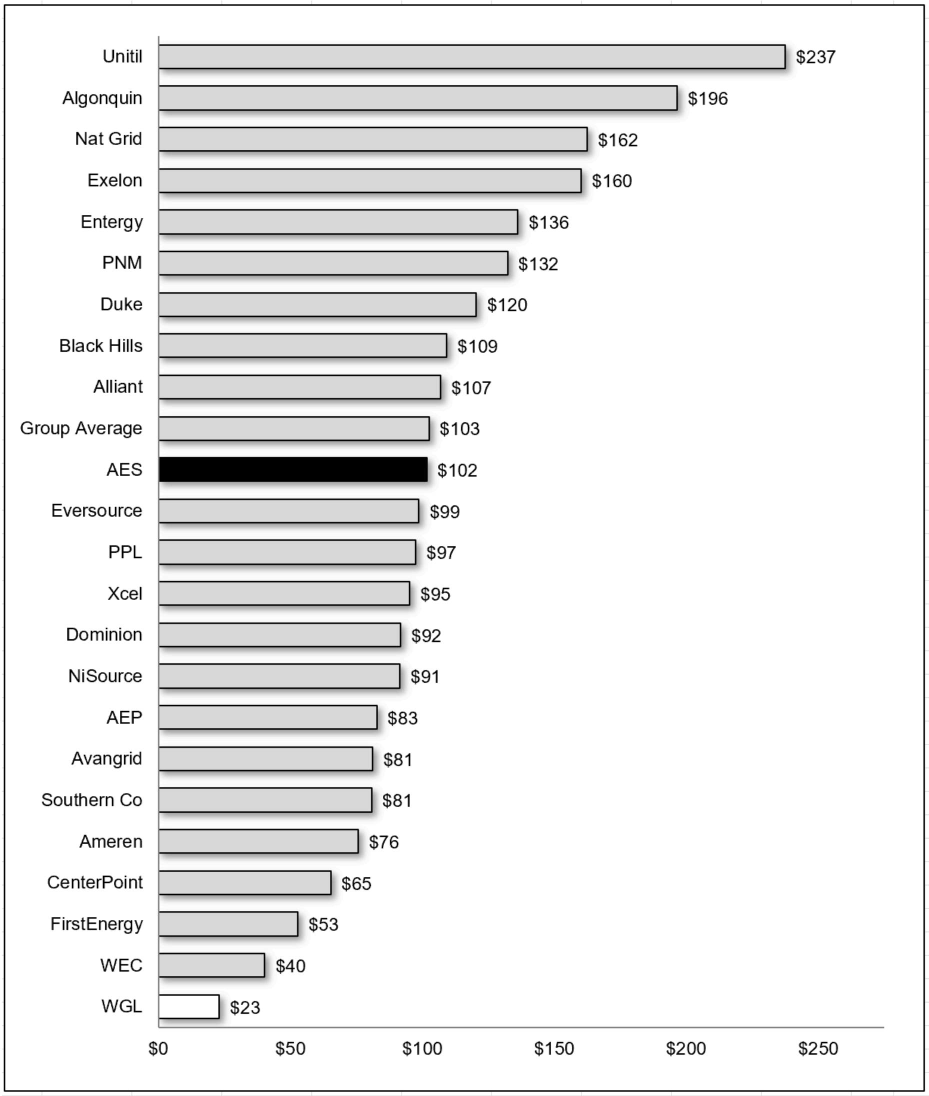
Source: Company information

This level of affiliate charges is not unusual. The table below shows the amount of A&G-related affiliate charges to the regulated utilities of the listed utility holding companies.

| Utility Company | 2023 Regulated Retail Service Company A&G Expenses | Regulated Retail Customers | Cost per Customer |
|---|---|---|---|
| AEP | $463,462,789 | 5,600,000 | $ 83 |
| AES | $107,305,433 | 1,056,000 | $ 102 |
| Algonquin | $235,778,007 | 1,200,000 | $ 196 |
| Alliant | $151,883,338 | 1,420,000 | $ 107 |
| Ameren | $249,624,936 | 3,300,000 | $ 76 |
| Avangrid | $267,637,704 | 3,300,000 | $ 81 |
| Black Hills | $142,009,582 | 1,300,000 | $ 109 |
| CenterPoint | $456,647,843 | 7,000,000 | $ 65 |
| Dominion | $412,743,398 | 4,500,000 | $ 92 |
| Duke | $1,192,398,534 | 9,900,000 | $ 120 |
| Entergy | $436,405,601 | 3,204,000 | $ 136 |
| Eversource | $434,227,112 | 4,400,000 | $ 99 |
| Exelon | $1,682,110,370 | 10,500,000 | $ 160 |
| FirstEnergy | $316,569,517 | 6,000,000 | $ 53 |
| Nat Grid | $1,120,437,236 | 6,900,000 | $ 162 |
| NiSource | $333,537,252 | 3,647,000 | $ 91 |
| PNM | $107,934,202 | 816,000 | $ 132 |
| PPL | $341,090,403 | 3,500,000 | $ 97 |
| Southern Co | $727,044,818 | 9,000,000 | $ 81 |
| Unitil | $46,758,285 | 196,900 | $ 237 |
| WEC | $187,079,034 | 4,643,000 | $ 40 |
| Xcel | $561,477,642 | 5,900,000 | $ 95 |
| Total/Average | $9,974,163,036 | 97,282,900 | $ 103 |

Source: FERC Form 60; Baryenbruch & Company, LLC, analysis

The graph below shows WGL's affiliate charges per customer are lower than all of the comparison group utility companies.



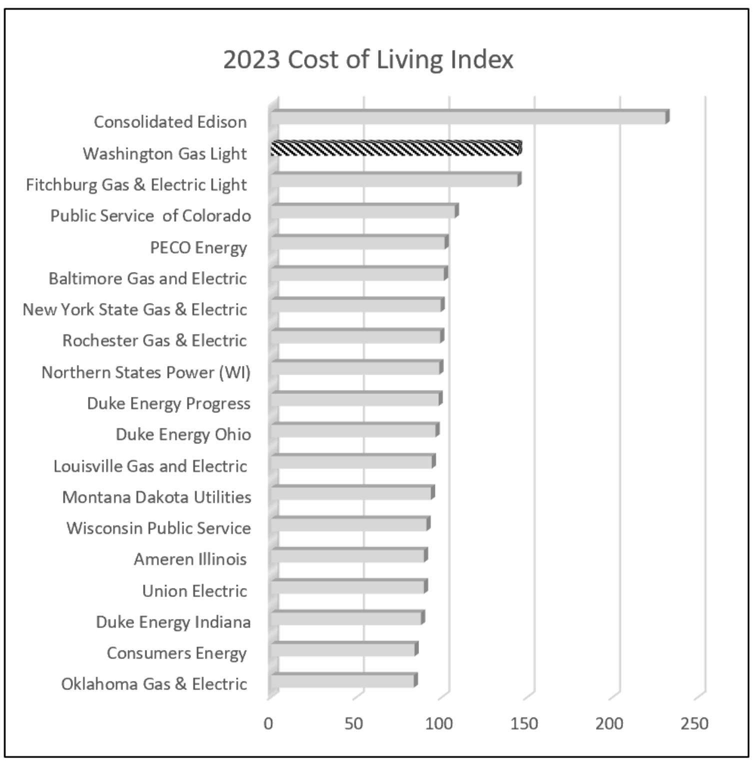

Source: Company information; 2023 FERC Form 60; Baryenbruch & Company, LLC, analysis

The remaining balance (87%) of WGL's total A&G expenses represents expenses that are directly incurred by WGL. Here, the major contributor to WGL's cost differential is the significantly higher cost of living (COL) in Washington, DC. Using data from Exhibit 12 on page 27 of 31, Mr. Baryenbruch gathered the cost-living indices for each utility whose total 2023 A&G expenses per customer are lower than those of WGL for TY 2024. Comparison group cost of living is based on the location of their headquarters office. The table below shows the resultant data set.

| Comparison Group Utilities | Total A&G Expenses Per Customer (A) | Headquarters City | 2023 Cost of Living Index |
|---|---|---|---|
| Washington Gas Light Company | $178 | Washington DC | 144.6 |
| Northern States Power Company (Wisconsin) | $168 | Eau Claire, WI | 98.5 |
| Montana Dakota Utilities, Inc. | $166 | Bismarck, ND | 93.6 |
| Union Electric Company | $160 | St. Louis, MO | 89.5 |
| Fitchburg Gas & Electric Light Company | $159 | Lunenburg, MA | 144.3 |
| Consolidated Edison Company | $148 | New York, NY | 231.0 |
| Duke Energy Progress, LLC | $140 | Raleigh, NC | 98.1 |
| New York State Gas & Electric Company | $134 | Binghamton, NY | 99.3 |
| Baltimore Gas and Electric Company | $131 | Baltimore, MD | 101.2 |
| Louisville Gas and Electric Company | $129 | Louisville, KY | 94.1 |
| Public Service Company of Colorado | $122 | Denver, CO | 107.6 |
| Ameren Illinois Company | $119 | Collinsville, IL | 89.5 |
| Rochester Gas & Electric Company | $119 | Rochester, NY | 99.0 |
| Duke Energy Indiana, LLC | $116 | Plainfield, IN | 87.8 |
| Oklahoma Gas & Electric Company | $115 | Oklahoma City, OK | 83.6 |
| PECO Energy Company | $99 | Philadelphia, PA | 101.6 |
| Wisconsin Public Service Corporation | $86 | Green Bay, WI | 91.0 |
| Consumers Energy Company | $66 | Jackson, MI | 84.0 |
| Duke Energy Ohio, Inc. | $58 | Cincinnati, OH | 96.3 |

Note A: Source is Company information, FERC Form 1 (2023), Baryenbruch & Company, LLC analysis
Note B: Source is Cost of Living Index (2024), Council for Community and Exonomic Research

When you align each utility's cost of living index, as shown in the graph below, it shows WGL's COL index to be the second highest among the 18 utilities with lower total A&G expenses per customer. WGL's significantly higher service territory drives up its cost of A&G salaries, contract services, office rents and other A&G-related expenses. Thus, a higher COL is the major contributor to WGL's relative cost position.




Please see the six (6) attached files for OPC Data Request 56.b.

c. The following statement in this question is absolutely false:

> "… causing Witness Baryenbruch to conclude that WGL's sizeable affiliate charges are the reason for its higher level of A&G expenses relative to comparable utilities."

Mr. Baryenbruch never made this statement.

See the response to b. above for the principal reason for WGL's relative cost position. It was not in Mr. Baryenbruch's work scope to evaluate the allocation methodology for the cost of affiliate services.

d. See the response to b. above for the principal reason for WGL's relative cost position.

e. See the response to b. above for the principal reason for WGL's relative cost position.

SPONSOR: Patrick Baryenbruch
Consultant

**OPC FOLLOW-UP REQUEST** **11/22/2024**

**Q.** WGL's response to OPC 4-56(b) states at pages 2 and 3 (of 6) that WGL's affiliate charges make-up 13% of WGL's total A&G expenses with test year March 31, 2024, affiliate charges per customer of $23.00. Then Witness Baryenbruch states that WGL's $23.00 level of affiliate charges is not unusual, and he states that the following table (at page 3 of 6) shows the A&G-related affiliate charges for other regulated utilities (although this table is titled "2023 Regulated Retail Service Company A&G Expenses"), and this table shows "Cost per Customer" amounts ranging from $40 for WEC to $196 for Algonquin (for this list of 22 utilities). Finally, Witness Baryunbruch provides a graph for which he states WGL's affiliate charges per customer are lower than all of the comparison group utilities (the graph is at page 4 of 6). Please address the following:

a. Regarding the table at page 3 of 6, Witness Baryenbruch cites as showing "A&G-related affiliates charges" but the heading at the table states" 2023 Regulated Retail Service Company A&G Expenses." Explain if this table shows the "affiliate charges and affiliate cost per customer" or if it shows the "A&G expense and A&G cost per customer."

b. Regarding (a) above for the table at page 3 of 6, provide all supporting documentation (FERC Form 60 and other data) and calculations supporting all amounts in this table showing either the “affiliate” or “A&G” cost per customer, including all expenses, number of customers, and the cost per customer and provide a citation to the related sources.

c. Explain why Witness Baryenbruch used a different sample of utility companies for determining the “affiliate cost per customer” (for the table at page 3 of 6) compared to the A&G cost per customer at his Exhibit 12 (A&G Expense per Customer) at Exhibit WG (L)-2, page 26 of 31. Provide the “affiliate cost per customer” using the same utilities listed at Exhibit WG (L)-2, page 26 of 31.

d. Explain why the 2023 A&G expense for Black Hills and other utilities at Exhibit 12 (A&G Expense per Customer) at Exhibit WG (L)-2, page 26 of 31 is greater than the “affiliate expenses” for the same utilities per the table at 4-56(b), page 3 of 6 – when affiliate expenses should be less than A&G expenses because affiliate expenses are a subset of A&G expenses.

e. Regarding the table at page 3 of 6 showing “affiliate” expenses per customer, provide the full name of the utility in place of the acronyms used for these utilities.

f. Explain why Witness Baryenbruch compares the $23.00 affiliate cost per customer of affiliate WGL (calculation at page 3 of 6) to the affiliate cost per customer of the entire holding/parent companies in the table (table at page 3 of 6), and explain how this is an apples-to-apples comparison of these affiliate costs per customer.

**WASHINGTON GAS’ RESPONSE** **12/06/2024**

**A.**

a. The table shows 2023 affiliate A&G charges per customer. The table with corrected headings is shown below.

| Utility Company | 2023 Service Company A&G Charges to Regulated Affiliates | Regulated Retail Customers | 2023 Affiliate A&G Charges per Customer |
|---|---|---|---|
| AEP | $463,462,789 | 5,600,000 | $ 83 |
| AES | $107,305,433 | 1,056,000 | $ 102 |
| Algonquin | $235,778,007 | 1,200,000 | $ 196 |
| Alliant | $151,883,338 | 1,420,000 | $ 107 |
| Ameren | $249,624,936 | 3,300,000 | $ 76 |
| Avangrid | $267,637,704 | 3,300,000 | $ 81 |
| Black Hills | $142,009,582 | 1,300,000 | $ 109 |
| CenterPoint | $456,647,843 | 7,000,000 | $ 65 |
| Dominion | $412,743,398 | 4,500,000 | $ 92 |
| Duke | $1,192,398,534 | 9,900,000 | $ 120 |
| Entergy | $436,405,601 | 3,204,000 | $ 136 |
| Eversource | $434,227,112 | 4,400,000 | $ 99 |
| Exelon | $1,682,110,370 | 10,500,000 | $ 160 |
| FirstEnergy | $316,569,517 | 6,000,000 | $ 53 |
| Nat Grid | $1,120,437,236 | 6,900,000 | $ 162 |
| NiSource | $333,537,252 | 3,647,000 | $ 91 |
| PNM | $107,934,202 | 816,000 | $ 132 |
| PPL | $341,090,403 | 3,500,000 | $ 97 |
| Southern Co | $727,044,818 | 9,000,000 | $ 81 |
| Unitil | $46,758,285 | 196,900 | $ 237 |
| WEC | $187,079,034 | 4,643,000 | $ 40 |
| Xcel | $561,477,642 | 5,900,000 | $ 95 |
| Total/Average | $9,974,163,036 | 97,282,900 | $ 103 |

Source: FERC Form 60; Baryenbruch & Company, LLC, analysis

b. See the following workpapers for supporting data:

- 4-56.b – FERC Form 60 DB (2033) WGL.xlsx
- 4-56.b – FERC Form 60 Acct 457 DB (2023) WGL.xlsx
- 4-56.b – Customer Counts 2023.docx

c. The table discussed in (a) above shows affiliate A&G charges per regulated customer for utility holding companies. Exhibit 12 in Exhibit WG (L)-2 page 26 of 31 shows total A&G expenses for individual utility companies that provide electric and gas service. Total A&G expenses include those incurred directly by the utility and allocated to it by affiliates.

Mr. Baryenbruch presents the affiliate A&G charges per customer in response to DR 4-56 to rebut the question's baseless assertion that the magnitude of WGL's affiliate charges were out of line compared to other utilities ("Please confirm the Direct Testimony of Witness Baryenbruch concludes that WGL's affiliate charges are the reason for its higher level of

A&G expenses compared to other utilities in the comparison group, and explain if Witness Baryenbruch agrees or disagrees with this conclusion").

d. Exhibit 12 shows total A&G expenses for individual utility companies. DR 4-56 shows affiliate A&G-related charges to individual regulated utility customers within utility holding companies.

e. See d. above.

f. Mr. Baryenbruch makes this comparison to show that the magnitude or proportion of WGL's affiliate charges is not unusual. He does not claim this is a comparison of the cost of affiliate services because service companies of utility holding companies generally provide a broader range of services to their utility operating utility affiliates.

SPONSOR: Patrick Baryenbruch
Consultant

| | |
|---|---|
| Function | A&G |
| In/Ex | Include |

| Sum of Amount | | Utility Holding Co | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FERC Acct # | FERC Acct Description | AEP | AES | Algonquin | Alliant | Ameren | Avangrid | Black Hills | CenterPoint | Dominion | Duke | Entergy | Eversource | Exelon | FirstEnergy | Nat Grid | NiSource | PNM | PPL | Southern Co | Unitil | WEC | Xcel | Grand Total |
| 920 | Administrative and General Salaries | $ 238,945,450 | $ 79,973,164 | $ 152,499,871 | $ 97,680,652 | $ 132,986,666 | $ 69,764,266 | $ 72,678,617 | $ 220,417,580 | $ 405,859,247 | $ 502,877,062 | $ 254,469,021 | $ 281,440,039 | $ 521,194,442 | $ 243,601,227 | $ 711,260,867 | $ 165,545,542 | $ 64,341,008 | $ 194,806,984 | $ 371,812,429 | $ 39,995,432 | $ 99,266,535 | $ 232,908,092 | $ 5,154,324,193 |
| 921 | Office Supplies and Expenses | $ 21,536,874 | $ 12,081,754 | $ 27,515,263 | $ 37,660,825 | $ 57,358,951 | $ 11,143,958 | $ 21,675,041 | $ 67,782,349 | $ 55,267,661 | $ 373,363,733 | $ 39,032,451 | $ 14,055,310 | $ 22,245,349 | $ 62,992,603 | $ 390,911,108 | $ 10,321,649 | $ 18,157,732 | $ 31,689,189 | $ 132,616,896 | $ 1,918,937 | $ 54,974,630 | $ 142,561,697 | $ 1,606,863,960 |
| 923 | Outside Services Employed | $ 77,052,760 | $ 41,973,716 | $ 111,245,929 | $ 19,965,014 | $ 44,069,823 | $ 151,264,651 | $ 25,220,952 | $ 275,494,801 | $ 42,985,309 | $ 177,214,923 | $ 130,673,367 | $ 143,803,349 | $ 1,177,888,762 | $ 74,070,712 | $ 164,928,397 | $ 100,505,165 | $ 25,317,139 | $ 165,878,951 | $ 257,444,726 | $ 1,589,605 | $ 17,833,521 | $ 50,472,433 | $ 3,276,894,005 |
| 931 | Rents | $ 50,551,916 | $ 15,110 | $ 23,939 | $ 2,828,322 | $ 28,536,682 | $ 3,625,691 | $ 14,231,550 | $ 24,543,102 | $ 9,660,752 | $ 166,123,864 | $ 15,566,027 | $ 6,552,542 | $ 48,255,955 | $ 18,037,966 | $ 39,674,488 | $ 13,657,793 | $ 210,328 | $ 9,189,730 | $ 18,763,610 | $ 1,922,254 | $ 19,633,687 | $ 143,297,462 | $ 634,902,770 |
| 935 | Maintenance of Structures and Equipment | $ 98,471,518 | $ 180,000 | $ - | $ 467,751 | $ 952,149 | $ 32,579,233 | $ 18,746,343 | $ 1,069 | $ 71,335,043 | $ 5,661,615 | $ 7,053,080 | $ 238,969 | $ 12,519,771 | $ 1,697,940 | $ 199,965 | $ 49,979,422 | $ 1,908,721 | $ 6,841,563 | $ 8,155,011 | $ 2,643,952 | $ 173,968 | $ 2,149,577 | $ 321,956,660 |
| **Grand Total** | | **$ 486,558,518** | **$ 134,223,744** | **$ 291,285,002** | **$ 158,602,564** | **$ 263,904,271** | **$ 268,377,799** | **$ 152,552,503** | **$ 588,238,901** | **$ 585,108,012** | **$ 1,225,241,197** | **$ 446,793,946** | **$ 446,090,209** | **$ 1,782,104,279** | **$ 400,400,448** | **$ 1,306,974,825** | **$ 340,009,571** | **$ 109,934,928** | **$ 408,406,417** | **$ 788,792,672** | **$ 48,070,180** | **$ 191,882,341** | **$ 571,389,261** | **$ 10,994,941,588** |

| Counts of Usage | AEP | AES | Algonquin | Alliant | Ameren | Avangrid | Black Hills | CenterPoint | Dominion | Duke | Entergy | Eversource | Exelon | FirstEnergy | Nat Grid | NiSource | PNM | PPL | Southern Co | Unitil | WEC | Xcel | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 901 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 22 |
| 903 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 22 |
| 905 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 22 |
| 910 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 22 |
| 920 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 21 |
| 921 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 22 |
| 923 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 924 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 930.2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 931 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 935 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-57

**Q.** **Witness Baryenbruch Comparison of A&G Expenses.** Witness Baryenbruch Direct Testimony (12:5-25, Table 8) and Exhibit WG (L)-2, page 27 of 31, Exhibit 13, show that WGL's 2023 A&G expenses per customer is $178.00, compared to other utilities. WGL's A&G expense of $178/per customer is in the middle of the third quartile and somewhat above the utility group median, with twelve other utilities having higher costs and eighteen utilities having lower costs (Baryenbruch 12:6-8), and WGL's affiliate charges represent a sizeable portion of WGL's A&G expenses, making up 13% of WGL's total A&G expenses (Baryenbruch 10:22-24). Address the following:

a. Explain why Witness Baryenbruch believes it would or would not be reasonable to adjust and reduce WGL A&G expenses of $178/customer in this rate proceeding to the utility group median level of A&G expenses per customer ($160/customer) or to the utility groups average level of A&G expenses per customer (or some other reasonable level of A&G expenses per customer).

b. In the opinion of Witness Baryenbruch, what level of WGL A&G expenses per customer compared to the utility group level of A&G expenses per customer (or which level of WGL A&G expense per customer deviation from the utility group median or average level of A&G expense per customer) would be significant enough (or reasonable), to propose an adjustment up or down to WGL's A&G expenses, and provide the reasons for this conclusion.

c. In the opinion of WGL, what level of WGL A&G expenses per customer compared to the utility group level of A&G expenses per customer (or which level of WGL A&G expense per customer deviation from the utility group median or average level of A&G expense per customer) would be significant enough (or reasonable), to propose an adjustment up or down to WGL's A&G expenses, and provide the reasons for this conclusion.

d. Regarding (a) and (b) above, explain if it is Witness Baryenbruch's conclusion that his contract did not task him with proposing any adjustments (up or down) to WGL affiliate expenses or A&G expenses, and cite to the specific contract language. If not, explain if Witness Baryenbruch did have the contract flexibility to propose adjustments (up or down) to WGL affiliate expenses or A&G expenses, and cite to the specific contract language.

e. Explain if the responsibility for proposing a proposing any adjustments (up or down) to WGL affiliate expenses or A&G expenses is a decision to be made only by WGL in this rate proceeding.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. As discussed in the response to OPC Data Request 4-56.b, WGL has to contend with operating in a service territory that has a significantly higher cost of living than most comparison group utilities. Its higher COL directly impacts its A&G expenses. Also, Mr. Baryenbruch believes performance in the first through third quartiles is reasonable. For these reasons, WGL's position in the middle of the third quartile is reasonable. There is no basis for a reduction in its revenue requirements.

b. See the response to a. above. It was not in Mr. Baryenbruch's scope of work to make these conjectures.

c. WGL believes its A&G expenses are reasonable and disagrees with this data request's notion that a rate case adjustment should be contemplated.

d. Mr. Baryenbruch's work scope in this case was to evaluate the reasonableness of WGL's total A&G expenses. In more than 100 rate case proceedings as a witness, he has never been expected to create adjustments to a client's revenue requirements.

e. See the response to d. above.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-43
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-58

**Q.** **Witness Baryenbruch Comparison of A&G Expenses.** Witness Baryenbruch Direct Testimony (12:5-25, Table 8) and Exhibit WG (L)-2, page 27 of 31, Exhibit 13, show that WGL's 2023 A&G expenses per customer is $178.00, compared to other utilities. WGL's A&G expense of $178/per customer is in the middle of the third quartile and somewhat above the utility group median, with twelve other utilities having higher costs and eighteen utilities having lower costs (Exhibit WG (L) at 12:6-8), and WGL's affiliate charges represent a sizeable portion of WGL's A&G expenses, making up 13% of WGL's total A&G expenses (Exhibit WG (L) at 10:22-24). Address the following:

a. Identify all regulatory proceedings where Witness Baryenbruch proposed adjustments to increase or decrease affiliate expenses or A&G expenses, and provide a copy (or link) to the specific testimony and exhibits, and provide the related case/docket number, the regulatory jurisdiction, and the name of utility client or state regulatory agency client. Briefly describe the reasons for proposing the related adjustments.

b. Regarding (a) above, explain if Witness Baryenbruch has ever contracted with a state utility public service commission (or the equivalent of such agency), a state consumer advocate office (or the equivalent of such office), a state energy office, or a state attorney general's office, to address affiliate charges or A&G expenses in a rate proceeding or other type of regulatory proceeding. If the answer is "yes", provide a copy (or link) to the specific testimony and exhibits, and provide the related case/docket number, the regulatory jurisdiction, and the name of the state regulatory agency or state office client. Briefly describe the proposed adjustments and the reasons for the related adjustments.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.** a. The purpose of Mr. Baryenbruch's work in all of his rate case assignments was to evaluate the necessity and reasonableness of client utility affiliate transactions. He has never been responsible for proposing adjustments to revenue requirements.

b. No.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-44
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-59

**Q.** **Witness Baryenbruch Comparison of A&G Expenses.** Witness Baryenbruch Direct Testimony (12:5-25, Table 8) and Exhibit WG (L)-2, page 27 of 31, Exhibit 13, show that WGL's 2023 A&G expenses per customer is $178.00, compared to other utilities. Address the following:

a. Explain why Witness Baryenbruch used the group of electric utilities at Table 8 for comparing levels of A&G expenses to WGL, and explain the criteria which he used to include or exclude other utilities from this comparison group. As part of the response, provide a list of utilities that were excluded from this comparison group based on certain criteria.

b. Explain if Witness Baryenbruch compared WGL's A&G expenses to other utilities for years other than 2023, and provide this analysis and related conclusions. If not, explain why Witness Baryenbruch did not perform this analysis for other comparative calendar years or other periods.

**WASHINGTON GAS'S RESPONSE 11/15/2024**

**A.**

a. Mr. Baryenbruch's comparison group contains combination electric/gas utilities that file a FERC Form 1. FERC has a Form 2 for gas companies, but most gas distribution companies are not regulated by FERC and they are not required to file a Form 2 with FERC. For this reason, Mr. Baryenbruch chose combination electric/gas utilities for the comparison group. See the response to OPC Data Request 4-19 for a complete listing of utilities that file a Form 1 and those selected for the comparison group.

b. Mr. Baryenbruch only performed the per-customer cost comparison for WGL's 2023 total A&G expenses. This is the same approach he has taken in all of his other rate case assignments.

SPONSOR: Patrick Baryenbruch
Consultant

Exhibit OPC (B)-45
Formal Case No. 1180
Direct Testimony of Bion Ostrander
PUBLIC VERSION

# Confidential and Attorney Eyes
# Exhibit Omitted

Exhibit OPC (B)-46
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential Exhibit Omitted

Exhibit OPC (B)-47
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential Exhibit Omitted

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 6

QUESTION NO. 6-12

**Q.** **Type of Non-Labor Inflation Rate.** Witness Tuoriniemi's Direct Testimony (72:11 – 75:12) generally describes WGL's proposed Non-Labor Inflation Adjustment No. 21, but does not explain why the 2.49% median CPIA inflation rate was used, versus some other type of inflation rate such as CPIB or CPIC (Exhibit WG (D)-5, Adjustment No. 21, page 5 of 22 identifies other types of inflation rates by year) from the Survey of Professional Forecasters (SPF) for February 2024 (Tuoriniemi Direct Testimony, page 73, hyperlink cited at footnote 113). Please address the following:

a. Explain why WGL used the inflation rate for CPIA as its non-labor inflation rate in Adjustment No. 21 and did not use CPIB, CPIC, or some other inflation rate from the SPF, or some other inflation rate from another source, and provide all supporting documentation for WGL's position.

b. Explain why WGL used the "median" CPIA inflation rate as its non-labor inflation rate in Adjustment No. 21, instead of using the "mean" CPIA inflation rate (or some other measure of the inflation rate) from the SPF.

**WASHINGTON GAS'S RESPONSE** 11/20/2024

**A.** a. CPIA was used in the approved adjustment in Formal Case No. 1169. See the column definitions in the document below.

https://www.philadelphiafed.org/-/media/frbp/assets/surveys-and-data/survey-of-professional-forecasters/spf-documentation.pdf?la=en&hash=F2D73A2CE0C3EA90E71A363719588D25

Using CPIB or CPIC would be inconsistent with the Commission approved measure of inflation only one year out.

b. The median CPIA was used in the approved adjustment in Formal Case No. 1169. Because the median and mean are very similar, the data does not demonstrate that it is skewed. The mean is an easily understood measure.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

Exhibit OPC (B)-49
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 6

QUESTION NO. 6-13

**Q.** **Correlation of Non-Labor Inflation Rate.** Witness Tuoriniemi's Direct Testimony (72:11 – 75:12) generally describes WGL's proposed Non-Labor Inflation Adjustment No. 21, but does not explain why the 2.49% median CPIA inflation rate was used, versus some other type of inflation rate such as CPIB or CPIC (Exhibit WG (D)-5, Adjustment No. 21, page 5 of 22 identifies other types of inflation rates by year) from the Survey of Professional Forecasters ("SPF") for February 2024 (Tuoriniemi direct, page 73, hyperlink cited at footnote 113). Please address the following:

a. Provide the percentage for each of the various types of goods and services comprising the February 2024 CPIA inflation rate (used by WGL in its non-labor inflation Adjustment No. 21) and compare to the actual percentage of each type of good and service included in WGL's Total O&M Non-Labor Expenses on its books for the test year ending March 31, 2024 (and provide supporting documentation showing the amount of each type of good and service and the calculation of the related percentage of each type of good and service). Explain why there is or is not a reasonable correlation between the non-labor goods and services included in the February 2024 CPIA inflation rate (used in WGL's inflation Adjustment No. 21) and the actual non-labor goods and services included in WGL's total O&M Non-Labor Expenses on its books at March 31, 2024.

b. Regarding (a) above, explain why it is or is not reasonable for WGL to use the CPIA inflation rate from SPF as the non-labor inflation rate in WGL's Adjustment No. 21 if the same types (and percentage composition) of goods and services included in the CPIA inflation rate from SPF are not the same types (and percentage composition) of goods and services included in WGL's actual total O&M Non-Labor Expenses per its books at March 31, 2024. Explain and provide all supporting documentation to support WGL's response.

c. Regarding (b) above, identify each type of goods and services included in the 2024 CPIA inflation rate from SPF (used as the non-labor inflation rate in WGL's Adjustment No. 21), and identify which of these types of goods and services are not reflected in the actual goods and services included in WGL's total O&M Non-Labor Expenses on its books at March 31, 2024. Also, identify each type of good and service included in WGL's total O&M Non-Labor Expense on its books at March 31, 2024, and identify which of these types of goods and services are not reflected in the 2024 CPIA inflation rate SPF (which WGL used as the non-labor inflation rate in Adjustment No. 21).

d. Regarding (b) and (c) above, identify all types of inflation factors that have the same (or similar) types (and percentage composition) of goods and services included in WGL's actual total O&M Non-Labor Expense per its books at March 31, 2024, and provide all supporting documentation and calculations (in native file form with all formulae and links intact) to show the similarity between the composition of goods and services included in the related inflation factor and the non-labor goods and services included in WGL's actual total O&M Non-Labor Expenses per its books at March 31, 2024.

e. Regarding (b) and (c) above, provide the annual amount and percentage change of the cost of each good and service included in WGL's actual total O&M Non-Labor Expense for each of the calendar years 2020 to 2023, and explain and show how these annual changes in cost correlate (or do not correlate) to the related CPIA inflation rate from SPF for that respective calendar year. Explain why it is or is not necessary for WGL's annual changes in costs for non-labor goods and services to approximate the related CPIA inflation rate for each of the related calendar years.

**WASHINGTON GAS'S RESPONSE** 11/20/2024

**A.** Please refer to the Company response to OPC DR 6-12 for a discussion of the use of CPIA rather than any other factor. The Company relied on the CPI calculations provided by the Philadelphia Federal Reserve's Survey of Professional Forecasters as a reasonable estimate of inflation and has not performed an independent analysis of the market basket of goods. Washington Gas does not have access to the components that make up of the Philadelphia Federal Reserve's Survey of Professional Forecasters projection.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

Exhibit OPC (B)-50
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential Exhibit Omitted

Exhibit OPC (B)-51
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential and Attorney Eyes
# Exhibit Omitted

# Confidential Exhibit Omitted

Exhibit OPC (B)-53
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential and Attorney Eyes Exhibit Omitted

Exhibit OPC (B)-54
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 10

QUESTION NO. 10-3

**Q.** **Short-Term Incentive Plan.** The Direct Testimony of Witness Smith (Exhibit WG (F) 10:7-13 and 11:15 - 12:2) addresses short-term incentives, with related amounts of short-term incentives included in the Wages and Salaries Adjustment No. 5, Exhibit WG (D)-5, pages 1 to 15. Please provide a copy of WGL's Short-Term Incentive Plan documents covering the periods 2021, 2022, 2023, and 2024.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.** Please see OPC 10-3 Attachments 1 – 2021 Utilities Value Drivers; Attachment 2 – 2022 Utilities Value Drivers; Attachment 3 – 2023 STI Plan; and Attachment 4 – 2024 STI Plan. For 2021 through 2023, the Utilities Value Drivers are included. For 2024, an overview of the company's revised STI plan is provided.

SPONSOR: Tom Burgum
Senior Director Total Rewards & HR Operations • VP Utilities HR

# 2021 Utilities Value Drivers

| | *Value Driver* | *Wgt* |
|---|---|---|
| Corporate Social Responsibility | Encompasses safety and environmental, diversity and inclusion, corporate compliance and cyber/IT compliance.<br>References ALA Codes of Business Ethics and progress our ESG initiatives. | 15% |
| Capital and Operations Efficiency & Effectiveness | Identify and implement a series of innovative process and technology initiatives to achieve key operational efficiencies driven through a high-performance culture. | 35% |
| Strategy | Execute regulatory strategy and capital portfolio management to achieve planned risk reduction and targeted rate of return, including developing an action plan to position WG to achieve its allowed ROE in each jurisdiction in 2021 and beyond.<br>Leverage our customer base to offer innovative ecofriendly opportunities for the emerging low carbon ecosystem. Expand the role we can play in energy diversity, leveraging and enhancing our existing assets and footprint. Develop an integrated business and regulatory strategy that is supported by public policy. Identify regulatory and community outreach initiatives. | 25% |
| Customer Strategy | Develop a customer strategy to move to first quartile customer satisfaction performance, including community engagement and creating lower effort interaction solutions for our customers while achieving targeted growth. | 15% |
| Emerging Ecosystem | Identify and develop action plans for near-term integrated strategies that are consistent with emerging public policy related to carbon reduction. Maximize opportunities for government incentives that will enhance our existing low carbon footprint.<br>Prepare for low-carbon future through design of innovative RNG, hydrogen and energy efficiency pilots. | 10% |
| | | 100% |

# 2022 Utilities Value Drivers

| | *Value Driver* | *Wgt* |
|---|---|---|
| Corporate Social Responsibility | Continued focus on safety and environmental, diversity and inclusion, employee engagement, corporate compliance and cyber/IT compliance and progress our ESG initiatives. References ALA Codes of Business Ethics. | 15% |
| Capital and Operations Efficiency & Effectiveness | Build an operationally excellent utility through an end-to-end process focus that supports employees, digitizes work, automates processes and provides better access to data. Obtain planned customer growth and optimize risk reduction for every dollar spent through effective long-term planning, risk/value modeling and prioritization, and capital portfolio management. | 30% |
| Customer Experience | Exceed customer expectations by providing efficient, professional and cost-effective services to our customers, maintaining affordability and improving digital capabilities. | 20% |
| Strategy | Advancing our regulatory strategy to continue to operate a safe and reliable system for the benefit of our employees, customers and communities while achieving our planned risk reduction and targeted rate of return.<br>Engage our customers and stakeholders to highlight our critical infrastructure and garner support for increased investment in our core assets and new energy ecosystem propositions. Identify opportunities in the emerging low carbon ecosystem to maximize our existing infrastructure. | 20% |
| Emerging Ecosystem | Identify, develop and advance near-term integrated strategies that are consistent with emerging public policy related to carbon reduction.<br>Identify investment opportunities in emerging energy technologies to supply additional carbon friendly opportunities domestic and global needs. Maximize opportunities through strategic relationships that will enhance our existing low carbon footprint. | 15% |
| | | 100% |

Exhibit OPC (B)-54
Formal Case No. 1180
Witness: Bion Ostrander
Page 4 of 21


# 2023 STI Plan Results – Utilities

## Human Resources & Compensation Committee Meeting

March 6, 2024

AltaGas

No change from
Feb 12th HRCC meeting

# Utilities 2023 Scorecard Results

| Utilities | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Priority – Measure | Wgt | Outlook | | Multiplier | | Key Achievement |
| **CSR** (20%) | Safety – TRIF & MVIR | 10% | ● (yellow) | **Partial Success** | 0.75x | 7.5% | 31% YOY decrease in injuries to utility employees and WGL decreased injuries from MVI's by 50%. |
| | People – Talent & Culture Roadmap | 10% | ● (green) | **Success** | 1.0x | 10% | Completed ~80% of the roadmap (factoring in new CEO). |
| **Operations** (30%) | Efficient Deployment of Capital – Capital Portfolio Exec | 20% | ● (green) | **Success+** | 1.25x | 25% | Replaced 70.1 Miles of Mains (9.4% above plan), and 8,607 Services (6.3%% above plan). |
| | Operational Excellence – Business Transformation | 10% | ● (yellow) | **Partial Success** | 0.75x | 7.5% | Executed the planned focus areas identifying $5.89MM Capex and $3.3MM O&M savings but did not meet the overall O&M target. |
| **Customer Experience** (15%) | Efficient Delivery of Service – Increase Utilization | 10% | ● (green) | **Success+** | 1.25x | 12.5% | WGL successfully launched new web and mobile tools, driving 2.83M self-service transactions (8% YOY increase) and delivered O&M budget. |
| | Meet Customer Expectations – Call Center Performance | 5% | ● (green) | **Success+** | 1.25x | 6.25% | Well above the service level and speed to answer targets even with significant increase in winter billing calls, significantly lowering call center costs YOY. |
| **Regulatory & Public Policy** (25%) | Revenue Growth – Execute Rate Cases | 15% | ● (yellow) | **Partial Success** | 0.75x | 11.25% | Achieved VA settlement that was $8M Favorable to budget, delivered a DC order that was $4M above budget; but had disappointing results in the Maryland case order. |
| | Revenue Growth – Execute APRP Extensions | 10% | ● (yellow) | **Partial Success** | 0.75x | 7.5% | Received the 5-year $332M MD STRIDE extension order. |
| **Emerging Ecosystem** (10%) | Lower-Carbon Gas Supply – RNG Procurement | 5% | ● (green) | **Success+** | 1.25x | 6.25% | Completed the PWC Landfill contracting and filed for regulatory approval, plus 4 other RNG agreements. |
| | Business Development – New Markets | 5% | ● (green) | **Success+** | 1.25x | 6.25% | Contracted design assessments with 3 data centers for a combined load of >32 BCF and coordinated the approval of key interstate highways in Virginia as Hydrogen Alternative Fuel Corridors. |
| **TOTAL** | | **100%** | | | **1.0x** | **100%** | |

AltaGas

**Utilities 2023 STI Scorecard proposed result is 1.0x**

No change from Feb 12th HRCC meeting

# Utilities 2023 Scorecard Results Details (pg 1 of 5)

| | *Value Driver* | | Success Measures | Exceeds Measures | *Wgt* | *Result* | *Mltplr* | *Mltplr %* | *Achievements (Value Delivered or to be Delivered)* |
|---|---|---|---|---|---|---|---|---|---|
| CSR (20%) | Safety | TRIF & MVIR | • TRIF: SEMCO ≤ 1; WGL ≤ 2<br>• MVIR: SEMCO ≤ 1.12; WGL ≤ 2.36 | • TRIF: SEMCO < 0.75; WGL < 1.62<br>• MVIR: SEMCO ≤ 1.06; WGL ≤ 2.07 | 10% | **Partial Success** | 0.75x | 7.5% | **Our improved safety culture is delivering value to all stakeholders, with overall injuries down 31% (45 to 31) from last year.**<br>**TRIF**<br>• WGL TRIF was 1.71 (**Success++**), 36% lower than last year.<br>• SEMCO TRIF was 1.64 (**Does Not Meet**) but had an incident-free Q4.<br>**MVIR**<br>• WGL MVIR was 2.87 (**Does Not Meet**) but saw a 50% decrease in MVI related injuries.<br>• SEMCO MVIR was 1.35 (**Does Not Meet**), with 80% of incidents being single vehicle accidents (backing & contact with stationary objects. |
| | | Execute Talent & Culture Roadmap | 80% of Roadmap Key Milestones Executed | Execute Roadmap | 10% | **Success** | 1.0x | 10% | **Completed ~80% of the roadmap (factoring in new CEO)**<br>• Completed a high-level cultural review of our Utilities business in early Q1, factoring in enterprise-wide considerations. These factors were used for WG President leadership activities and the resetting of our core values.<br>• Launched simplified core values to foster improved employee engagement and commitment, which were well received across the organization.<br>• Utilities Operating Model review deferred to be completed as part of Project Volta.<br>• Completed high level capability assessments, highlighting areas to build (regulatory, advocacy, asset & work management), with talent plans to address capability gaps.<br>• Succession plans created for all roles Director and above, with success profiles created for all key roles.<br>• Increased completion and quality of Individual Development Plans (~20%) for succession candidates (action oriented and measurable), with focus on building capabilities for the future.<br>• Talent development focused on providing key talent with 'experiences' for development. |

AltaGas

No significant change from Feb 12th HRCC meeting

# Utilities 2023 Scorecard Results Details (pg 2 of 5)

| Value Driver | | | Success Measures | Exceeds Measures | Wgt | Result | Mltplr | Mltplr % | Achievements (Value Delivered or to be Delivered) |
|---|---|---|---|---|---|---|---|---|---|
| Operations (30%) | Efficient Deployment of Capital | Capital Portfolio Execution | Execute APR Programs per the Annual Plans Filed for a total of $308M capital deployed | Deliver 5% More Services at Approved Funding Level | 20% | **Success+** | 1.25x | 25% | **Replaced 70 miles of mains (9.4% more than planned), and 8,607 Services, within 1.2% of budget and delivering incremental revenue of $23.1MM ($21.5MM WGL APRP + $1.6MM SEMCO MRP).**<br>• WGL retired 39.4 miles of main (4.5% above planned 37.7) and 8,607 of services (6.3% above planned 8,097).<br>• WGL unit cost was favorable to plan. WGL APRP CapEx was at $278.8MM (1.4% above plan), but with significantly more scope.<br>• SEMCO delivered 31.1 MRP miles, exceeding planned 26.4 miles by 18% while being 2.2% under their IRIP/MRP budget. |
| | Operational Excellence | Business Transform ation | Execute 9 Planned Focus Areas and Deliver Approved 2023 budgets | Deliver $5MM incremental savings in 2023 or Identify $10MM savings incorporated into the 2024 budget | 10% | **Partial Success** | 0.75x | 7.5% | **Stood up our Business Transformation team and worked through key processes this year to identify gaps and savings opportunities that will roll into Project Volta but missed the overall Operations O&M budget target for the year.**<br>• WGL Operations executed the nine planned focus areas and identified $5.9M in Capital savings opportunities (Engineering and SCM collaborated to improve procurement and contracting for capital projects) and $3.2M in O&M savings opportunities (contingent on Scheduling Field Mobility system investment). WGL Operations O&M was $7M (4%) over budget due to higher transportation costs, shifting crew work from capital projects at the end of the year, and unrealized savings.<br>• SEMCO Operations implemented enhancements in work leveling, effective staffing, and reduced after-hours leak repair resulting in a YOY 20% reduction in overtime, as well as an idling reduction program that saved $130k. SEMCO's overall 2023 Operation's budget came in 5% under 2022 and 8% ($1.5M) under budget. |

No change from Feb 12th HRCC meeting

# Utilities 2023 Scorecard Results Details (pg 3 of 5)

| *Value Driver* | | | Success Measures | Exceeds Measures | *Wgt* | *Result* | *Mltplr* | *Mltplr %* | *Achievements (Value Delivered or to be Delivered)* |
|---|---|---|---|---|---|---|---|---|---|
| Customer Experience (15%) | Efficient Delivery of Service | Increase Utilization of Lower Cost Service Channels | Launch new web & mobile services and Deliver Approved 2023 budgets | Redirect 10% of WGL agent assisted non-emergency calls to lower cost channels for sustainable savings in 2024 & beyond | 10% | **Success+** | 1.25x | 12.5% | **This year, we drove 2.83M self-service transactions, an 8% increase over 2022. We saw an accompanying 4.5% reduction in call volume. We project that this reduction in call volume will continue and have a positive impact on 2024 call center contract negotiations. The current contract cost is $10.5M (compared to $17.5M in 2022).**<br>WGL launched new web & mobile services (**Success**)<br>• Deliver approved budgets, coming in almost $5M under budget (**Success**)<br>• Self-service transactions increased 8% in 2023, resulting in a 4.5% decrease in agent-assisted calls even with the surge of high bill call in Q1. (**Success++**) |
| | Meet Customer Expectations | Call Center Performance | • Lower SEMCO Avg Speed to Answer by 15%<br>• Maintain WGL performance with 70% of calls w/in 30 secs = <60 seconds avg wait | Identify partners & design pilot to deliver affordable net zero energy homes that feature natural gas | 5% | **Success+** | 1.25x | 6.25% | **In addition to achieving the targeted Call Center performance, we were also able to finalize the Net Zero Home pilot design and the HomeServe service agreement. The HomeServe agreement is projected to deliver incremental revenue ($500k in 2024 upon signature of agreement), with > $1M per year incremental projected by Year 3.**<br>• SEMCO 47 second ASA significantly better than target (**Success++**)<br>• WGL Service Level – Non-Emergency was 80.11% significantly better than target (**Success++**)<br>• WGL Average Wait Time of 91 seconds was unfavorable to the 60 second target (**Does Not Meet**)<br>• Identified partners for the development of a Net Zero home offering in Q4 2024. In discussion re: deal terms with a large developer in Montgomery County. **(Exceeds)**<br>• WGL completed HomeServe business case; received President and Leadership team approval to implement HomeServe as a beyond the meter program. Finalizing regulatory approach and revenue treatment. Remain on target for Q1 2024 launch. |

No change from Feb 12th HRCC meeting

# Utilities 2023 Scorecard Results Details (pg 4 of 5)

| Value Driver | | | Success Measures | Exceeds Measures | Wgt | Result | Mltplr | Mltplr % | Achievements (Value Delivered or to be Delivered) |
|---|---|---|---|---|---|---|---|---|---|
| Regulatory & Public Policy (25%) | Revenue Growth | Execute Rate Cases | Successfully deliver $45MM in incremental revenue from rate case filings | One Non-Precedential Decision Received in DC Case | 15% | **Partial Success** | 0.75x | 11.25% | **WGL executed rate cases in all three jurisdictions this year, delivering 73% of the targeted 2023 revenues despite ongoing delays in the District and disappointing results in Maryland**.<br>• VA Commission Final Order was issued on August 29, 2023, approving the Rate Case Settlement Agreement that includes $73MM revenue increase ($8MM favorable to 2023 Budget).<br>• MD rate case order received timely in December granting a disappointing revenue increase of $10MM that includes STRIDE surcharge roll-in and provides for STRIDE surcharge headroom in 2024.<br>• DC order received in December grants revenue increase of $24.6MM (includes PIPES transfer from surcharge of $4.7MM). We were successful in avoiding a hearing for the case and achieved the opening of a ratemaking NOI.<br>• While neither the CART or Decoupling were approved, the PSC did approve our Non-Labor Inflation Adjustment for the first time, added $1.55M in revenue. |
| | | Execute APRP Extensions | Extend DC & MD APR Programs | APR Programs Approved at Level Needed to Achieve Safety, Reliability, Customer & Emerging Ecosystem Goals | 10% | **Partial Success** | 0.75x | 7.5% | **The Maryland PSC approved the extension of the STRIDE program for five years at similar levels to the previous extension.**<br>• The MD PSC approved the Law Judge Order that authorizes 2/3rds of Company ask, or $332MM over 5 years, which is similar to our previous extension.<br>• While the DC order on the PIPES 3 program is not expected until mid 2024, the Company also filed a request for a 12-month extension of PIPES 2 on November 6, 2023, for $57.3MM. Unfortunately, that has not yet been decided. |

No change from
Feb 12th HRCC meeting

# Utilities 2023 Scorecard Results Details (pg 5 of 5)

| *Value Driver* | | | Success Measures | Exceeds Measures | *Wgt* | *Result* | *Mltplr* | *Mltplr %* | *Achievements (Value Delivered or to be Delivered)* |
|---|---|---|---|---|---|---|---|---|---|
| Emerging Ecosystem (10%) | Lower-Carbon Gas Supply | RNG Procurement | PWC Landfill Interconnection Regulatory Filing by Q3 & Two RNG Agreements | PWC Landfill Filing Approval & Four RNG Agreements | 5% | **Success+** | 1.25x | 6.25% | **In addition to the $4M/yr. EBITDA to be generated by finalizing the Prince William County Landfill RNG Interconnection, the SEMCO RNG interconnects will add $185,000 annually in incremental transportation revenue.**<br>• The Prince William County Landfill RNG Interconnection transaction with Opal Fuels was approved by the WGL and AltaGas Board of Directors on September 26th. The final commercial agreements were signed / executed by WGL and Opal Fuels on October 20th. The Regulatory Filing was submitted to the VA SCC in December.<br>• WGL & SEMCO finalized 4 additional RNG agreements in 2023, including two WGL MOUs (CleanBay Renewables and the University of Maryland), plus two SEMCO interconnections (Zeeland Landfill and Spring Creek). Additionally, WGL responded to the Prince Georges County Landfill RNG RFI for the installation and operation of RNG infrastructure, including the above-mentioned MOU with the University of Maryland for offtake of the supply. |
| | Business Development | New Markets | DOE Clean Hydrogen Hub Program Application Submitted | MAHH Selected as DOE Regional Hydrogen Hub or Secure Agreements that deliver $6M of Data Center EBITDA by 2027 | 5% | **Success+** | 1.25x | 6.25% | **WGL took a leading role in the development of the Mid-Atlantic Hydrogen Hub DOE grant application, and while no DOE funding was awarded, the Company is now well positioned for future opportunities. Additionally, the data center market continues to heat up with three design studies underway for 2024 that could generate >$30M EBITDA annually.**<br>• Coordinated a successful nomination and approval of key interstate highways in Virginia as Hydrogen Alternative Fuel Corridors by the Federal Highway Administration and Joint Office of Energy and Transportation, opening up federal funding opportunities for state and county authorities to seek hydrogen fueling infrastructure grants.<br>• WGL has taken key steps in pursuing hydrogen opportunities in both Transportation and Data Centers market.<br>• Supported Arlington County Transit and Prince William County Transit Authorities in Virginia for proposing hydrogen fuel cell electric bus pilots to their respective Boards and grant funding opportunities.<br>• Contracted engineering design assessments with two data centers, Aligned and PointOne, for a combined load of over 100M therms annually and projected EBITDA of $3M-$7M, and contracted with Quantum loophole for a third engineering design assessment for gas to support 300 MW of power generation. |

# Appendix – WG Union Annual Bonus Plan

AltaGas

(for WG Board approval)

No significant change from Feb 12th HRCC meeting

# 2023 WG Union Employees Annual Bonus Plan (ABP)

Washington Gas union employees are eligible to receive bonus payments annually under the WG ABP plan.

ABP awards are tied to corporate performance with discretion applied to develop the final ABP award guidance (% awarded).

Individual ABP % awards for employees are then determined based on their performance rating. The starting point is as follows per union CBA:

- Meets (Success) Requirements: 3% x ABP award factor
- Exceeds Requirements: Meets Requirements guidance x 1.5
- Partial Meets / Does Not Meet: 0%

Review - 2023 ABP award guidance multiplier is proposed at 1.0x target based on WG corporate performance and non-union management results.

- Proposed guidance (% award) by performance rating for employees under the plan is provided below
- 2023 ABP cost is ~C$2.4 MM (~US$1.8 MM) for 716 employees (2021 – US$1.7 MM for 739 employees)
- Approval of the 2023 ABP will be presented to the WGL Board at the March 1st meeting

| Rating | | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|---|---|
| WG Corporate Factor / Utilities Multiplier | | 1.2x | 1.075x | 0.9x | 1.29x | 1.3x | 1.31x | 1.0x |
| ABP Factor | | 1.0x | 1.0x | 0.9x | 1.1x | 1.0x | 1.0x | **1.0x** |
| Union | - Exceeds | 4.50% | 4.50% | 4.05% | 4.95% | 4.50% | 4.50% | 4.50% |
| | - Meets / Success | 3.00% | 3.00% | 2.70% | 3.30% | 3.00% | 3.00% | 3.00% |
| | - Partial / Does Not Meet | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |



- 2023 FX rate (USD/CAD): 1.35

# 2023 WG Union Employees Annual Bonus Plan

Formal Case No. 1180

## Corporate Factor Considerations



(for WG Board approval)

Exhibit OPC (B)-54
Formal Case No. 1180
Witness: Bion Ostrander
Page 13 of 21

No change from
Feb 12th HRCC meeting

| | Utilities (WGL & SEMCO) | | | | | | WG ABP | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Priority – Measure | Wgt | Outlook | | Multiplier | | Wgt | Mltplr | Mltplr % | Justification |
| **CSR** (20%) | Safety – TRIF & MVIR | 10% | ● (yellow) | Partial Success | 0.75x | 7.5% | 10% | **1.0x** | 10% | ABP multiplier reflects WG safety metrics |
| | People – Talent & Culture Roadmap | 10% | ● (green) | Success | 1.0x | 10% | 10% | **1.0x** | 10% | Utilities multiplier reflects non-union initiative |
| **Operations** (30%) | Efficient Deployment of Capital – Capital Portfolio Exec | 20% | ● (green) | Success+ | 1.25x | 25% | 20% | **1.0x** | 20% | Utilities multiplier reflects non-union initiative |
| | Operational Excellence – Business Transformation | 10% | ● (yellow) | Partial Success | 0.75x | 7.5% | 10% | **1.0x** | 10% | Utilities multiplier reflects non-union initiative |
| **Customer Experience** (15%) | Efficient Delivery of Service – Increase Utilization | 10% | ● (green) | Success+ | 1.25x | 12.5% | 10% | **1.0x** | 10% | Utilities multiplier reflects non-union initiative |
| | Meet Customer Expectations – Call Center Performance | 5% | ● (green) | Success+ | 1.25x | 6.25% | 5% | **1.0x** | 5% | Utilities multiplier reflects non-union initiative |
| **Regulatory & Public Policy** (25%) | Revenue Growth – Execute Rate Cases | 15% | ● (yellow) | Partial Success | 0.75x | 11.25% | 15% | **1.0x** | 15% | Utilities multiplier reflects non-union initiative |
| | Revenue Growth – Execute APRP Extensions | 10% | ● (yellow) | Partial Success | 0.75x | 7.5% | 10% | **1.0x** | 10% | Utilities multiplier reflects non-union initiative |
| **Emerging Ecosystem** (10%) | Lower-Carbon Gas Supply – RNG Procurement | 5% | ● (green) | Success+ | 1.25x | 6.25% | 5% | **1.0x** | 5% | Utilities multiplier reflects non-union initiative |
| | Business Development – New Markets | 5% | ● (green) | Success+ | 1.25x | 6.25% | 5% | **1.0x** | 5% | Utilities multiplier reflects non-union initiative |
| **TOTAL** | | 100% | | | 1.00x | 100% | **100%** | **1.0x** | **100%** | |

# Short-Term Incentive Plan (STIP)

## Your STIP at AltaGas (Utilities Employees)

AltaGas provides a total rewards package to recognize you for your contributions to our company's success. Your total rewards package at AltaGas includes a competitive base salary, benefits to support you and your family, a supportive work environment, and diverse career opportunities to foster your growth with AltaGas.

Your total rewards package also includes incentive compensation in the form of the **STIP** which rewards the achievement of short-term goals and allows us to differentiate pay based on performance.

This STIP-at-a-Glance document outlines:

- Our plan and its key elements,
- The formulas used to calculate your awards,
- The mechanics of how it works, and
- Provides answers to some frequently asked questions.

### STIP Overview

The STIP provides an opportunity for you to earn a cash award to reward you for both your individual performance and AltaGas' organizational performance against business objectives.

More specifically, the formula used to calculate your STIP award is based on the following:

- **Organizational Performance**
- **Individual Performance**

These plan components have different weightings depending on your level. Weightings are balanced to reflect where each level is expected to have the most impact with senior levels weighted more heavily on organizational scorecard results and junior levels weighted more heavily on individual performance.

## What's Changing in 2024 and Why?

As our organization continues to evolve, we want to make it easier for you to understand how you are rewarded for the contributions you make to AltaGas while we continue to strengthen our pay-for-performance culture. That's why we are reviewing our compensation and rewards structure across the organization, starting with our STIP.

With this goal in mind, we are introducing the following changes:

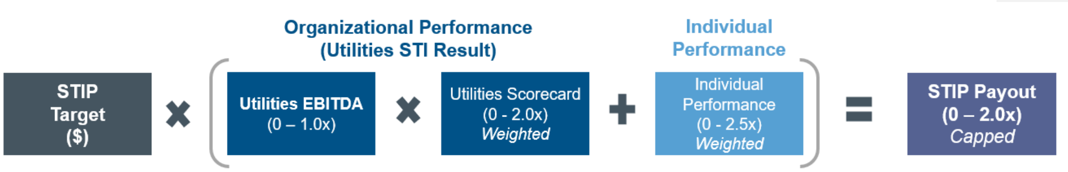
- **Introducing new scorecards:** we have new scorecards for Corporate, Midstream, and Utilities – each made up of four components. The Corporate and Midstream scorecards track Financial, Safety, ESG, and Growth metrics while the Utilities scorecard tracks Operations, Safety, ESG, and Growth metrics.
  - Notably, Utilities now has its own unique scorecard which is used to calculate STIP payouts for Utilities employees.
- **Moving to an additive plan:** our new STIP uses an additive formula, meaning the multiplier applied to your STIP target is comprised of our organizational results, based on Utilities EBITDA and our new Utilities scorecard, *plus* your Individual Performance results. These two components have different weightings depending on your level.
- **New plan maximum:** all plans are capped at 200% of target. However, you can still earn up to 250% on the individual performance component.

## Plan Eligibility

All permanent, non-union salaried AltaGas employees qualify for the STIP.

## How The Plan Works

STIP payouts are calculated as follows with a maximum payout of up to 200% of the STIP target.



**The additive plan in action**

AltaGas' additive STIP gives you the opportunity to obtain a payout based on strong individual performance – even if AltaGas doesn't fully meet organizational objectives. It also allows us to provide a clear weighting on organizational performance and individual performance and adjust these as appropriate based on role level.

### *Understanding the Organizational Performance Component*

The organizational performance component of our plan formula is based on the Utilities performance result. This represents the Utilities business unit's EBITDA for the year, as well as our Utilities scorecard which consists of four different KPIs that are weighted as follows:

| KPI | Weight |
|---|---|
| Operations | 50% |
| Safety | 20% |
| ESG | 10% |
| Growth | 20% |

### *Understanding the Individual Performance Component*

Your individual performance component is based on the performance rating set by your manager at year-end, which is associated with a specific multiplier.

## Utilities STIP: SVP and VP-Level Roles

### *Plan Component Weightings*

As noted above, the weightings assigned to organizational performance and individual performance depend on the level and are balanced to reflect where each level is expected to have the most impact. For Utilities SVP and VP-level roles, the component weighting is 75% organizational performance and 25% individual performance.

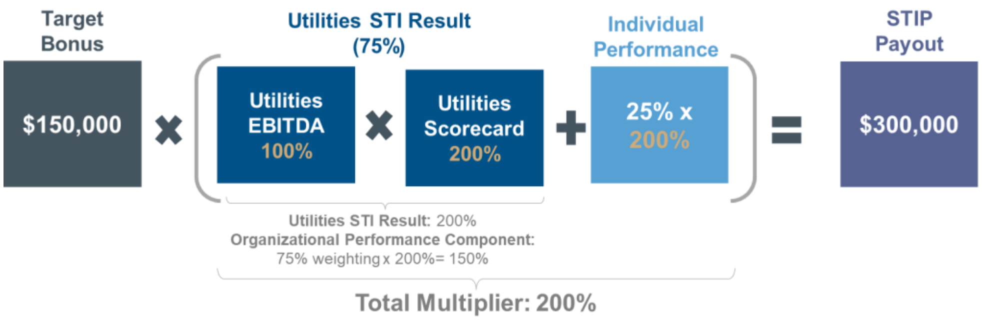
| 75% Utilities STI Result | 25% Individual |
|---|---|

### *Illustrative Example*

An AltaGas Utilities SVP has a target bonus opportunity of **$150,000**. Based on their role, their performance metric weightings are **75%** organizational performance and **25%** individual performance.

The employee significantly surpassed expectations this year, and their individual performance rating is [TBC: "Exceeds"]. As such, their manager deems their individual performance multiplier to be **200%**. AltaGas Utilities also performed well this year and achieved an overall **200%** Utilities Performance Result.

The employee's STIP payout is calculated as follows, and they receive a STIP payout of **$300,000**.




## Utilities STIP: Director and Manager-level Roles (including Senior Directors and Senior Managers)

### *Plan Component Weightings*

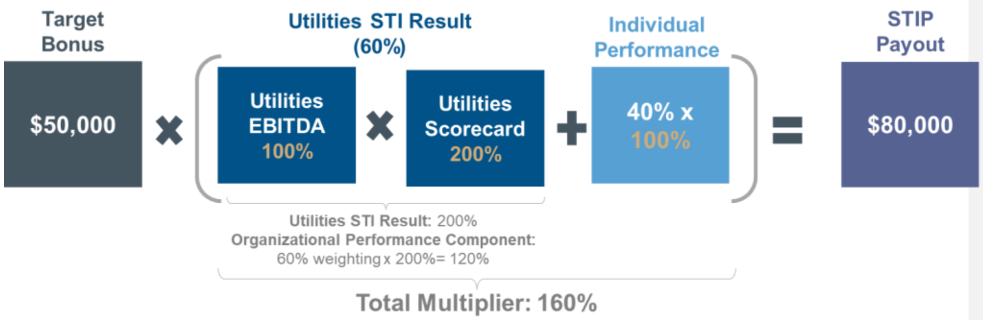
As noted above, the weightings assigned to organizational performance and individual performance depend on the level and are balanced to reflect where each level is expected to have the most impact. For Utilities Director and Manager-level roles, the component weighting is 60% organizational performance and 40% individual performance.


### *Illustrative Example*

An AltaGas Utilities Director has a target bonus opportunity of **$50,000**. Based on their role, their performance metric weightings are **60%** organizational performance and **40%** individual performance.

The employee met expectations this year, and their individual performance rating is As such, their manager set their individual performance multiplier at **100%**.
AltaGas Utilities performed very well this year and achieved an overall Utilities Performance Result of **200%.**

The employee's STIP payout is calculated as follows, and they will receive a STIP payout of **$80,000**.




## Utilities STIP: Professional-Level Roles

### *Plan Component Weightings*

As noted above, the weightings assigned to organizational performance and individual performance depend on the level and are balanced to reflect where each level is expected to have the most impact. For Professional-level roles, the component weighting is 50% organizational performance and 50% individual performance.

| 50% Utilities STI Result | 50% Individual |
|---|---|

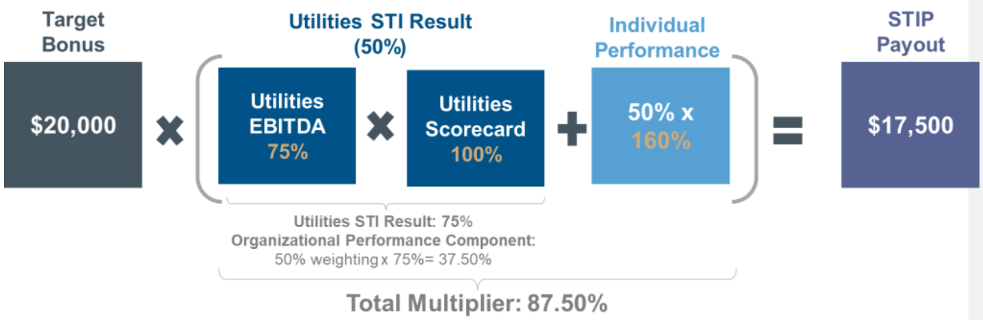
### *Illustrative Example*

An AltaGas Utilities Professional-level employee has a target bonus opportunity of **$20,000**. Based on their role, their performance metric weightings are **50%** organizational performance and **50%** individual performance.

The employee received an individual performance rating of [TBC: "Success"] and an individual performance multiplier of **160%**. AltaGas Utilities underperformed slightly this year and achieved an overall Utilities Performance Result of **75%.**

**Commented [NL2]:** Note to AltaGas reviewers: may need to be updated pending new rating scale

The employee's STIP payout will be calculated as follows, and they receive a STIP payout of **$17,500**.




## Utilities STIP: Para-Professional-Level Roles

Para-professional-level roles are individual contributors within the organization who provide support or service (administrative or clerical), or roles operating in a "hands on" environment in support of daily business activities (e.g., technical, production or craft levels). Examples of para-professionals include clerical or administrative staff or trade jobs.

### *Plan Component Weightings*

As noted above, the weightings assigned to organizational performance and individual performance depend on the level and are balanced to reflect where each level is expected to have the most impact. For Utilities Para-professional-level roles, the component weighting is 40% organizational performance and 60% individual performance.

| 40% Utilities STI Result | 60% Individual |
|---|---|

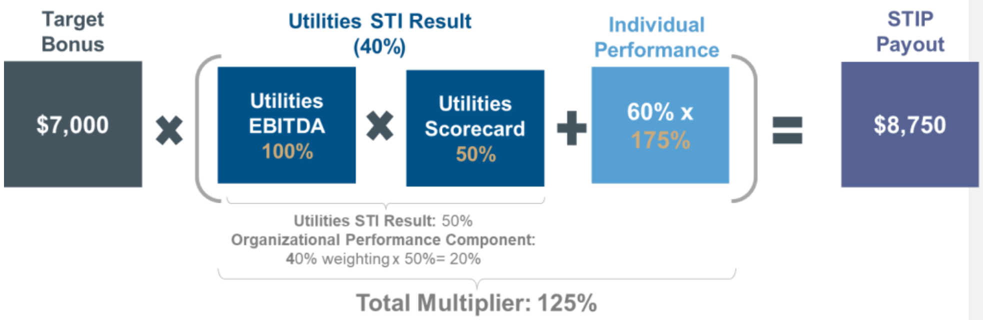
### *Illustrative Example*

An AltaGas Utilities Para-professional-level employee has a target bonus opportunity of **$7,000**. Based on their role, their performance metric weightings are **40%** organizational performance and **60%** individual performance.

The employee received an individual performance rating of [TBC: "Success++"] and an individual performance multiplier of **175%**. AltaGas underperformed this year and achieved an overall Utilities Performance Result of **50%.**

**Commented [NL3]:** Note to AltaGas reviewers: may need to be updated pending new rating scale

The employee's STIP payout will be calculated as follows, and they receive a STIP payout of **$8,750**.




*** End of variable text: FAQs will be consistent across versions***

## Frequently Asked Questions (FAQs)

**Q1. Why is the STIP changing?**
Our STIP has been, and continues to be, an important part of our total rewards package. As we continue to evolve as an organization, we are also evolving the ways in which we recognize and reward our employees. The goal of this evolution is to strengthen our pay-for-performance culture by increasing consistency, simplicity, and transparency for our employees, introducing a largely consistent framework across the business, and rewarding employees in the areas where they have the most impact. We are also more closely aligning our STIP to market practices.

**Q2. Why are we modifying our scorecards?**
By introducing simplified and unique scorecards for Utilities, Midstream and Utilities, which include metrics specific to each division, we are adjusting how we are measuring collective performance and changing the formula used to calculate the STIP. This type of formula is prevalent among our peers and allows us to link performance and the segment of the business to which employees have the greatest line-of-sight and ability to impact results.

**Q3. What is the benefit of moving to an additive plan?**
Moving to an additive plan gives employees an opportunity to obtain a payout based on their individual performance regardless of organizational results. The two components – organizational performance (comprised of Utilities EBITDA and Utilities scorecard elements) and individual performance – will have different weightings depending on the employee's level and provide them with more clarity on performance outcomes and rewards.

**Q4. How are the component weightings in the new plan formula determined?**
The weightings assigned to each plan component depend on employees' level and are balanced to reflect where each level is expected to have the most impact and control. Senior roles, which have increased line-of-sight and impact on business results, are weighted more heavily on organizational performance. Junior levels are weighted more heavily on individual performance.

**Q5. When does the new plan take effect?**
The new STIP took effect January 1, 2024.

**Q6. Is there any action I need to take?**
No immediate action is required on your part. We ask that you take the time to review this STIP-at-a-Glance document and get to know the changes. You will also receive your 2024 STIP Letter in March outlining your STIP payout opportunity for 2024.

**Q7. Will my 2024 payout be based on the old plan or the new STIP?**
Your payout for 2024 will be based on the new STIP.

**Q8. Who do I contact if I have any questions about the new STIP?**
If you have any questions, reach out to your People Manager or to your HRBP.

*AltaGas reserves the right to change, amend, or terminate this plan at any time. This document is intended to provide a summary of the Short-Term Incentive Plan at AltaGas for eligible employees. The full provisions of this plan are contained in the official plan documents. If there are any discrepancies between the official plan documents and this statement, the terms and conditions of the plan documents will apply in all cases. Examples provided are for illustrative purposes only. Special rules and tax implications may apply if you reside outside of Canada. Please work with a qualified tax advisor to determine tax considerations and impacts.*

Exhibit OPC (B)-55
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 10

QUESTION NO. 10-5

**Q.** **Short-Term Incentive Expense True-Up.** The Direct Testimony of Witness Smith (10:7-11) and 11:4-14) states that short-term incentive expense is included in this rate case and has not been removed, and Adjustment No. 5 (Exhibit WG (D)-5, page 14) appears to include these short-term incentive expenses although the specific amounts are not identified in this payroll annualization adjustment. Please address the following:

a. Provide the amount of per book short-term incentive expense by account number for each of the calendar years 2019, 2020, 2021, 2022, 2023 and the test year end March 31, 2024, (before any rate case adjustments for the test period), and identify all short-term incentive expense that has been allocated/assigned from AltaGas, ASUS, SEMCO, and other affiliates to WGL by account number, and identify all WGL-specific long-term incentive expense by account number.

b. Regarding (a) above, explain if there are any periods where WGL (or AltaGas) has shifted compensation from short-term incentive (at-risk pay) to base salary compensation, or shifted base salary compensation to short-term incentive, and explain the reasons for this shift in compensation policy.

c. Explain if the short-term incentive expense for the test year end March 31, 2024, has been adjusted to reflect an adjustment of accrued amounts for the subsequent actual amounts paid (either a true-up of the 2023 calendar year short-term incentive expense accrual included in the test year end March 31, 2024, or any other type of true-up). Explain why this is or is not reasonable based on WGL's adjustment to short-term incentive expense in the prior rate case, Formal Case No. 1169.

d. Regarding (c) above, provide the amount of true-up for the per book test year end March 31, 2024, short-term incentive expense regardless of whether WGL agrees with this approach.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.**

a. Please see Attachment No. 1 for per book short-term incentive expense by account number for the calendar years 2019, 2020, 2021, 2022, 2023 and the test year end March 31, 2024, for WGL and SEMCO. Please refer to Attachment No. 2 for short-term incentive compensation expense from ALA that is included in the cost of service.

b. There are no periods where Washington Gas has shifted pay between incentive compensation and base pay.

c. STI expense is accrued throughout the performance year and trued-up annually after the STI payout occurs in March. The test year in this case includes a true-up for the 2023 performance year in March 2024 and a true-up for the 2022 performance year in April 2023. No rate making adjustment was made to remove these true-ups from the test year.

d. In the test year, there was a total true-up of short-term compensation expense of ($125,070), composed of a $21,196 increase in expense that occurred in April 2023 for the performance year 2022 and ($146,266) decrease to expense that occurred in March 2024 for the 2023 performance year.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

**FOLLOW-UP DATA REQUEST** **12/2/2024**

**Q.** WGL's response to OPC 10-5, Attachment 1, shows short-term incentive (STI) compensation costs that fluctuate significantly in certain years from calendar years 2019 to 2023, and test year end March 31, 2024. Also, certain incentive expense for accounts 920431 and 920432 refer to "ROE Gross" or "ROE Distr." Please address the following:

a. Per Attachment 1, explain why there were STI expenses for account 920401 and 920402 in calendar years 2019 through 2022, but not for subsequent calendar years or the test period end March 31, 2024. Provide copies of Company policy or incentive plans policy that altered these STI costs and explain if these related management/executive employees are no longer eligible for STI or if these employees' related STI expense are now recorded in other expense accounts. Please also identify the STI costs included in other expense accounts for these employees.

b. Per Attachment 1 and (a) above, explain why STI costs gradually increased from calendar years 2019 to 2021, and then increased significantly in 2022, and then declined to STI cost levels that represented more gradual increases over the December 2021 levels. Identify specific Value Drivers (and their associated performance metrics) that primarily contributed to the increases in STI costs and the targeted and actual results for these Value Driver performance metrics that caused the change in STI costs for these years.

c. Regarding (b) above, explain how COVID-19, results from rate cases in D.C. and other jurisdictions, along with other factors besides Value Drivers, impacted incentive cost changes from calendar year 2019 to 2023, and for test year end March 31, 2024.

d. Per Attachment 1, explain why incentive expense for accounts 920431 refer to "ROE Gross" and why account 920432 refers to "ROE Distr.". Explain if the "Return on Equity" results for WGL (and/or SEMCO) was a specific target or driver for these STI costs, and provide the related ROE results for the related years for WGL, SEMCO, and other affiliates/entities used in determining the amount of these STI costs.

e. Regarding (d) above, refer to the specific Value Driver Scorecard performance metric for each year that includes these "ROE" measures used for determining or impacting the amount of STI costs.

f. Regarding (d) and (e) above, provide the calculation of the related "ROE" for each of the calendar years 2018 to 2023, and test year end March 31, 2024, that impacted the determination of the STI costs for each year.

**WASHINGTON GAS'S FOLLOW-UP RESPONSE** 12/9/2024

**A.**

a. Effective 1/1/2022, the Company's prior Annual Bonus Plan ("ABP") and Short-term Incentive Compensation ("STIC") plans for management employees were combined into a single plan called the Short-term Incentive Plan ("STIP"). Consequently, the recording of short-term incentive compensation expense for management was consolidated into existing account 920431 and the distribution of gross expense to capital and affiliate accounts to existing account 920432. At that time, the Company discontinued using accounts 920401 and 920402. There are not STI expenses recorded in accounts other than what is reflected in OPC Data Request 10-5 Attachment No. 1.

b. STI expense varies depending on numerous factors including headcount, company performance and organizational structure (i.e. job levels). As each of those may change year to year, total STI expense will also fluctuate accordingly. Additionally, effective with the 2022 performance year, STI targets percentages were increased. Furthermore, the 2022 performance year true-up that occurred in Q1 2023 (outside the test year in this case) impacted the 2023 calendar year STI expense total.

c. The Value Drivers in the Utilities STI scorecard determine the STI pool to be distributed to employees. To the extent factors such as COVID-19 or rate case outcomes affected the Value Drivers, that impact would carry through to the STI pool.

d. These are legacy account names and the expense recorded in these accounts is for the ABP and STIC for 2019-2021 and for the STIP from 2022 forward. The 2019 scorecard included a "Utility ROE" target. There were no ROE Value Drivers in the scorecards for 2020-2023. Refer to the 2021-2023 Value Drivers provided in the Company's response to OPC Data Request 10-3.

e. Refer to part (d).

f. For 2019, the "Utility ROE" target on the scorecard was not met. This metric was rated at 10% of the total scorecard and not meeting it resulted in a 10% reduction of the STI target pool for that year.

CO-SPONSOR: Tracey M. Smith (as to part (a))
Director, Regulatory Accounting & Financial Reporting

CO-SPONSOR: Tom Burgum (as to parts (b) and (c))
Senior Director Total Rewards & HR Operations • VP Utilities HR

CO-SPONSOR: Jim Steffes (as to parts (d), (e) and (f))
Senior VP, Regulatory Affairs

Washington Gas Light Company
District of Columbia Jurisdiction

**Short-Term Incentive Compensation**

TME December 2019 - 2023 and TME March 2024

| Account | Description | Dec 2019 | Dec 2020 | Dec 2021 | Dec 2022 | Dec 2023 | Mar 2024 |
|---|---|---|---|---|---|---|---|
| WGL Cost | | | | | | | |
| 920401 | Exec IncentiveProgram-Gross | 5,615,327 | 4,157,877 | 660,812 | - | - | - |
| 920402 | Exec Incentive Progr-Distr | (877,563) | (78,471) | (76,406) | - | - | - |
| 920431 | Employee Incentive - ROE Gross | 6,581,604 | 7,746,302 | 9,111,833 | 17,114,369 | 12,250,938 | 11,612,309 |
| 920431 | Employee Incentive - ROE Gross - SEMCO | - | - | 144,885 | 169,251 | 63,952 | 63,991 |
| 920432 | Empl Incentive-ROE Distr | (1,934,068) | (1,260,608) | (1,809,490) | (3,876,150) | (3,067,014) | (2,656,847) |
| 920441 | ABP Union Utility Gross | - | - | 2,211,710 | 1,612,614 | 1,266,422 | 3,373,243 |
| 417902 | Incentives (Utility Other) | 74,840 | 11,360 | 27,220 | 12,056 | 12,354 | 10,391 |
| 107100 | Gas Plant | 1,238,529 | 1,040,945 | 1,612,266 | 3,498,358 | 2,749,653 | 2,416,185 |
| 146000 | Interunit-Receiv/Payable-Net | 1,498,263 | 286,774 | 246,410 | 365,735 | 305,007 | 257,249 |
| Expense Allocaiton Factor (Comp A&G) | | 19.27% | 21.01% | 19.73% | 18.45% | 18.51% | 19.54% |
| Capital Allocation Factor (Net Rate Base) | | 17.60% | 17.98% | 18.19% | 18.32% | 18.57% | 19.08% |
| DC Jurisdictional Amounts | | | | | | | |
| 920401 | Executive STI (Gross) | 1,082,299 | 873,379 | 130,393 | - | - | - |
| 920402 (Note 1) | Executive STI (Distribution) | (169,142) | (16,483) | (15,076) | - | - | - |
| 920431 | Employee Incentive - ROE Gross | 1,268,539 | 1,627,142 | 1,797,965 | 3,157,464 | 2,267,294 | 2,269,140 |
| 920431 | Employee Incentive - ROE Gross - SEMCO | - | - | 28,589 | 31,225 | 11,836 | 12,504 |
| 920432 (Note 1 and 2) | Non Executive STI (Distribution) | (372,773) | (264,796) | (357,052) | (715,119) | (567,615) | (519,170) |
| 920441 | ABP Union Utility Gross | - | - | 436,419 | 297,514 | 234,378 | 659,159 |
| 417902 (Note 1) | Incentives (Utility Other) | 14,425 | 2,386 | 5,371 | 2,224 | 2,286 | 2,031 |
| 107100 (Note 1) | Gas Plant | 217,949 | 187,208 | 293,234 | 640,915 | 510,746 | 461,049 |
| 146000 (Note 1) | Interunit-Receiv/Payable-Net | 288,775 | 60,238 | 48,622 | 67,475 | 56,448 | 50,269 |
| Total Per Book O&M STI Expense (DC): Sum of 920 accounts | | $ 1,808,924 | $ 2,219,241 | $ 2,021,238 | $ 2,771,085 | $ 1,945,892 | $ 2,421,634 |

Note (1): For the DC jurisdictional amounts, the expense distribution accounts (920402 and 920432) do not net to zero with the accounts to which the expense is distributed (417902, 107100, and 146000) because of an assumed allocation to CWIP which is not included in this analysis.
Note (2): SEMCO amount distributed to other affiliates is included in account 920432

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 10

QUESTION NO. 10-5

**Q.** **Short-Term Incentive Expense True-Up.** The Direct Testimony of Witness Smith (10:7-11) and 11:4-14) states that short-term incentive expense is included in this rate case and has not been removed, and Adjustment No. 5 (Exhibit WG (D)-5, page 14) appears to include these short-term incentive expenses although the specific amounts are not identified in this payroll annualization adjustment. Please address the following:

a. Provide the amount of per book short-term incentive expense by account number for each of the calendar years 2019, 2020, 2021, 2022, 2023 and the test year end March 31, 2024, (before any rate case adjustments for the test period), and identify all short-term incentive expense that has been allocated/assigned from AltaGas, ASUS, SEMCO, and other affiliates to WGL by account number, and identify all WGL-specific long-term incentive expense by account number.

b. Regarding (a) above, explain if there are any periods where WGL (or AltaGas) has shifted compensation from short-term incentive (at-risk pay) to base salary compensation, or shifted base salary compensation to short-term incentive, and explain the reasons for this shift in compensation policy.

c. Explain if the short-term incentive expense for the test year end March 31, 2024, has been adjusted to reflect an adjustment of accrued amounts for the subsequent actual amounts paid (either a true-up of the 2023 calendar year short-term incentive expense accrual included in the test year end March 31, 2024, or any other type of true-up). Explain why this is or is not reasonable based on WGL's adjustment to short-term incentive expense in the prior rate case, Formal Case No. 1169.

d. Regarding (c) above, provide the amount of true-up for the per book test year end March 31, 2024, short-term incentive expense regardless of whether WGL agrees with this approach.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.**

a. Please see Attachment No. 1 for per book short-term incentive expense by account number for the calendar years 2019, 2020, 2021, 2022, 2023 and the test year end March 31, 2024, for WGL and SEMCO. Please refer to Attachment No. 2 for short-term incentive compensation expense from ALA that is included in the cost of service.

b. There are no periods where Washington Gas has shifted pay between incentive compensation and base pay.

c. STI expense is accrued throughout the performance year and trued-up annually after the STI payout occurs in March. The test year in this case includes a true-up for the 2023 performance year in March 2024 and a true-up for the 2022 performance year in April 2023. No rate making adjustment was made to remove these true-ups from the test year.

d. In the test year, there was a total true-up of short-term compensation expense of ($125,070), composed of a $21,196 increase in expense that occurred in April 2023 for the performance year 2022 and ($146,266) decrease to expense that occurred in March 2024 for the 2023 performance year.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

Washington Gas Light Company
District of Columbia Jurisdiction

**Short-Term Incentive Compensation**

TME December 2019 - 2023 and TME March 2024

| Account | Description | Dec 2019 | Dec 2020 | Dec 2021 | Dec 2022 | Dec 2023 | Mar 2024 |
|---|---|---|---|---|---|---|---|
| WGL Cost | | | | | | | |
| 920401 | Exec IncentiveProgram-Gross | 5,615,327 | 4,157,877 | 660,812 | - | - | - |
| 920402 | Exec Incentive Progr-Distr | (877,563) | (78,471) | (76,406) | - | - | - |
| 920431 | Employee Incentive - ROE Gross | 6,581,604 | 7,746,302 | 9,111,833 | 17,114,369 | 12,250,938 | 11,612,309 |
| 920431 | Employee Incentive - ROE Gross - SEMCO | - | - | 144,885 | 169,251 | 63,952 | 63,991 |
| 920432 | Empl Incentive-ROE Distr | (1,934,068) | (1,260,608) | (1,809,490) | (3,876,150) | (3,067,014) | (2,656,847) |
| 920441 | ABP Union Utility Gross | - | - | 2,211,710 | 1,612,614 | 1,266,422 | 3,373,243 |
| 417902 | Incentives (Utility Other) | 74,840 | 11,360 | 27,220 | 12,056 | 12,354 | 10,391 |
| 107100 | Gas Plant | 1,238,529 | 1,040,945 | 1,612,266 | 3,498,358 | 2,749,653 | 2,416,185 |
| 146000 | Interunit-Receiv/Payable-Net | 1,498,263 | 286,774 | 246,410 | 365,735 | 305,007 | 257,249 |
| Expense Allocaiton Factor (Comp A&G) | | 19.27% | 21.01% | 19.73% | 18.45% | 18.51% | 19.54% |
| Capital Allocation Factor (Net Rate Base) | | 17.60% | 17.98% | 18.19% | 18.32% | 18.57% | 19.08% |
| DC Jurisdictional Amounts | | | | | | | |
| 920401 | Executive STI (Gross) | 1,082,299 | 873,379 | 130,393 | - | - | - |
| 920402 (Note 1) | Executive STI (Distribution) | (169,142) | (16,483) | (15,076) | - | - | - |
| 920431 | Employee Incentive - ROE Gross | 1,268,539 | 1,627,142 | 1,797,965 | 3,157,464 | 2,267,294 | 2,269,140 |
| 920431 | Employee Incentive - ROE Gross - SEMCO | - | - | 28,589 | 31,225 | 11,836 | 12,504 |
| 920432 (Note 1 and 2) | Non Executive STI (Distribution) | (372,773) | (264,796) | (357,052) | (715,119) | (567,615) | (519,170) |
| 920441 | ABP Union Utility Gross | - | - | 436,419 | 297,514 | 234,378 | 659,159 |
| 417902 (Note 1) | Incentives (Utility Other) | 14,425 | 2,386 | 5,371 | 2,224 | 2,286 | 2,031 |
| 107100 (Note 1) | Gas Plant | 217,949 | 187,208 | 293,234 | 640,915 | 510,746 | 461,049 |
| 146000 (Note 1) | Interunit-Receiv/Payable-Net | 288,775 | 60,238 | 48,622 | 67,475 | 56,448 | 50,269 |
| Total Per Book O&M STI Expense (DC): Sum of 920 accounts | | $ 1,808,924 | $ 2,219,241 | $ 2,021,238 | $ 2,771,085 | $ 1,945,892 | $ 2,421,634 |

Note (1): For the DC jurisdictional amounts, the expense distribution accounts (920402 and 920432) do not net to zero with the accounts to which the expense is distributed (417902, 107100, and 146000) because of an assumed allocation to CWIP which is not included in this analysis.
Note (2): SEMCO amount distributed to other affiliates is included in account 920432

# Washington Gas Light Company
# District of Columbia Jurisdiction

## Short-Term Incentive Compensation

TME December 2019 - 2023 and TME March 2024

### AltaGas MMF allocation to ASUS (US$MM) - Short-term Incentive

| | Dec 2019 | Dec 2020 | Dec 2021 | Dec 2022 | Dec 2023 | TME March 2024 |
|---|---|---|---|---|---|---|
| Total | $ 4.23 | $ 3.34 | $ 4.22 | $ 5.20 | $ 3.13 | $ 3.88 |
| WGL % of ASUS | 53.22% | 65.98% | 67.84% | 69.59% | 77.90% | 77.90% |
| WGL Amount | $ 2.25 | $ 2.20 | $ 2.86 | $ 3.62 | $ 2.44 | $ 3.02 |
| DC Factor (Comp A&G) | 19.27% | 21.01% | 19.73% | 18.45% | 18.51% | 19.54% |
| $ Applicable to DC | $ 0.43 | $ 0.46 | $ 0.56 | $ 0.67 | $ 0.45 | $ 0.59 |

Note - ALA labor costs are recorded on Washington Gas ledger in account 920188 which is allocated among the Washington Gas jurisdictions on the Composite Administrative & General factor.

Exhibit OPC (B)-56
Formal Case No. 1180
Direct Testimony of Bion Ostrander
PUBLIC VERSION

# Confidential Exhibit Omitted

Exhibit OPC (B)-57
Formal Case No. 1180
Direct Testimony of Bion Ostrander
PUBLIC VERSION

# Confidential Exhibit Omitted

Exhibit OPC (B)-58
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 10

QUESTION NO. 10-15

**Q.** **Uncollectible Expense.** WGL proposes Adjustment No. 1 (Exhibit WG (D)-5, pages 32 and 33, to increase Uncollectible Expense by $1,038,168. Please address the following:

a. Explain why WGL's Distribution Only per book Uncollectible Expense of $2,421,478 at December 31, 2021 (per prior rate case, Formal Case No. 1169, Adjustment No. 1.3 (Exhibit WG (D)-3, page 14 of 47)) nearly doubled when compared to the Distribution Only Uncollectible Expense of $4,531,435 in this rate case for the test year end March 31, 2024, per Adjustment No. 1 (Exhibit WG (D)-5, page 32 of 46). Provide all documentation and calculations to support WGL's position.

b. Per Adjustment No. 1 (Exhibit WG (D)-5, page 33 of 46), explain why it is reasonable to include the unusually large Net Charge Offs of $15.40 million from the March 2020 COVID-19 period as part of WGL's five-year average calculation of the charge-off ratio (when subsequent years net charge-off from 2021 to 2024 range from $2.10 million to $7.40 million).

c. For each of the years TME March 2020 to March 2024 used by WGL in its Uncollectible Expense Adjustment at Adjustment No. 1 (Exhibit WG (D)-5, page 33) provide the <u>monthly</u> amounts for the "Gas Charge Off", "Gas Collections", and "Net Charge Off."

d. Regarding (c) above, provide this same information for each of the months April 2024 through the most recent date of information available.

e. Per Adjustment No. 1 (Exhibit WG (D)-5, page 33 of 46), explain why Net Charge-Offs fluctuated from $15.40 million (March 2020), to $2.10M (March 2021), to $2.40 million (March 2022), to $7.40 million (March 2023), to $5.90 million in March 2024. Explain why Net Charge-Offs declined significantly the first two years after COVID-19 in 2021 and

2022, but then increased in years 2023 and 2024, provide all supporting documentation and calculations.

f. Per Adjustment No. 1 (Exhibit WG (D)-5, page 33 of 46), for each of the years TME March 2021, TME March 2022, TME March 2023, and TME March 2024, provide the ten largest "Net Charge-Offs" by account/customer, and explain the reasons for these significant Net Charge-Off and if they recurring or nonrecurring in nature.

g. Provide WGL's forecasted Distribution Only Uncollectibles Expense for December 31, 2024 and December 31, 2025, and provide the source document showing this forecasted amount and related supporting documentation.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.**

a. The Distribution Only Uncollectible Expense for the period prior to December 31, 2021, did not include the full effect of COVID-19. WGL was precluded from conducting charge-offs during this period. The assessment for the TME March 31, 2024, is based on WGL's ability to act in its capacity to fully conduct charge-offs.

b. WGL was precluded from conducting charge-offs during the COVID period. Had WGL been allowed to charge off during this period the five-year average would have included the Net Charge Offs of $15.40 million from the March 2020 COVID-19 period as part of WGL's five-year average calculation of the charge-off ratio.

c. Please refer to Attachment 1 for the requested information. Note that this information was provided in Exhibit WG (D)-5 DC Adj WP2, however, periods April 2020 – June 2020 were inadvertently excluded.

d. Please refer to Attachment 1 for the requested information.

e. The net charge-off increase in the TME March 2020 was related to a large write-off posted in December 2019 in the District of Columbia for accumulated hard access accounts. This action was previously discussed with the Commission. During the TME March 2021 and 2022 WGL was precluded from fully performing charge-offs. The charge offs for the TME March 2023 and 2024 are based on WGL's ability to act in its capacity to fully perform charge-offs.

f. Please refer to Attachment 1 for the requested information. These charge-offs occurred during the normal course of the charge-off process. Customers that are 90 days or more delinquent are subject to disconnection. Once the customer is disconnected, charge-offs are performed 120 days after final billing.

g. Please refer to Attachment 1 for the requested information.

SPONSOR: Katina Banks
Manager, Utility Revenue Accounting

tm1serv:GL Cube
Actual

| Period | Gas Charge Off | Gas Collections | Net Charge Off |
|---|---|---|---|
| A | B | C | D = B + C |
| Apr-2019 | 426,619.91 | (20,226.36) | 406,393.55 |
| May-2019 | 451,935.31 | (3,649.26) | 448,286.05 |
| Jun-2019 | 351,721.54 | (58,067.72) | 293,653.82 |
| Jul-2019 | 257,568.04 | (24,763.96) | 232,804.08 |
| Aug-2019 | 1,219,027.65 | (25,334.36) | 1,193,693.29 |
| Sep-2019 | 1,922,967.56 | (27,405.91) | 1,895,561.65 |
| Oct-2019 | 451,822.50 | (62,084.74) | 389,737.76 |
| Nov-2019 | 696,032.85 | (48,293.35) | 647,739.50 |
| Dec-2019 | 7,574,467.36 | (71,824.64) | 7,502,642.72 |
| Jan-2020 | 904,771.48 | (77,261.82) | 827,509.66 |
| Feb-2020 | 652,928.32 | (46,627.70) | 606,300.62 |
| Mar-2020 | 994,883.82 | (45,714.89) | 949,168.93 |
| | **15,904,746.34** | **(511,254.71)** | **15,393,491.63** |
| Apr-2020 | 315,802.36 | (292,932.50) | 22,869.86 |
| May-2020 | 280,076.18 | (24,418.44) | 255,657.74 |
| Jun-2020 | 241,070.49 | (42,668.51) | 198,401.98 |
| Jul-2020 | 77,558.34 | (48,162.39) | 29,395.95 |
| Aug-2020 | 747,234.24 | (61,398.80) | 685,835.44 |
| Sep-2020 | 199,428.05 | (23,709.66) | 175,718.39 |
| Oct-2020 | 249,781.78 | (28,374.61) | 221,407.17 |
| Nov-2020 | 173,698.40 | (22,110.29) | 151,588.11 |
| Dec-2020 | 254,049.15 | (25,889.95) | 228,159.20 |
| Jan-2021 | 209,429.34 | (19,227.85) | 190,201.49 |
| Feb-2021 | 281,416.97 | (18,220.64) | 263,196.33 |
| Mar-2021 | 185,945.53 | (37,872.13) | 148,073.40 |
| | **3,215,490.83** | **(644,985.77)** | **2,570,505.06** |
| Apr-2021 | 287,431.90 | (27,100.38) | 260,331.52 |
| May-2021 | 35,334.18 | (137,728.54) | (102,394.36) |
| Jun-2021 | 363,576.55 | (85,106.01) | 278,470.54 |
| Jul-2021 | 356,521.97 | (48,515.93) | 308,006.04 |
| Aug-2021 | 306,209.19 | (20,511.46) | 285,697.73 |
| Sep-2021 | 207,714.09 | (23,407.99) | 184,306.10 |
| Oct-2021 | 301,133.30 | (26,281.22) | 274,852.08 |
| Nov-2021 | 350,407.92 | (374,994.84) | (24,586.92) |
| Dec-2021 | 186,527.89 | (17,467.16) | 169,060.73 |
| Jan-2022 | 224,752.37 | (70,695.94) | 154,056.43 |
| Feb-2022 | 319,147.31 | (15,316.96) | 303,830.35 |
| Mar-2022 | 366,626.07 | (13,603.46) | 353,022.61 |
| | **3,305,382.74** | **(860,729.89)** | **2,444,652.85** |
| Apr-2022 | 323,253.53 | (16,065.43) | 307,188.10 |
| May-2022 | 305,643.23 | (160,101.29) | 145,541.94 |
| Jun-2022 | 330,760.35 | (183,435.74) | 147,324.61 |
| Jul-2022 | 392,840.17 | (24,567.56) | 368,272.61 |
| Aug-2022 | 361,208.45 | (28,692.02) | 332,516.43 |
| Sep-2022 | 627,889.72 | (34,897.70) | 592,992.02 |
| Oct-2022 | 551,223.46 | (47,917.26) | 503,306.20 |
| Nov-2022 | 661,560.40 | (45,461.95) | 616,098.45 |
| Dec-2022 | 1,134,662.00 | (45,512.06) | 1,089,149.94 |
| Jan-2023 | 867,024.28 | (32,281.63) | 834,742.65 |
| Feb-2023 | 1,446,817.27 | (80,886.49) | 1,365,930.78 |
| Mar-2023 | 1,127,690.35 | (74,489.55) | 1,053,200.80 |
| | **8,130,573.21** | **(774,308.68)** | **7,356,264.53** |
| Apr-2023 | 975,898.55 | (54,240.23) | 921,658.32 |
| May-2023 | 732,145.76 | (32,985.62) | 699,160.14 |
| Jun-2023 | 725,075.31 | (51,385.25) | 673,690.06 |
| Jul-2023 | 705,943.45 | (63,326.27) | 642,617.18 |
| Aug-2023 | 697,780.16 | (83,701.92) | 614,078.24 |
| Sep-2023 | 483,911.34 | (80,625.22) | 403,286.12 |
| Oct-2023 | 607,759.12 | (123,101.32) | 484,657.80 |
| Nov-2023 | 430,671.77 | (83,762.23) | 346,909.54 |
| Dec-2023 | 260,643.77 | (42,269.41) | 218,374.36 |
| Jan-2024 | 615,755.60 | (57,275.07) | 558,480.53 |
| Feb-2024 | 82,707.96 | (86,545.12) | (3,837.16) |
| Mar-2024 | 385,702.02 | (80,359.49) | 305,342.53 |
| | **6,703,994.81** | **(839,577.15)** | **5,864,417.66** |

tm1serv:GL Cube
Actual

| Period | Gas Charge Off | Gas Collections | Net Charge Off |
|---|---|---|---|
| A | B | C | D = B + C |
| Apr-2024 | 438,305.86 | (60,404.53) | 377,901.33 |
| May-2024 | 954,734.78 | (21,709.83) | 933,024.95 |
| Jun-2024 | 568,235.85 | (58,263.46) | 509,972.39 |
| Jul-2024 | 1,073,723.24 | (61,708.08) | 1,012,015.16 |
| Aug-2024 | 412,627.57 | (55,103.85) | 357,523.72 |
| Sep-2024 | 447,044.97 | (20,980.89) | 426,064.08 |
| | **3,894,672.27** | **(278,170.64)** | **3,616,501.63** |

| | CONTRACT ACCOUNT | Amount | TME Period |
|---|---|---|---|
| 1 | 120001848098 | $ 51,638.73 | 3/31/2021 |
| 2 | 120000192332 | $ 36,721.45 | 3/31/2021 |
| 3 | 120000404273 | $ 32,933.41 | 3/31/2021 |
| 4 | 120000198537 | $ 24,848.99 | 3/31/2021 |
| 5 | 120001704523 | $ 24,521.38 | 3/31/2021 |
| 6 | 120001245980 | $ 15,076.79 | 3/31/2021 |
| 7 | 110001104451 | $ 14,650.92 | 3/31/2021 |
| 8 | 110000087954 | $ 13,593.91 | 3/31/2021 |
| 9 | 110001365169 | $ 12,866.22 | 3/31/2021 |
| 10 | 120002345201 | $ 12,651.56 | 3/31/2021 |

| | CONTRACT ACCOUNT | Amount | TME Period |
|---|---|---|---|
| 1 | 110001315719 | $ 102,191.88 | 3/31/2022 |
| 2 | 110000469780 | $ 94,207.59 | 3/31/2022 |
| 3 | 120000095501 | $ 76,958.62 | 3/31/2022 |
| 4 | 110001146569 | $ 37,478.49 | 3/31/2022 |
| 5 | 120000984613 | $ 30,953.16 | 3/31/2022 |
| 6 | 120002384721 | $ 26,788.07 | 3/31/2022 |
| 7 | 120001684774 | $ 25,832.88 | 3/31/2022 |
| 8 | 120000792214 | $ 25,382.39 | 3/31/2022 |
| 9 | 120001684493 | $ 23,622.75 | 3/31/2022 |
| 10 | 120001684295 | $ 22,219.04 | 3/31/2022 |

| | CONTRACT ACCOUNT | Amount | TME Period |
|---|---|---|---|
| 1 | 110000929502 | $ 50,680.75 | 3/31/2023 |
| 2 | 120001024369 | $ 31,508.66 | 3/31/2023 |
| 3 | 110001376943 | $ 30,776.92 | 3/31/2023 |
| 4 | 110001134433 | $ 30,151.24 | 3/31/2023 |
| 5 | 110001170452 | $ 27,027.76 | 3/31/2023 |
| 6 | 120000959342 | $ 26,958.23 | 3/31/2023 |
| 7 | 120001518832 | $ 26,520.73 | 3/31/2023 |
| 8 | 120001497946 | $ 24,767.37 | 3/31/2023 |
| 9 | 110000331915 | $ 24,623.22 | 3/31/2023 |
| 10 | 120000680955 | $ 23,095.03 | 3/31/2023 |

| | CONTRACT ACCOUNT | Amount | TME Period |
|---|---|---|---|
| 1 | 120001342290 | $ 60,096.89 | 3/31/2024 |
| 2 | 120001411269 | $ 41,877.24 | 3/31/2024 |
| 3 | 110001200267 | $ 39,701.78 | 3/31/2024 |
| 4 | 120000933305 | $ 36,597.76 | 3/31/2024 |
| 5 | 110000526951 | $ 34,118.08 | 3/31/2024 |
| 6 | 110001250569 | $ 29,113.35 | 3/31/2024 |
| 7 | 110001206439 | $ 27,866.89 | 3/31/2024 |
| 8 | 110001589115 | $ 27,784.34 | 3/31/2024 |
| 9 | 120000121331 | $ 27,684.35 | 3/31/2024 |
| 10 | 110000380169 | $ 27,138.43 | 3/31/2024 |

**WGL's Forecasted Distribution Only Uncollectibles Expense**

| | TME Dec-2024 | TME Dec-2025 |
|---|---|---|
| Uncollectible Gas Accounts Expense | $ 5,262,917 | $ 6,425,904 |
| Distribution Adjustment to Uncollectible Expense [1] | (1,680,680) | (1,680,680) |
| Distribution Only Uncollectible Expense | $ 3,582,237 | $ 4,745,224 |

1/ Based on TME September 2024, the most readily available amount.

tm1serv:GL Cube
Actual

| Period | Gas Charge Off | Gas Collections | Net Charge Off |
|---|---|---|---|
| A | B | C | D = B + C |
| Apr-2019 | 426,619.91 | (20,226.36) | 406,393.55 |
| May-2019 | 451,935.31 | (3,649.26) | 448,286.05 |
| Jun-2019 | 351,721.54 | (58,067.72) | 293,653.82 |
| Jul-2019 | 257,568.04 | (24,763.96) | 232,804.08 |
| Aug-2019 | 1,219,027.65 | (25,334.36) | 1,193,693.29 |
| Sep-2019 | 1,922,967.56 | (27,405.91) | 1,895,561.65 |
| Oct-2019 | 451,822.50 | (62,084.74) | 389,737.76 |
| Nov-2019 | 696,032.85 | (48,293.35) | 647,739.50 |
| Dec-2019 | 7,574,467.36 | (71,824.64) | 7,502,642.72 |
| Jan-2020 | 904,771.48 | (77,261.82) | 827,509.66 |
| Feb-2020 | 652,928.32 | (46,627.70) | 606,300.62 |
| Mar-2020 | 994,883.82 | (45,714.89) | 949,168.93 |
| | **15,904,746.34** | **(511,254.71)** | **15,393,491.63** |
| Apr-2020 | 315,802.36 | (292,932.50) | 22,869.86 |
| May-2020 | 280,076.18 | (24,418.44) | 255,657.74 |
| Jun-2020 | 241,070.49 | (42,668.51) | 198,401.98 |
| Jul-2020 | 77,558.34 | (48,162.39) | 29,395.95 |
| Aug-2020 | 747,234.24 | (61,398.80) | 685,835.44 |
| Sep-2020 | 199,428.05 | (23,709.66) | 175,718.39 |
| Oct-2020 | 249,781.78 | (28,374.61) | 221,407.17 |
| Nov-2020 | 173,698.40 | (22,110.29) | 151,588.11 |
| Dec-2020 | 254,049.15 | (25,889.95) | 228,159.20 |
| Jan-2021 | 209,429.34 | (19,227.85) | 190,201.49 |
| Feb-2021 | 281,416.97 | (18,220.64) | 263,196.33 |
| Mar-2021 | 185,945.53 | (37,872.13) | 148,073.40 |
| | **3,215,490.83** | **(644,985.77)** | **2,570,505.06** |
| Apr-2021 | 287,431.90 | (27,100.38) | 260,331.52 |
| May-2021 | 35,334.18 | (137,728.54) | (102,394.36) |
| Jun-2021 | 363,576.55 | (85,106.01) | 278,470.54 |
| Jul-2021 | 356,521.97 | (48,515.93) | 308,006.04 |
| Aug-2021 | 306,209.19 | (20,511.46) | 285,697.73 |
| Sep-2021 | 207,714.09 | (23,407.99) | 184,306.10 |
| Oct-2021 | 301,133.30 | (26,281.22) | 274,852.08 |
| Nov-2021 | 350,407.92 | (374,994.84) | (24,586.92) |
| Dec-2021 | 186,527.89 | (17,467.16) | 169,060.73 |
| Jan-2022 | 224,752.37 | (70,695.94) | 154,056.43 |
| Feb-2022 | 319,147.31 | (15,316.96) | 303,830.35 |
| Mar-2022 | 366,626.07 | (13,603.46) | 353,022.61 |
| | **3,305,382.74** | **(860,729.89)** | **2,444,652.85** |

| | | | |
|---|---|---|---|
| Apr-2022 | 323,253.53 | (16,065.43) | 307,188.10 |
| May-2022 | 305,643.23 | (160,101.29) | 145,541.94 |
| Jun-2022 | 330,760.35 | (183,435.74) | 147,324.61 |
| Jul-2022 | 392,840.17 | (24,567.56) | 368,272.61 |
| Aug-2022 | 361,208.45 | (28,692.02) | 332,516.43 |
| Sep-2022 | 627,889.72 | (34,897.70) | 592,992.02 |
| Oct-2022 | 551,223.46 | (47,917.26) | 503,306.20 |
| Nov-2022 | 661,560.40 | (45,461.95) | 616,098.45 |
| Dec-2022 | 1,134,662.00 | (45,512.06) | 1,089,149.94 |
| Jan-2023 | 867,024.28 | (32,281.63) | 834,742.65 |
| Feb-2023 | 1,446,817.27 | (80,886.49) | 1,365,930.78 |
| Mar-2023 | 1,127,690.35 | (74,489.55) | 1,053,200.80 |
| | **8,130,573.21** | **(774,308.68)** | **7,356,264.53** |

| | | | |
|---|---|---|---|
| Apr-2023 | 975,898.55 | (54,240.23) | 921,658.32 |
| May-2023 | 732,145.76 | (32,985.62) | 699,160.14 |
| Jun-2023 | 725,075.31 | (51,385.25) | 673,690.06 |
| Jul-2023 | 705,943.45 | (63,326.27) | 642,617.18 |
| Aug-2023 | 697,780.16 | (83,701.92) | 614,078.24 |
| Sep-2023 | 483,911.34 | (80,625.22) | 403,286.12 |
| Oct-2023 | 607,759.12 | (123,101.32) | 484,657.80 |
| Nov-2023 | 430,671.77 | (83,762.23) | 346,909.54 |
| Dec-2023 | 260,643.77 | (42,269.41) | 218,374.36 |
| Jan-2024 | 615,755.60 | (57,275.07) | 558,480.53 |
| Feb-2024 | 82,707.96 | (86,545.12) | (3,837.16) |
| Mar-2024 | 385,702.02 | (80,359.49) | 305,342.53 |
| | **6,703,994.81** | **(839,577.15)** | **5,864,417.66** |

tm1serv:GL Cube
Actual

| Period | Gas Charge Off | Gas Collections | Net Charge Off |
|---|---|---|---|
| A | B | C | D = B + C |
| Apr-2024 | 438,305.86 | (60,404.53) | 377,901.33 |
| May-2024 | 954,734.78 | (21,709.83) | 933,024.95 |
| Jun-2024 | 568,235.85 | (58,263.46) | 509,972.39 |
| Jul-2024 | 1,073,723.24 | (61,708.08) | 1,012,015.16 |
| Aug-2024 | 412,627.57 | (55,103.85) | 357,523.72 |
| Sep-2024 | 447,044.97 | (20,980.89) | 426,064.08 |
| | **3,894,672.27** | **(278,170.64)** | **3,616,501.63** |

| | CONTRACT ACCOUNT | Amount | TME Period |
|---|---|---|---|
| 1 | 120001848098 | $ 51,638.73 | 3/31/2021 |
| 2 | 120000192332 | $ 36,721.45 | 3/31/2021 |
| 3 | 120000404273 | $ 32,933.41 | 3/31/2021 |
| 4 | 120000198537 | $ 24,848.99 | 3/31/2021 |
| 5 | 120001704523 | $ 24,521.38 | 3/31/2021 |
| 6 | 120001245980 | $ 15,076.79 | 3/31/2021 |
| 7 | 110001104451 | $ 14,650.92 | 3/31/2021 |
| 8 | 110000087954 | $ 13,593.91 | 3/31/2021 |
| 9 | 110001365169 | $ 12,866.22 | 3/31/2021 |
| 10 | 120002345201 | $ 12,651.56 | 3/31/2021 |

| | CONTRACT ACCOUNT | Amount | TME Period |
|---|---|---|---|
| 1 | 110001315719 | $ 102,191.88 | 3/31/2022 |
| 2 | 110000469780 | $ 94,207.59 | 3/31/2022 |
| 3 | 120000095501 | $ 76,958.62 | 3/31/2022 |
| 4 | 110001146569 | $ 37,478.49 | 3/31/2022 |
| 5 | 120000984613 | $ 30,953.16 | 3/31/2022 |
| 6 | 120002384721 | $ 26,788.07 | 3/31/2022 |
| 7 | 120001684774 | $ 25,832.88 | 3/31/2022 |
| 8 | 120000792214 | $ 25,382.39 | 3/31/2022 |
| 9 | 120001684493 | $ 23,622.75 | 3/31/2022 |
| 10 | 120001684295 | $ 22,219.04 | 3/31/2022 |

| | CONTRACT ACCOUNT | Amount | TME Period |
|---|---|---|---|
| 1 | 110000929502 | $ 50,680.75 | 3/31/2023 |
| 2 | 120001024369 | $ 31,508.66 | 3/31/2023 |
| 3 | 110001376943 | $ 30,776.92 | 3/31/2023 |
| 4 | 110001134433 | $ 30,151.24 | 3/31/2023 |
| 5 | 110001170452 | $ 27,027.76 | 3/31/2023 |
| 6 | 120000959342 | $ 26,958.23 | 3/31/2023 |
| 7 | 120001518832 | $ 26,520.73 | 3/31/2023 |
| 8 | 120001497946 | $ 24,767.37 | 3/31/2023 |
| 9 | 110000331915 | $ 24,623.22 | 3/31/2023 |
| 10 | 120000680955 | $ 23,095.03 | 3/31/2023 |

| | CONTRACT ACCOUNT | Amount | TME Period |
|---|---|---|---|
| 1 | 120001342290 | $ 60,096.89 | 3/31/2024 |
| 2 | 120001411269 | $ 41,877.24 | 3/31/2024 |
| 3 | 110001200267 | $ 39,701.78 | 3/31/2024 |
| 4 | 120000933305 | $ 36,597.76 | 3/31/2024 |
| 5 | 110000526951 | $ 34,118.08 | 3/31/2024 |
| 6 | 110001250569 | $ 29,113.35 | 3/31/2024 |
| 7 | 110001206439 | $ 27,866.89 | 3/31/2024 |
| 8 | 110001589115 | $ 27,784.34 | 3/31/2024 |
| 9 | 120000121331 | $ 27,684.35 | 3/31/2024 |
| 10 | 110000380169 | $ 27,138.43 | 3/31/2024 |

Question F

WGL's Forecasted Distribution Only Uncollectibles Expense

| | TME Dec-2024 | TME Dec-2025 |
|---|---|---|
| Uncollectible Gas Accounts Expense | $ 5,262,917 | $ 6,425,904 |
| Distribution Adjustment to Uncollectible Expense [1] | (1,680,680) | (1,680,680) |
| Distribution Only Uncollectible Expense | $ 3,582,237 | $ 4,745,224 |

1/ Based on TME September 2024, the most readily available amount.

# Washington Gas Light Company
# District of Columbia Jurisdiction

## Short-Term Incentive Compensation

TME December 2019 - 2023 and TME March 2024

### AltaGas MMF allocation to ASUS (US$MM) - Short-term Incentive

| | Dec 2019 | Dec 2020 | Dec 2021 | Dec 2022 | Dec 2023 | TME March 2024 |
|---|---|---|---|---|---|---|
| Total | $ 4.23 | $ 3.34 | $ 4.22 | $ 5.20 | $ 3.13 | $ 3.88 |
| WGL % of ASUS | 53.22% | 65.98% | 67.84% | 69.59% | 77.90% | 77.90% |
| WGL Amount | $ 2.25 | $ 2.20 | $ 2.86 | $ 3.62 | $ 2.44 | $ 3.02 |
| DC Factor (Comp A&G) | 19.27% | 21.01% | 19.73% | 18.45% | 18.51% | 19.54% |
| $ Applicable to DC | $ 0.43 | $ 0.46 | $ 0.56 | $ 0.67 | $ 0.45 | $ 0.59 |

Note - ALA labor costs are recorded on Washington Gas ledger in account 920188 which is allocated among the Washington Gas jurisdictions on the Composite Administrative & General factor.

Exhibit OPC (B)-59
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA 

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-2

**Q.** **Other Prior Separation Plans.** Witness Tuoriniemi's Direct Testimony (61:21 – 63:6) addresses prior proceedings where the Commission has allowed WGL to amortize "implementation costs" for Accenture and Business Process Outsourcing ("BPO"), but Witness Tuoriniemi does not cite to any prior WGL or AltaGas involuntary or voluntary separation programs. Please address the following:

a. Identify all voluntary and involuntary separations programs that were implemented and resulted in a reduction in WGL employees (this also includes separation programs implemented by AltaGas and/or WGL after the merger) from the period January 1, 2015, through the most recent date in 2024, and provide the following information for each employee reduction program:

(i) Descriptions of each employee voluntary and involuntary reduction plan.

(ii) Date implemented for each employee reduction plan.

(iii) Reasons for implementing each employee reduction plan.

(iv) The number of employee reductions by job position for each state/jurisdiction and affiliate.

(v) The costs to implement each employee reduction plan by type of cost for each state/jurisdiction and affiliate (provide calculations in native file form with all formulae and links intact to show WGL and WGL-DC amounts, including all allocation factors and calculations used to determine the WGL-DC amounts).

(vi) The total cost savings and reduction in payroll expenses (and all other costs) for each employee reduction plan in each state/jurisdiction and affiliate (provide calculations in native file form with all formulae and links intact to show WGL and WGL-DC amounts, including all allocation factors and calculations used to determine the WGL-DC amounts).

b. Regarding (a) above, provide an active hyperlink to WGL testimony (or full copies of) and related Commission Orders where WGL requested regulatory treatment (such as amortization of the related costs to implement these separation programs) of these other separation programs, or explain why WGL did not request any regulatory treatment for these prior separation programs.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.**

a. Beyond 2024, there have been no other voluntary or involuntary separation programs that were implemented and resulted in a reduction in WGL employees from January 1, 2020 beyond the normal course of business in rightsizing and optimizing employee headcount.

b. N/A

SPONSOR: Jim Steffes
SVP, Regulatory, Policy & Advocacy

Exhibit OPC (B)-60
Formal Case No. 1180
Direct Testimony of Bion Ostrander

Page 1 of 2

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-3

**Q.** **Reconcile Separation Program Information to Public Financial Records.** Witness Tuoriniemi's Direct Testimony (60:8 – 63:6) generally describes WGL's adjustment to amortize the costs incurred to implement the involuntary separation program, including related Adjustment No. 14 (Exhibit WG (D)-5, pages 1 to 5) which shows total amortizable costs to implement the separation program of $6,998,583. Also, Adjustment No. 13 (Exhibit WG (D)-5, page 1 to 4) shows separation program total labor O&M expense reduction of $10,217,373. Finally, Witness Steffes states (Exhibit WG (A) at 13:16-18) that over 70 positions were eliminated in April 2024 related to this separation program. Please address the following:

a. Refer to WGL's Adjustment No. 13 separation program labor O&M expense reduction ($10,217,373), Adjustment No. 14 costs to implement the separation program ($6,998,583), and the related 70 employee reduction – and reconcile this information to an active hyperlink to (or full copies of) AltaGas and/or WGL publicly issued Annual or Quarterly Financial Reports for 2023 or 2024 which discloses these costs, savings, and number of employees related to the involuntarily separation program. Provide all supporting documentation and calculations.

b. Regarding (a) above, if the involuntary separation program (or the details of the separation program, such as related costs, savings, and number of employees) were not previously disclosed in 2023 or 2024 public financial records of AltaGas or WGL, explain the reason for the nondisclosure.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.**

a. There is no reconciliation to provide. The involuntary separation program was not disclosed in either AltaGas and/or WGL publicly issued annual or quarterly financial reports for 2023 or 2024 through the filing date of the rate case.

Page 2 of 2

b. Washington Gas and AltaGas determined that there was no requirement to disclose the involuntary separation program in their financial statements because the costs did not meet the audit materiality threshold and did not represent a material change in the nature of the Company's business operations.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

Exhibit OPC (B)-61
Formal Case No. 1180
Direct Testimony of Bion Ostrander

Page 1 of 4

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-4

**Q.** **Separation Program O&M Labor Expense Reduction Source and Calculations.** Witness Smith's Direct Testimony (Exhibit WG (F) at 19:8-14) states that approximately 70 employee positions were eliminated in April 2024 due to the involuntary separation program, and related Adjustment No. 13 (Exhibit WG (D)-5, pages 1 to 4) removes the test year labor O&M expenses of salaries and wages, short-term incentives, and employer portion of benefits related to these 70 employees, resulting in a WGL separation program labor O&M expense reduction of $10,217,373, and a related WGL-DC portion of $1,978,270. However, Witness Smith does not explain this adjustment in detail. Please address the following:

a. Witness Smith states that the involuntary reduction eliminates "approximately" 70 employee positions, provide the updated actual number of employees eliminated, along with an updated Adjustment No. 13 with related supporting documentation and calculations (and all updated working Excel files in native file form with all formulae and links intact).

b. Explain the source of the spreadsheet workpaper shown at Adjustment No. 13, Exhibit WG (D)-5, page 2 of 4, and explain if: (1) this is a specific workpaper prepared to show the total reduction in salary costs of the separation program for the approximate 70 employees; (2) this workpaper pieces together parts of the actual WGL financial statements to show the total reduction in salary costs; or (3) if the workpaper reflects some other information or has some other purpose.

c. Explain if Adjustment No. 13 (Exhibit WG (D)-5, page 1 of 4) O&M labor expense reduction of $10,2317,373 is based on:

(i) Actual costs for these 70 employees for the test year end March 31, 2024 (or identify the related time period) and provide all supporting documentation and calculations in native file form with all formulae and links intact.

(ii) Estimated costs for 70 employees for the test year end March 31, 2024 (or identify the related time period) and provide all supporting documentation and calculations in native file form with all formulae and links intact.

(iii) Annualized costs for 70 employees, and identify the timeperiod(s) of the costs that are annualized, and provide all supporting documentation and calculations in native file form with all formulae and links intact.

d. Explain why Adjustment No. 13, Exhibit WG (D)-5, page 1 of 4, only removes “O&M labor expenses” related to the separation program, but does not remove the related salary, incentive, and benefit “Capital” costs of $837,907, “Other” costs of $294,278, and “Affiliates” costs of $673,334 shown at Adjustment No. 13, Exhibit WG (D)-5, page 2 of 4. Explain if the “Other” costs and “Affiliates” costs are expensed or capitalized salary, incentive, and benefit costs. Otherwise, cite to other WGL adjustments where these capitalized and other costs have been removed by WGL.

e. Adjustment No. 13, Exhibit WG (D)-5, page 1 of 4 removes total salary expenses of $7,233,986, and when divided by 70 employees, equals an average salary of $103,343 for the eliminated employees. Explain if this average salary expense of the eliminated employees is true and accurate or if it is understated, and in either case, please explain why WGL believes the amount shown is reasonable.

f. Provide the management employee benefits overhead loading rate for 2024 and explain if this loadings rate applied to the salary costs of the 70 eliminated employees produces an adjustment similar to the total labor O&M expense reduction of $10,217,373 at Adjustment No. 13, Exhibit WG (D)-5, page 1 of 4. Explain why this is not a reasonable test of the payroll costs removed by WGL at Adjustment No. 13 related to the involuntary separation program.

g. Explain if it is not necessary to remove long-term incentives expense related to the eliminated 70 employees because Adjustment No. 6, Exhibit WG (D)-5, page 1 of 3, already removes all long-term incentive expense from this rate case.

**WASHINGTON GAS’S RESPONSE** 11/22/2024

**A.** As an initial matter, the assertion that this adjustment is not discussed in detail is incorrect. Adjustment 13 is described on page 19 of my Direct Testimony at lines 6-18.

a. The actual number of Washington Gas employees terminated during the ISP event was seventy (70). No update to Exhibit WG (D)-5 Adjustment 13 is needed.

b. This workpaper was prepared using actual test year pay information for the 70 employees whose positions were terminated during the April 2024 ISP event.

c. The information provided is based on the actual costs for these 70 employees. Refer to Exhibit WG (D)-5 Adjustment 13 pages 2 and 3 (PDF) as well as the electronic copy of Exhibit WG (D)-5 Adjustment 13 provided on the FC1180 SharePoint site in Electronic Materials > Public > WORKPAPERS for the requested information.

d. The Company has removed the Utility O&M expense portion of these employees' expense as those expenses will not recur in the future and represent a permanent reduction in payroll costs.

Capitalized labor costs have not been removed. Test year capitalized labor was related to work employees performed on capital projects and represents historical amounts. Future capitalization of expenses, and consequently a future increase in rate base, is NOT included in the revenue requirement of this case. It is inappropriate to remove the capitalized payroll amounts that were already incurred for these employees as the involuntary separation does not in any way demonstrate or prove that the capital expense amounts were imprudent.

The "Affiliates" and "Other" amounts are primarily expense amounts, as reflected on page 2 of Exhibit WG (D)-5 Adjustment 13 page. A small portion of "Other" (approximately $1,000) was recorded to a non-utility property (i.e., capital) account. Labor amounts charged to affiliates and non-utility property are not included in the revenue requirement of this case; thus, no adjustment needs to be made to remove them. $120K of "Other" is for a pool account (184241) that would be 100% allocated to capital costs. Refer to capitalized labor cost above about what costs were not removed.

e. The Company does not dispute OPC's math, but it is irrelevant. The $7.3M of base pay presented in the adjustment is reasonable because it is the **ACTUAL** amount paid to the impacted employees in the test year, and therefore is the most reasonable estimate of the expected annual savings for these employees.

f. The composite benefits load rate for STI, medical insurance, and 401(k) for 2024 is 25.66%. However, this load rate is irrelevant. The **ACTUAL** incurred benefits costs in the test year for the impacted employees is the most reasonable estimate of the expected annual savings for these employees.

g. Correct.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

Exhibit OPC (B)-62
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-5

**Q.** **Involuntary Separation Job Titles and Costs.** Witness Smith's Direct Testimony (19:8-11) states that approximately 70 employee positions were eliminated in April 2024 due to the involuntary separation program. Adjustment No. 13 (Exhibit WG (D)-5, page 1 of 4) shows total labor O&M expenses of $10,217,373 (or $7,233,986 excluding short-term incentives) removed from the test year related to the involuntary separation. Please address the following:

a. Provide the actual number of employees eliminated due to the involuntary separation program (provide an update to the 70 approximate employees if applicable) and show the job/position job title of each employee that was eliminated.

b. Regarding (a) above, explain if all employees were flash-cut eliminated in April 2024, or explain if the date they were eliminated varies and continued beyond April 2024.

c. Regarding (a) above, provide the date each employee was terminated.

d. Regarding (a) above, for each employee position, separately provide the amount of salary expense and short-term incentive expense, and reconcile the total salaries expense reduction and short-term incentive expense reduction to the related amounts of $7,233,986 and $986,995, respectively, at Adjustment No. 13, Exhibit WG (D)-5, page 1 of 4.

e. Regarding (a) above, explain why each of these positions were selected to be eliminated.

f. Explain if any of the eliminated positions have been backfilled with new and less expensive employees as of the most recent date in 2024, and explain if there are any plans to backfill these positions.

g. Regarding (a) above, identify all eliminated employees that were Officers or Executives of WGL, Officers of WGL and AltaGas, and Officers of WGL and any other affiliate, if applicable.

h. Regarding (g) above, if applicable, explain why the involuntary separation program did not eliminate any Executive or Officer positions of WGL or other affiliates.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.**

a. Please refer to **CONFIDENTIAL** Attachment No. 2 provided in response to OPC Data Request 6-19 for the requested list of the seventy (70) Washington Gas employees who were impacted by the ISP event in April 2024.

b. All employees were terminated in a single event on April 17, 2024, except for 5 employees who were out of the office that day and were terminated when they returned to the office. All terminations were completed in April 2024.

c. Refer to part (b).

d. There is no change to the salary and STI information previously provided and no reconciliation to perform. The amounts in Exhibit WG (D)-5 Adjustment 13 are actual costs for the 70 employees who were impacted by the ISP.

e. As discussed in the Direct Testimony of Company Witness Steffes at pages 6-7, these positions were eliminated as a result of the Company striving to align its workforce by eliminating operational overlap.

f. The Company did not plan to backfill the directly impacted positions involved in the ISP. Any future changes will be made in the normal course of business as the Company responds to changing business needs.

g. Three (3) of the employees included on the **CONFIDENTIAL** list in part (a) were officers of Washington Gas. Those three officers are aliases 14, 51, and 55. Adjustment No. 5 does not include any officer costs for AltaGas or other affiliates.

h. Not applicable.

parts (a) and (d)
SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

parts (b), (c), (e), (f), (g), and (h)

SPONSOR: James D. Steffes
Sr. Vice President – Regulatory Affairs

Exhibit OPC (B)-63
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-6

**Q.** **Future Involuntary Separation Plans.** Witness Smith's Direct Testimony (19:8-11) states that approximately 70 employee positions were eliminated in April 2024 due to the involuntary separation program. Please address the following:

a. Explain if AltaGas or WGL has any formal plans or projections to eliminate any additional employees (including Officers and Executives) in 2024 and future years. If the answer is "yes", provide the number of employees to be eliminated and provide a copy of such projected plans, budgets, and supporting documentation.

b. Explain if the 2024 involuntary separation plan also eliminated employees for AltaGas and other affiliates and provide the reduction in the number of employees for each affiliate by specific date.

c. If applicable, explain why the 2024 involuntary separation plan did not eliminate Officer and Executive positions for WGL, AltaGas, and other affiliates.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.**

a. The Company currently has no plans or projections for any future involuntary separation programs to eliminate any additional employees.

b. Yes.

c. Not applicable. Refer to the Company's response to OPC DR 11-5(g).

SPONSOR: Jim Steffes
SVP, Regulatory, Policy & Advocacy

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-6

**Q.** **Future Involuntary Separation Plans.** Witness Smith's Direct Testimony (19:8-11) states that approximately 70 employee positions were eliminated in April 2024 due to the involuntary separation program. Please address the following:

a. Explain if AltaGas or WGL has any formal plans or projections to eliminate any additional employees (including Officers and Executives) in 2024 and future years. If the answer is "yes", provide the number of employees to be eliminated and provide a copy of such projected plans, budgets, and supporting documentation.

b. Explain if the 2024 involuntary separation plan also eliminated employees for AltaGas and other affiliates and provide the reduction in the number of employees for each affiliate by specific date.

c. If applicable, explain why the 2024 involuntary separation plan did not eliminate Officer and Executive positions for WGL, AltaGas, and other affiliates.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.**

a. The Company currently has no plans or projections for any future involuntary separation programs to eliminate any additional employees.

b. Yes.

c. Not applicable. Refer to the Company's response to OPC DR 11-5(g).

SPONSOR: Jim Steffes
SVP, Regulatory, Policy & Advocacy

**FOLLOW-UP DATA REQUEST** **12/2/2024**

Q. OPC 11-6(b) and (c) asks WGL to explain if the 2024 involuntary separation plans also eliminated employees for AltaGas and other affiliates and to provide this reduction in employees for each affiliate. WGL's response to OPC 11-6(b) only answers "yes" to the question but does not identify the number of employee reductions by affiliate and date, and the response to OPC 11-6(c) refers to WGL's response to OPC 11-5(g), but this response indicates that WGL's Adjustment No. 5 does not remove any terminated officer costs for AltaGas or other affiliates. Please address the following:

a. Explain why WGL did not propose an adjustment to reduce affiliate charges to WGL related to the payroll costs of employees of affiliates that were terminated due to the involuntary separation agreement.

b. Regarding (a), for those affiliate employees whose costs were assigned/allocated to WGL for test year end March 31, 2024, provide the payroll and other costs of these affiliate employees that were terminated due to the involuntary separation agreement, and provide adjustments for these employee costs similar to related Adjustments No. 5 (payroll adjustment), Adjustment No. 13 (separation program labor expense reduction), and Adjustment No. 14 (involuntary separation programs costs amortized over 5 years). Provide all supporting documentation and calculations.

**WASHINGTON GAS'S FOLLOW-UP RESPONSE** 12/9/2024

**A.**

a. Affiliate charges from AltaGas to Washington Gas can increase or decrease for a variety of reasons. The AltaGas cost savings resulting from the ISP were immaterial to the total in-bound charges and will be more than offset by inflationary costs increases going forward. Therefore, no adjustment to in-bound affiliate costs is necessary.

b. The DC portion of affiliate ISP cost savings were approximately $43K. Severance costs associated with the ISP were excluded from the allocation of costs from AltaGas to WGL.

| | |
|---|---|
| ALA ISP-related cost savings ($CAD) | $ 571,281 |
| $USD conversion factor | 1.3495 |
| ALA ISP-related cost savings ($USD) | $ 423,328 |
| DC % of ALA (see OPC 4-14) | 10.15% |
| DC Portion of ALA ISP-related cost savings | $ 42,977 |

CO-SPONSOR: Jim Steffes
SVP, Regulatory, Policy & Advocacy

CO-SPONSOR: Eric Block
Vice President and Controller, AltaGas, Ltd.

Exhibit OPC (B)-64
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-8

**Q.** **Reconciliation of WGL Payroll Adjustment No. 5.** Witness Smith's Direct Testimony (7:9 – 11:3) addresses WGL's annualized payroll adjustment, which is reflected at Adjustment No. 5 (Exhibit WG (D)-5, pages 1 to 15). Adjustment No. 5, Exhibit WG (D)-5, page 1 shows total actual payroll costs per books at test year end March 31, 2024, (expensed and capitalized) of $184,177,030 net of employee labor costs of $9,945,883 that were removed due to the separation program, Adjustment No. 5 (Exhibit WG (D)-5, page 14) shows total payroll costs per books of $194,122,913 ($184,177,030 + $9,945,883) before removing labor costs due to the separation program, and Adjustment No. 5 Exhibit WG (D)-5, page 6, shows total payroll costs per books (expensed, capitalized, and other) of $153,584,096. Please address the following:

a. Please reconcile the above total payroll costs of $194,122,913 (test year 2024 per books) and $184,177,030 (test year reduced for employee separation program costs) to the payroll costs of $153,584,096, and identify and explain all differences (and provide supporting documentation and calculations). Explain if the difference is due to the amounts of $194,122,913 and $184,177,030 including some short-term and long-term incentive costs and $153,584,096 not including any incentive costs. Also, identify all reconciling items that are included or excluded from WGL's annualized payroll adjustment, Adjustment No. 5 (Exhibit WG (D)-5, pages 1 to 15).

b. Regarding (a) above, separately provide the amount of short-term incentive costs (separately show amounts expensed and capitalized) and long-term incentive costs (separately show amounts expensed and capitalized) included in the above amounts of $194,122,913, $184,177,030, and $153,584,096 by account number.

c. Per the amount of $153,584,096 in Adjustment No. 5, Exhibit WG (D)-5, page 6, explain if the "Other" payroll costs of $4,090,382 and "Affiliate" payroll costs of $1,793,552 are included in the test period and explain if these amounts have been annualized via WGL's payroll adjustment, Adjustment No. 5 (Exhibit WG (D)-5, pages 1 to 15).

**WASHINGTON GAS'S RESPONSE** 11/25/2024

**A.**

a. The $153,584,096 on the O&M factor calculation page (Exhibit WG (D)-5 Adjustment No. 5, page 6) reflects direct payroll only (i.e., how employees charged their productive time), as the labels above each table indicated. The purpose of the calculation on this page is to determine the O&M portion of the incremental payroll increase (see Exhibit WG (D)-5 Adjustment No. 5, page 1, line 7). This amount is not intended to reflect total gross payroll (Exhibit WG (D)-5 Adjustment No. 5, page 1, line 1), which includes both productive and non-productive (primarily paid time off) time. Please refer to Attachment No. 1 for additional reconciliation details.

| Description | Amount |
|---|---|
| Gross Annual Payroll TME 3/31/2024 (Adj No. 5, Pg 1, Ln 1) | $ 184,177,030 |
| Add back: Excluded Involuntary Separation Program | $ 9,945,883 |
| Gross Annual Payroll TME 3/31/2024 | $ 194,122,913 |
| Paid time off included in Gross Payroll | $ (24,908,341) |
| Short-term Incentive Compensation included in Gross Payroll | $ (15,804,177) |
| Other Differences | $ 173,701 |
| O&M Factor Calculation TME March 2024 (Expected) | $ 153,584,096 |
| O&M Factor Calculation TME March 2024 (Adj No. 5, pg 6) | $ 153,584,096 |

b. Please refer to FC 1180 OPC Data Requests 10-5 and 10-8 for short-term and long-term incentive costs, including expensed and capitalized amounts as well as amounts allocated to other activity and to affiliates. Note that there is a difference between the amount of short-term incentive compensation paid out as reflected in the table above and the total amount of STI recorded on the ledger due to the timing to STI expense accruals and true-ups.

c. "Affiliate" and "Other" costs are not included in gross payroll costs in Exhibit WG (D)-5 Adjustment No. 5 and therefore are excluded from the incremental increase calculation in that adjustment.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-8

**Q.** **Reconciliation of WGL Payroll Adjustment No. 5.** Witness Smith's Direct Testimony (7:9 – 11:3) addresses WGL's annualized payroll adjustment, which is reflected at Adjustment No. 5 (Exhibit WG (D)-5, pages 1 to 15). Adjustment No. 5, Exhibit WG (D)-5, page 1 shows total actual payroll costs per books at test year end March 31, 2024, (expensed and capitalized) of $184,177,030 net of employee labor costs of $9,945,883 that were removed due to the separation program, Adjustment No. 5 (Exhibit WG (D)-5, page 14) shows total payroll costs per books of $194,122,913 ($184,177,030 + $9,945,883) before removing labor costs due to the separation program, and Adjustment No. 5 Exhibit WG (D)-5, page 6, shows total payroll costs per books (expensed, capitalized, and other) of $153,584,096. Please address the following:

a. Please reconcile the above total payroll costs of $194,122,913 (test year 2024 per books) and $184,177,030 (test year reduced for employee separation program costs) to the payroll costs of $153,584,096, and identify and explain all differences (and provide supporting documentation and calculations). Explain if the difference is due to the amounts of $194,122,913 and $184,177,030 including some short-term and long-term incentive costs and $153,584,096 not including any incentive costs. Also, identify all reconciling items that are included or excluded from WGL's annualized payroll adjustment, Adjustment No. 5 (Exhibit WG (D)-5, pages 1 to 15).

b. Regarding (a) above, separately provide the amount of short-term incentive costs (separately show amounts expensed and capitalized) and long-term incentive costs (separately show amounts expensed and capitalized) included in the above amounts of $194,122,913, $184,177,030, and $153,584,096 by account number.

c. Per the amount of $153,584,096 in Adjustment No. 5, Exhibit WG (D)-5, page 6, explain if the "Other" payroll costs of $4,090,382 and "Affiliate" payroll costs of $1,793,552 are included in the test period and explain if these amounts have been annualized via WGL's payroll adjustment, Adjustment No. 5 (Exhibit WG (D)-5, pages 1 to 15).

**WASHINGTON GAS'S RESPONSE** 11/25/2024

**A.**

a. The $153,584,096 on the O&M factor calculation page (Exhibit WG (D)-5 Adjustment No. 5, page 6) reflects direct payroll only (i.e., how employees charged their productive time), as the labels above each table indicated. The purpose of the calculation on this page is to determine the O&M portion of the incremental payroll increase (see Exhibit WG (D)-5 Adjustment No. 5, page 1, line 7). This amount is not intended to reflect total gross payroll (Exhibit WG (D)-5 Adjustment No. 5, page 1, line 1), which includes both productive and non-productive (primarily paid time off) time. Please refer to Attachment No. 1 for additional reconciliation details.

| Description | Amount |
|---|---|
| Gross Annual Payroll TME 3/31/2024 (Adj No. 5, Pg 1, Ln 1) | $ 184,177,030 |
| Add back: Excluded Involuntary Separation Program | $ 9,945,883 |
| Gross Annual Payroll TME 3/31/2024 | $ 194,122,913 |
| Paid time off included in Gross Payroll | $ (24,908,341) |
| Short-term Incentive Compensation included in Gross Payroll | $ (15,804,177) |
| Other Differences | $ 173,701 |
| O&M Factor Calculation TME March 2024 (Expected) | $ 153,584,096 |
| O&M Factor Calculation TME March 2024 (Adj No. 5, pg 6) | $ 153,584,096 |

b. Please refer to FC 1180 OPC Data Requests 10-5 and 10-8 for short-term and long-term incentive costs, including expensed and capitalized amounts as well as amounts allocated to other activity and to affiliates. Note that there is a difference between the amount of short-term incentive compensation paid out as reflected in the table above and the total amount of STI recorded on the ledger due to the timing to STI expense accruals and true-ups.

c. "Affiliate" and "Other" costs are not included in gross payroll costs in Exhibit WG (D)-5 Adjustment No. 5 and therefore are excluded from the incremental increase calculation in that adjustment.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

**FOLLOW-UP DATA REQUEST** **12/2/2024**

Q. WGL's response to OPC 11-8 (a) identifies test year end March 31, 2024, short-term incentive (STI) payroll costs included in gross payroll of $15,804,177. However, this STI gross cost of $15,804,177 does not agree with WGL's response to OPC 10-5, Attachment 1, which appears to show test year end March 31, 2024, WGL total STI gross cost of $15,076,522. Also, this STI gross cost of $15,804,177 does not agree with WGL's response to OPC 11-14, Attachment 1, which appears to show adjusted test year end March 31, 2024, WGL total STI gross cost of $22,238,819. Please address the following:

a. Please reconcile the test year end March 31, 2024, WGL total STI gross cost of $15,804,177 at OPC 11-8(a) to the STI gross costs of $15,076,522 provided in WGL's response to OPC 10-5, Attachment 1, and the adjusted STI gross costs of $22,238,819 provided in WGL's response to OPC 11-14, Attachment No. 1. Explain which of these STI amounts are correct (and why) for the per book test year end March 31, 2024, and which are correct for the adjusted STI amounts included in this rate case. Please also provide the correct WGL-DC STI gross costs per books at test year end March 31, 2024, and the correct adjusted STI amounts included in this rate case.

b. Regarding (a) above, provide the correct amount of WGL and WGL-DC STI expense for test year end March 31, 2024 and reconcile to the responses to OPC 10-5, Attachment 1 and OPC 11-14, Attachment No. 1.

c. Regarding (a) and (b) above, provide the amount of true-up included in the total and expensed STI amounts for the 2023 performance year in March 2024 and for the 2022 performance year in April 2023.

**WASHINGTON GAS'S FOLLOW-UP RESPONSE** 12/09/2024

A.

a. This question incorrectly implies that any of these STI amounts are incorrect. Each number represents a different value based on the questions that were asked by OPC. In OPC 11-8(a), $15,804,177 represents the amount of STI **PAID** to employees that is included in the gross payroll total (page 1, line 1 of Exhibit WG (D)-5 Adjustment No. 5). In OPC 10-5, $15,076,522 presents the per book **EXPENSE** recorded in the test year. The difference between paid STI and expensed STI is the timing of expense accruals and true-ups and the STI payout. The $22,238,819 amount in OPC 11-14 is the **ADJUSTED** STI expense on a system basis as requested in OPC 11-14 part (e).

b. See part (a). No change is needed.

c. Refer to the Company's response to OPC Data Request 10-5 where the test year STI true-up amounts have already been provided.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

Exhibit OPC (B)-65
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-10

**Q.** **Reason for Increase in Payroll Costs from 2023 to Test Year 2024.** Witness Smith's Direct Testimony (7:9 – 11:3) addresses WGL's annualized payroll adjustment. Adjustment No. 5 (Exhibit WG (D)-5, page 14 of 15) shows test period end March 31, 2024, total payroll costs per books of $194,122,913 ($184,177,030 equals total payroll costs of $194,122,913 net of employee labor costs of $9,945,883 that were removed due to the separation program). Also, Supplemental Compliance Filing information at 206.8 shows WGL total payroll costs of $172,961,019 at December 31, 2023, Please address the following:

a. Explain why payroll costs increased from the calendar year December 31, 2023, balance of $172,961,019 to the test year end March 31, 2024, balance of $194,122,913, a significant increase of $21,161,894 over a very short period. Provide all supporting documentation and calculations in native file form with all formulae and links intact.

b. Regarding (a) above, address the change by explaining and providing the changes in short-term incentives (both expensed and capitalized), long-term incentive expense, overtime (expensed and capitalized), severance (expensed and capitalized), SERP (expensed and capitalized), and all other changes.

c. Regarding (a) and (b), identify all types of payroll costs (and the related amounts) at December 31, 2022, that have been removed via rate case adjustments to the test year end March 31, 2024, payroll costs in this rate case.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.**

a. Compliance 206.8 reflects $176,351,584 for the twelve months ended March 31, 2024, rather than $194,122,913 as stated in the question. The change is approximately 2%.

b. Refer to part (a). The change is immaterial and the requested study has not been prepared by the Company.

c. Refer to the Direct Testimony of Company Witness Smith beginning at page 6, which shows a summary table of the labor and labor-related adjustments (increases and decreases to expense) as well as detail descriptions of each adjustment.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-10

**Q.** **Reason for Increase in Payroll Costs from 2023 to Test Year 2024.** Witness Smith's Direct Testimony (7:9 – 11:3) addresses WGL's annualized payroll adjustment. Adjustment No. 5 (Exhibit WG (D)-5, page 14 of 15) shows test period end March 31, 2024, total payroll costs per books of $194,122,913 ($184,177,030 equals total payroll costs of $194,122,913 net of employee labor costs of $9,945,883 that were removed due to the separation program). Also, Supplemental Compliance Filing information at 206.8 shows WGL total payroll costs of $172,961,019 at December 31, 2023, Please address the following:

a. Explain why payroll costs increased from the calendar year December 31, 2023, balance of $172,961,019 to the test year end March 31, 2024, balance of $194,122,913, a significant increase of $21,161,894 over a very short period. Provide all supporting documentation and calculations in native file form with all formulae and links intact.

b. Regarding (a) above, address the change by explaining and providing the changes in short-term incentives (both expensed and capitalized), long-term incentive expense, overtime (expensed and capitalized), severance (expensed and capitalized), SERP (expensed and capitalized), and all other changes.

c. Regarding (a) and (b), identify all types of payroll costs (and the related amounts) at December 31, 2022, that have been removed via rate case adjustments to the test year end March 31, 2024, payroll costs in this rate case.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.**

a. Compliance 206.8 reflects $176,351,584 for the twelve months ended March 31, 2024, rather than $194,122,913 as stated in the question. The change is approximately 2%.

b. Refer to part (a). The change is immaterial and the requested study has not been prepared by the Company.

c. Refer to the Direct Testimony of Company Witness Smith beginning at page 6, which shows a summary table of the labor and labor-related adjustments (increases and decreases to expense) as well as detail descriptions of each adjustment.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

**FOLLOW-UP DATA REQUEST 12/2/2024**

Q. WGL's response to OPC 11-10 correctly states that Compliance filing information at 206.8 for March 31, 2024, reflects total payroll costs per books of \$176,351,584. However, WGL never explains why its annualized payroll adjustment at Adjustment No. 5 reflects March 31, 2024, per book payroll costs of \$194,122,913 prior to the \$9,945,883 amount of payroll costs removed due to the separation program (termination of 70 employees), resulting in net payroll costs of \$184,177,030 (Exhibit WG (D)-5, Adjustment No. 5, page 14 of 15), with \$184,177,030 also shown as the starting point of WGL's Adjustment No. 5 (Exhibit WG (D)-5, Adjustment No. 5, page 1 of 15). Please address the following:

a. Explain why WGL's Compliance fling information at 206.8 for March 31, 2024, reflects total payroll costs of \$176,351,584. However, WGL's annualized payroll adjustment at Adjustment No. 5 reflects per book March 31, 2024, total payroll costs of \$194,122,913 before the \$9,945,883 amount of payroll costs removed due to the separation program (elimination of 70 employees), resulting in net payroll costs of \$184,177,030 (Exhibit WG (D)-5, Adjustment No. 5. Explain the reason(s) for the variance of \$17,771,329 between these two different payroll costs cited at March 31, 2024. Provide all supporting documentation and calculations (including identification of all underlying types of payroll cost differences due to short-term incentives, long-term incentives, etc.

b. Per Exhibit WG (D)-5, Adjustment No. 5, Page 14 of 15, explain why the month of March 2024 payroll costs for Executive Compensation of \$2,813,802 is as much as seven times greater than most of the prior eleven months of payroll balances and why and Non-Executive Management payroll of \$19,296,224 is more than double the average of the prior eleven months of payroll balances. Provide all supporting documentation and calculations (including identification of all underlying types of payroll cost differences due to short-term incentives, long-term incentives, etc.

c. Explain why the starting point of Adjustment No. 5 should not be the actual March 31, 2024, payroll costs per the Compliance fling information at 206.8 of $176,351,584, before deducting $9,945,883 of payroll costs removed due to the separation program (elimination of 70 employees).

**WASHINGTON GAS'S FOLLOW-UP RESPONSE** 12/9/2024

**A.**

a. As noted in my Direct Testimony on page 8 at lines 1-2 (including the footnote) where I state that the gross payroll amount that is the starting point of Adjustment No. 5 includes only those amounts related to base pay. The primary difference between these two amounts is that gross payroll included in Adjustment No. 5 are short-term incentives and time billed to affiliates that are not included in that total payroll in the compliance filing.

| | | |
|---|---|---|
| Gross Annual Payroll TME 3/31/2024 (Adj No. 5, Pg 1, Ln 1) | $ | 184,177,030 |
| Add back: Excluded Involuntary Separation Program | $ | 9,945,883 |
| Gross Annual Payroll TME 3/31/2024 | $ | 194,122,913 |
| Less: Short-term Incentive Compensation | $ | (15,804,177) |
| Less: Amounts charged to Affiliates | $ | (1,967,152) |
| Compliance filing 206.8 TME March 2024 | $ | 176,351,584 |

b. Short-term incentive compensation is paid out in March each year; therefore, March 2024 payroll is higher than payroll in other periods. Please see below for STI payout amount in March 2024 for 2023 performance year by labor group.

c. As noted in my Direct Testimony on page 10 at line 25, Adjustment No. 5 calculates **INCREMENTAL** additional payroll costs. This calculation appropriately starts with only those amounts paid to employees that vary based on base pay. Refer to pages 8-11 for a description of Adjustment No. 5 and the detailed workpapers provided in Exhibit WG (D)-5 Adjustment No. 5. Starting with the total payroll costs from the compliance filing would overstate the incremental pay increase calculation.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

Exhibit OPC (B)-66
Formal Case No. 1180
Direct Testimony of Bion Ostrander
PUBLIC VERSION

# Confidential Exhibit Omitted

Exhibit OPC (B)-67
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-12

**Q.** **Headcount Data Updated.** WGL's Supplemental Filing (Compliance Filing) §206-22, shows full-time equivalent employees (headcount) on a monthly basis for the period January 2022 through March 2024 on a basis of: (a) Functional Area; and (b) Exempt versus Non-Exempt; and (c) Management versus Union. Please address the following:

a. Provide headcount data for WGL on the same basis as provided in the preamble above for Supplemental Filing §206-22, for each of the months January to December 31, 2022.

b. Provide headcount data for WGL on the same basis as provided in the preamble above for Supplemental Filing §206-22, for each of the months after March 2024 through the most recent date available and explain the reasons for the monthly changes in employee headcount for: (i) each Functional Area; and (ii) each Management/Union class.

c. Per the preamble above, explain why headcount changed for each of the periods 2021, 2022, 2023, and 2024 year-to-date for: (i) each Functional Area; and (ii) each Management/Union class, and provide supporting documentation.

d. Per WGL's headcount data at Supplemental Filing (Compliance Filing) §206-22, explain why Management headcount increased from 735 at January 2022 to 787 at December 2022, and then increased to 824 at December 2023, and then declined somewhat to 808 at March 2024.

e. Regarding (d) above, explain why WGL gradually increased its Management employee levels from January 2022 to December 2023, only to then reduce employee levels by about 70 employees per the involuntary separation program – which appears to have reduced Management headcount to about the early to mid-2022 levels.

f. Regarding (a) to (c) above, identify the impact of the involuntary separation program employee reduction on a monthly basis for: (i) each Functional Area; and (ii) each Management/Union class, and provide supporting documentation.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.**

a. See Compliance Filing that includes data for the requested time period.

b. See OPC DR 11-12 Attachment 1 – Headcount Data and Attachment 2 – Variance Explanations. Changes in headcount in each functional area are due to normal ongoing, individual decisions by employees departing or management making vacancy hires, based on the information available to managers and executives at the time. April reductions reflect the impacts of involuntary separations. September/October reductions may also reflect the impacts of voluntary separations.

c. See OPC DR 11-12 Attachment 2 – Variance Explanations.

d. See the response to parts (b) and (c).

e. See the response to parts (b) and (c).

f. See the response to parts (b) and (c).

SPONSOR: Jim Steffes
SVP, Regulatory, Policy & Advocacy

| | 2024 | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Mar | | | Apr | | | May | | | Jun | | | Jul | | | Aug | | | Sep | | | Oct | | | Nov* |
| **Functional Area** | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | HC 22Nov2024 |
| Accounting | | | 52.5 | 1 | 10.5 | 43 | 1 | 1 | 43 | | | 42 | | | 41 | | | 41 | | 1 | 40 | | | 40 | 40 |
| Asset Management, Engineering & Supply | 2 | | 192 | | 3 | 189 | | 1 | 187 | 1 | 3 | 184 | | 1 | 183 | 1 | 4 | 180 | 1 | 10 | 174 | | 1 | 172 | 169 |
| Business Services | | | 2.5 | | | 2.5 | | | 2.5 | | | 2.5 | | | 2.5 | | | 2.5 | | 2 | 2.5 | | | 2.5 | 2.5 |
| Business Transformation | | | 18 | | 1 | 14 | | | 14 | | | 14 | | | 14 | | | 14 | | | 12 | | | 12 | 12 |
| Construction | | 1 | 123 | | | 123 | | 2 | 121 | | | 121 | | 1 | 120 | 2 | 1 | 120 | | 10 | 110 | 1 | | 110 | 111 |
| Corporate Communication | | 1 | 9 | | 1 | 8 | | | 8 | | 1 | 7 | | | 7 | | | 7 | | 3 | 4 | | 1 | 3 | 3 |
| Corporate Public Policy | | | 7 | | | 7 | | 1 | 6 | | | 6 | | | 6 | | | 6 | | | 6 | | | 6 | 6 |
| Customer Billing | | | 20 | | | 20 | | | 20 | | | 20 | | | 20 | | | 20 | | 1 | 20 | | | 20 | 17 |
| Customer Experience | | | 43 | | 4 | 39 | | | 39 | | | 39 | | | 39 | | | 39 | | 7 | 31 | | | 31 | 32 |
| Digital | 1 | | 31 | | 2 | 32 | | 2 | 30 | | | 30 | | | 30 | 1 | | 31 | | 3 | 28 | | 1 | 27 | 24 |
| EHS | | 1 | 43 | 1 | 10 | 34 | | 1 | 32 | 1 | | 33 | | 1 | 31 | | 1 | 30 | | | 30 | | | 30 | 30 |
| External Affairs and Sustainability | | | 1 | | | 1 | | | 1 | | | 1 | | | 1 | | | 1 | | | 1 | | | 1 | 1 |
| FP&A and Strategic Finance | | | 11 | | 3 | 8 | | | 8 | | | 8 | 1 | | 10 | | | 10 | | | 10 | | | 10 | 10 |
| Growth & Customer Experience | | | 4 | | | 4 | | | 4 | | | 4 | | | 4 | | | 4 | | | 4 | | 1 | 3 | 3 |
| Human Resources | 1 | 1 | 20 | | 5 | 15 | 2 | | 17 | 1 | | 17.5 | | 1 | 16.5 | 2 | | 18.5 | | 3 | 15.5 | | | 15.5 | 15.5 |
| Internal Audit & Controls - US | | 1 | 7 | | 2 | 5 | | | 5 | | | 5 | | | 5 | 1 | | 6 | | 1 | 5 | | | 5 | 5 |
| Legal | | | 25.75 | 1 | 5 | 21.75 | | 1 | 20.75 | | | 20.75 | | | 20.75 | | | 20.75 | | | 20.75 | | | 20.75 | 20.75 |
| Office of the CFO | | | 5 | | | 5 | | | 5 | 7 | | 12 | | | 11 | | 4 | 7 | | 1 | 4 | | | 4 | 4 |
| Office of the President & CEO | | | 2 | | | 2 | | | 3 | | | 3 | | | 3 | | | 3 | | | 3 | | | 3 | 4 |
| Operations Services | 2 | 2 | 140 | | 4 | 136 | | 3 | 134 | 1 | 1 | 135 | | 1 | 134 | | 1 | 133 | | 6 | 127 | | 1 | 127 | 123 |
| Performance Management | | | 6 | | 4 | 2 | | | 3 | | | 3 | | | 3 | | | 3 | | | 3 | | | 3 | 2 |
| Public Affairs | | | 2 | | | 2 | | | 2 | 1 | | 3 | | | 3 | | | 3 | | 1 | 2 | | | 2 | 2 |
| Rates & Regulatory Affairs | | | 10 | | | 10 | | | 10 | | | 10 | | | 10 | | | 10 | | 1 | 9 | | | 9 | 9 |
| Retail Operations | | | 5 | | 1 | 4 | | | 4 | | | 4 | | | 4 | | | 4 | | | 4 | | 1 | 3 | 3 |
| Risk Management | | | 9 | | 3 | 6 | | | 6 | | | 6 | | | 6 | | | 6 | | 1 | 5 | | | 5 | 5 |
| Sales & Customer Growth | | | 59 | | 5 | 54 | | | 54 | | | 54 | | | 54 | | 2 | 53 | | 6 | 47 | | | 47 | 44 |
| Strategy | | 1 | 8 | | 2 | 6 | 2 | | 6 | | | 6 | | | 6 | | 2 | 4 | | | 4 | | | 4 | 4 |
| Supply Chain | | | 14 | | 2 | 12 | 1 | | 13 | | | 13 | | | 13 | | | 13 | | 2 | 11 | | | 11 | 11 |
| System Operations | 1 | 1 | 617 | | 12 | 606 | | 3 | 605 | 1 | 3 | 605 | | 4 | 609 | 1 | 2 | 608 | 1 | 14 | 593 | 5 | 6 | 593 | 591 |
| Tax | | 1 | 12 | | 2 | 10 | | | 10 | | 1 | 9 | 8 | | 9 | | 1 | 8 | | | 8.5 | 2 | | 10.5 | 10.5 |
| Treasury | | | 2.5 | | 1 | 1.5 | | | 1.5 | | | 2 | | | 3 | | | 3 | | | 3 | | | 3 | 3 |
| **Grand Total** | 7.00 | 10.00 | **1501.25** | 3.00 | 82.50 | **1422.75** | 7.00 | 15.00 | **1414.75** | 14.00 | 9.00 | **1419.75** | 9.00 | 9.00 | **1418.75** | 8.00 | 18.00 | **1408.75** | 2.00 | 73.00 | **1337.25** | 8.00 | 12.00 | **1333.25** | **1317.25** |

| | 2024 | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Mar | | | Apr | | | May | | | Jun | | | Jul | | | Aug | | | Sep | | | Oct | | | Nov |
| **Employee Class** | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | Hires | Terms | Month End HC | HC 22Nov2024 |
| Management | 3 | 8 | 806.25 | 3 | 76.5 | 732.75 | 6 | 12 | 726.75 | 12 | 5 | 733.75 | 1 | 4 | 729.75 | 7 | 15 | 721.75 | 0 | 69 | 652.25 | 3 | 7 | 650.25 | 640.25 |
| Union | 4 | 2 | 695 | 0 | 6 | 690 | 1 | 3 | 688 | 2 | 4 | 686 | 8 | 5 | 689 | 1 | 3 | 687 | 2 | 4 | 685 | 5 | 5 | 683 | 677 |
| **Grand Total** | 7.00 | 10.00 | **1501.25** | 3.00 | 82.50 | **1422.75** | 7.00 | 15.00 | **1414.75** | 14.00 | 9.00 | **1419.75** | 9.00 | 9.00 | **1418.75** | 8.00 | 18.00 | **1408.75** | 2.00 | 73.00 | **1337.25** | 8.00 | 12.00 | **1333.25** | **1317.25** |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Finance Total** | **0** | **2** | **94** | **1** | **21.5** | **73.5** | **1** | **1** | **73.5** | **0** | **1** | **72** | **9** | **0** | **74** | **1** | **1** | **74** | **0** | **3** | **71.5** | **2** | **0** | **73.5** | **73.5** |

For finance, most months (Mar, May, June, Aug, Oct) reflect minor changes in headcount of one or two people. This is due to normal ongoing, individual decisions by employees departing or management making vacancy hires. April reductions reflect the impacts of involuntary separations. Tax did not hire 8 people in July. Likely due to hires for the summer internship program. September reductions are driven by employees accepting voluntary separation.

| | 2021* | | | 2022 | | |
|---|---|---|---|---|---|---|
| **Functional Area** | Hires | Terms | YE FTE HC | Hires | Terms | YE FTE HC |
| Accounting | 8 | 9 | 53 | 14 | 8 | 53.5 |
| Asset Management, Engineering & Supply* | 7 | *15* | 177 | 24 | 23.5 | 175 |
| Business Services | | | 2 | 0.5 | | 2.5 |
| Business Transformation | 1 | | | | | |
| Construction** | 5 | *20* | 116 | 17 | 11 | 132 |
| Corporate Communication | 1 | 3 | 5 | 6 | 1 | 9.5 |
| Corporate Public Policy | 3 | 1 | 5 | 2 | 1 | 6 |
| Customer Billing | | 2 | 7 | 1 | | 14 |
| Customer Experience | 1 | 3 | 43 | 7 | 2 | 50 |
| Digital | 1 | 3 | 27 | 4 | 5 | 21 |
| EHS | 3 | 9 | 39 | 3 | 4 | 41 |
| External Affairs and Sustainability | | | | | | 1 |
| FP&A and Strategic Finance | 1 | 3 | 10 | 5 | 7 | 10 |
| Growth & Customer Experience | 2 | 7 | | | | |
| Human Resources | 6 | 7 | 23.15 | 11 | 10.4 | 26.75 |
| Internal Audit & Controls - US | 1 | 2 | 13 | 4 | 4 | 11 |
| Legal | 4 | 5 | 19 | 3 | 1 | 19 |
| Office of the CFO | 2 | 1 | 4 | 1 | 2 | 4 |
| Office of the President & CEO | | | 3 | 1 | 1 | 2 |
| Operations Services | 15 | 4 | 167 | 20 | 22 | 152.5 |
| Performance Management | 1 | 1 | 5 | 4 | 4 | 6 |
| Public Affairs | 1 | 1 | 4 | 1 | 1 | 4 |
| Rates & Regulatory Affairs | | 1 | 8 | 1 | | 9 |
| Retail Operations | | | 3 | | | 5 |
| Risk Management | | 3 | 9 | 1 | 2 | 9 |
| Sales & Customer Growth | 5 | 6 | 47 | 7 | 3 | 56 |
| Strategy | 3 | 5 | 7 | 6 | 2 | 9 |
| Supply Chain | 2 | 3 | 6 | 14 | 2 | 20 |
| System Operations | 11 | 43 | 640 | 43 | 34 | 638 |
| Tax | 2 | 2 | 12 | 2 | 2 | 11 |
| Treasury | | | 3 | 1 | 2 | 2 |
| Other*** | | 2 | | | | |
| **Grand Total** | 86.00 | 161.00 | **1457.15** | 203.50 | 154.90 | **1499.75** |

**For 2021 Only:**

*Historical functional area "Gas Supply & Engineering" added to "Asset Management, E

**Historical functional area "Construction, Compliance, & Safety" added to "Constructi

***Includes Historical functional areas "Office of SVP Utility Operations" and "US Midst

| | 2021 | | | 2022 | | |
|---|---|---|---|---|---|---|
| **Employee Class** | **Hires** | **Terms** | **YE FTE HC** | **Hires** | **Terms** | **YE FTE HC** |
| Management | | 13 | 737.15 | 148.5 | 111.9 | 784.75 |
| Union | | 6 | 720 | 55 | 43 | 715 |
| **Grand Total** | 86.00 | 19.00 | **1457.15** | 203.50 | 154.90 | **1499.75** |

| 2023 | | | 2024 | | |
|---|---|---|---|---|---|
| **Hires** | **Terms** | **YE FTE HC** | **Hires** | **Terms** | **YE FTE HC**** |
| 6 | 4 | 54.5 | 3 | 15.5 | 40 |
| 29 | 20 | 194 | 5 | 26 | 172 |
| 0.5 | 0.5 | 2.5 | | | 2.5 |
| 6 | 1 | 18 | | 3 | 12 |
| 5 | 12 | 126 | 3 | 17 | 110 |
| | | 10 | | 7 | 3 |
| | | 6 | | 1 | 6 |
| 3 | 0 | 17 | 1 | 1 | 20 |
| 5 | 4 | 45 | 1 | 12 | 31 |
| 9 | 4 | 28 | 5 | 9 | 27 |
| 8 | 3 | 46 | 2 | 16 | 30 |
| | | 1 | | | 1 |
| 1 | 1 | 10.5 | 1 | 3 | 10 |
| | | 4 | | 1 | 3 |
| 5 | 4 | 20.75 | 6 | 11 | 15.5 |
| 2 | 4 | 9 | 1 | 5 | 5 |
| 1 | 1 | 25.75 | 1 | 6 | 20.75 |
| 12 | 10 | 6 | 7 | 5 | 4 |
| | | 2 | | 1 | 3 |
| 14 | 12.5 | 139 | 4 | 24 | 127 |
| 1 | 2 | 6 | | 4 | 3 |
| 0 | 2 | 3 | 1 | 1 | 2 |
| 1 | 1 | 10 | | 1 | 9 |
| | | 5 | | 2 | 3 |
| | | 9 | | 4 | 5 |
| 7 | 5 | 57 | 1 | 13 | 47 |
| 2 | 2 | 9 | 2 | 5 | 4 |
| 1 | 5 | 16 | 1 | 5 | 11 |
| 30 | 39 | 621 | 22 | 48 | 593 |
| 3 | 2 | 12 | 3 | 5 | 10.5 |
| | | 2.5 | | 1 | 3 |
| | | | | | |
| 151.50 | 139.00 | **1515.50** | 70.00 | 252.50 | **1333.25** |

**as of most recent complet

ngineering, & Supply"

on"

ream"

| 2023 | | | 2024 | | |
|---|---|---|---|---|---|
| Hires | Terms | YE FTE HC | Hires | Terms | YTD FTE HC** |
| 113.5 | 90 | 821.5 | 44 | 216.5 | 650.25 |
| 38 | 49 | 694 | 26 | 36 | 683 |
| 151.50 | 139.00 | **1515.50** | 70.00 | 252.50 | **1333.25** |

**as of most recent complet

e month (Oct 31, 2024)

e month (Oct 31, 2024)

| | 2022 | | | | | | | | | | | | 2023 | | | | | | | | | | | | 2024 | | | Variance Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Functional Area** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | |
| Accounting | 54 | 54 | 52 | 51 | 52 | 61 | 60 | 55 | 55 | 53 | 54 | 54 | 54 | 54 | 53 | 54 | 54 | 54 | 53 | 51 | 52 | 54 | 54 | 55 | 53 | 53 | 53 | No significant changes. Note increase in summer 2022 relates to summer intern program |
| Asset Management, Engineering & Supply | 175 | 172 | 172 | 169 | 175 | 182 | 181 | 180 | 181 | 180 | 179 | 175 | 179 | 179 | 180 | 183 | 188 | 190 | 192 | 191 | 194 | 196 | 195 | 194 | 193 | 190 | 192 | Movement of employees from Operations Services in mid-2023 |
| Business Services | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | No significant changes. |
| Business Transformation | | | | | | | | | | | | | | | | | | 15 | 15 | 16 | 18 | 18 | 19 | 18 | 18 | 18 | 18 | New department created to focus on efficiencies |
| Construction | 118 | 122 | 124 | 124 | 125 | 125 | 128 | 126 | 125 | 133 | 133 | 132 | 133 | 132 | 132 | 132 | 129 | 129 | 128 | 128 | 127 | 127 | 127 | 126 | 125 | 124 | 123 | Minor changes focused on business needs, APRP and new business work |
| Corporate Communication | 5 | 5 | 6 | 6 | 5 | 8 | 7 | 9 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 9 | Vacancies in early 2022 filled; no significant change therafter |
| Corporate Public Policy | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 7 | No significant changes. |
| Customer Billing | 7 | 7 | 9 | 9 | 11 | 12 | 12 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 15 | 16 | 16 | 16 | 17 | 17 | 18 | 20 | 20 | Growth with variations on business needs; some movement from Customer Experience |
| Customer Experience | 44 | 42 | 44 | 45 | 46 | 48 | 48 | 46 | 47 | 48 | 50 | 50 | 45 | 45 | 45 | 44 | 47 | 48 | 47 | 46 | 45 | 44 | 45 | 45 | 45 | 43 | 43 | Movement of employees to Growth and Customer Experience and Customer Billing |
| Digital | 26 | 24 | 24 | 25 | 26 | 25 | 24 | 23 | 21 | 22 | 21 | 21 | 21 | 21 | 22 | 24 | 24 | 25 | 26 | 28 | 29 | 29 | 28 | 28 | 30 | 30 | 31 | Growth with emphasis on IT projects |
| EHS | 39 | 40 | 40 | 41 | 40 | 41 | 39 | 39 | 39 | 40 | 40 | 41 | 41 | 41 | 41 | 40 | 40 | 42 | 43 | 42 | 43 | 45 | 46 | 46 | 45 | 44 | 43 | Minor increases with increase safety staffing |
| External Affairs and Sustainability | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | No significant changes. |
| FP&A and Strategic Finance | 11 | 11 | 10 | 9 | 9 | 12 | 12 | 11 | 9 | 10 | 10 | 10 | 10 | 11 | 11 | 11 | 11 | 11 | 10 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | No significant changes. |
| Growth & Customer Experience | | | | | | | | | | | | | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | Group split out from Customer Experience |
| Human Resources | 25 | 24 | 24 | 26 | 24 | 26 | 25 | 26 | 25 | 25 | 26 | 27 | 20 | 20 | 21 | 22 | 22 | 22 | 22 | 23 | 23 | 23 | 20 | 21 | 21 | 20 | 20 | Movement of certain employees (Labor Relations, etc) to Legal at start of 2023 |
| Internal Audit & Controls - US | 12 | 12 | 13 | 13 | 12 | 14 | 13 | 11 | 11 | 11 | 11 | 11 | 10 | 10 | 11 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 7 | Staff turnover, some aspects of work shifted to Calgary |
| Legal | 18 | 19 | 19 | 18 | 18 | 18 | 18 | 18 | 19 | 20 | 20 | 19 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | Movement of certain employees (Labor Relations, etc) from HR at start of 2023 |
| Office of the CFO | 4 | 4 | 4 | 4 | 4 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 5 | 5 | 18 | 18 | 6 | 6 | 6 | 6 | 6 | 6 | 5 | 5 | No significant changes. Note increase in summer relates to summer intern program |
| Office of the President & CEO | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 1 | 2 | 2 | No significant changes. |
| Operations Services | 164 | 163 | 163 | 157 | 159 | 151 | 152 | 154 | 155 | 155 | 153 | 153 | 154 | 156 | 156 | 155 | 157 | 139 | 139 | 138 | 138 | 138 | 137 | 139 | 139 | 139 | 140 | Movement of employees to Asset Mgt, Engineering in mid-2023 |
| Performance Management | 5 | 5 | 5 | 3 | 3 | 4 | 4 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 7 | 8 | 8 | 7 | 7 | 6 | 6 | 6 | 6 | 6 | No significant changes. |
| Public Affairs | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 3 | 3 | 3 | 3 | 2 | No significant changes. |
| Rates & Regulatory Affairs | 8 | 8 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | No significant changes. |
| Retail Operations | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | No significant changes. |
| Risk Management | 9 | 9 | 9 | 8 | 8 | 7 | 7 | 7 | 8 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | No significant changes. |
| Sales & Customer Growth | 48 | 49 | 50 | 50 | 51 | 50 | 51 | 54 | 54 | 55 | 55 | 56 | 55 | 55 | 55 | 55 | 57 | 57 | 57 | 58 | 58 | 58 | 57 | 57 | 58 | 59 | 59 | Increase in staffing relating to growth in Energy Efficiency programs (e.g., MD Empower) |
| Strategy | 6 | 6 | 6 | 6 | 8 | 9 | 9 | 7 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 11 | 11 | 11 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 8 | No significant changes. Note increase in summer 2023 relates to summer intern program |
| Supply Chain | 6 | 6 | 6 | 7 | 10 | 11 | 15 | 16 | 15 | 18 | 21 | 20 | 18 | 18 | 18 | 16 | 16 | 16 | 16 | 16 | 17 | 16 | 16 | 16 | 14 | 14 | 14 | Growth in 2022 as contractors were replaced by FTE's; minimal changes therafter |
| System Operations | 635 | 639 | 637 | 637 | 639 | 637 | 633 | 635 | 631 | 638 | 639 | 638 | 637 | 636 | 631 | 628 | 625 | 620 | 616 | 619 | 616 | 623 | 621 | 621 | 621 | 618 | 617 | Minor variations on business needs; also decline in leaks |
| Tax | 12 | 12 | 12 | 12 | 11 | 12 | 12 | 12 | 12 | 11 | 11 | 11 | 12 | 12 | 13 | 12 | 13 | 13 | 13 | 12 | 12 | 12 | 12 | 12 | 13 | 13 | 12 | No significant changes. |
| Treasury | 3 | 3 | 3 | 3 | 3 | 4 | 4 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | No significant changes. |
| **Grand Total** | **1453** | **1456** | **1462** | **1453** | **1469** | **1493** | **1490** | **1486** | **1484** | **1503** | **1507** | **1502** | **1505** | **1506** | **1506** | **1503** | **1512** | **1524** | **1522** | **1510** | **1513** | **1524** | **1517** | **1518** | **1514** | **1506** | **1503** | |

| | 2022 | | | | | | | | | | | | 2023 | | | | | | | | | | | | 2024 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **FLSA Status** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | |
| Exempt | 675 | 675 | 683 | 676 | 681 | 696 | 698 | 706 | 703 | 716 | 722 | 722 | 729 | 733 | 738 | 738 | 742 | 743 | 743 | 749 | 754 | 759 | 754 | 755 | 752 | 745 | 741 | Growth in certain groups, notably Business Transformation and Digital |
| Non Exempt | 778 | 781 | 779 | 777 | 788 | 797 | 792 | 781 | 781 | 787 | 785 | 780 | 776 | 773 | 768 | 765 | 770 | 781 | 779 | 761 | 759 | 765 | 763 | 763 | 762 | 761 | 762 | Minor variations on business needs; also decline in leaks |
| **Grand Total** | **1453** | **1456** | **1462** | **1453** | **1469** | **1493** | **1490** | **1487** | **1484** | **1503** | **1507** | **1502** | **1505** | **1506** | **1506** | **1503** | **1512** | **1524** | **1522** | **1510** | **1513** | **1524** | **1517** | **1518** | **1514** | **1506** | **1503** | |

| | 2022 | | | | | | | | | | | | 2023 | | | | | | | | | | | | 2024 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Employee Class** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | |
| Management | 735 | 734 | 742 | 734 | 746 | 778 | 778 | 769 | 767 | 783 | 788 | 787 | 794 | 797 | 802 | 804 | 814 | 830 | 831 | 819 | 824 | 829 | 823 | 824 | 820 | 813 | 808 | Growth in certain groups, notably Business Transformation and Digital |
| Union | 718 | 722 | 720 | 719 | 723 | 715 | 712 | 718 | 717 | 720 | 719 | 715 | 711 | 709 | 704 | 699 | 698 | 694 | 691 | 691 | 689 | 695 | 694 | 694 | 694 | 693 | 695 | Minor variations on business needs; also decline in leaks |
| **Grand Total** | **1453** | **1456** | **1462** | **1453** | **1469** | **1493** | **1490** | **1487** | **1484** | **1503** | **1507** | **1502** | **1505** | **1506** | **1506** | **1503** | **1512** | **1524** | **1522** | **1510** | **1513** | **1524** | **1517** | **1518** | **1514** | **1506** | **1503** | |

Exhibit OPC (B)-68
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-13

**Q.** **Overtime Payroll Costs.** WGL's Supplemental Filing (Compliance Filing) §206-22, shows full-time equivalent employees (headcount) on a monthly basis for the period January 2022 through March 2024 for Management versus Union. Also, Adjustment No. 5, (Exhibit WG (D)-5, page 14) shows Union employee payroll expense for the test period end March 31, 2024. Please address the following:

a. For each of the calendar years 2020, 2021, 2022, 2023, and test period end March 31, 2024, provide the total WGL payroll expense for Union employees (similar to the Union payroll expense format at Adjustment No. 5, (Exhibit WG (D)-5, page 14), and explain the reasons for changes in these payroll expenses from year-to-year. If possible, provide the Union employee payroll expense by each type of Union (such as per Exhibit WG (D)-5, page 14), such as the Unions of Frederick, Shenandoah, IBT, Local 2, etc.

b. Provide the amount of overtime expense for each of the same periods in (a) above and by each type of Union (Frederick, Shenandoah, IBT, Local 2, etc.), and explain the reasons for changes in these payroll overtime expenses for each of the same periods in (a) above.

c. Regarding (a) above, provide the related Union employee headcount by month (by type of Union if possible) for each month of the same periods January 2020 through March 31, 2024 (and months subsequent to March 2024), and explain the reasons for changes in headcount from January 2020 through March 31, 2024 for each of these Union groups.

d. Regarding (a) and (b) above, identify which of the Unions incur overtime payroll costs related to leak identification and repair, and provide the related overtime payroll expense related to leak identification and repair for each of the periods in (a) above. Explain the reasons for the changes in overtime-related payroll expense related to leak identification and repair for each of the periods in (a) above.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.**

a. Refer to Attachment No. 1 for the requested detail. Union payroll expense varies from year to year generally based on the number of union employees in addition to contractually obligated pay increases and the amount of overtime incurred.

b. Refer to Attachment No. 2 for the requested information. Changes in overtime pay are driven by emergency work such as meter repairs, leak repairs, and other critical maintenance.

c. Refer to Attachment No. 3 for union headcount for January 2020 – December 2021. Refer to Compliance Filing Item 206.22 for union headcount for January 2022 through March 2024. Refer to the Company's response to OPC Data Request 11-12(b) for post-test year union headcount.

   Union headcount fluctuates with business needs and employee turnover.

d. Refer to Attachment No. 4 for the requested information. Refer to part (b) above for the reasons for changes in over-time pay.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

# Washington Gas Light Company
# District of Columbia Jurisdiction

## Union Gross Pay

| No. | Description | TME Dec 2020 | TME Dec 2021 | TME Dec 2022 | TME DEC 2023 | TME Mar 2024 1/ |
|---|---|---|---|---|---|---|
| | A | B | C | D | E | F |
| 1 | Frederick Union | $ 2,089,934 | $ 2,003,000 | $ 2,024,995 | $ 2,205,634 | $ 2,236,285 |
| 2 | IBT Union | $ 59,670,320 | $ 60,607,087 | $ 62,507,771 | $ 66,012,595 | $ 67,841,004 |
| 3 | Local 2 Union | $ 7,439,497 | $ 7,308,448 | $ 7,040,279 | $ 6,878,442 | $ 6,952,074 |
| 4 | Shenandoah | $ 2,673,682 | $ 2,699,003 | $ 2,765,322 | $ 2,938,832 | $ 3,003,954 |
| 5 | **Total Gross Pay** | **$ 71,873,434** | **$ 72,617,537** | **$ 74,338,367** | **$ 78,035,503** | **$ 80,033,317** |

Notes:
1/ TME MAR 2024 is test year, April 2023 through March 2024

## Washington Gas Light Company
## District of Columbia Jurisdiction

### Union Overtime Pay

| Line No. | Description | TME Dec 2020 | TME Dec 2021 | TME Dec 2022 | TME Dec 2023 | TME Mar 2024 1/ |
|---|---|---|---|---|---|---|
| | A | B | C | D | E | F |
| 1 | Frederick Union | $ 162,668 | $ 146,235 | $ 163,538 | $ 141,107 | $ 170,080 |
| 2 | IBT Union | $ 10,666,497 | $ 11,185,616 | $ 12,411,140 | $ 15,051,163 | $ 16,541,225 |
| 3 | Local 2 Union | $ 516,267 | $ 529,561 | $ 555,172 | $ 578,654 | $ 598,867 |
| 4 | Shanandoah Union | $ 131,760 | $ 95,559 | $ 114,487 | $ 133,814 | $ 151,797 |
| 5 | Union Overtime Pay | $ 11,477,192 | $ 11,956,971 | $ 13,244,337 | $ 15,904,737 | $ 17,461,969 |

Notes:
1/ TME Mar 2024 is test year, April 2023 through March 2024

| | 2020 | | | | | | | | | | | | 2021 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Functional Area** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
| Functional Area - Accounting & Tax | 74 | 74 | 73 | 73 | 73 | 72 | 73 | 70 | 69 | 68 | 71 | 56 | 56 | 54 | 52 | 51 | 51 | 50 | 51 | 51 | 52 | 52 | 53 | 53 |
| Functional Area - Business Development Strategy and NonUtility Ops | | | | | | | | | | | | | | | | | | | | | | | | |
| Functional Area - Business Services | 50 | 48 | 47 | 47 | 46 | 48 | 45 | 45 | 48 | 47 | 44 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 17 | 17 | 17 | 16 | 16 | 15 |
| Functional Area - Construction, Compliance & Safety | 196 | 196 | 195 | 194 | 195 | 194 | 193 | 195 | 195 | 195 | 198 | 198 | 195 | 195 | 193 | 190 | 189 | 189 | 186 | 186 | 183 | 182 | 180 | 180 |
| Functional Area - Consumer Services | | | | | | | | | | | | | | | | | | | | | | | | |
| Functional Area - Corporate Communication | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 5 | 5 |
| Functional Area - Corporate Development | | | | | | | | | | | | | | | | | | | | | | | | |
| Functional Area - Corporate Public Policy | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 5 | 5 | 5 | 5 |
| Functional Area - Corporate Social Responsibility | 9 | 8 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 4 | 3 | 5 | 5 | 5 |
| Functional Area - CRO Utility | | | | | | | | | | | | | | | | | | | | | | | | |
| Functional Area - Digital | 43 | 43 | 43 | 43 | 43 | 41 | 38 | 37 | 37 | 36 | 35 | 33 | 25 | 24 | 25 | 25 | 25 | 25 | 28 | 27 | 27 | 26 | 28 | 28 |
| Functional Area - EHS | | | | | | | | | | | | 41 | 44 | 44 | 44 | 43 | 41 | 40 | 40 | 40 | 39 | 37 | 37 | 39 |
| Functional Area - FP&A and Strategic Finance | 16 | 15 | 15 | 15 | 16 | 17 | 17 | 18 | 18 | 16 | 17 | 14 | 14 | 14 | 14 | 13 | 11 | 11 | 11 | 11 | 10 | 11 | 11 | 10 |
| Functional Area - Gas Supply & Engineering | 180 | 180 | 181 | 176 | 177 | 179 | 176 | 176 | 173 | 173 | 173 | 163 | 166 | 163 | 162 | 160 | 161 | 162 | 161 | 159 | 158 | 158 | 157 | 157 |
| Functional Area - Gen Counsel & Corp Secretary | | | | | | | | | | | | | | | | | | | | | | | | |
| Functional Area - Growth & Customer Experience | 113 | 111 | 108 | 105 | 103 | 102 | 101 | 100 | 100 | 97 | 100 | 99 | 100 | 99 | 100 | 97 | 95 | 96 | 96 | 93 | 90 | 88 | 89 | 92 |
| Functional Area - Human Resources | 32 | 30 | 28 | 27 | 27 | 28 | 29 | 27 | 27 | 25 | 24 | 25 | 25 | 26 | 24 | 23 | 23 | 21 | 22 | 22 | 23 | 22 | 23 | 24 |
| Functional Area - Information Technology Service | | | | | | | | | | | | | | | | | | | | | | | | |
| Functional Area - Internal Audit & Controls | 15 | 15 | 15 | 15 | 14 | 14 | 14 | 14 | 14 | 14 | 13 | 14 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Functional Area - Legal | 23 | 23 | 23 | 22 | 21 | 22 | 23 | 23 | 23 | 21 | 20 | 20 | 20 | 18 | 18 | 18 | 19 | 20 | 19 | 19 | 18 | 18 | 20 | 19 |
| Functional Area - Office of SVP Utility Ops | 7 | 7 | 7 | 6 | 6 | 6 | 6 | 6 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 5 | 6 | 6 | 6 | 6 | 6 | 6 |
| Functional Area - Office of CFO | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 3 | 2 | 3 | 3 | 3 | 3 | 4 | 4 | 4 | 4 |
| Functional Area - Office of the President & CEO | 2 | 1 | 2 | 2 | 2 | 3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Functional Area - Performance Management | | | | | | | 3 | 4 | 4 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 7 | 7 | 6 | 6 | 6 | 6 | 5 |
| Functional Area - Public Affairs | 4 | 4 | 7 | 7 | 7 | 7 | 7 | 7 | 5 | 5 | 5 | 4 | 3 | 3 | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Functional Area - Rates & Regulatory Affairs | 12 | 12 | 12 | 12 | 12 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 10 | 10 | 10 | 9 | 9 | 9 | 9 | 8 |
| Functional Area - Retail Operations | | | | | | | | | | | | 2 | 5 | 5 | 5 | 5 | 5 | 5 | 3 | 3 | 3 | 3 | 2 | 2 |
| Functional Area - Risk Management | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 12 | 12 | 11 | 10 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Functional Area - Safety, Quality, & System Prot | 182 | 184 | 185 | 186 | 186 | 186 | | | | | | | | | | | | | | | | | | |
| Functional Area - Shared Services & CHRO | | | | | | | 188 | 186 | 188 | 187 | 187 | | | | | | | | | | | | | |
| Functional Area - State & Local Policy | 5 | 5 | 5 | 5 | 5 | 5 | 4 | 4 | | | | | | | | | | | | | | | | |
| Functional Area - Strategy | | | | | | | | | 4 | 4 | 7 | 7 | 6 | 6 | 9 | 9 | 9 | 12 | 9 | 9 | 10 | 10 | 7 | 7 |
| Functional Area - Supply Chain | 8 | 7 | 7 | 7 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 6 | 6 |
| Functional Area - Support Services | | | | | | | | | | | | | | | | | | | 10 | 10 | 10 | 10 | 11 | 17 |
| Functional Area - System Operations | 598 | 591 | 595 | 596 | 596 | 593 | 594 | 592 | 585 | 586 | 590 | 773 | 777 | 776 | 771 | 766 | 765 | 758 | 742 | 737 | 736 | 736 | 737 | 728 |
| Functional Area - Tax | | | | | | | | | | | | 12 | 12 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 13 | 13 | 12 |
| Functional Area - Treasury | | | | | | | | | | | | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Functional Area - US Midstream | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | | | | | |
| Functional Area - Treasury, FP&A, and Strategic Finance | | | | | | | | | | | | | | | | | | | | | | | | |
| Functional Area - Utility Operations | | | | | | | | | | | | | | | | | | | | | | | | |
| Functional Area - WGL Energy Services | 1 | 1 | 1 | | | | | | | | | | | | | | | | | | | | | |
| **Grand Total** | **1596** | **1581** | **1580** | **1569** | **1566** | **1564** | **1560** | **1553** | **1544** | **1535** | **1543** | **1539** | **1537** | **1526** | **1521** | **1503** | **1500** | **1495** | **1486** | **1472** | **1462** | **1460** | **1462** | **1459** |

| | 2020 | | | | | | | | | | | | 2021 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **FLSA Status** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
| Exempt | 776 | 767 | 816 | 814 | 813 | 812 | 809 | 806 | 804 | 804 | 808 | 808 | 809 | 806 | 804 | 801 | 801 | 798 | 693 | 685 | 678 | 676 | 677 | 679 |
| Non Exempt | 820 | 814 | 764 | 755 | 753 | 752 | 751 | 747 | 740 | 731 | 735 | 731 | 728 | 720 | 717 | 702 | 699 | 697 | 793 | 787 | 784 | 784 | 785 | 780 |
| **Grand Total** | **1596** | **1581** | **1580** | **1569** | **1566** | **1564** | **1560** | **1,553** | **1544** | **1535** | **1543** | **1539** | **1537** | **1526** | **1521** | **1503** | **1500** | **1495** | **1486** | **1472** | **1462** | **1460** | **1462** | **1459** |

| | 2020 | | | | | | | | | | | | 2021 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Employee Class** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
| Management | 843 | 832 | 828 | 818 | 817 | 816 | 815 | 812 | 805 | 792 | 796 | 793 | 791 | 783 | 781 | 764 | 761 | 763 | 756 | 746 | 739 | 735 | 737 | 739 |
| Union | 753 | 749 | 752 | 751 | 749 | 748 | 745 | 741 | 739 | 743 | 747 | 746 | 746 | 743 | 740 | 739 | 739 | 732 | 730 | 726 | 723 | 725 | 725 | 720 |
| **Grand Total** | **1596** | **1581** | **1580** | **1569** | **1566** | **1564** | **1560** | **1553** | **1544** | **1535** | **1543** | **1539** | **1537** | **1526** | **1521** | **1503** | **1500** | **1495** | **1486** | **1472** | **1462** | **1460** | **1462** | **1459** |

## Washington Gas Light Company
## District of Columbia Jurisdiction

### Union Overtime Payroll Related to Leaks

| Line No. | Account | TME Dec 2020 | TME Dec 2021 | TME Dec 2022 | TME Dec 2023 | TME Mar 2024 1/ |
|---|---|---|---|---|---|---|
| 1 | 887000 | $ 2,224,615 | $ 878,071 | $ 872,491 | $ 800,692 | $ 835,807 |
| 2 | 892300 | $ 1,548,997 | $ 3,430,628 | $ 3,360,002 | $ 3,555,772 | $ 3,870,923 |
| 3 | 893300 | $ 3,204,578 | $ 3,807,730 | $ 4,021,356 | $ 4,596,221 | $ 4,826,706 |
| 4 | Total | $ 6,978,190 | $ 8,116,428 | $ 8,253,848 | $ 8,952,686 | $ 9,533,436 |

Notes:
1/ TME Mar 2024 is test year, April 2023 through March 2024

Exhibit OPC (B)-69
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-14

**Q.** **Short-Term Incentive Expense.** WGL Witness Smith (10:7-11) states that short-term incentive costs are included this rate case (and have not been removed), and Adjustment No. 5, (Exhibit WG (D)-5, page 14) appears to include these short-term incentive expenses (although the specific amounts are not identified) in the payroll annualization adjustment of this rate case. Adjustment No. 13 (Exhibit WG (D)-5, page 1 of 4) shows the amount of short-term incentive expense removed for employees eliminated via the involuntary separation program O&M expenses. Also, Adjustment No. 14 (Exhibit WG (D)-5, page1 of 5 shows the amount of short-term incentive expense included in the amortization of involuntary separation program costs. Please address the following:

a. Provide the amount of short-term incentive expensed by month and account number for each of the calendar years 2020, 2021, 2022, 2023 and for the test year end March 31, 2024, (before any rate case adjustments for the test period), and reconcile these incentive costs to the test year end March 31, 2024, payroll costs at Adjustment No. 5, Exhibit WG (D)-5, page 14.

b. Regarding (a) above, provide this same information for capitalized incentive costs for the same periods.

c. Regarding (a) above, begin with the short-term incentive expense per books at March 31, 2024, and provide the amount of short-term incentive expense removed and reflected in: (i) Adjustment No. 13 (Exhibit WG (D)-5, page 1 of 4); and (ii) Adjustment No. 14 (Exhibit WG (D)-5, page 1 of 5).

d. Regarding (a) and (c) above, begin with the short-term incentive expense per books at March 31, 2024, and provide the provide amount by which short-term incentive expense is increased due to the percentage salary increases at the payroll annualization adjustment at Adjustment No. 5 (Exhibit WG (D)-5, page 1 of 15).

e. Regarding (c) and (d) above, show all rate case adjustments to short-term incentive expense to arrive at the final adjusted net short-term incentive expense included in the adjusted test year end balance at March 31, 2024.

**WASHINGTON GAS'S RESPONSE** 11/25/2024

**A.**

a. Refer to the Company's response to OPC Data Request 10-5, Attachment No. 1 for the requested information.

b. Refer to the Company's response to OPC Data Request 10-5, Attachment No. 1 for the requested information.

c. Refer to Attachment No. 1 for the requested information.

d. Refer to Attachment No. 1 for the requested information.

e. Refer to Attachment No. 1 for the requested information.

SPONSOR: Tracey M. Smith
Director, Regulatory Accounting & Financial Reporting

Washington Gas Light Company
District of Columbia Jurisdiction

**Short-term Incentive Compensation After Adjustments**

Twelve Months Ended March 31, 2024

| Line | Description | Reference | System | O&M Factor | Factor **(NOTE 2)** | Amort | DC Amount |
|---|---|---|---|---|---|---|---|
| 1 | Per book STI TME March 2024 booked to O&M **(NOTE 1)** | OPC DR 10-5 Att 1 Pg 1 | $ 12,392,696 | 100.00% | 19.54% | | $ 2,421,634 |
| 2 | Per book STI TME March 2024 booked to Capital | OPC DR 10-5 Att 1 Pg 1 | 2,416,185 | 0.00% | 19.08% | | - |
| 3 | Per book STI TME March 2024 booked to Non-utility Affiliates | OPC DR 10-5 Att 1 Pg 1 | 267,640 | 0.00% | 19.54% | | - |
| 4 | Per book ST TME March 2024 inbounds ALA | OPC DR 10-5 Att 2 Pg 1 | 3,022,520 | 100.00% | 19.54% | | 590,625 |
| 5 | Incremental STI in Adjustment No. 5 | Analysis | 647,001 | 75.53% | 19.36% | | 94,605 |
| 6 | STI Elimination for ISP in Adjustment No. 13 | Exhibit WG (D)-5 Adj 13 Pg 1 Ln 2 | (986,995) | 100.00% | 19.36% | | (191,100) |
| 7 | STI Elimination for ISP in Adjustment No. 13 | Exhibit WG (D)-5 Adj 14 Pg 1 Ln 1 | 4,479,772 | 100.00% | 19.36% | 20.00% | 173,473 |
| 8 | Total Adjusted STI Expense in O&M | Sum Lns. 1 > 7 | $ 22,238,819 | | | | $ 3,089,237 |

Notes:
(1) Includes SEMCO
(2) In the jurisdictional allocation study (Exhibit WG (F)-2) short-term incentive compensation is allocated to DC using the Comp A&G factor. In the adjustments, labor is allocated to DC using the Total Labor Factor.

Exhibit OPC (B)-70
Formal Case No. 1180
Direct Testimony of Bion Ostrander

Page 1 of 4

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-15

**Q.** **Short-Term Incentive Expense and Value Drivers.** WGL Witness Smith's Direct Testimony (10:7-11) states that short-term incentive costs are included this rate case (per Adjustment No. 5, (Exhibit WG (D)-5, pages 1 and 14). WGL Witness Steffes' Direct Testimony (16:12 – 18:12) generally addresses Utilities Value Drivers (and the Scorecard) and how the Value Drivers work together with short-term incentives to support customers. WGL Witness Burgum's Direct Testimony (Exhibit WG (M) at 4:12 – 5:7) generally explains how short-term incentive payout depends on goals included in the Value Drivers. Please address the following:

a. Provide the total amount of rate case adjusted short-term incentive cost (expensed and capitalized) and the amount of rate case adjusted short-term incentive expense (by account number and month) for the test period end March 31, 2024, that is specifically related to each of the 2023 Utilities Value Drivers goals below:

(i) Corporate Social Responsibility.

(ii) Operations.

(iii) Customer Experience.

(iv) Regulatory and Public Policy.

(v) Emerging Ecosystem.

b. Regarding (a) above, explain how the total short-term incentive cost and the short-term incentive expense for each of the 2023 Utilities Value Driver goals (or the 2024 Utilities Value Driver goals if this was relied upon in total or part for the test period end March 31, 2024 short-term incentive costs) was determined, and provide all supporting documentation and calculations.

Page 2 of 4

c. Regarding (a) and (b) above, provide a copy of Utilities Value Drivers Scorecard and related goals for each of the calendar years 2020, 2021, 2022, and 2024, and provide the same information in (a) and (b) above for each year (use the specific goals/Drivers for each of these cited years).

d. Regarding (a) to (c) above, for each of the calendar years 2020 to 2023, and for test year end March 31, 2024, provide the amount (and weighted percentage) of STI expense associated with each Value Driver/goal that is related to:

   (i) Financial-related (focused) performance and outcomes. WGL Witness Burgum's Direct Testimony (5:3-4) states that employee performance for "operational and financial measures" help determine the amount of incentives paid.

   (ii) Customer-related (focused) performance and outcomes. WGL Witness Burgum's Direct Testimony (5:3-4) states that employee performance for "operational and financial measures" help determine the amount of incentives paid.

   (iii) Operational (non-financial and non-customer related) performance and outcomes. WGL Witness Burgum's Direct Testimony (5:3-4) states that employee performance for "operational and financial measures" help determine the amount of incentives paid.

e. If WGL concludes that none of the Value Drivers/goals are financial-related or customer-related, then explain and provide the specific quantitative and qualitative benefits to the Company, its customers, and other interests for each of the Value Drivers/goals and provide all supporting documentation and calculations.

f. If WGL concludes that all of the Value Drivers/goals are customer-related, then provide the specific quantitative and qualitative benefits to customers for each of the Value Drivers/goals and provide all supporting documentation and calculations.

g. Regarding (a) to (f) above, if WGL cannot identify specific quantitative and/or qualitative benefits related to each Value Driver/goal, then explain how the Company tracks, evaluates, and compares the benefits and changes in the types of Value Drivers/goals from year-to-year.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.**

Page 3 of 4

a. STI expense is not broken down by each value driver. The total STI pool is determined based on the overall scorecard result and is then distributed to employees based on role and performance.

b. See the response to part (a).

c. See the response to OPC DR 11-16 Attachment [excel sheet labeled FC1180 OPC 11-16 2020-2024 Utilities Value Drivers] and OPC DR 10-2.

d. See the response to part (a).

e. In addition to, and consistent with, the Company's previous statements regarding customer benefits, the Company's annual performance scorecards have evolved multiple times over the years but have remained primarily customer and operations focused. Customer focused metrics, like Customer Satisfaction, have a direct impact on customers, while Operations focused metrics, like Safety, provide an indirect benefit to customers through optimizing the operation and delivery of services to our customers.

• Corporate Social Responsibility value drivers directly impact the safety and security of the Company's employees, customers and both physical and informational assets. Increasing the safety of our distribution system and decreasing motor vehicle accidents have a direct benefit to the entire community we serve, including both customers and those we do not currently serve. Developing high performance employees benefits customers through lower costs and more efficient operations.

• Operations value drivers directly impact the cost of the Company's operations and the rates our customers pay. With a focus on efficiently delivering services to customers and executing capital projects to plan, customers will benefit from lower costs and more efficient operations.

• Customer Experience value drivers directly benefits all our customers through the delivery of customer self-service options that improve the customer experience and lower costs and supporting customers that need service timely and efficiently.

• Regulatory and Public Policy value drivers indirectly benefit our customers through approval of programs to deliver safe and reliable service.

• Emerging Ecosystem value drivers directly benefit customers through the execution of actions to support global and regional carbon reduction goals through a three-pronged approach of reducing customer end-use, decarbonizing our gas supply and reducing our own GHG emissions.

f. See the response to part (e).

g. See the response to part (e).

SPONSOR: Tom Burgum
Senior Director Total Rewards & HR Operations • VP Utilities HR

Exhibit OPC (B)-71
Formal Case No. 1180
Direct Testimony of Bion Ostrander

Page 1 of 2

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-17

**Q.** **Value Driver Versus Financial/Customer-Focused Incentives.** WGL Witness Steffes' Direct Testimony (16:12 – 18:12) generally addresses Utilities Value Drivers (and the Scorecard) and how the Value Drivers work together with short-term incentives to support customers. WGL Witness Burgum's Direct Testimony (4:12 – 5:7) generally explains how short-term incentive payout depends on goals included in the Value Drivers. Please address the following:

a. Identify the year when WGL changed from its historical short-term incentive expense driven by a combination of Financial-focused (measures of financial results) and Customer-focused performance metrics (measures of results that are not financial but are more qualitative and service quality driven) to the Utilities Value Driver Scorecard approach.

b. Beginning with the first year of the Utilities Value Driver Scorecard approach, identify and explain all Value Driver performance metrics that measure financial results (financially-focused) and identify this Value Driver performance metric for each year, the specific Value Driver Key Measures, the related "percentage weighting", and provide both the related Value Driver performance metric "goal/target" and the "actual results."

c. If the Utilities Value Driver Scorecards do not include any Value Driver performance measure goals/targets that measure financial results (financially focused), or which do not include a percentage weighting over 25% for the Value Drivers measuring financial results, then explain why WGL transitioned away from measuring financial results for purposes of awarding the related short-term incentives and explain how employees continue to be "incentivized" to achieve favorable financial results if they are not rewarded via short-term incentives to achieve favorable financial results.

Page 2 of 2

d. Regarding (c) above, if employees are not currently incentivized under the current Utilities Value Driver Scorecards to achieve specific financial goals/targets (and be rewarded via short-term incentives for achieving these financial goals/targets), then explain why, or if, it was ever reasonable or necessary to incentivize employees in prior years to achieve financial-focused results in those years prior to the current Utilities Value Driver Scorecards. In other words, if Utilities Value Driver Scorecards do not currently incentivize financial performance goals/results in any significant manner, then explain why it was it ever necessary to incentivize employees via short-term incentives to achieve financial goals/targets.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.** a. The Company transitioned to the Value Drivers Scorecard format in 2020 to align with the AltaGas performance management approach. 2019 was the last year that ROE and EBITDA were on the annual performance scorecards.

b. See the response to OPC 11-16 for all the scorecards from 2020 to 2024.

c. The scorecards used for measuring annual performance continually evolve due to changes in the business and based on feedback from internal and external stakeholders. This was the case prior to 2020 and continues to be the case now. Examples of this include the addition of a Merger Commitment metric in 2019 after the AltaGas merger was approved in 2018, or the addition of Emerging Ecosystem metrics in 2021 after the publishing of the Washington Gas Climate Business Plan for the District of Columbia in 2020.

d. Annual performance scorecards can never represent all important metrics or they would become ineffective. Like anyone else with a scorecard, the Company continues to evolve the scorecard to focus employees on specific performance targets.

SPONSOR: James D. Steffes
Senior VP, Regulatory Affairs

Exhibit OPC (B)-72
Formal Case No. 1180
Direct Testimony of Bion Ostrander

Page 1 of 2

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-18

**Q.** **Value Drivers Support the Reasonableness of WGL Rates.** WGL Witness Steffes' Direct Testimony (17:10-16) generally states that Value Drivers support the reasonableness of WGL's rates in this rate case, although Witness Steffes' does not provide any specific documentation for this statement. Please address the following:

a. Provide copies of all documentation and calculations in native format which support Mr. Steffes' statement that Value Drivers support the reasonableness of WGL's rates in this rate case.

b. For each specific type of Value Driver (and the related performance metric goal/target) for each of the Utilities Value Driver Scorecards for 2022 and 2023, explain how each specific Value Driver supports the reasonableness of WGL's rates in this rate case, and provide the specific impact of each Value Driver on the rates in this rate case.

c. For each Value Driver performance metric, explain the level of "actual results" that needs to be achieved in order for it to support the reasonableness of WGL's rates in this case, and provide the level when the Value Driver performance metric actual results have no impact on the reasonableness of WGL's rates, and provide the level Value Driver performance metric actual results have a negative impact on the reasonableness of WGL's rates.

d. Identify the specific 2022 and 2023 Value Driver target/goals (from the 2022 and 2023 Utilities Value Driver Scorecard) which includes a measurement (Key Measures) via customer surveys of WGL's rate levels, and identify the related Value Driver performance metric goal/target and actual results for 2022 and 2023. Provide all supporting documentation, including a copy of the actual customer survey of WGL's rates, along with the results of the customer surveys.

**WASHINGTON GAS'S RESPONSE** 11/22/2024



**A.**

a.-c. The referenced statement does not seek to quantitatively tie the Company's Value Drivers to the proposed rates. Mr. Steffes' testimony does not state that each Value Driver performance metric nor the level of "actual results" support the reasonableness of WGL's rates in this rate case. Rather, the Company's cost-of-service presented in this case reflects, in relevant part, the investments Washington Gas has made in our distribution network and people to reflect and execute our customer-centric Value Drivers.

d. Washington Gas understands this data request to ask for customer surveys of the Company's rate levels mapped to 2022 and 2023 Value Driver target/goals, identifying the related Value Driver performance metric goal/target and actual results for 2022 and 2023. Washington Gas is not aware of any customer survey mapping its rate levels to 2022 and 2023 Value Driver target/goals, identifying the related Value Driver performance metric goal/target and actual results for 2022 and 2023, nor is the Company aware that it was obligated to conduct such a survey or engage in such mapping.

SPONSOR: James D. Steffes
Sr. Vice President – Regulatory Affairs

Exhibit OPC (B)-73
Formal Case No. 1180
Direct Testimony of Bion Ostrander
PUBLIC VERSION

# Confidential Exhibit Omitted

Page 1 of 2

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 11

QUESTION NO. 11-20

**Q.** **Compensation Studies per Burgum's Prior Rate Case Testimony.** WGL Witness Burgum's Direct Testimony (2:12-16) states that his testimony describes the approach WGL takes to ensure the Company pays competitive and reasonable compensation that will ensure value for customers. Also, Mr. Burgum's Public Rebuttal Testimony in prior rate case, Formal Case No. 1169, cited to other compensation studies which OPC seeks in this proceeding. Please address the following:

a. Mr. Burgum's Public Rebuttal Testimony (4:17-19) in WGL's prior rate case, Formal Case No. 1169, refers to an exhibit attached to his testimony as Confidential Exhibit WG (T)-1, which was a 2022 Study conducted by WTW on Utility Industry Compensation Trends. Provide a copy of this 2022 study, along with related updated studies for 2023 and 2024.

b. Regarding (a) above, explain how this compensation study supports Mr. Burgum's statement that WGL's compensation is competitive and reasonable for base salary, short-term incentives, long-term incentives, benefits, and total compensation.

c. Regarding (b) above, provide all other compensation studies that WGL relies upon to reach a conclusion that its compensation is competitive and reasonable for base salary, short-term incentives, long-term incentives, benefits, and total compensation.

**WASHINGTON GAS'S RESPONSE** 11/22/2024

**A.** a. The Company is not in possession of this study for 2023 or 2024 and does not know if WTW ran the study again for 2023 or 2024. Companies do not materially change incentive plan designs often, making the 2022 data still relevant today.

Page 2 of 2

b. The WTW study notes the prevalence of STI and LTI plans offered along with the metrics most often used in each. Those are the metrics employed in the WGL STI and LTI plan designs.

c. There are no other studies to share at this time.

SPONSOR: Tom Burgum
Senior Director Total Rewards & HR Operations • VP Utilities HR

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 12

QUESTION NO. 12-1

**Q.** **Net Operating Loss Carryforward ("NOLC") Private Letter Ruling ("PLR").** WGL Witness Bell's Direct Testimony (Exhibit WG (H) 2:9 – 9:11) refers to an Internal Revenue Service ("IRS") PLR for another company and she explains how the related tax sharing payments received from other member of the consolidated group of AltaGas companies for the utilization (and benefit) of WGL's Deferred Tax Asset ("DTA") NOLC causes a normalization violation under tax rules. Witness Tuoriniemi (Exhibit WG(D) 97:12 – 104:11) provides the regulatory and ratemaking impacts and adjustments to income tax expense and the state and federal NOLC for the effect PLR. Please address the following regarding the PLR NOLC issue:

a. Witness Bell states that PLRs are issued to a specific taxpayer and apply solely to that taxpayer, although she notes that the facts in the PLR also apply to WGL (3:1-6). Please confirm that IRS PLRs issued to other companies do not hold any precedent for WGL or any other company, and if WGL disagrees then provide documentation from the IRS which states that PLRs have precedent for other companies.

b. Witness Bell states that the Company has a tax normalization violation based on the PLR (2:18-22). Explain if AltaGas, WGL, or any other affiliate has been contacted or notified by state or federal income tax agencies/authorities that the Company has a tax normalization violation based on the PLR and the manner in which it has treated tax sharing payments received from other members of the consolidated group for the utilization (and benefit) of WGL's DTA-NOLC. Provide a copy of all written and oral correspondence, notices, and other documentation from state and federal tax authorities to AltaGas, WGL, and other affiliates regarding a tax normalization violation and any related possible penalties.

c. Regarding (b) above, explain if AltaGas, WGL, or any other affiliate has voluntarily notified or initiated contact with state or federal tax agencies and authorities to discuss the possible tax normalization violation related

Page 2 of 4

to this PLR NOLC issue, and provide a copy of all written and oral correspondence, notices, and other documentation addressing the status of this issue between the Company and state and federal tax agencies. If not, explain why AltaGas, WGL, or any other affiliate has not initiated contact with state or federal tax agencies to discuss this issue and to determine if there is a possible tax normalization violation and to determine the proper remedies and how to address and determine the potential impacts on state and federal income taxes and the NOLC.

d. If WGL is concerned with a potential tax normalization violation regarding this PLR NOLC issue, explain why it is considered to be a more reasonable, accurate, legal, expedient, and necessary approach to first propose ratemaking adjustments in this rate case for the impact of the PLR NOLC issue, instead of first contacting and receiving guidance from state and federal tax agencies and reflecting the required changes in state/federal income tax returns (including amended prior year tax returns) to ensure that state and federal tax agencies agree with the Company's approach, calculations, and required changes to ensure there is no tax normalization violation.

e. Regarding (a) to (d), identify all other utilities companies (including AltaGas/WGL affiliates) that have identified this same PLR NOLC concern and have used the same approach as the Company in proposing similar adjustments in rate cases (prior to filing any state or federal income tax returns addressing these impacts), and whereby the related ratemaking adjustments were approved by the state regulatory agency. Provide an active hyperlink to (or full copies of) utility company testimony and related regulatory agency orders where this same PLR NOLC issue has been addressed.

f. Regarding (e) above, regarding AltaGas, WGL and affiliates, identify where this same PLR NOLC issue is being addressed in other jurisdictions (although a regulatory agency decision is still pending), and explain if AltaGas, WGL and other affiliates have addressed the PLR NOLC issue and calculations in the same manner as in this rate proceeding. Provide an active hyperlink to (or full copies of) utility company testimony where this same PLR NOLC issue has been addressed by AltaGas, WGL, and other affiliates.

g. Provide copies of all AltaGas, WGL, and other affiliate state and federal income tax returns that have been filed with related tax agencies, and which address this PLR NOLC issue.

h. Explain why it is more reasonable and necessary for the Commission to accept WGL's ratemaking adjustments for this PLR NOLC issue of first impression and without precedent, instead of deferring this issue until the

Page 3 of 4

Company files its income tax returns addressing this issue and there is a definitive determination on this issue by state and federal tax agencies. Cite to all precedent for WGL's actions seeking regulatory action and adjustments prior to state/federal tax agency approval and action, and provide an active hyperlink to (or full copies of) utility company testimony and other documentation supporting WGL's actions in this rate proceeding.

**WASHINGTON GAS'S PARTIAL OBJECTION 11/7/2024**

**Subparts (e) and (f)**

Washington Gas objects to subparts (e) and (f) of this request on grounds that they require a special study which the Company has not performed. However, the Company will provide responsive information that is in its possession. Further, the public version of the requested information related to other utilities is equally available to the Office of the People's Counsel for the District of Columbia and its consultants and can be researched and assembled by them.

**WASHINGTON GAS'S RESPONSE 11/25/2024**

**A.** a. Private letter rulings are issued by the IRS Office of Chief Counsel. A private letter ruling is specific and applicable to an individual taxpayer and the facts outlined in the ruling request. While a PLR is applicable to the requesting taxpayer, the ruling itself provides a clear indication for how the IRS interprets the application of tax law to a particular set of facts and circumstances. The IRS publishes the PLR so that other taxpayers can understand what to expect from the IRS for similar circumstances and the rationale for that particular ruling. The WGL facts mirror the facts in the PLRs and based on these rulings, WGL understands how the IRS will interpret the law when applied to these facts.

b. Neither AltaGas, WGL, nor any affiliates have been contacted by the IRS regarding a normalization violation based on the PLR and in the manner in which WGL has treated tax sharing payments received from other members of the consolidated group for utilization of net operating losses generated by WGL.

c. WGL reported the normalization issue on the 2023 federal corporate tax return in accordance with the rules for reporting inadvertent normalization violations published in Revenue Ruling 2017-47. Please see hyperlink: https://www.irs.gov/pub/irs-drop/rp-17-47.pdf

d. The WGL fact pattern mirrors the fact pattern included in the PLR. As such, after the publication of the PLR, WGL is now on notice of an inadvertent normalization violation. In order to remedy the inadvertent normalization violation, WGL must follow the safe-harbor procedures outlined in Revenue Procedure 2017-47 which addresses how to resolve this inadvertent normalization violation. Revenue Procedure 2017-47 addresses how owners of public utility property can remedy a normalization violation caused by "inadvertently or unintentionally using a practice or procedure" that is inconsistent with IRC Section 168(i)(9). Revenue Procedure 2017-47 stipulates the company must report the change in accounting to the public service commissions with jurisdiction over customer rates at the earliest available opportunity. Formal Case No. 1180 is the earliest opportunity for WGL to comply with the Safe Harbor provisions for how and when to report inadvertent normalization violations.

g. Please see Formal Case No. 1180, response to OPC Data Request 6-5 for copies of the tax year 2023 federal and state income tax returns.

h. Based upon the ruling, WGL is on notice of an inadvertent violation of the normalization rules. In order to avoid the drastic penalties associated with normalization violations and the ensuing detrimental effects of such a violation on customer rates, it is reasonable and prudent to follow the safe harbor provisions outlined by the IRS to cure the normalization violation and avoid the penalty. By delaying action, WGL would not meet the safe harbor provisions and the IRS would have no recourse but to impose the penalties for a normalization violation. As required under the safe harbor provisions of the Revenue Procedure WGL notified the IRS by disclosing the normalization violation on the 2023 federal income tax return. There are no state income tax implications caused by the normalization violation. Please see the response to OPC Data Request 6-5 for copies of the tax year 2023 federal tax return which includes the required normalization violation safe harbor statement.

SPONSOR: Kimberly Bell
Sr. Manager, Tax Technology, Special Projects and Regulatory Liaison

Exhibit OPC (B)-76
Formal Case No. 1180
Direct Testimony of Bion Ostrander

Page 1 of 5

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 12

QUESTION NO. 12-2

**Q.** **Rate Case Adjustments Related to NOLC PLR Issue.** Witness Tuoriniemi (97:12 – 104:11) provides the regulatory and ratemaking impacts and adjustments to income tax expense and the state and federal NOLC for the effect of the PLR. WGL Witness Bell's Direct Testimony (7:1-6, 9:4-6, and Exhibit WG (H)-1 also provide some total WGL financial impacts, but do not provide WGL-DC impacts). OPC was unable to reconcile the PLR NOLC adjustments and impacts in Witness Tuoriniemi's Direct Testimony with the adjustments and amounts at various WGL exhibits, including Exhibit WG (D)-2, pages 1 to 3 and Exhibit WG (D)-1, pages 1 and 2. Please address the following regarding the NOLC PLR issue:

a. Please cite to all specific exhibits that include rate case adjustments related to the NOLC PLR issue, and identify the specific adjustments that would need to be reversed or changed in order to remove the impact of this proposed adjustment on income tax expense, NOLC, and other income statement and rate base accounts – and in all cases provide a specific citation to the amounts by exhibit, row, column, and line number for all related amounts and impacts.

b. Witness Tuoriniemi (98:6-13) states the impact of the NOLC PLR issue is a decrease to the state/DC NOLC of $878,155, an increase to the federal NOLC of $24,088,259, and a decrease to income tax expense of $140,599, with a breakdown of the state/DC NOLC of $878,155 provided at page 100, footnote 139, and cited as Exhibit WGL (D)-1, page 2 of 4 (based on the netting of the NOLC Federal of $6,403,501, NOLC State of $857,265, NOLC Federal Benefit of State of ($180,026), ADIT MACRS Depreciation Federal of ($5,451,639), and ADIT MACRS Depreciation State ($750,946). Provide a reconciliation regarding the following:

   (i) The above amounts of NOLC State $857,265 and NOLC Federal Benefit of State ($180,026) appear at Exhibit WG (D)-1, page 2 of 4, and none of the other amounts appear at this exhibit (and OPC

Page 2 of 5

was unable to net other amounts at this exhibit to arrive at these amounts). Provide a complete reconciliation of all above NOLC amounts from Witness Tuoriniemi's Direct Testimony (page 100, footnote 139) to the NOLC amounts at Exhibit WG (D)-1, page 2 of 4, and provide all necessary corrections with explanations. Also, reconcile all amounts to Adjustment No. 32, Exhibit WG (D)-5, pages 1 to 10.

(ii) WGL did not cite to Exhibit WG (D)-2, page 2 of 3, for these NOLC amounts, but the above amounts from Witness Tuoriniemi's Direct Testimony (page 100, footnote 139) of NOLC State $857,264, NOLC Federal Benefit of State ($180,026), and NOLC Federal $6,403,501 agree with amounts at Exhibit WG (D)-2, page 2 of 3, but the ADIT MACRS Depreciation Federal ($5,451,639) and ADIT MACRS Depreciation State ($750,946) do not appear at Exhibit WG (D)-2, page 2 of 3. Provide a complete reconciliation of all above NOLC amounts from Witness Tuoriniemi's Direct Testimony (page 100, footnote 139) to the NOLC amounts at Exhibit WG (D)-2, page 2 of 3, and provide all necessary corrections with explanations. Also, reconcile all amounts to Adjustment No. 32, Exhibit WG (D)-5, pages 1 to 10.

(iii) Witness Tuorinemi's Direct Testimony (98:10) rate base adjustment that increases the Federal DTA NOLC by $24,088,259 could not be reconciled or identified at Exhibit WG (D)-2, page 2 of 3, although a different DTA NOLC increase of $27,248,768 was identified at Exhibit WG (D)-2, page 2 of 3, and yet another different Federal NOLC increase of $20,845,267 was identified at Exhibit WG (D)-1, page 2 of 4. Provide a complete reconciliation of the Federal NOLC of $24,088,259 from Witness Tuoriniemi's Direct Testimony (98:10) to the above noted NOLC amounts at Exhibit WG (D)-2, page 2 of 3 and Exhibit WG (D)-1, page 2 of 4, and provide all necessary corrections with explanations. Also, reconcile all amounts to Adjustment No. 32, Exhibit WG (D)-5, pages 1 to 10.

(iv) Witness Tuorinemi's Direct Testimony (98:13) identifies an adjustment that decreases Income Tax Expense by $140,599, but this amount could not be identified or reconciled to income tax expense amounts at Exhibit WG (D)-2, page 2 of 3, or to Exhibit WG (D)-1, page 1 of 4. Provide a complete reconciliation of the Income Tax Expense of $140,599 from Witness Tuoriniemi's Direct Testimony to Exhibits WG (D)-2, page 2 of 3, and Exhibit WG (D)-1, page 1 of 4. Also, reconcile all amounts to Adjustment No. 32, Exhibit WG (D)-5, pages 1 to 10.

c. Witness Tuorinemi's Direct Testimony (98:10) states that the NOLC PLR issue increase the Federal DTA NOLC by $24,088,259 (although a different amount Federal NOLC of $27,248,768 was identified at Exhibit WG (D)-1, page 2 of 4). Also, Witness Tuorinemi's Direct Testimony (98:13) cites to a decrease in income tax expense of $140,599 for the related NOLC PLR impact. Typically, a change in the NOLC account (regardless of an increase or decrease), will have the same corresponding change in the income tax expense (either an increase or decrease). Explain why WGL's NOLC PLR adjustment does not appear to have the same corresponding impact on the related income tax expense adjustment. For example, WGL increased NOLC by an amount of $27,248,768 (or $24,088,259 or $27,248,768 from other sources), but the related income tax expense adjustment is only decreased by $140,599. Explain and provide all reconciliation and calculations in native form to show why the change in NOLC PLR did not have a corresponding impact on income tax expense.

d. Explain if AltaGas, WGL, or other affiliates will need to file amended state and federal income tax returns for prior years in order to address the impact of the NOLC PLR on income taxes, explain why or why not.

e. Provide a copy of the AltaGas, WGL, or other affiliates income tax returns for 2022 and 2023 (including any preliminary drafts of the 2023 state and federal income tax returns that may not have been filed yet) that show the impact of the NOLC PLR on income taxes, and specifically identify and explain these impacts on the state and federal income tax returns.

**WASHINGTON GAS'S RESPONSE** 11/25/2024

**A.** See Exhibit WG (H)-1. The schedule shows $864,955,260 as the Loss carryforward subject to normalization.. That same schedule is included in the support in WG (D)-5, Adjustment No. 32, page 5 of 10. That balance is converted into 13-month average on WG (D)-5, Adjustment No. 32, page 3 of 10, and carried forward to WG (D)-5, Adjustment No. 32, page 1 of 10. See the electronic version of Adjustment 32 where the links can be traced.

a. See Exhibit WG (D)-5, Adjustment No. 32, pages 1-10 of 10 and Exhibit WG (D) page 97, line 12 to page 98, line 17, Adjustment 32—Deferred Tax Asset for Net Operating Loss Carryforwards Tax Normalization, as corrected.[1] As shown on Exhibit WG (D)-5, Adjustment No. 32, page 1 of 10, line 16, column c, the increase in DC DTA-NOLC Depreciation of $27,248,768 would need to be reversed. Also, as shown on Exhibit WG (D)-5, Adjustment No. 32, page 1 of 10,

[1] Errata filed 11/06/2024 Exhibit WG (D) page 98, line 10, the amount of Federal DTA- NOLC Depreciation was corrected from $24,088,259 to $27,248,768.

Page 4 of 5

line 19, column c, the EDIT Income Tax Expense of $140,599 would need to be reversed.

b. Please see the errata filed November 6, 2024. Exhibit WG (D) page 98, line 10, the amount of Federal DTA- NOLC Depreciation was corrected from $24,088,259 to $27,248,768. None of the workpapers or underlying computations were affected.

(i) The amounts on Exhibit (WG (D)-9, page 2 of 4 reflect the summation of 4 adjustments that impact Accumulated Deferred Income taxes shown on Exhibit WG (D)-2, page 2 of 3, not just the impact of the NOLC PLR. The electronic version of these files clearly demonstrates how the amounts tie and is summarized below. No corrections are necessary.

| Exhibit WG (D)-2, page 2 of 3 | | | | Exhibit WG (D)-1, page 2 of 4 | | | |
|---|---|---|---|---|---|---|---|
| Line | Description | Reference | Amount | NOL Carryforward Federal Line 13 | NOL Carryforward State Line 15 | NOL Federal Benefit of State Line 16 | ADIT: M.A.C.R.S. Depreciation Line 17 |
| 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) | |
| 37 | Other Tax Credits | Adj. No. 32 | (6,202,585) | | | | (6,202,585) |
| 38 | Accumulated Deferred Income Taxes - NOL DTA | Adj. No. 32 | (27,248,768) | (27,248,768) | | | |
| 28 | Accumulated Deferred Income Tax for new depreciation rate | Adj. No. 4 | 1,049,482 | | | | 1,049,482 |
| 29 | 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 |
| | Total | | $ (16,290,991) | $ (20,845,267) | $ 857,264 | $ (180,026) | $ 3,877,037 |

(ii.) See part b (i.).

(iii.) See part b (i.).

(iv.) See the income tax computation Exhibit WG (D)-5, Adjustment 10D and 31, page 1 of 8, line 19, column d.

c. 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. 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. The receipt of tax sharing payments is a balance sheet transaction that has no effect on taxes payable, current, or deferred income tax expense.

The $140,599 tax effect results from the decrease in the excess deferred income tax (“EDIT”) amounts (included as a component of the in the related to the Net Operating Loss being lowered due to tax sharing payments that existed when the Tax Cuts and Jobs Act lowered federal income rates 35% to 21%. This has the effect of lowering the remaining EDIT and therefore lowers the future amortization.

d. AltaGas, WGL and other affiliates do not need to file amended state and federal income tax returns for prior years in order to address the impact of the NOLC PLR on income taxes. The normalization impact is a ratemaking matter only.

e. The NOLC PLR has no impact on the income tax returns. The normalization impact is a ratemaking matter only.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

Exhibit OPC (B)-77
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 15

QUESTION NO. 15-2

**Q.** **DC Common Plant Additions Actual Versus Budget – Supplemental Testimony.** Witness Tuoriniemi's Supplemental Direct Testimony, related Excel spreadsheet "Exhibit WG (2D)-1, including workpapers.xlsb", and specifically tab "$100,000 or greater" shows the related actual project costs and budget costs for plant additions greater than $100,000. Please address the following regarding the WGL actual project costs of $277,500,661 and budget costs of $221,838,964 (these WGL amounts are prior to the allocation to the WGL-DC amounts that reconcile to the "DC Share of Common" plant addition costs of $44,733,909 (at Exhibit WG (2D)-1, page 1 of 8):

a. Regarding the WGL "DC Share of Common" (prior to allocation to the WGL-DC amount of $44,733,909), explain why the total Project cost of $277,500,661 at column D (for all underlying plant additions greater than $100,000) exceeds the related Budget cost of $221,838,964 at column E, resulting in costs exceeding budget by $55,661,697 (or 200%). Provide copies of workpapers and other supporting documentation and calculations to explain the reasons why actual project costs exceed budgeted projected costs by a significant amount.

b. Regarding (a) above, explain why some significant actual project costs do not have a corresponding budget amount, such as the related software costs (lines 5 to 9, columns D and E), along with other line item actual projects costs that do not show a corresponding budget amount. Provide all supporting documentation and calculations to explain the absence of budgeted project costs, and explain if this is unique situation for the test year end March 31, 2024, plant additions in this rate case, or provide similar documentation to explain this situation in prior years.

c. Regarding (a) above, for the ten largest project costs where actual project costs exceed budget costs by the largest amount, provide detailed supporting documentation and calculations to explain the reason for this budget variance.

d. Regarding (a) above, for the ten largest project costs where actual project costs are less than budget costs by the largest amount, provide detailed supporting documentation and calculations to explain the reason for this budget variance.

e. Regarding (a) above, for all software with an actual cost (WGL cost, not WGL-DC cost) greater than $300,000, provide the following:

(i) A description of the type of software (system, application, upgrade, etc.), the name of the software and vendor, and the purpose/function of the software.
(ii) Provide the annual amortization expense and the number of years to be amortized.
(iii) Provide the date the software was placed in service (month/year).
(iv) Regarding the previous software that will be replaced by the new software, provide the original cost and date placed in service, retirement date, number of years to be amortized, and annual amortization expense. Explain if this software has been retired or explain why it should continue to be expensed until it is fully amortized.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.** a. Washington Gas does not capture budget information within its property accounting system for all projects which is the source of the information included in Exhibit WG (2D)-1, because the system is not used as a tool by the Company to manage capital additions. Therefore, the comparison the question makes provides no meaningful information to make an informed assessment of capital additions. Please refer to the Supplemental Direct Testimony of Company Witness Morrow, Exhibit WG (2I). Company Witness Morrow prepared an analysis of capital additions since the last rate case with a cost of more than $100,000 and an explanation of variances between estimated and actual costs for such projects. Also refer to the Supplemental Direct Testimony of Company Witness Murphy, Exhibit WG (P) for a discussion of the Company's cost estimation process.

b. See part a.

c. See part a.

d. See part a.

e. See the Company's response to OPC DR 15-3, which asks the same question.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

Exhibit OPC (B)-78
Formal Case No. 1180
Direct Testimony of Bion Ostrander

Page **1** of **2**

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 15

QUESTION NO. 15-3

**Q.** **Operating Unit 01 DC Plant Additions Actual Versus Budget – Supplemental Testimony.** Witness Tuoriniemi's Supplemental Direct Testimony, related Excel spreadsheet "Exhibit WG (2D)-1, including workpapers.xlsb", and specifically tab "$100,000 or greater" shows the related actual project costs and budget costs for plant additions greater than $100,000. Please address the following regarding the WGL-DC actual project costs of $123,414,127 and budget costs of $38,170,546 for "Operating Unit 01 DC" (which also agrees to the $123,414,127 amount at Exhibit WG (2D)-1, page 1 of 8):

a. Regarding the WGL "Operating Unit 01 DC" related WGL-DC project costs of $123,414,127 (column D) that exceed the related budget costs of $38,170,546 (column E) by $85,243,581 (or 69%). Provide copies of workpapers and other supporting documentation and calculations to explain the reasons why actual project costs exceed budgeted projected costs by a significant amount.

b. Regarding (a) above, explain why most of these actual project costs do not have a corresponding budget amount. Provide all supporting documentation and calculations to explain the absence of budgeted project costs, and explain if this is unique situation for the test year end March 31, 2024, plant additions in this rate case, or provide similar documentation to explain this situation in prior years.

c. Regarding (a) above, for the ten largest project costs where actual project costs exceed budget costs by the largest amount, provide detailed supporting documentation and calculations to explain the reason for this budget variance.

d. Regarding (a) above, for the ten largest project costs where actual project costs are less than budget costs by the largest amount, provide detailed

 Page **2** of **2**

supporting documentation and calculations to explain the reason for this budget variance.

e. Regarding (a) above, for all software with an actual WGL-DC cost greater than $300,000, provide the following:

(i) A description of the type of software (system, application, upgrade etc.), the name of the software and vendor, and the purpose/function of the software.

(ii) Provide the annual amortization expense and the number of years to be amortized.

(iii) Provide the date the software was placed in service (month/year).

(iv) Regarding the previous software that will be replaced by the new software, provide the original cost and date placed in service, retirement date, number of years to be amortized, and annual amortization expense. Explain if this software has been retired or explain why it should continue to be expensed until it is fully amortized.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.** a. Washington Gas does not capture budget information within its property accounting system for all projects which is the source of the information included in Exhibit WG (2D)-1, because the system is not used as a tool by the Company to manage capital additions. Therefore, the comparison the question makes provides no meaningful information to make an informed assessment of capital additions. Please refer to the Supplemental Direct Testimony of Company Witness Morrow, Exhibit WG (2I). Company Witness Morrow prepared an analysis of capital additions since the last rate case with a cost of more than $100,000 and an explanation of variances between estimated and actual costs for such projects. Also refer to the Supplemental Direct Testimony of Company Witness Murphy, Exhibit WG (P) for a discussion of the Company's cost estimation process.

b. See part a.

c. See part a.

d. See part a.

e. Please refer to the Company's response to OPC DR 12-6 for the requested information.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

Exhibit OPC (B)-79
Formal Case No. 1180
Direct Testimony of Bion Ostrander
PUBLIC VERSION

Exhibit OPC (B)-79
Formal Case No. 1180
Witness: Bion Ostrander
PUBLIC VERSION

# Confidential Exhibit Omitted

Exhibit OPC (B)-80
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 17

QUESTION NO. 17-2

**Q.** **Rate Case Adjustments Related to NOLC PLR Issue.** Witness Tuoriniemi's Direct Testimony (97:12 – 104:11) provides the regulatory and ratemaking impacts and adjustments to income tax expense and the state and federal NOLC for the effect of the PLR. WGL's November 6, 2024, filing provides a Replacement Page for Witness Tuoriniemi's Direct Testimony, Exhibit WG (D), page 98. Please address the following regarding the replacement page:

a. Provide all documentation and calculations to support the replacement amount of Federal DTA-NOLC Depreciation of $27,248,768, along with all other related impacts on other account numbers.

b. Witness Tuoriniemi's Direct Testimony (98:16-17) and the related Replacement Page (98:16-17) show the same impact on the revenue requirement for Adjustment No. 32 related to the DTA-NOLC-Tax Normalization PLR of $2,840,840. Explain why the change in the Federal DTA-NOLC Depreciation from $24,088,259 to $27,248,768 in the Replacement Page did not result in a change in the $2,840,840 revenue requirement impact and provide supporting documentation and calculations for the original revenue requirement impact of $2,840,840, along with supporting calculations for any revised requirement impact.

**WASHINGTON GAS'S RESPONSE** 12/03/2024

**A.** a. and b. The original amount of $24,088,259 was a typographical error and was not used in any computation in Adjustment 32. The computation of the $27,248,768 is shown in Company Witness Tuoriniemi's Direct Testimony, Exhibit WG (D), page 103, lines 1-7. Also see Exhibit WG (D)-3, Adjustment 32 of 32, page 49 of 49, line 16, column D. It had no impact on any amounts in the adjustment.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 17

QUESTION NO. 17-3

**Q.** **Tax Sharing Agreement Approval.** WGL Witness Bell's Direct Testimony (4:1-6) 5:5) states that the tax sharing agreement between WGL and AltaGas was approved by the Virginia State Corporation Commission as part of affiliate agreements on December 11, 2023 and replaces the prior tax sharing agreement policy of the ASUS consolidated group in place since July 6, 2018. Please address the following:

a. Explain why the Virginia State Corporate Commission's approval of the current (and prior) tax sharing agreement between WGL and AltaGas is relevant to the Public Service Commission of the District of Columbia and this rate case.

b. Explain why the WGL and AltaGas tax sharing agreement was never approved by the Public Service Commission of the District of Columbia, or explain why this was not necessary.

c. Explain if WGL/AltaGas ever asked the Public Service Commission of the District of Columbia to approve the tax sharing agreements between WGL and AltaGas, and explain why or why not? If this request for approval was made to the Public Service Commission of the District of Columbia, provide a copy of the request and all supporting documentation including the Commission's response (along with all related Commission Orders addressing the matter).

**WASHINGTON GAS'S ANSWER** 12/03/2024

**A.**

a. Decisions by other regulatory bodies are routinely cited by parties before the District of Columbia Public Service Commission. This is especially true of decisions by contiguous local commissions that regulate Washington Gas.

b. There is no requirement to seek District of Columbia Public Service Commission approval.

c. Neither the District of Columbia nor Maryland law requires Washington Gas to seek approval of its tax sharing agreements.

SPONSOR: Kimberly Bell
Senior Manager - Tax

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 17

QUESTION NO. 17-3

**Q.** **Tax Sharing Agreement Approval.** WGL Witness Bell's Direct Testimony (4:1-6) 5:5) states that the tax sharing agreement between WGL and AltaGas was approved by the Virginia State Corporation Commission as part of affiliate agreements on December 11, 2023 and replaces the prior tax sharing agreement policy of the ASUS consolidated group in place since July 6, 2018. Please address the following:

a. Explain why the Virginia State Corporate Commission's approval of the current (and prior) tax sharing agreement between WGL and AltaGas is relevant to the Public Service Commission of the District of Columbia and this rate case.

b. Explain why the WGL and AltaGas tax sharing agreement was never approved by the Public Service Commission of the District of Columbia, or explain why this was not necessary.

c. Explain if WGL/AltaGas ever asked the Public Service Commission of the District of Columbia to approve the tax sharing agreements between WGL and AltaGas, and explain why or why not? If this request for approval was made to the Public Service Commission of the District of Columbia, provide a copy of the request and all supporting documentation including the Commission's response (along with all related Commission Orders addressing the matter).

**WASHINGTON GAS'S OBJECTION** 11/19/2024

Washington Gas objects to this request on grounds that it seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. The Company further objects on grounds that this request calls for a legal conclusion and legal research.

Exhibit OPC (B)-82
Formal Case No. 1180
Direct Testimony of Bion Ostrander

Page **1** of **2**

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 17

QUESTION NO. 17-4

**Q.** **Impact of NOLC and PLR Issue on Merger Commitment No. 44.** WGL Witness Bell's Direct Testimony (2:10 – 9:13) addresses the NOLC and related PLR issue and Witness Tuoriniemi (97:12 – 104:11) provides the regulatory and ratemaking impacts and adjustments to income tax expense and the state and federal NOLC for the effect of the PLR. Also, Merger Commitment No. 44 requires that, "no tax elections or accounting methods shall be employed related to the Merger that would in any way result in any reduction to Washington Gas's net accumulated deferred income tax balances that are used to reduce rate base in Washington Gas's rate case (Formal Case No. 1142, Order No. 19396, Appendix A, pages 18-19). In prior rate case, Case No. 1169, Witness Tuoriniemi's Direct Testimony (135:1 – 136-2) explains that per Merger Commitment No. 44, the merger has not affected any accounting and ratemaking policies, including income tax policies (and it has not impacted accumulated deferred income taxes, accumulated deferred income tax credits, and net operating losses). However, in this rate case, WGL proposes adjustments to reverse the cumulative impact of tax sharing arrangements between WGL and AltaGas, which impacts taxes, decreases the accumulated deferred income taxes (because it increases the NOLC account amount), increases rate base, and increases the bottom line revenue requirement by $2,840,840. Address the following regarding the PLR NOLC issue:

a. Explain why WGL's NOLC/Tax Adjustment No. 32 (which reverses the cumulative impact of prior years' Tax Sharing Agreements between WGL and AltaGas by decreasing the accumulated deferred income taxes account because it increases the accumulated NOLC account balance due to the PLR issue raised by WGL) does, or does not, result in a violation of Merger Commitment No. 44. Provide all supporting documentation and calculations for WGL's position.

b. Please confirm that if WGL and AltaGas had not implemented the Tax Sharing Agreement arrangements as part of the merger, then there would not be an Adjustment No. 32 (or similar adjustment) required in this rate case to reverse the cumulative impact of the Tax Sharing arrangement as proposed by WGL via the PLR issue it raises in this rate case. If WGL disagrees, explain the type and amount of income tax adjustments that would be necessary in this rate case to be compliant with the PLR if the Tax Sharing Agreement was never put in place between WGL and AltaGas and there was never any tax sharing transactions between WGL and AltaGas (and affiliates). Provide all supporting documentation and calculations to address all adjustments in this rate case that would be necessary if there were no prior Tax Sharing agreements or transactions in place between WGL and AltaGas.

**WASHINGTON GAS'S OBJECTION** 11/19/2024

Washington Gas objects to this request on grounds that it calls for a legal conclusion and legal research.

Exhibit OPC (B)-83
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 17

QUESTION NO. 17-5

**Q.** **Tax Sharing Agreement Approval.** WGL Witness Bell's Direct Testimony (2:10 – 9:13) explains that due to the Tax Sharing Agreement between WGL and AltaGas (and affiliates) WGL received tax sharing payments in cash from AltaGas and other members of the consolidated group for the use of the WGL NOLC, and that these Company actions have caused a tax normalization violation per interpretation of an IRS PLR – which in turn requires Adjustment No. proposed by Witness Tuoriniemi (97:12 – 104:11). Please address the following:

a. Explain if WGL has notified any other state regulatory agencies in other jurisdictions (including Maryland, Virginia, New Hampshire and others) regarding this Tax Sharing Agreement/NOLC PLR issue as either part of a rate case proceeding, as part of a non-rate case proceeding, or as part of any formal correspondence to alert the Commission (or related state regulatory agency) of the Company's possible tax normalization violation. Provide a copy of all supporting documentation and correspondence with other state regulatory jurisdictions regarding this matter, and provide an active hyperlink to other correspondence or filings in other jurisdictions.

b. Regarding (a) above, if WGL has not notified any other state regulatory jurisdiction of this NOLC PLR issue and a possible tax normalization violation, then explain the basis for the different approach as between WGL's notification to the Public Service Commission of the District of Columbia of a possible tax normalization violation in this rate case and not doing so in other state regulatory jurisdictions, including the basis for prioritizing the change in the District of Columbia versus other jurisdictions and if WGL has determined that this Tax Sharing Agreement situation would not create a tax normalization violation in these other jurisdictions.

c. For other jurisdictions (such as various states or provinces in the U.S. and/or Canada) where AltaGas (and/or WGL) does not have a regulated public utility affiliate, explain if AltaGas/WGL has a Tax Sharing Agreement with these affiliates or explain if Tax Sharing Agreements are only in place between AltaGas/WGL and “regulated public utilities” but not with any other affiliates. Explain why Tax Sharing Agreements are only in place with affiliates that are regulated public utilities, if this is the case, and provide all supporting documentation and support for this position.

d. Regarding (c) above, provide a copy of Tax Sharing Agreements in place between AltaGas and three non-regulated public utilities, and explain how these Tax Sharing Agreements differ from the Tax Sharing Agreements between AltaGas and WGL.

**WASHINGTON GAS’S RESPONSE** 12/03/2024

**A.**

- **a.** WGL has not had an opportunity to notify the state regulatory agencies in other jurisdictions. Formal Case 1180 is the first rate proceeding to commence after the issuance of the DTA-NOL PLR. For the Company to qualify for the safe harbor to remediate an inadvertent normalization violation, Revenue Proc. 2017-47 indicates a taxpayer must change to a practice or procedure consistent with the normalization rules at the next available opportunity, usually the current or next rate case.
- **b.** The inadvertent normalization violation applies to all regulatory jurisdictions. A filing will be made in each jurisdiction at the earliest opportunity as required by Revenue Proc. 2017-47.
- **c.** The Tax Sharing Agreement applies to all US entities included in the AltaGas Services US consolidated federal income tax return. This includes both regulated and unregulated affiliates.
- **d.** Please see OPC 6-7, for a copy of the current Tax Sharing Agreement. There is only one Tax Sharing Agreement that applies to all US subsidiaries of AltaGas Services US.

SPONSOR: Kimberly Bell
Senior Manager - Tax

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 17

QUESTION NO. 17-5

**Q.** **Tax Sharing Agreement Approval.** WGL Witness Bell's Direct Testimony (2:10 – 9:13) explains that due to the Tax Sharing Agreement between WGL and AltaGas (and affiliates) WGL received tax sharing payments in cash from AltaGas and other members of the consolidated group for the use of the WGL NOLC, and that these Company actions have caused a tax normalization violation per interpretation of an IRS PLR – which in turn requires Adjustment No. proposed by Witness Tuoriniemi (97:12 – 104:11). Please address the following:

a. Explain if WGL has notified any other state regulatory agencies in other jurisdictions (including Maryland, Virginia, New Hampshire and others) regarding this Tax Sharing Agreement/NOLC PLR issue as either part of a rate case proceeding, as part of a non-rate case proceeding, or as part of any formal correspondence to alert the Commission (or related state regulatory agency) of the Company's possible tax normalization violation. Provide a copy of all supporting documentation and correspondence with other state regulatory jurisdictions regarding this matter, and provide an active hyperlink to other correspondence or filings in other jurisdictions.

b. Regarding (a) above, if WGL has not notified any other state regulatory jurisdiction of this NOLC PLR issue and a possible tax normalization violation, then explain the basis for the different approach as between WGL's notification to the Public Service Commission of the District of Columbia of a possible tax normalization violation in this rate case and not doing so in other state regulatory jurisdictions, including the basis for prioritizing the change in the District of Columbia versus other jurisdictions and if WGL has determined that this Tax Sharing Agreement situation would not create a tax normalization violation in these other jurisdictions.

c. For other jurisdictions (such as various states or provinces in the U.S. and/or Canada) where AltaGas (and/or WGL) does not have a regulated public utility affiliate, explain if AltaGas/WGL has a Tax Sharing Agreement with these affiliates or explain if Tax Sharing Agreements are only in place between AltaGas/WGL and “regulated public utilities” but not with any other affiliates. Explain why Tax Sharing Agreements are only in place with affiliates that are regulated public utilities, if this is the case, and provide all supporting documentation and support for this position.

d. Regarding (c) above, provide a copy of Tax Sharing Agreements in place between AltaGas and three non-regulated public utilities, and explain how these Tax Sharing Agreements differ from the Tax Sharing Agreements between AltaGas and WGL.

**WASHINGTON GAS’S OBJECTION** 11/19/2024

Washington Gas objects to this request on the following grounds:

- Subpart (a) – Unduly burdensome and seeks publicly available information that is as easily gathered by the requester as it is produced by the Company.
- Subpart (b) - Seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence. Calls for a legal conclusion and legal research.
- Subpart (c) - Seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence.
- Subpart (d) - Seeks information that is irrelevant and not likely to lead to the discovery of admissible evidence.

Exhibit OPC (B)-84
Formal Case No. 1180
Direct Testimony of Bion Ostrander
PUBLIC VERSION

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 18

QUESTION NO. 18-1

**Q.** **Net Operating Loss Carryover ("NOLC" or "NOL") Federal Benefit of State.** Witness Tuoriniemi (Exhibit WG (D) at 97:12 – 104:11) provides the regulatory and ratemaking impacts and adjustments to income tax expense and the state and federal NOLC (or NOL) for the effect of the Private Letter Ruling ("PLR"). Exhibit WG (D)-1, page 2 of 4 includes a credit account balance in rate base (a balance sheet account) titled "NOL Federal Benefit of State" with a per book March 31, 2024, credit amount (reduction of plant/rate base) of ($2,749,985), a debit ratemaking adjustment of $180,026, and a final adjusted ratemaking credit amount of ($2,569,959). Please address the following:

a. Explain the amounts included in the "NOL Federal Benefit of State" account balance and explain how these balances differ from the "NOL Carryforward Federal" balance and the "NOL Carryforward State" balance. Also explain if this is the balance related to the NOL effect recorded pursuant to the Tax Cuts and Job Act ("TCJA").

b. Explain when the "NOL Federal Benefit of State" balance was first created and provide supporting documentation and calculations supporting the March 31, 2024, per book balance of ($2,749,985) and the related ratemaking adjustment of $180,026 (this should include all calculations and allocation factors used in determining the "WGL-DC" portion of the WGL balance).

c. Provide the "NOL Federal Benefit of State" balance for every month from the date of inception on WGL's books through the most recent month end balance in 2024, and explain the reasons for the change in these annual calendar year-end balances through December 31, 2023, and for all additional changes through the most recent month-end balance in 2024.

d. Regarding (b) and (c) above, regarding all changes in the "NOL Federal Benefit of State" account balance, provide the monthly and annual amortization amounts (and the related amortization expense impact on income tax expense and other accounts) related to the impact recorded pursuant to the TCJA (if applicable). Please provide all calculations and allocation factors used in determining the "WGL-DC" portion of the WGL balance for all amortized amounts.

**WASHINGTON GAS'S RESPONSE** 12/05/2024

**A.**

a. State taxes are deductible for federal income tax purposes. This is the federal tax benefit the state NOL has on federal income taxes. It is unrelated to the TCJA.

b. The amount first arose when Washington Gas first recorded a NOL Carryforward-State. See Attachment 1 for the balances. Also see Exhibit WG (D)-5, Adjustment No. 32, Page 2 of 10 for the computation of the $180,026. The account is derivative of the Company State NOL and fluctuates accordingly.

c. See part b.

d. The account is not amortized.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

# Washington Gas Light Company
## Federal NOL
## Merger to Date

| | | | DC Allocation | | |
|---|---|---|---|---|---|
| Date | Amount | Cumulative | Factor | Rate | DC Amount |
| June-18 | | 27,997,191 | Net_Rate_Base | 19.0817% | 5,342,343 |
| July-18 | (13,915,504) | 14,081,687 | Net_Rate_Base | 19.0817% | 2,687,027 |
| August-18 | | 14,081,687 | Net_Rate_Base | 19.0817% | 2,687,027 |
| September-18 | 79,818,782 | 93,900,469 | Net_Rate_Base | 19.0817% | 17,917,816 |
| October-18 | | 93,900,469 | Net_Rate_Base | 19.0817% | 17,917,816 |
| November-18 | | 93,900,469 | Net_Rate_Base | 19.0817% | 17,917,816 |
| December-18 | 3,480,253 | 97,380,722 | Net_Rate_Base | 19.0817% | 18,581,907 |
| January-19 | | 97,380,722 | Net_Rate_Base | 19.0817% | 18,581,907 |
| February-19 | | 97,380,722 | Net_Rate_Base | 19.0817% | 18,581,907 |
| March-19 | 26,897,260 | 124,277,982 | Net_Rate_Base | 19.0817% | 23,714,365 |
| April-19 | (26,897,260) | 97,380,722 | Net_Rate_Base | 19.0817% | 18,581,907 |
| May-19 | | 97,380,722 | Net_Rate_Base | 19.0817% | 18,581,907 |
| June-19 | 26,868,020 | 124,248,742 | Net_Rate_Base | 19.0817% | 23,708,785 |
| July-19 | (17,728,761) | 106,519,981 | Net_Rate_Base | 19.0817% | 20,325,834 |
| August-19 | (9,139,259) | 97,380,722 | Net_Rate_Base | 19.0817% | 18,581,907 |
| September-19 | 9,024,456 | 106,405,178 | Net_Rate_Base | 19.0817% | 20,303,928 |
| October-19 | (10,629,695) | 95,775,483 | Net_Rate_Base | 19.0817% | 18,275,600 |
| November-19 | | 95,775,483 | Net_Rate_Base | 19.0817% | 18,275,600 |
| December-19 | 5216423.75 | 100,991,907 | Net_Rate_Base | 19.0817% | 19,270,983 |
| January-20 | | 100,991,907 | Net_Rate_Base | 19.0817% | 19,270,983 |
| February-20 | | 100,991,907 | Net_Rate_Base | 19.0817% | 19,270,983 |
| March-20 | 26,106,717 | 127,098,624 | Net_Rate_Base | 19.0817% | 24,252,591 |
| April-20 | 1,561,854 | 128,660,478 | Net_Rate_Base | 19.0817% | 24,550,620 |
| May-20 | (1,420,471) | 127,240,006 | Net_Rate_Base | 19.0817% | 24,279,569 |
| June-20 | (4,140,265) | 123,099,741 | Net_Rate_Base | 19.0817% | 23,489,536 |
| July-20 | (3,874,313) | 119,225,428 | Net_Rate_Base | 19.0817% | 22,750,251 |
| August-20 | (7,494,361) | 111,731,067 | Net_Rate_Base | 19.0817% | 21,320,199 |
| September-20 | 10,742,695 | 122,473,762 | Net_Rate_Base | 19.0817% | 23,370,089 |
| October-20 | 9,634,388 | 132,108,150 | Net_Rate_Base | 19.0817% | 25,208,495 |
| November-20 | (2,444,110) | 129,664,040 | Net_Rate_Base | 19.0817% | 24,742,117 |
| December-20 | (99,077,618) | 30,586,422 | Net_Rate_Base | 19.0817% | 5,836,412 |
| January-21 | (12,866,934) | 17,719,488 | Net_Rate_Base | 19.0817% | 3,381,181 |
| February-21 | (4,180,155) | 13,539,333 | Net_Rate_Base | 19.0817% | 2,583,536 |
| March-21 | (13,539,333) | 0 | Net_Rate_Base | 19.0817% | 0 |
| April-21 | 0 | 0 | Net_Rate_Base | 19.0817% | 0 |
| May-21 | 2,344,488 | 2,344,488 | Net_Rate_Base | 19.0817% | 447,368 |
| June-21 | 7,309,495 | 9,653,983 | Net_Rate_Base | 19.0817% | 1,842,145 |
| July-21 | 8,331,683 | 17,985,666 | Net_Rate_Base | 19.0817% | 3,431,973 |
| August-21 | 9,016,903 | 27,002,569 | Net_Rate_Base | 19.0817% | 5,152,552 |

| | | | | | |
|---|---|---|---|---|---|
| September-21 | 14,259,912 | 41,262,481 | Net_Rate_Base | 19.0817% | 7,873,587 |
| October-21 | 10,097,108 | 51,359,589 | Net_Rate_Base | 19.0817% | 9,800,288 |
| November-21 | (3,588,763) | 47,770,826 | Net_Rate_Base | 19.0817% | 9,115,491 |
| December-21 | 19,215,119 | 66,985,945 | Net_Rate_Base | 19.0817% | 12,782,064 |
| January-22 | 804,647 | 67,790,592 | Net_Rate_Base | 19.0817% | 12,935,604 |
| February-22 | (22,638,113) | 45,152,479 | Net_Rate_Base | 19.0817% | 8,615,865 |
| March-22 | 105,908 | 45,258,387 | Net_Rate_Base | 19.0817% | 8,636,074 |
| April-22 | 70,605 | 45,328,992 | Net_Rate_Base | 19.0817% | 8,649,547 |
| May-22 | 12,888,474 | 58,217,466 | Net_Rate_Base | 19.0817% | 11,108,888 |
| June-22 | 7,159,150 | 65,376,616 | Net_Rate_Base | 19.0817% | 12,474,977 |
| July-22 | 5,192,195 | 70,568,811 | Net_Rate_Base | 19.0817% | 13,465,736 |
| August-22 | 7,414,667 | 77,983,478 | Net_Rate_Base | 19.0817% | 14,880,581 |
| September-22 | (47,131,818) | 30,851,660 | Net_Rate_Base | 19.0817% | 5,887,024 |
| October-22 | 3,392,773 | 34,244,433 | Net_Rate_Base | 19.0817% | 6,534,423 |
| November-22 | (1,686,517) | 32,557,916 | Net_Rate_Base | 19.0817% | 6,212,607 |
| December-22 | (1,794,021) | 30,763,895 | Net_Rate_Base | 19.0817% | 5,870,277 |
| January-23 | (9,120,842) | 21,643,053 | Net_Rate_Base | 19.0817% | 4,129,865 |
| February-23 | (7,795,132) | 13,847,921 | Net_Rate_Base | 19.0817% | 2,642,420 |
| March-23 | (1,223,169) | 12,624,752 | Net_Rate_Base | 19.0817% | 2,409,019 |
| April-23 | 1,411,161 | 14,035,913 | Net_Rate_Base | 19.0817% | 2,678,292 |
| May-23 | 8,213,793 | 22,249,706 | Net_Rate_Base | 19.0817% | 4,245,624 |
| June-23 | 7,371,728 | 29,621,434 | Net_Rate_Base | 19.0817% | 5,652,276 |
| July-23 | 9,213,094 | 38,834,528 | Net_Rate_Base | 19.0817% | 7,410,292 |
| August-23 | 9,100,379 | 47,934,907 | Net_Rate_Base | 19.0817% | 9,146,800 |
| September-23 | (13,832,969) | 34,101,938 | Net_Rate_Base | 19.0817% | 6,507,233 |
| October-23 | 2,845,606 | 36,947,544 | Net_Rate_Base | 19.0817% | 7,050,223 |
| November-23 | (3,022,938) | 33,924,606 | Net_Rate_Base | 19.0817% | 6,473,395 |
| December-23 | 2,563,393 | 36,487,999 | Net_Rate_Base | 19.0817% | 6,962,534 |
| January-24 | (11,380,717) | 25,107,282 | Net_Rate_Base | 19.0817% | 4,790,899 |
| February-24 | 11,411,868 | 36,519,150 | Net_Rate_Base | 19.0817% | 6,968,478 |
| March-24 | - | 36,519,150 | Net_Rate_Base | 19.0817% | 6,968,478 |
| April-24 | - | 36,519,150 | Net_Rate_Base | 19.0817% | 6,968,478 |
| May-24 | - | 36,519,150 | Net_Rate_Base | 19.0817% | 6,968,478 |
| June-24 | - | 36,519,150 | Net_Rate_Base | 19.0817% | 6,968,478 |
| July-24 | - | 36,519,150 | Net_Rate_Base | 19.0817% | 6,968,478 |
| August-24 | - | 36,519,150 | Net_Rate_Base | 19.0817% | 6,968,478 |
| September-24 | - | 36,519,150 | Net_Rate_Base | 19.0817% | 6,968,478 |
| October-24 | - | 36,519,150 | Net_Rate_Base | 19.0817% | 6,968,478 |
| | | | | | |
| Total | 36,519,150 | | | | |
| Average | | 31,146,839 | | | 5,943,350 |

# Washington Gas Light Company
## State NOL
## Merger to Date

| | | | DC Allocation | | |
|---|---|---|---|---|---|
| Date | Amount | Cumulative | Factor | Rate | DC Amount |
| June-18 | - | 2,689,965 | Net_Rate_Base | 19.0817% | 513,291 |
| July-18 | - | 2,689,965 | Net_Rate_Base | 19.0817% | 513,291 |
| August-18 | - | 2,689,965 | Net_Rate_Base | 19.0817% | 513,291 |
| September-18 | 16,927,868 | 19,617,833 | Net_Rate_Base | 19.0817% | 3,743,418 |
| October-18 | - | 19,617,833 | Net_Rate_Base | 19.0817% | 3,743,418 |
| November-18 | - | 19,617,833 | Net_Rate_Base | 19.0817% | 3,743,418 |
| December-18 | 3,554,480 | 23,172,314 | Net_Rate_Base | 19.0817% | 4,421,674 |
| January-19 | - | 23,172,314 | Net_Rate_Base | 19.0817% | 4,421,674 |
| February-19 | - | 23,172,314 | Net_Rate_Base | 19.0817% | 4,421,674 |
| March-19 | - | 23,172,314 | Net_Rate_Base | 19.0817% | 4,421,674 |
| April-19 | - | 23,172,314 | Net_Rate_Base | 19.0817% | 4,421,674 |
| May-19 | - | 23,172,314 | Net_Rate_Base | 19.0817% | 4,421,674 |
| June-19 | - | 23,172,314 | Net_Rate_Base | 19.0817% | 4,421,674 |
| July-19 | - | 23,172,314 | Net_Rate_Base | 19.0817% | 4,421,674 |
| August-19 | - | 23,172,314 | Net_Rate_Base | 19.0817% | 4,421,674 |
| September-19 | 1,093,457 | 24,265,771 | Net_Rate_Base | 19.0817% | 4,630,324 |
| October-19 | (1,557,172) | 22,708,599 | Net_Rate_Base | 19.0817% | 4,333,189 |
| November-19 | - | 22,708,599 | Net_Rate_Base | 19.0817% | 4,333,189 |
| December-19 | 9,046,951 | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| January-20 | - | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| February-20 | - | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| March-20 | - | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| April-20 | - | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| May-20 | - | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| June-20 | - | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| July-20 | - | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| August-20 | - | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| September-20 | - | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| October-20 | - | 31,755,549 | Net_Rate_Base | 19.0817% | 6,059,502 |
| November-20 | 14,418,620 | 46,174,170 | Net_Rate_Base | 19.0817% | 8,810,821 |
| December-20 | (3,952,906) | 42,221,264 | Net_Rate_Base | 19.0817% | 8,056,539 |
| January-21 | (4,150,919) | 38,070,345 | Net_Rate_Base | 19.0817% | 7,264,473 |
| February-21 | (1,208,744) | 36,861,601 | Net_Rate_Base | 19.0817% | 7,033,824 |
| March-21 | (3,712,958) | 33,148,643 | Net_Rate_Base | 19.0817% | 6,325,328 |
| April-21 | (313,408) | 32,835,235 | Net_Rate_Base | 19.0817% | 6,265,524 |
| May-21 | 1,742,517 | 34,577,752 | Net_Rate_Base | 19.0817% | 6,598,026 |
| June-21 | 3,206,893 | 37,784,645 | Net_Rate_Base | 19.0817% | 7,209,956 |
| July-21 | 3,203,817 | 40,988,462 | Net_Rate_Base | 19.0817% | 7,821,300 |
| August-21 | 3,324,828 | 44,313,290 | Net_Rate_Base | 19.0817% | 8,455,734 |

| | | | | | |
|---|---|---|---|---|---|
| September-21 | (16,297,494) | 28,015,796 | Net_Rate_Base | 19.0817% | 5,345,893 |
| October-21 | 9,653,855 | 37,669,651 | Net_Rate_Base | 19.0817% | 7,188,014 |
| November-21 | (2,509,450) | 35,160,201 | Net_Rate_Base | 19.0817% | 6,709,168 |
| December-21 | 35,411,565 | 70,571,766 | Net_Rate_Base | 19.0817% | 13,466,300 |
| January-22 | (3,831,654) | 66,740,112 | Net_Rate_Base | 19.0817% | 12,735,155 |
| February-22 | (883,209) | 65,856,903 | Net_Rate_Base | 19.0817% | 12,566,623 |
| March-22 | (374,662) | 65,482,241 | Net_Rate_Base | 19.0817% | 12,495,132 |
| April-22 | (336,213) | 65,146,028 | Net_Rate_Base | 19.0817% | 12,430,976 |
| May-22 | 5,084,893 | 70,230,921 | Net_Rate_Base | 19.0817% | 13,401,261 |
| June-22 | 1,198,727 | 71,429,648 | Net_Rate_Base | 19.0817% | 13,629,999 |
| July-22 | 2,165,186 | 73,594,834 | Net_Rate_Base | 19.0817% | 14,043,153 |
| August-22 | 2,463,818 | 76,058,652 | Net_Rate_Base | 19.0817% | 14,513,292 |
| September-22 | (13,076,296) | 62,982,356 | Net_Rate_Base | 19.0817% | 12,018,111 |
| October-22 | (409,563) | 62,572,793 | Net_Rate_Base | 19.0817% | 11,939,959 |
| November-22 | 410,827 | 62,983,620 | Net_Rate_Base | 19.0817% | 12,018,352 |
| December-22 | (945,628) | 62,037,992 | Net_Rate_Base | 19.0817% | 11,837,910 |
| January-23 | (2,839,395) | 59,198,597 | Net_Rate_Base | 19.0817% | 11,296,105 |
| February-23 | 836,441 | 60,035,038 | Net_Rate_Base | 19.0817% | 11,455,712 |
| March-23 | (1,821,192) | 58,213,846 | Net_Rate_Base | 19.0817% | 11,108,197 |
| April-23 | 1,499,252 | 59,713,098 | Net_Rate_Base | 19.0817% | 11,394,280 |
| May-23 | 1,666,692 | 61,379,790 | Net_Rate_Base | 19.0817% | 11,712,314 |
| June-23 | 1,707,479 | 63,087,269 | Net_Rate_Base | 19.0817% | 12,038,130 |
| July-23 | 2,000,094 | 65,087,363 | Net_Rate_Base | 19.0817% | 12,419,782 |
| October-23 | 2,325,429 | 68,395,743 | Net_Rate_Base | 19.0817% | 13,051,078 |
| November-23 | (1,917,781) | 66,477,962 | Net_Rate_Base | 19.0817% | 12,685,132 |
| December-23 | (963,121) | 65,514,841 | Net_Rate_Base | 19.0817% | 12,501,352 |
| January-24 | (3,509,213) | 62,005,628 | Net_Rate_Base | 19.0817% | 11,831,734 |
| February-24 | 3,360,873 | 65,366,501 | Net_Rate_Base | 19.0817% | 12,473,046 |
| March-24 | - | 65,366,501 | Net_Rate_Base | 19.0817% | 12,473,046 |
| April-24 | - | 65,366,501 | Net_Rate_Base | 19.0817% | 12,473,046 |
| May-24 | - | 65,366,501 | Net_Rate_Base | 19.0817% | 12,473,046 |
| June-24 | - | 65,366,501 | Net_Rate_Base | 19.0817% | 12,473,046 |
| July-24 | - | 65,366,501 | Net_Rate_Base | 19.0817% | 12,473,046 |
| August-24 | - | 65,366,501 | Net_Rate_Base | 19.0817% | 12,473,046 |
| September-24 | - | 65,366,501 | Net_Rate_Base | 19.0817% | 12,473,046 |
| October-24 | - | 65,366,501 | Net_Rate_Base | 19.0817% | 12,473,046 |
| | | | | | |
| Total | 65,366,501 | | | | |
| Average | | 64,134,187 | | | 12,237,900 |

# Washington Gas Light Company
## Federal Benefit of State NOL
## Merger to Date

| State NOL | | | | | DC Allocation | | |
|---|---|---|---|---|---|---|---|
| Date | Amount | Cumulative | Tax rate | Taxes | Factor | Rate | DC Amount |
| June-18 | - | 2,689,965 | 21% | 564,893 | Net_Rate_Base | 19.0817% | 107,791 |
| July-18 | - | 2,689,965 | 21% | 564,893 | Net_Rate_Base | 19.0817% | 107,791 |
| August-18 | - | 2,689,965 | 21% | 564,893 | Net_Rate_Base | 19.0817% | 107,791 |
| September-18 | 16,927,868 | 19,617,833 | 21% | 4,119,745 | Net_Rate_Base | 19.0817% | 786,118 |
| October-18 | - | 19,617,833 | 21% | 4,119,745 | Net_Rate_Base | 19.0817% | 786,118 |
| November-18 | - | 19,617,833 | 21% | 4,119,745 | Net_Rate_Base | 19.0817% | 786,118 |
| December-18 | 3,554,480 | 23,172,314 | 21% | 4,866,186 | Net_Rate_Base | 19.0817% | 928,551 |
| January-19 | - | 23,172,314 | 21% | 4,866,186 | Net_Rate_Base | 19.0817% | 928,551 |
| February-19 | - | 23,172,314 | 21% | 4,866,186 | Net_Rate_Base | 19.0817% | 928,551 |
| March-19 | - | 23,172,314 | 21% | 4,866,186 | Net_Rate_Base | 19.0817% | 928,551 |
| April-19 | - | 23,172,314 | 21% | 4,866,186 | Net_Rate_Base | 19.0817% | 928,551 |
| May-19 | - | 23,172,314 | 21% | 4,866,186 | Net_Rate_Base | 19.0817% | 928,551 |
| June-19 | - | 23,172,314 | 21% | 4,866,186 | Net_Rate_Base | 19.0817% | 928,551 |
| July-19 | - | 23,172,314 | 21% | 4,866,186 | Net_Rate_Base | 19.0817% | 928,551 |
| August-19 | - | 23,172,314 | 21% | 4,866,186 | Net_Rate_Base | 19.0817% | 928,551 |
| September-19 | 1,093,457 | 24,265,771 | 21% | 5,095,812 | Net_Rate_Base | 19.0817% | 972,368 |
| October-19 | (1,557,172) | 22,708,599 | 21% | 4,768,806 | Net_Rate_Base | 19.0817% | 909,970 |
| November-19 | - | 22,708,599 | 21% | 4,768,806 | Net_Rate_Base | 19.0817% | 909,970 |
| December-19 | 9,046,951 | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| January-20 | - | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| February-20 | - | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| March-20 | - | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| April-20 | - | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| May-20 | - | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| June-20 | - | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| July-20 | - | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| August-20 | - | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| September-20 | - | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| October-20 | - | 31,755,549 | 21% | 6,668,665 | Net_Rate_Base | 19.0817% | 1,272,495 |
| November-20 | 14,418,620 | 46,174,170 | 21% | 9,696,576 | Net_Rate_Base | 19.0817% | 1,850,272 |
| December-20 | (3,952,906) | 42,221,264 | 21% | 8,866,465 | Net_Rate_Base | 19.0817% | 1,691,873 |
| January-21 | (4,150,919) | 38,070,345 | 21% | 7,994,772 | Net_Rate_Base | 19.0817% | 1,525,539 |
| February-21 | (1,208,744) | 36,861,601 | 21% | 7,740,936 | Net_Rate_Base | 19.0817% | 1,477,103 |
| March-21 | (3,712,958) | 33,148,643 | 21% | 6,961,215 | Net_Rate_Base | 19.0817% | 1,328,319 |
| April-21 | (313,408) | 32,835,235 | 21% | 6,895,399 | Net_Rate_Base | 19.0817% | 1,315,760 |
| May-21 | 1,742,517 | 34,577,752 | 21% | 7,261,328 | Net_Rate_Base | 19.0817% | 1,385,586 |
| June-21 | 3,206,893 | 37,784,645 | 21% | 7,934,775 | Net_Rate_Base | 19.0817% | 1,514,091 |
| July-21 | 3,203,817 | 40,988,462 | 21% | 8,607,577 | Net_Rate_Base | 19.0817% | 1,642,473 |
| August-21 | 3,324,828 | 44,313,290 | 21% | 9,305,791 | Net_Rate_Base | 19.0817% | 1,775,704 |
| September-21 | (16,297,494) | 28,015,796 | 21% | 5,883,317 | Net_Rate_Base | 19.0817% | 1,122,638 |
| October-21 | 9,653,855 | 37,669,651 | 21% | 7,910,627 | Net_Rate_Base | 19.0817% | 1,509,483 |
| November-21 | (2,509,450) | 35,160,201 | 21% | 7,383,642 | Net_Rate_Base | 19.0817% | 1,408,925 |
| December-21 | 35,411,565 | 70,571,766 | 21% | 14,820,071 | Net_Rate_Base | 19.0817% | 2,827,923 |
| January-22 | (3,831,654) | 66,740,112 | 21% | 14,015,424 | Net_Rate_Base | 19.0817% | 2,674,383 |
| February-22 | (883,209) | 65,856,903 | 21% | 13,829,950 | Net_Rate_Base | 19.0817% | 2,638,991 |
| March-22 | (374,662) | 65,482,241 | 21% | 13,751,271 | Net_Rate_Base | 19.0817% | 2,623,978 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| April-22 | (336,213) | 65,146,028 | 21% | 13,680,666 | Net_Rate_Base | 19.0817% | 2,610,505 |
| May-22 | 5,084,893 | 70,230,921 | 21% | 14,748,493 | Net_Rate_Base | 19.0817% | 2,814,265 |
| June-22 | 1,198,727 | 71,429,648 | 21% | 15,000,226 | Net_Rate_Base | 19.0817% | 2,862,300 |
| July-22 | 2,165,186 | 73,594,834 | 21% | 15,454,915 | Net_Rate_Base | 19.0817% | 2,949,062 |
| August-22 | 2,463,818 | 76,058,652 | 21% | 15,972,317 | Net_Rate_Base | 19.0817% | 3,047,791 |
| September-22 | (13,076,296) | 62,982,356 | 21% | 13,226,295 | Net_Rate_Base | 19.0817% | 2,523,803 |
| October-22 | (409,563) | 62,572,793 | 21% | 13,140,287 | Net_Rate_Base | 19.0817% | 2,507,391 |
| November-22 | 410,827 | 62,983,620 | 21% | 13,226,560 | Net_Rate_Base | 19.0817% | 2,523,854 |
| December-22 | (945,628) | 62,037,992 | 21% | 13,027,978 | Net_Rate_Base | 19.0817% | 2,485,961 |
| January-23 | (2,839,395) | 59,198,597 | 21% | 12,431,705 | Net_Rate_Base | 19.0817% | 2,372,182 |
| February-23 | 836,441 | 60,035,038 | 21% | 12,607,358 | Net_Rate_Base | 19.0817% | 2,405,700 |
| March-23 | (1,821,192) | 58,213,846 | 21% | 12,224,908 | Net_Rate_Base | 19.0817% | 2,332,721 |
| April-23 | 1,499,252 | 59,713,098 | 21% | 12,539,751 | Net_Rate_Base | 19.0817% | 2,392,799 |
| May-23 | 1,666,692 | 61,379,790 | 21% | 12,889,756 | Net_Rate_Base | 19.0817% | 2,459,586 |
| June-23 | 1,707,479 | 63,087,269 | 21% | 13,248,326 | Net_Rate_Base | 19.0817% | 2,528,007 |
| July-23 | 2,000,094 | 65,087,363 | 21% | 13,668,346 | Net_Rate_Base | 19.0817% | 2,608,154 |
| August-23 | 1,978,217 | 67,065,580 | 21% | 14,083,772 | Net_Rate_Base | 19.0817% | 2,687,425 |
| September-23 | (995,266) | 66,070,314 | 21% | 13,874,766 | Net_Rate_Base | 19.0817% | 2,647,543 |
| October-23 | 2,325,429 | 68,395,743 | 21% | 14,363,106 | Net_Rate_Base | 19.0817% | 2,740,726 |
| November-23 | (1,917,781) | 66,477,962 | 21% | 13,960,372 | Net_Rate_Base | 19.0817% | 2,663,878 |
| December-23 | (963,121) | 65,514,841 | 21% | 13,758,117 | Net_Rate_Base | 19.0817% | 2,625,284 |
| January-24 | (3,509,213) | 62,005,628 | 21% | 13,021,182 | Net_Rate_Base | 19.0817% | 2,484,664 |
| February-24 | 3,360,873 | 65,366,501 | 21% | 13,726,965 | Net_Rate_Base | 19.0817% | 2,619,340 |
| March-24 | - | 65,366,501 | 21% | 13,726,965 | Net_Rate_Base | 19.0817% | 2,619,340 |
| April-24 | - | 65,366,501 | 21% | 13,726,965 | Net_Rate_Base | 19.0817% | 2,619,340 |
| May-24 | - | 65,366,501 | 21% | 13,726,965 | Net_Rate_Base | 19.0817% | 2,619,340 |
| June-24 | - | 65,366,501 | 21% | 13,726,965 | Net_Rate_Base | 19.0817% | 2,619,340 |
| July-24 | - | 65,366,501 | 21% | 13,726,965 | Net_Rate_Base | 19.0817% | 2,619,340 |
| August-24 | - | 65,366,501 | 21% | 13,726,965 | Net_Rate_Base | 19.0817% | 2,619,340 |
| September-24 | - | 65,366,501 | 21% | 13,726,965 | Net_Rate_Base | 19.0817% | 2,619,340 |
| October-24 | - | 65,366,501 | 21% | 13,726,965 | Net_Rate_Base | 19.0817% | 2,619,340 |
| | | | | | | | |
| Total | 65,366,501 | | | | | | |
| Average | | | | 13,468,179 | | | 2,569,959 |

# Confidential Follow-up Exhibit Omitted

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 18

QUESTION NO. 18-2

**Q.** **Deferred Tax Asset ("DTA") Net Operating Loss Carryover ("NOLC") Balances.** Witness Tuoriniemi (97:12 – 104:11) provides the regulatory and ratemaking impacts and adjustments to income tax expense and the state and federal NOLC for the effect PLR. Also, Exhibit WG (D)-1, page 2 of 4 includes debit account balances in rate base (balance sheet accounts) titled "NOL Carryforward Federal" with a per book March 31, 2024, balance of $14,916,809, a ratemaking adjustment of $20,845,267, and a ratemaking balance of $35,762,077, and an account titled "NOL Carryforward State" with a per book March 31, 2024, balance of $13,095,164, a ratemaking adjustment of ($857,264), and a ratemaking balance of $12,237,900. Please address the following:

a. Provide the balances in the "NOL Carryforward Federal" and "NOL Carryforward State" for every month from the merger of AltaGas and WGL through the most recent date in 2024, and explain the reasons for the change in these annual calendar year-end balances from the merger date through December 31, 2023, and for all additional changes through the most recent month-end balance in 2024.

b. Regarding (a) above, provide all calculations and allocation factors used in determining the "WGL-DC" portion of the WGL balance for all periods.

c. Regarding (a) above, identify all other subaccounts for other NOL (or NOLC) accounts recorded on WGL's books from the merger date through the most recent date in 2024, explain each of these account, and provide the related balances for same periods – and explain the reasons for the changes in these balances from the merger date through the most recent date in 2024.

d. Regarding (a) through (c), explain how the amount of net operating losses related to the deferred depreciation tax impacts has impacted these NOL Federal and State balances for each of the periods identified in (a) above.

**WASHINGTON GAS'S RESPONSE** 12/05/2024 

**A.**

a. See the Company's response to OPC DR 18-1, Attachment 1 for the monthly balances. The changes in the NOL accounts are driven by Washington Gas's taxable income, its ability to utilize the net operating losses (currently or via carryback or carryforward) on its income tax returns, the extent Washington Gas receives reimbursements from other affiliates for use of its net operating losses and the impact of the reduction in the federal income tax rate pursuant to the Tax Cuts and Jobs Act. The merger had no impact on the NOL.

b. See OPC DR 18-1, Attachment 1.

c. All NOL-related accounts are reflected in OPC DR 18-1, Attachment 1.

d. Washington Gas's substantial tax depreciation deductions are the driver the Net Operating Loss. However, Washington Gas does not compute its net operating loss by the individual drivers that comprise the loss.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

Exhibit OPC (B)-86
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential Exhibit Omitted

Exhibit OPC (B)-87
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential Exhibit Omitted

Exhibit OPC (B)-88
Formal Case No. 1180
Direct Testimony of Bion Ostrander

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 4

QUESTION NO. 4-10

**Q.** **Allocation Factors for Services Allocated from WGL to Affiliates.** Witness Tuoriniemi's Direct Testimony (34:4-15) identifies those affiliates to which WGL provides services, including WGL Holdings, Hampshire Gas, WGL Energy Services, WGL Energy Systems, WGL Midstream, SEMCO Energy, ASUS, AltaGas, Ltd., and Other Affiliates (Other Affiliates are identified in more detail at Witness Quenum's testimony (9:1-16) and at ACOSS and other Confidential Exhibits WG (J)-3 and (J)-5). Address the following regarding allocated/assigned costs from WGL to all affiliates using the MMF and other allocation factors for the test year end March 31, 2024, and prior calendar years 2019 to 2023:

a. Provide the amount and percent of expenses by type of ALA Corporate expense (Executive Management, Finance, Accounting and Tax, etc.) allocated from WGL to each affiliate for each type of allocation factor method (including MMF and other methods) for calendar years 2019 to 2023, and test year end March 31, 2024.

b. Regarding (a) above, if the amount and percent of expense allocated from WGL to each affiliate for each type of allocation factor method (including MMF and other allocation methods, including those identified at Witness Quenum's testimony 9:6-16) cannot be provided by "type of ALA Corporate expense" (Finance, Accounting and Tax, etc.), then provide the amount and percent allocated from WGL to each affiliate by each type of "cost pool" for each type of allocation factor method – and describe and identify the costs included in each cost pool. This should include (but not be limited to), cost pool allocation calculations for Overheads (Common Services, Payroll, Executive, Other, Building, Telephone and Software per the December 2023 CAM (pages 39-41) and per Quenum Exhibit (WG (J)-5 Parts A, B, and C). Also, reconcile these allocated expense amounts to the allocated amount of expenses by type of ALA Corporate expense (Finance, Accounting and Tax, etc.) for calendar years 2019 to 2023, and test year end March 31, 2024.

c. Regarding (a) and (b) above, provide the numerator and denominator of each allocation factor (including MMF other allocation methods, including those identified at Witness Quenum's testimony 9:6-16)) for WGL and each affiliate (along with the total allocation factor used for all affiliates subject to allocation), and provide the related underlying financial and other inputs to the allocation factors (including inputs of net revenue, direct & assigned labor, and average invested capital), that are used to allocate expenses from WGL to each affiliate for calendar years 2019 to 2023, and test year end March 31, 2024. Provide all supporting documentation and calculations for all allocation factor calculations, including all inputs and summary financial data for each U.S. affiliate to which expenses are allocated by WGL using the allocation factors.

d. Regarding (b) and (c) above, provide a citation to Service Agreements and provide copies of other documentation which identify and describe each allocation factor method and how it is calculated.

e. Regarding (b) and (c) above, translate the above MMF allocation factor information to the quarterly MMF factors calculation used for allocating expenses from WGL to affiliates (Witness Quenum, 9:8-9), and provide this same calculation for other allocation factor methods that are used. Explain if any MMF allocation factor component (or other allocation factor methods) is used in arrears and the period of data to which the allocation factor is applied. For example, explain if the MMF allocation factors used for the March 31, 2024, test period are all based on financial inputs/data ending March 31, 2024, or if the factors are a combination of actual and historical (or projected data) inputs/data, such as using actual information for April 2023 to December 31, 2023 and using estimated or historical data in place of actual March 31, 2024 actual data.

f. Regarding (c) above, provide the names of each of the affiliates to which WGL expenses are allocated using the various allocation factors (including the MMF), and provide the following:

(i) A general description of each affiliate's type of business that is conducted with WGL and with non-affiliate third parties – and state the reason for the existence of the business.

(ii) Identify the year when each affiliate (to which WGL allocates expenses) was created and if it has operated as a going concern for all years through test year end March 31, 2024.

(iii) Explain if each affiliate (to which WGL allocates expenses) is a profit center for WGL, AltaGas or other affiliates, or otherwise explain the purposes of the affiliate if not for generating profits for AltaGas and WGL (or for other entities).

(iv) Explain if each affiliate (to which WGL allocates expenses) is any of the following: a "capital intensive" business with substantial fixed plant investment on the balance sheet that is used to provide services and generate revenues, a "service-providing" company that is not capital intensive; or a mix of capital intensive and service-related. Explain the basis and provide supporting documentation for your response.

(v) Identify each affiliate (to which WGL allocates expenses) that has and has not generated a profit for each year (calendar years 2019 to 2023 and test year end March 31, 2024).

g. Explain if and why each of the cost allocation factors (including the MMF) are the best and most reasonable allocation factors to use for allocating the related expenses or cost pools from WGL to each of the affiliates. Explain how each of the cost allocation methods used for each expense or cost pool is a reasonable driver of the related expenses, how it supports cost-causation, and if and how it is measurable, objective, stable and predictable, and consistent. Identify those cost allocation methods that do not meet these criteria.

h. Identify all U.S. affiliates/businesses that do not receive an allocation of expenses from WGL for each of the periods (calendar years 2019 to 2023, and test year end March 2024) and explain why this is the case. Provide supporting documentation for your response.

i. Two separate Service Agreements exist for WGL providing services to both ASUS and AltaGas Ltd., with most of the same services being provided to both affiliates (although Sustainability, Corporate Public Policy, Utility Operations, Engineering Construction, and Regulatory Affairs are provided only to AltaGas Ltd.), explain the primary reasons for having two separate agreements with each of these related affiliates and why there is a difference in services provided to each.

j. Two separate Service Agreements exist for WGL providing services to both WGL Energy Services, Inc. and WGL Holdings, Inc. with most of the same services being provided to both affiliates (although Payroll, Cash Receipts, and Human Resources and Benefits are provided only to WGL Energy Services, Inc.), explain the primary reasons for having two separate agreements with each of these related affiliates and why there is a difference in services provided to each.

**WASHINGTON GAS'S OBJECTION** 11/1/2024

Washington Gas objects to this request on grounds that it requires a special study which has not been performed. Without waiving this objection, the Company will provide responsive information that is available.

**WASHINGTON GAS'S RESPONSE** 11/15/2024

**A.**

a. As stated on Page 21 of the 2023 DC Cost Allocation and Inter-company Pricing Manual (CAM), "*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*."

Please find attached the allocation of AltaGas corporate shared costs by function, from WGL Holdings to each of its pre-merger US Affiliates. AltaGas corporate shared costs allocations from ASUS to its direct US Affiliates is addressed in WGL's Response to OPC DR 4-8.

b. Please refer to WGL's Response for 4-10.a.

c. ASUS used Washington Gas' MMF to allocate corporate shared services costs to WGL and US Affiliates. The three factors used in the computation of the MMF are 1) Average Invested Capital (AIC), 2) Adjusted Net Revenue, and 3) Direct & Assigned Labor.

**Average Invested Capital (AIC)** = Capitalization (Sum of Common Stock includes RE) + Net Income (Current Year before closing RE) + Total Long-term debt + Notes Payable & Pref Stock & LT Due in 1 Year + Money Pool Borrowings - Investment in Subs.

**Adjusted Net Revenue** = Operating Revenue – Cost of Sale – Revenue Taxes

**Direct & Assigned Labor** = Productive Labor + Non-Productive Labor

The MMF ratio is a simple average of the three factors for each affiliate.

Average Invested Capital of affiliate / Total Average Invested Capital
Adjusted Net Revenue of the Affiliate / Total Adjusted Revenue
Direct & Assigned Labor of the Affiliate / Total Direct & Assigned Labor

d. The MMF formula is not discussed in the Service Agreements between WGL and other Affiliates. DC Cost Allocation and Inter-company Pricing Manual (CAM) describes each allocation factor and method and how it is calculated.

e. The MMF calculation is based on actuals from historical financial statements data as of the prior quarter; it does not include projections or estimates.

Please refer to WGL's Response for OPC DR 4-8.e for all quarterly MMF factors calculation worksheets from 2019 to March 31, 2024.

f. Please refer to the 2023 DC CAM
   (i) Please refer to Page 25 of the 2023 DC CAM.
   (ii) Please refer to Page 25 of the 2023 DC CAM.
   (iii) Each affiliate is a profit center for AltaGas.
   (iv) Please refer to WGL's Responses to OPC DR 4-8.e and OPC DR 4-7.j.
   (v) Affiliates have been profitable over the stated periods.

g. Please refer to WGL's Responses to OPC DR 4-15.

h. Please refer to WGL's Response for OPC DR 4-10-a. All operating affiliates received an allocation; affiliates which assets are sold do not receive an allocation of expenses.

i. Chapter 39, "Affiliate Transactions Code of Conduct," of Title 15, District of Columbia Municipal Regulation, does not require that Service Agreements be in place and used as a basis for services rendered between a Utility and its Affiliates. Each service agreement defines the scope of activity and business relationship between WGL and an affiliate as a legal entity; it also documents the services that the Company provides to and receives from each Affiliate based on each Affiliate's operational needs. Separate service agreements are required for each affiliate based on each entity's requirements. See generally Virginia Code Section 56-77:

**§ 56-77. Certain contracts must be approved by the Commission.**
No contract or arrangement providing for the furnishing of management, supervisory, construction, engineering, accounting, legal, financial, or similar services, and no contract or arrangement for the purchase, sale, lease or exchange of any property, right or thing, other than those above enumerated, or for the purchase or sale of treasury bonds or treasury capital stock made or entered into between a public service company and any affiliated interest shall be valid or effective unless and until it shall have been filed with and approved by the Commission.

"Affiliated interest" is defined in Section 56-76 of the Virginia Code:

1. Every corporation, partnership, association, or person owning or holding directly or indirectly ten percent or more of the voting securities of any public service company engaged in any intrastate business in this Commonwealth.

2. Every corporation, partnership, association, or person, other than those specified in subdivision 1 hereof, in any chain of successive ownership of ten percent or more of voting securities, the chain beginning with the holder or holders of the voting securities of such public service company.

3. Every corporation, partnership, association, or person ten percent or more of whose voting securities are owned by any person, corporation, partnership, or association owning ten percent or more of the voting securities of such public service company or by any person, corporation, association, or partnership in any such chain of successive ownership of ten percent or more of voting securities.

4. Every corporation, partnership, association, or person with which such public service company has a management or service contract.

5. Every corporation in which two or more of the corporate directors are common to those of such public service company, or which is managed or supervised by the same individual, group or corporation.

6. Every corporation or person which the Commission may determine as a matter of fact after investigation and hearing is actually exercising any substantial influence over the policies and actions of such public service company even though such influence is not based upon stockholding, stockholders, directors or officers to the extent specified in this section.

7. Every person or corporation which the Commission may determine as a matter of fact after investigation and hearing is actually exercising such substantial influence over the policies and action of such public service company in conjunction with one or more other corporations or persons with which or whom they are so connected or related by ownership or blood relationship or by action in concert that when taken together they are affiliated with such public service company within the meaning of this section even though no one of them alone is so affiliated.

But no such person or corporation shall be considered as affiliated within the meaning of this section if such person or corporation shall not have had transactions or dealings other than the holding of stock and the receipt of dividends thereon with such public service company during the two-year period next preceding.

j. Please refer to WGL's Response for Question OPC DR 4-10.i above.

SPONSOR: Ghislaine (Celine) Quenum
Manager, Corporate Accounting

**AltaGas Corporate Services Costs Allocated From WGLH to WGL and Pre-Merger Affiliates**

| Function | CY2019 | CY2020 | CY2021 | CY2022 | CY2023 | TME MARCH 2024 | Grand Total |
|---|---|---|---|---|---|---|---|
| **Washington Gas Light Company** | | | | | | | |
| Accounting and Tax | $ 3,115,288 | $ 5,500,731 | $ 3,955,910 | $ 3,541,200 | $ 5,421,084 | $ 5,273,385 | $ 26,807,598 |
| Board of Directors | 514,752 | 643,561 | 531,104 | 555,042 | 1,271,103 | 1,236,472 | 4,752,035 |
| Exec Mgmt | 1,433,343 | 1,800,528 | 2,691,506 | 2,480,795 | 3,280,807 | 3,191,420 | 14,878,398 |
| Finance | 1,910,168 | 1,844,002 | 2,394,428 | 1,717,075 | 1,783,442 | 1,734,851 | 11,383,967 |
| HR | 2,810,876 | 2,550,543 | 1,170,295 | 2,729,478 | 2,955,152 | 2,874,638 | 15,090,981 |
| IT | 4,843,255 | 4,499,675 | 4,563,108 | 5,322,496 | 7,534,124 | 7,328,854 | 34,091,511 |
| Legal and Compliance | 2,300,618 | 2,900,409 | 3,748,950 | 3,859,489 | 4,175,676 | 4,061,908 | 21,047,050 |
| Supply Chain | 235,911 | 341,301 | 396,790 | 270,518 | 359,715 | 349,914 | 1,954,149 |
| Cost-To-Achieve (IT) | 1,220,964 | 613,564 | 465,940 | 74,753 | - | - | 2,375,220 |
| **Total** | **$ 18,385,175** | **$ 20,694,313** | **$ 19,918,031** | **$ 20,550,846** | **$ 26,781,102** | **$ 26,051,443** | **$ 132,380,909** |
| **Hampshire Gas Company** | | | | | | | |
| Accounting and Tax | $ 25,591 | $ 45,287 | $ 33,163 | $ 32,510 | $ 48,466 | $ 44,536 | $ 229,553 |
| Board of Directors | 4,229 | 5,298 | 4,452 | 5,096 | 11,364 | 10,443 | 40,881 |
| Exec Mgmt | 11,774 | 14,823 | 22,563 | 22,775 | 29,332 | 26,953 | 128,220 |
| Finance | 15,691 | 15,181 | 20,073 | 15,764 | 15,945 | 14,652 | 97,305 |
| HR | 23,090 | 20,998 | 9,811 | 25,058 | 26,420 | 24,278 | 129,655 |
| IT | 39,786 | 37,045 | 38,253 | 48,863 | 67,358 | 61,895 | 293,200 |
| Legal and Compliance | 18,899 | 23,879 | 31,428 | 35,432 | 37,332 | 34,305 | 181,274 |
| Supply Chain | 1,938 | 2,810 | 3,326 | 2,483 | 3,216 | 2,955 | 16,729 |
| Cost-To-Achieve (IT) | 10,312 | 4,976 | 1,551 | 662 | - | - | 17,501 |
| **Total** | **$ 151,310** | **$ 170,297** | **$ 164,621** | **$ 188,642** | **$ 239,433** | **$ 220,015** | **$ 1,134,318** |
| **WGL Energy Services, Inc** | | | | | | | |
| Accounting and Tax | $ 264,275 | $ 418,560 | $ 273,199 | $ 218,958 | $ 296,144 | $ 256,478 | $ 1,727,614 |
| Board of Directors | 43,667 | 48,970 | 36,679 | 34,319 | 69,438 | 60,137 | 293,210 |
| Exec Mgmt | 121,593 | 137,005 | 185,878 | 153,391 | 179,224 | 155,219 | 932,311 |
| Finance | 162,043 | 140,313 | 165,362 | 106,169 | 97,426 | 84,377 | 755,690 |
| HR | 238,452 | 194,075 | 80,822 | 168,768 | 161,434 | 139,812 | 983,362 |
| IT | 410,862 | 342,388 | 315,133 | 329,098 | 411,575 | 356,448 | 2,165,504 |
| Legal and Compliance | 195,166 | 220,697 | 258,906 | 238,638 | 228,109 | 197,556 | 1,339,072 |
| Supply Chain | 20,013 | 25,970 | 27,403 | 16,727 | 19,651 | 17,019 | 126,781 |
| Cost-To-Achieve (IT) | 106,385 | 45,917 | 12,863 | 4,703 | - | - | 169,868 |
| **Total** | **$ 1,562,456** | **$ 1,573,897** | **$ 1,356,243** | **$ 1,270,770** | **$ 1,463,002** | **$ 1,267,046** | **$ 8,493,413** |
| **Washington Gas Resources** | | | | | | | |
| Accounting and Tax | $ 2,742 | $ 62,850 | $ 27,649 | $ 13,907 | $ - | $ - | $ 107,148 |
| Board of Directors | 453 | 7,353 | 3,712 | 2,180 | - | - | 13,698 |
| Exec Mgmt | 1,262 | 20,572 | 18,812 | 9,742 | - | - | 50,388 |
| Finance | 1,681 | 21,069 | 16,735 | 6,743 | - | - | 46,229 |
| HR | 2,474 | 29,142 | 8,180 | 10,719 | - | - | 50,515 |
| IT | 4,263 | 51,412 | 31,893 | 20,902 | - | - | 108,470 |
| Legal and Compliance | 2,025 | 33,139 | 26,203 | 15,157 | - | - | 76,524 |
| Supply Chain | 208 | 3,900 | 2,773 | 1,062 | - | - | 7,943 |
| Cost-To-Achieve (IT) | 1,126 | 7,260 | 975 | 460 | - | - | 9,821 |
| **Total** | **$ 16,234** | **$ 236,697** | **$ 136,932** | **$ 80,872** | **$ -** | **$ -** | **$ 470,736** |
| **WGSW** | | | | | | | |
| Accounting and Tax | $ 34,094 | $ - | $ - | $ - | $ - | $ - | $ 34,094 |
| Board of Directors | 5,633 | - | - | - | - | - | 5,633 |
| Exec Mgmt | 15,687 | - | - | - | - | - | 15,687 |
| Finance | 20,905 | - | - | - | - | - | 20,905 |
| HR | 30,762 | - | - | - | - | - | 30,762 |
| IT | 53,005 | - | - | - | - | - | 53,005 |
| Legal and Compliance | 25,178 | - | - | - | - | - | 25,178 |
| Supply Chain | 2,582 | - | - | - | - | - | 2,582 |
| Cost-To-Achieve (IT) | 12,274 | - | - | - | - | - | 12,274 |
| **Total** | **$ 200,120** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 200,120** |
| **WGL Energy Systems** | | | | | | | |
| Accounting and Tax | $ 299,540 | $ - | $ - | $ - | $ - | $ - | $ 299,540 |
| Board of Directors | 49,494 | - | - | - | - | - | 49,494 |
| Exec Mgmt | 137,818 | - | - | - | - | - | 137,818 |
| Finance | 183,666 | - | - | - | - | - | 183,666 |
| HR | 270,270 | - | - | - | - | - | 270,270 |
| IT | 465,687 | - | - | - | - | - | 465,687 |
| Legal and Compliance | 221,208 | - | - | - | - | - | 221,208 |
| Supply Chain | 22,683 | - | - | - | - | - | 22,683 |
| Cost-To-Achieve (IT) | 111,330 | - | - | - | - | - | 111,330 |
| **Total** | **$ 1,761,698** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 1,761,698** |
| **WGL Midstream** | | | | | | | |
| Accounting and Tax | $ 19,830 | $ 75,275 | $ 46,537 | $ - | $ - | $ - | $ 141,642 |
| Board of Directors | 3,277 | 8,807 | 6,248 | - | - | - | 18,331 |
| Exec Mgmt | 9,124 | 24,639 | 31,663 | - | - | - | 65,426 |
| Finance | 12,159 | 25,234 | 28,168 | - | - | - | 65,561 |
| HR | 17,892 | 34,903 | 13,767 | - | - | - | 66,562 |
| IT | 30,829 | 61,576 | 53,680 | - | - | - | 146,085 |
| Legal and Compliance | 14,644 | 39,691 | 44,103 | - | - | - | 98,438 |
| Supply Chain | 1,502 | 4,671 | 4,668 | - | - | - | 10,840 |
| Cost-To-Achieve (IT) | 62,632 | 9,834 | - | - | - | - | 72,466 |
| **Total** | **$ 171,887** | **$ 284,630** | **$ 228,834** | **$ -** | **$ -** | **$ -** | **$ 685,351** |
| **WGL Midstream CP, LLC** | | | | | | | |
| Accounting and Tax | $ 4,926 | $ - | $ - | $ - | $ - | $ - | $ 4,926 |
| Board of Directors | 814 | - | - | - | - | - | 814 |
| Exec Mgmt | 2,267 | - | - | - | - | - | 2,267 |
| Finance | 3,021 | - | - | - | - | - | 3,021 |
| HR | 4,445 | - | - | - | - | - | 4,445 |
| IT | 7,659 | - | - | - | - | - | 7,659 |
| Legal and Compliance | 3,638 | - | - | - | - | - | 3,638 |
| Supply Chain | 373 | - | - | - | - | - | 373 |
| Cost-To-Achieve (IT) | 1,667 | - | - | - | - | - | 1,667 |
| **Total** | **$ 28,809** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 28,809** |
| **WGL Midstream MP, LLC** | | | | | | | |
| Accounting and Tax | $ 130,553 | $ - | $ - | $ - | $ - | $ - | $ 130,553 |
| Board of Directors | 21,572 | - | - | - | - | - | 21,572 |
| Exec Mgmt | 60,067 | - | - | - | - | - | 60,067 |
| Finance | 80,050 | - | - | - | - | - | 80,050 |
| HR | 117,796 | - | - | - | - | - | 117,796 |
| IT | 202,967 | - | - | - | - | - | 202,967 |
| Legal and Compliance | 96,412 | - | - | - | - | - | 96,412 |
| Supply Chain | 9,886 | - | - | - | - | - | 9,886 |
| Cost-To-Achieve (IT) | - | - | - | - | - | - | - |
| **Total** | **$ 719,304** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 719,304** |
| **WGL Midstream MVP, LLC** | | | | | | | |
| Accounting and Tax | $ 70,761 | $ 174,479 | $ 162,958 | $ 129,635 | $ 160,037 | $ 145,766 | $ 843,636 |
| Board of Directors | 11,692 | 20,413 | 21,878 | 20,319 | 37,525 | 34,178 | 146,005 |
| Exec Mgmt | 32,557 | 57,111 | 110,872 | 90,816 | 96,853 | 88,217 | 476,427 |
| Finance | 43,388 | 58,490 | 98,635 | 62,858 | 52,649 | 47,955 | 363,975 |
| HR | 63,846 | 80,901 | 48,209 | 99,920 | 87,240 | 79,460 | 459,576 |
| IT | 110,010 | 142,726 | 187,970 | 194,845 | 222,416 | 202,583 | 1,060,551 |
| Legal and Compliance | 52,256 | 91,999 | 154,432 | 141,287 | 123,271 | 112,279 | 675,524 |
| Supply Chain | 5,358 | 10,826 | 16,345 | 9,903 | 10,619 | 9,672 | 62,724 |
| Cost-To-Achieve (IT) | 30,575 | 23,456 | 7,627 | 2,922 | - | - | 64,580 |
| **Total** | **$ 420,443** | **$ 660,402** | **$ 808,926** | **$ 752,506** | **$ 790,610** | **$ 720,111** | **$ 4,152,999** |
| **WGL Midstream SGG, LLC** | | | | | | | |
| Accounting and Tax | $ 51,783 | $ - | $ - | $ - | $ - | $ - | $ 51,783 |
| Board of Directors | 8,556 | - | - | - | - | - | 8,556 |
| Exec Mgmt | 23,825 | - | - | - | - | - | 23,825 |
| Finance | 31,751 | - | - | - | - | - | 31,751 |
| HR | 46,723 | - | - | - | - | - | 46,723 |
| IT | 80,505 | - | - | - | - | - | 80,505 |
| Legal and Compliance | 38,241 | - | - | - | - | - | 38,241 |
| Supply Chain | 3,921 | - | - | - | - | - | 3,921 |
| Cost-To-Achieve (IT) | - | - | - | - | - | - | - |
| **Total** | **$ 285,305** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 285,305** |
| **Grand Total** | **$ 23,702,740** | **$ 23,620,237** | **$ 22,613,587** | **$ 22,843,636** | **$ 29,274,147** | **$ 28,258,615** | **$ 150,312,961** |

**AltaGas Corporate Services Costs Allocated From WGLH to WGL and Pre-Merger Affiliates**

| Function | CY2019 | CY2020 | CY2021 | CY2022 | CY2023 | TME MARCH 2024 | Grand Total |
|---|---|---|---|---|---|---|---|
| **Washington Gas Light Company** | | | | | | | |
| Accounting and Tax | 13% | 23% | 17% | 16% | 19% | 19% | 18% |
| Board of Directors | 2% | 3% | 2% | 2% | 4% | 4% | 3% |
| Exec Mgmt | 6% | 8% | 12% | 11% | 11% | 11% | 10% |
| Finance | 8% | 8% | 11% | 8% | 6% | 6% | 8% |
| HR | 12% | 11% | 5% | 12% | 10% | 10% | 10% |
| IT | 20% | 19% | 20% | 23% | 26% | 26% | 23% |
| Legal and Compliance | 10% | 12% | 17% | 17% | 14% | 14% | 14% |
| Supply Chain | 1% | 1% | 2% | 1% | 1% | 1% | 1% |
| Cost-To-Achieve (IT) | 5% | 3% | 2% | 0% | 0% | 0% | 2% |
| **Total** | **78%** | **88%** | **88%** | **90%** | **91%** | **92%** | **88%** |
| **Hampshire Gas Company** | | | | | | | |
| Accounting and Tax | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Finance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| HR | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| IT | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Legal and Compliance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **1%** | **1%** | **1%** | **1%** | **1%** | **1%** | **1%** |
| **WGL Energy Services, Inc** | | | | | | | |
| Accounting and Tax | 1% | 2% | 1% | 1% | 1% | 1% | 1% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| Finance | 1% | 1% | 1% | 0% | 0% | 0% | 1% |
| HR | 1% | 1% | 0% | 1% | 1% | 0% | 1% |
| IT | 2% | 1% | 1% | 1% | 1% | 1% | 1% |
| Legal and Compliance | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **7%** | **7%** | **6%** | **6%** | **5%** | **4%** | **6%** |
| **Washington Gas Resources** | | | | | | | |
| Accounting and Tax | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Finance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| HR | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| IT | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Legal and Compliance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **0%** | **1%** | **1%** | **0%** | **0%** | **0%** | **0%** |
| **WGSW** | | | | | | | |
| Accounting and Tax | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Finance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| HR | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| IT | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Legal and Compliance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **1%** | **0%** | **0%** | **0%** | **0%** | **0%** | **0%** |
| **WGL Energy Systems** | | | | | | | |
| Accounting and Tax | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| Finance | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| HR | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| IT | 2% | 0% | 0% | 0% | 0% | 0% | 0% |
| Legal and Compliance | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **7%** | **0%** | **0%** | **0%** | **0%** | **0%** | **1%** |
| **WGL Midstream** | | | | | | | |
| Accounting and Tax | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Finance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| HR | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| IT | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Legal and Compliance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **1%** | **1%** | **1%** | **0%** | **0%** | **0%** | **0%** |
| **WGL Midstream CP, LLC** | | | | | | | |
| Accounting and Tax | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Finance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| HR | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| IT | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Legal and Compliance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **0%** | **0%** | **0%** | **0%** | **0%** | **0%** | **0%** |
| **WGL Midstream MP, LLC** | | | | | | | |
| Accounting and Tax | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Finance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| HR | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| IT | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| Legal and Compliance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **3%** | **0%** | **0%** | **0%** | **0%** | **0%** | **0%** |
| **WGL Midstream MVP, LLC** | | | | | | | |
| Accounting and Tax | 0% | 1% | 1% | 1% | 1% | 1% | 1% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Finance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| HR | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| IT | 0% | 1% | 1% | 1% | 1% | 1% | 1% |
| Legal and Compliance | 0% | 0% | 1% | 1% | 0% | 0% | 0% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **2%** | **3%** | **4%** | **3%** | **3%** | **3%** | **3%** |
| **WGL Midstream SGG, LLC** | | | | | | | |
| Accounting and Tax | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Board of Directors | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Exec Mgmt | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Finance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| HR | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| IT | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Legal and Compliance | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Supply Chain | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Cost-To-Achieve (IT) | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Total** | **1%** | **0%** | **0%** | **0%** | **0%** | **0%** | **0%** |
| | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** |

Exhibit OPC (B)-89
Formal Case No. 1180
Direct Testimony of Bion Ostrander
[PUBLIC VERSION]

# Confidential Exhibit Omitted

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 15

QUESTION NO. 15-1

**Q.** **Retirements – Supplemental Testimony.** Witness Tuoriniemi's Supplemental Direct Testimony, Exhibit WG (2D)-1, pages 2 to 7 (of 18), and related Excel spreadsheet "Exhibit WG (2D)-1, including workpapers.xlsb", specifically tab "By FERC Account" shows WGL's detailed plant in service additions and retirements for this rate proceeding (which agree to total amounts at Exhibit WG (2D)-1, page 1 of 18). Please address the following:

a. Confirm if Gas General Plant additions of $6,738,404 do not include any related plant retirements. If yes, explain why and provide all supporting documentation and calculations for the response. If no, please explain the basis for the response, including with all supporting documentation and calculations for the response.

b. Explain why Gas Intangible Plant additions related to computer software (account 303000) shows plant additions of $3,231,038, but only includes $161,107 of related software retirements. Provide all supporting documentation and calculations for the response. Identify the specific type of software additions and its purposes, explain the specific type of software it replaced, and explain why the new software is significantly more costly than the software that it replaced.

c. Confirm Gas Transmission Plant additions of $35,353,537 only includes related plant retirements of $19,871. If yes, explain why and provide all supporting documentation and calculations for the response. If no, please explain the basis for the response, including with all supporting documentation and calculations for the response. Also confirm if these gas transmission plant additions reflect mostly extensions of existing equipment that do not replace existing equipment (and do not require any plant retirement). If yes, provide copies of workorders and other documentation to show these plant additions do not replace existing plant, along with other documentation explaining why retirement of existing plant was largely not necessary. If no, please explain the basis for the response, including with all supporting documentation and calculations for the response.

d. Confirm whether Gas Distribution Plant additions of $186,330,696 only includes related plant retirements of $8,025,734? If yes, please explain why and provide all supporting documentation and calculations for the response. If no, please explain the basis for the response, including with all supporting documentation and calculations for the response. Also explain if the related steel mains additions (account 376100), plastic mains additions (account 376200), steel services additions (380100), plastic services additions (380200) reflect mostly extensions of existing equipment that do not replace existing equipment (and do not require any plant retirement). Provide copies of workorders and other documentation to show whether these plant additions do not replace existing plant, along with other documentation explaining whether and why retirement of existing plant was largely not necessary.

e. Regarding (d) above, explain why distribution meter install (account 382000 shows plant additions of $1,440,935 and significantly larger related plant retirements of $4,258,692. Explain why the retirement of meters would be almost three times larger than the related installation of new meters and provide copies of workorders and other documentation to support this calculation. Also, explain why it is common (or uncommon) for the retirement of meters cost to significantly exceed the cost of new meter installs and provide supporting documentation for these reasons.

f. Confirm whether Gas General Plant additions of $14,795,799 only includes related plant retirements of $1,154,996? ? If yes, please explain why and provide all supporting documentation and calculations for the response. If no, explain the basis for the response, including with all supporting documentation and calculations for the response. Explain if the related steel mains additions (account 376100), plastic mains additions (account 376200), steel services additions (380100), plastic services additions (380200) reflect mostly extensions of existing equipment that do not replace existing equipment (and do not require any plant retirement). Provide copies of work orders and other documentation to show whether these plant additions do not replace existing plant, along with other documentation explaining whether and why retirement of existing plant was largely not necessary.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.** Please refer to the Supplemental Direct Testimony of Company Witness Morrow. Exhibit WG (2I)-1, which provides project descriptions of all projects in excess of $100,000 since Formal Case No.1169.

a. General Plant additions do not include retirements. Additions and retirements are tracked separately, and the information was extracted from the Company's property accounting system. Additionally, the $6,738,404 represents the DC Portion of Common or Allocable General Plant Additions. The total DC portion of General Plant Additions (DC direct and allocated) is $7,893,400 and retirements is $1,228,225 as shown in Exhibit WG (2D)-1 in the "By FERC Account" tab.

b. The $3,231,038 of additions and $161,107 in retirements is only the DC Allocated portion of total additions and retirements. Retirements also includes $612,252 which is the direct DC portion of Intangible Plant Assets retirements as shown in Exhibit WG (2D)-1 in the "By FERC Account" tab. During the period between January 2022 and March 2024, Washington Gas recognized more Intangible Plant Additions than Retirements. Software Retirements are based on the duration of the amortization period derived from when the asset was first placed into service at a rate of generally five (5) or ten (10) years. Depending upon the initial cost of the Software, additions or retirements can fluctuate. Also refer to the Company response to OPC 12-6 which provides additional detail related to software.

c. Gas Transmission Plant Additions do not contain Retirements. Additions and Retirements are tracked separately. The average service life of most Transmission plant ranges from 50-80 years, with an original cost significantly less that the cost of new transmission plant. Based on the service life of these assets, retirements do not occur proportionally to the rate of Transmission additions which mostly serve to improve and extend the life of asset. Additionally, because of the size and scope transmission plant replacement portions are placed into service in phases that do not correspond to the discontinuation and removal of the existing facilities. Since Formal Case No. 1169 Washington Gas's Transmission Plant Additions include two major projects including major new additions. Please refer to the Supplemental Direct Testimony of Company Witness Morrow. Exhibit WG (2I)-1 addresses new Transmission Plant projects.

d. Gas Distribution Plant Additions do not contain Retirements. Additions and Retirements are tracked separately. The average service life of most Distribution plant range between 50 and 55 years with an original cost significantly less that the cost of new distribution plant. When pipe is added it is not necessarily replaced simultaneously with the same type of attributes. The rate of retirement is a little more consistent due to various different pipe sizes within Distribution mains- Steel (account 376100), Distribution Mains Plastic (account 376200), Distribution Services Steel (account 380100) and Distribution Services Plastic (account 380200) rather than by pipe type.

Page **4** of **4**

e. The question confuses meters and meter installations. This account does not include the cost of adding or retiring a meter, rather just the meter installation. The Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts requires utilities to capture the cost of the meter installations as follows:

382 Meter installations.
A. This account shall include the cost of labor and materials used, and expenses incurred in connection with the **original installation** of customer meters.
B. When a meter installation is permanently retired from service, the cost thereof shall be credited to this account.

Therefore, it is common that meter installation in any given year can be less that retirement as the installation occurred when the facility first had the original meter installed.

f. No, the $14,795,799 is the beginning balance for general plant and plant additions are $1,154,996. The premise of the remainer of the question is also incorrect. Steel mains additions (account 376100), plastic mains additions (account 376200), steel services additions (380100), plastic services additions (380200) are not components of general plant additions as the question asserts.

SPONSOR: Robert E. Tuoriniemi
Chief Regulatory Accountant

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

| | | |
|---|---|---|
| **In the Matter of** | **§** | |
| | **§** | |
| **The Application of Washington Gas** | **§** | **Formal Case No. 1180** |
| **Light Company for Authority to** | **§** | |
| **Increase Existing Rates and** | **§** | |
| **Charges for Gas Service** | **§** | |

**DIRECT TESTIMONY**
**AND SUPPORTING EXHIBITS OF**
**COLIN T. FITZHENRY**

**Exhibit OPC (C)**

**On behalf of the**
**Office of the People's Counsel**
**for the District of Columbia**

January 24, 2025

**TABLE OF CONTENTS**

**EXHIBIT LIST**

| | |
|---|---|
| Exhibit OPC (C)-1 | Qualifications of Colin T. Fitzhenry |
| Exhibit OPC (C)-2 | WGL Response to OPC Data Request No. 19-1 |
| Exhibit OPC (C)-3 | WGL Response to OPC Data Request No. 2-7 |
| Exhibit OPC (C)-4 | WGL Response to OPC Data Request No. 5-15 |
| Exhibit OPC (C)-5 | Maryland PSC Case No. 9754, Attachment A provided in Response to Data Request Question No. Staff 2-041 |
| Exhibit OPC (C)-6 | DHInfrastructure, *Maryland Gas Utility Spending: Projections and Analysis* (Oct. 2022) |
| Exhibit OPC (C)-7 | WGL Response to OPC Data Request No. 19-2 |
| Exhibit OPC (C)-8 | FC 1180 OPC DR 2-1, Attachment 01 provided in WG Response to OPC Data Request No. 2-1 |
| Exhibit OPC (C)-9 | WGL Response to OPC Data Request No. 16-1 |

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Colin T. Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q. WHAT IS YOUR OCCUPATION?**

A. I am an Associate in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI") energy, economic and regulatory consultants.

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.**

A. This information is included in Exhibit OPC (C)-1.

**Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A. I am appearing in this proceeding on behalf of the Office of the People's Counsel for the District of Columbia ("OPC").

**Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON THE TOPIC OF NATURAL GAS CAPITAL EXPENDITURES?**

A. Yes. I have provided expert witness testimony in regulated utility proceedings before the Michigan Public Service Commissions (Case No. U-21291), the Maryland Public Service Commission (Case Nos. 9701, 9704, 9719, 9722, 9645, and 9754), and the Public Service Commission of the District of Columbia ("Commission") (Formal Case No. 1179) related to natural gas capital expenditures.

**Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?**

A. Yes.

## II. <u>SUMMARY</u>

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

A. The purpose of my testimony is to address Washington Gas Light Company's ("WGL" or "Company) utility operations, capital expenditures, PROJECT*pipes* costs that are being transferred to base rates, and non-PROJECT*pipes* plant proposed to be collected in base rates.

The fact that I do not address certain aspects of the Company's proposals should not indicate agreement with any specific element of such proposals.

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.**

A. My conclusions and recommendations are as follows:

- Even when compared to some of the worst performing utilities in terms of gas safety and reliability in the northeastern United States, WGL has a higher than average leak rate per mile of distribution mains and services. This clearly demonstrates that WGL's safety and reliability performance is worse than utilities in similar positions. The Company should not be allowed to continue to grow its rate base while demonstrating neither improvements in its distribution system's reliability and safety nor capital expenditure changes tailored to meet the District's climate goals. Requiring customers to incur additional costs while WGL continues to perform below average compared to its peer utilities, creates an unreasonable burden on customers.

- WGL has incurred its highest levels of mains and services capital expenditures over the past two years since the Company's last rate case ($148 million in mains and service plant additions in 2022 and 2023). This has been a significant cost driver in the $45.6 million base rate increase the Company is requesting in this proceeding.[1] Furthermore, the Company has not completed this work efficiently. According to the Company's Year 9 Annual Project Reconciliation Report, WGL spent 12.3% more in 2023 than budgeted amounts while only completing 6.4% more project work than estimated.

- WGL has continued to increase investment in distributions mains and services while doing so in an inefficient manner. This has resulted in incurring excess project costs that are both imprudent, and unsupported by the Company. I recommend the Commission disallow $16.7 million of PROJECT*pipes* expenditure cost overruns for 2023 which exceeded the historical PROJECT*pipes* expenditure rate (on a dollar per mile and dollar per service replacement basis) and $5.6 million of cost variances associated with the non-PROJECT*pipes* projects discussed herein. These adjustments remove $22.3 million of plant additions from rate base. The plant additions associated with the PROJECT*pipes* and non-PROJECT*pipes* projects have experienced significant cost overruns and exhibit poor project management.

## III. <u>SUMMARY OF NATURAL GAS DISTRIBUTION SYSTEM</u>

**Q. PLEASE DESCRIBE THE CURRENT STATE OF WGL'S NATURAL GAS DISTRIBUTION SYSTEM?**

A. As of 2023, WGL's distribution system in the District of Columbia contained 1,218 miles of distribution mains and 124,913 miles of service lines. Of the distribution mains, approximately 393 miles are cast iron (32%) and 20 miles are bare steel (1.6%). The Company experienced 668 mains leaks in 2023, or over one leak for every two miles of mains. The vast majority of distribution mains leaks were considered hazardous (542 out of 668 or 81%). Likewise, the Company had 590 service leaks in 2023, 554 (94%) of which were considered hazardous.[2]

---

[1] Exhibit WG (D) (Tuoriniemi) at 3.
[2] 2023 Gas Distribution Report, PHMSA Form F-7100.

**Q. ARE YOU CONCERNED ABOUT THE STATE OF THE COMPANY'S DISTRIBUTION SYSTEM?**

A. Yes. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") has long recognized that cast iron and bare steel pipe should be removed from gas distribution systems. Pipe made of these materials are often referred to as "leak-prone" pipe due to their greater propensity for leaks caused by corrosion or breaks. These types of pipes represent a greater risk to the public and the environment than newer pipes made of modern materials and installed using modern construction and protection methods.

**Q. WITNESS MORROW TESTIFIED TO A 99.69% RELIABILITY PERCENTAGE. DO YOU HAVE ANY THOUGHTS ON THAT ANALYSIS?**

A. Yes. Witness Morrow's calculation simply took the number of unplanned outages and divided it by the number of customers on the Company's system.[3] He did not consider planned outages required for repairs on the system, or the length of the unplanned outages, nor did he consider leak/odor reports from customers, which are clearly a concern to ratepayers.

**Q. HOW DOES THE COMPANY COMPARE TO OTHER UTILITIES IN THE COUNTRY WITH RESPECT TO ADDRESSING LEAK PRONE PIPE?**

A. Unfortunately, the District has one of the highest percentages of remaining cast iron pipe in the country. PHMSA reports that nationwide about 99% of cast iron has been

---

[3] Exhibit OPC (C)-2.

removed[4] while WGL's system contains a much higher percentage of cast iron pipe (32%) on its system.

**Q. DID YOU CONDUCT AN ANALYSIS OF THE COMPANY'S LEAK RATE PERFORMANCE IN LIGHT OF THESE CONCERNS?**

A. Yes. Given the statistics discussed above, it is difficult to identify a peer group of utilities because the Company has far more miles of leak-prone pipe than similarly sized utilities. I have nevertheless performed a peer group analysis in an attempt to analyze the leak rates on the Company's distribution system.

**Q. PLEASE EXPLAIN THE FINDINGS OF YOUR PEER GROUP LEAK RATE ANALYSIS?**

A. I have compared the gas leaks per mile of mains and per mile of services in WGL's DC service territory to that of other natural gas utilities. The data is shown in number of leaks per mile in order to determine a leak rate, as opposed to just showing the number of leaks in each system, which would be distorted by the system size. In order to keep the comparison reasonable, I have only compared the gas leak rate to other natural gas utilities that meet the following three conditions: (1) located in the northeastern United States, (2) urban and suburban service territory, and (3) between 12% and 39% of their distribution mains are comprised of cast iron. The six utilities shown in Table 1 meet these criteria.

---

4 https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/pipeline-replacement-background.

**Table 1**

**2023 Gas Leak Rates**

| Utility Company | Operating State | Per Main Mile | Per Service Mile |
|---|---|---|---|
| Washington Gas Light Company | District of Columbia | **0.5483** | **0.0047** |
| Boston Gas Company | Massachusetts | 0.4210 | 0.0037 |
| Philadelphia Gas Works | Pennsylvania | 0.6734 | 0.0047 |
| Keyspan Energy Delivery - NY City | New York | 0.5064 | 0.0016 |
| Baltimore Gas and Electric Company | Maryland | 0.4002 | 0.0083 |
| Southern Connecticut Gas Company | Connecticut | 0.1213 | 0.0028 |
| Average | | **0.4451** | **0.0043** |

**Source:** Annual Gas Distribution Report, PHMSA Form F-7100

I stress that these utilities are all outliers in the sense that 99% of cast iron has been removed by natural gas distribution utilities nationwide. Nevertheless, as can be seen from Table 1 above, in 2023, WGL had a higher gas leak rate per mile of mains than four other utilities in this peer group, and a higher per mile of service leak rate than three other utilities in the peer group, while having the same rate as another. On average, WGL was 23% more likely to experience a gas main leak than the average distribution company in the peer group. Similarly, the Company was 10% more likely to experience a service line leak. Additionally, WGL's leak rate in its DC service territory is six times worse than the leak rate in its Maryland service territory (0.0881 leaks per mile).

**Q. WHAT CAN YOU CONCLUDE FROM THE ANALYSES PROVIDED IN TABLE 1?**

A. The Company's current safety and reliability metrics are below average compared to peer utilities with similar distribution systems. Despite increased investment in its service and main replacement capital expenditures, WGL continues to demonstrate poor performance in terms of its mains and services leak rates. Allowing WGL to receive increasing amounts of ratepayer dollars and thus requiring customers to incur additional costs while WGL continues to perform below average compared to its peer utilities, creates an unnecessary and unreasonable burden on customers. As will be discussed later in my testimony, despite significant and increasing expenditures, the Company has been unable to demonstrate significant improvements, because the pace of main and service replacement projects has been slow with increasing costs on a dollars per mile and dollars per service replacement basis.

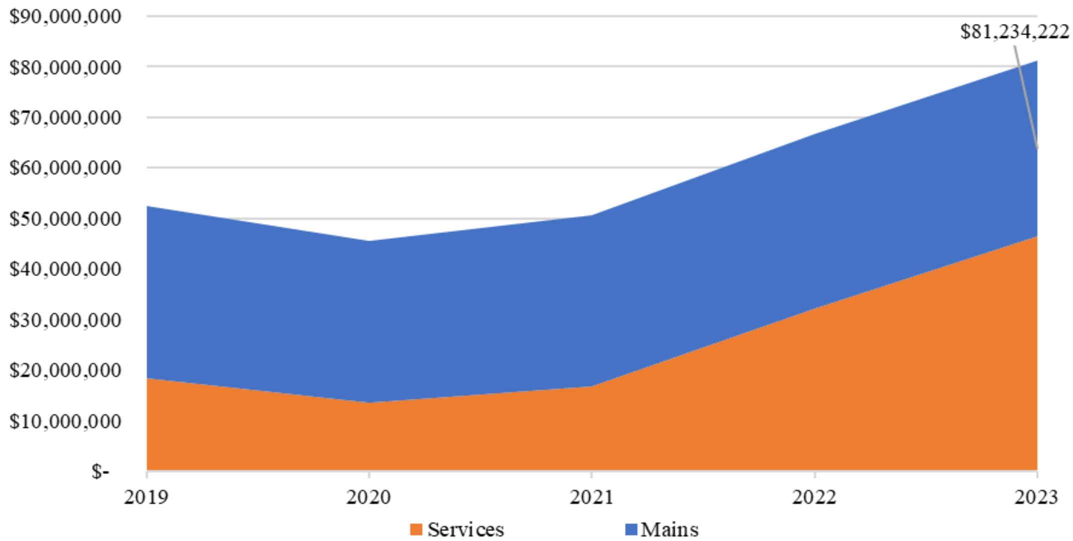
## IV. <u>MAIN AND SERVICE CAPITAL EXPENDITURES</u>

**Q. DO YOU HAVE ANY OBSERVATIONS ON THE RATE OF MAINS AND SERVICES CAPITAL EXPENDITURES?**

A. Yes. I have summarized these capital expenditures by showing the main and service plant additions over the past five years in Figure 1.

**Figure 1**

**<u>Mains and Services Replacement Capital Expenditures</u>**




Sources: OPC Data Request Questions 2-7 and 5-15.

As can be seen in Figure 1 above, aside from a brief decrease in expenditures in 2020, the mains and services replacement capital expenditures have been increasing over the past five years, with the largest level of expenditures occurring in 2022 and 2023. The Company has incurred approximately $169 million in distribution mains replacements expenditures and $128 million for services replacements for a total of $297 million over the period 2019-2023. Furthermore, 50% of all expenditures ($148 million) came in the past two years alone (2022 and 2023). These capital expenditures were made following WGL's last rate case (Formal Case No. 1169) with a test year ending December 2021.

**Q. HAVE THE COMPANY'S MAINS AND SERVICES REPLACEMENT CAPITAL EXPENDITURES IMPACTED RATE BASE?**

A. Yes. WGL has spent more money in the last two years for mains and services replacements than in any prior period. As a result, the Company is now requesting a $761.0 million[5] rate base in this proceeding, an increase of $180.6 million, or 31%, in just over two years.

**Q. HAS THE COMPANY BEEN EFFICIENT AT REPLACING PIPE SINCE THE COMPANY'S LAST RATE CASE?**

A. No. According to WGL's Year 9 Annual Project Reconciliation Report,[6] the Company budgeted $66.7 million for calendar year 2023 to replace 4.7 miles of main and remediate 1,850 services. However, actual expenditures were $72.4 million, an increase of $8.2 million, or 12.3%. And although the Company completed slightly more work than projected, specifically, 0.3 additional miles of main replacement and 118 additional services remediated, this is only a 6.4% increase in project work.[7] Thus, the cost overruns (12.3%) are almost double the slight increase in project work (6.4%). In addition, the cost per service only replacement was approximately $25,000 in 2023, $6,000 more than the average cost of service replacement during the PROJECT*pipes* period.[8] While it is important that the Company remove leak prone pipe from its system, it must do so efficiently in order for ratepayers to be able to afford the needed repairs.

---

5 Exhibit WG (D) (Tuoriniemi) at 3.
6 Exhibit WG (I)-2.
7 Exhibit WG (I) - 2 PUBLIC, Page 4 of 19.
8 Formal Case No. 1179, Exhibit WG (A)-1, Figure 13: Comparison Between Annual Nominal Average Cost Per Service Only Replacement and Overall PROJECTpipes Average Cost Per Service Only Replacement.

My review of the Company's filing indicates that the Company did not complete the work cost effectively. In 2023, the average cost per mile of mains replacement was approximately $8 million. This is $2 million more than the average cost of pipe replacement during the entire PROJECT*pipes* period (2014-2023) and approximately $1.5 million more per mile than the Company reported for replacement activity in 2022.[9] I am not aware of any justification in the Company's presentation in this proceeding for these significant cost increases over historical spending in 2023. Moreover, when compared to national studies, the Company's cost per mile of mains replacement is an outlier. According to a U.S. Department of Energy ("DOE") Report, the cost of replacing cast iron and unprotected steel mains can range from $1 million to $5 million per mile depending on location.[10] This figure takes into account that the cost of replacing cast iron and unprotected steel mains is likely higher than other mains types, and that cast iron and unprotected steel pipe is primarily located in urban areas, where the cost of excavation is typically higher. WGL's cost of pipe replacement over the past ten years has been consistently higher than the upper range presented in the DOE Report and, the Company's 2023 statistics are a significant outlier. The Commission recently noted that WGL's pipe replacement program was more expensive than Con Edison's Leak-Prone Main Replacement Program, which covers the Boroughs of Manhattan,

---

[9] Formal Case No. 1179, Exhibit WG (A)-1, Figure 12: Comparison Between Annual Nominal Average Cost Per Mile Retired and overall PROJECTpipes Average Cost Per Mile Retired.

[10] U.S. Department of Energy, Office of Energy Policy and Systems Analysis, *Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations*, Jan. 2017, at page 6 of 78, *available at*: https://energy.gov/epsa/downloads/natural-gas-infrastructure-modernization-programs-local-distribution-companies-key.

Brooklyn, Queens, Bronx, Staten Island, and Westchester County, and reported a cost of roughly $5 million per mile in 2022.[11]

**Q. ARE YOU CONCERNED ABOUT THIS TREND?**

A. Yes. There are limited dollars that District ratepayers can afford to address the leak prone pipe issue on the WGL distribution system. Accordingly, it is imperative that the Company efficiently implement its pipe replacement activity. As discussed later in my testimony, I believe that the Commission should disallow costs that go above an established dollar per mile threshold. This will help impose cost discipline on the Company as it continues to remediate the leak prone pipe issue on its system.

**Q. HAS THE COMPANY BEEN EFFICIENT WITH PIPE REPLACEMENT ACTIVITY IN ITS OTHER JURISDICTIONS?**

A. As noted above, the location of a utility can impact the total cost per mile for replacement activity. So, it is not surprising that the Company's Maryland pipe replacement activity has a lower overall projected cost ($4.3 million per mile), however, when compared to other utilities operating in Maryland, WGL's costs are significantly higher on a cost per mile basis. For example, in Columbia Gas of Maryland's most recent rate case the cost per mile of distribution main replacement was $1.6 million.[12]

---

[11] Formal Case No. 1179, *In the Matter of the Investigation Into Washington Gas Light Company's Strategically Targeted Pipe Replacement Plan ("Formal Case No. 1179"),* Order No. 22003 at ¶ 50, n. 125, rel. June 12, 2024 ("Order No. "22003").

[12] Exhibit OPC (C)-5, Maryland PSC Case No. 9754, Attachment A provided in Response to Data Request Question No. Staff 2-041.

Baltimore Gas & Electric has performed pipe replacement activity at a cost of $2.63 million per mile.[13]

**Q. ARE YOU AWARE OF ANY POTENTIAL SOURCES OF COST INEFFICIENCIES IN THE COMPANY'S REPLACEMENT PROGRAM?**

A. Yes. I am concerned that the Company may be overly reliant on external contractor crews. In response to an OPC data request, the Company indicated that 91% of the service replacements were conducted by external contractor crews for the twelve-months ended March 31, 2024. While it is not clear from the Company's response if this percentage also applied to mains replacement, I believe this issue should be probed more thoroughly in this proceeding.

**Q. WHY ARE YOU CONCERNED ABOUT OVER-RELIANCE ON EXTERNAL CREWS?**

A. The Company has admitted that labor constraints and cost escalations associated with qualified underground contractor crews have impacted the Company's activities.[14] Additionally, the time and resources needed to bring a contractor up to speed on the WGL process and procedures is a potential source of inefficiency. For example, in response to an OPC data request in this proceeding, the Company stated that "[o]nce a contractor is brought onto the Company's system, they are trained on Washington Gas specific processes, procedures, and Operation Qualifications by Washington Gas

---

[13] Exhibit OPC (C)-6 at 8, 22. I note that a restraining order obtained by BG&E customers resulted in a work stoppage in 2024, which significantly skewed the dollars per mile calculation for 2024.

[14] Formal Case No. 1179, Exhibit WC (C) (Jacas) at 31:6-16.

personnel."[15] If the Company retained more internal crews this would not be needed as those crews would develop a deep understanding of the WGL distribution system and processes and procedures and would not require training. In a recent independent audit of the Company's accelerated pipe replacement program ("APRP"),[16] Continuum noted that plans such as the Company's PROJECT*pipes* program "are generational and there are benefits to establishing consistency in workforce capabilities and knowledge . . ."[17] For this reason, the Continuum Audit found further that "WGL should take a regular look at the pros and cons of internal versus external resources along with blended approaches that meet multiple needs and strategies."[18] Moreover, the Company would have more control over how and when to dispatch and use internal crews which could produce efficiencies.

**Q. WHAT JUSTIFICATION HAS THE COMPANY PROVIDED FOR ITS RELIANCE ON EXTERNAL CREWS?**

A. The Company stated that its decision to proceed with external crew resources "has granted the Company the maximum flexibility to increase or decrease resources with the fluctuation of the accelerated pipeline replacement work."[19]

**Q. DOES THAT JUSTIFICATION MAKE SENSE TO YOU?**

A. No. Based on the current pace of replacement activity, the Company will not complete the pipe replacement work on its system until approximately 2094, meaning that the

---

15 Exhibit OPC (C)-7.

16 Formal Case No. 1154, Continuum Independent Management Audit of PROJECT*pipes* 2 Final Report, Dec. 12, 2023 ("Continuum Audit").

17 Continuum Audit at 90.

18 *Id.*

19 Exhibit OPC (C)-7.

Company has approximately 70 years of work ahead of it at its current pace. What the Company seems to be saying in this response is that it will not perform or will significantly reduce pipe replacement activity work if it is not guaranteed accelerated cost recovery from the Commission. However, as the Commission has noted, the Company is "obligated to maintain the safety and reliability of the gas distribution system with or without surcharge recovery."[20] Accordingly, there should be utilization of internal crews regardless of the amount of APRP spending approved by the Commission.

**Q. HAS THE COMPANY STUDIED THE ISSUE OF INTERNAL VERSUS EXTERNAL CREW RESOURCES?**

A. In response to OPC's data request, the Company indicated that it, "at various intervals, has evaluated the utilization of internal versus external crew resources" but did not identify any specific study.[21] The Continuum Audit indicates that the last formal assessment was prepared by the Company in 2017. In Order No. 22003 the Company was directed to "[p]rovide the results of the formal assessment on internal versus external crew usage."[22] In response, the Company did not submit an analysis with its proposed District SAFE plan but instead stated that it would "conduct a formal assessment for the use of internal versus external crews to be submitted within 18 months of the approval of "DC SAFE" in Formal Case No. 1179."[23] I think it is

---

20 Order No. 22003 at ¶ 44.
21 Exhibit OPC (C)-7 at 1.
22 Order No. 22003 at ¶ 51.
23 Formal Case No. 1179, Exhibit (C)-1 at 16.

important for the Commission to get a better understanding of these staffing decisions in order to assess the reasonableness of the Company's capital expenditures in this proceeding.

**Q. HAS THE COMPANY SUPPORTED THE PRUDENCY OF ITS PROJECT*PIPES* COSTS BASED IN PART ON ITS USE OF EXTERNAL CREWS?**

A. No. Witness Morrow testifies that "[t]he 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."[24]

**Q. DO YOU HAVE ANY CONCERNS WITH THIS STATEMENT?**

A. Yes. In addition to the concerns identified above, in Formal Case No. 1179, Company witness Jacas indicated that "[t]he 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."[25] One way that the Company could have insulated itself from these market forces would have been to bring on full-time internal crews.

**Q. DID THE COMPANY'S REPORT ON COST VARIANCES WITH RESPECT TO SPECIFIC PROJECTS IDENTIFY ANY INEFFICIENCIES?**

---

24 Exhibit WG (I) at 8:13-17.

25 Formal Case No. 1179, Exhibit WG (C), Direct Testimony of Wayne A. Jacas, at 31:8-11.

A. Yes. On October 9, 2024, the Commission issued Order No. 22311 in this proceeding, which directed the Company to file detailed tables showing the capital additions represented by each itemized project over $100,000, the remaining capital additions, the capital retirements, and the resulting net change in plant in service for each Federal Energy Regulatory Commission ("FERC") account from the approved values in Formal Case No. 1169.[26] In response to this Commission directive, WGL witness Frederick Morrow filed supplemental testimony along with Exhibit (2I) - 1. I have produced a summary of this exhibit in Table 2 below.

**Table 2**

**Summary of Capital Expenditures for Projects Greater than $100,000**

| Project Category | Number of Projects | Budgeted | Actual | Variance |
|---|---|---|---|---|
| Safety and Maintenance | 69 | $240,484,299 | $245,502,708 | $5,018,409 |
| APRP | 108 | $203,078,646 | $85,669,162 | ($117,409,484) |
| New Business and Market Enhancement | 35 | $6,241,132 | $9,931,850 | $3,690,718 |
| IT | 17 | $25,992,318 | $27,554,740 | $1,562,422 |
| General Structure | 1 | $900,000 | $844,980 | ($55,020) |
| Total | 230 | $476,696,395 | $369,503,440 | ($107,192,955) |

Source: WGL witness Morror Supplemental Direct Testimony, Exhibit (2I) - 1.

**Q. WHAT OBSERVATIONS CAN BE DRAWN FROM THIS INFORMATION?**

A. As can be seen from Table 2, the Company spent approximately $117 million less than actual for the APRP projects over $100,000, which appears to be based on the Commission's ultimate budget approvals in the APRP proceeding and resulted in many APRP projects showing a negative cost variance. When those projects are excluded, an

26 Formal Case No. 1180, Order No. 22311, rel. Oct. 9, 2024.

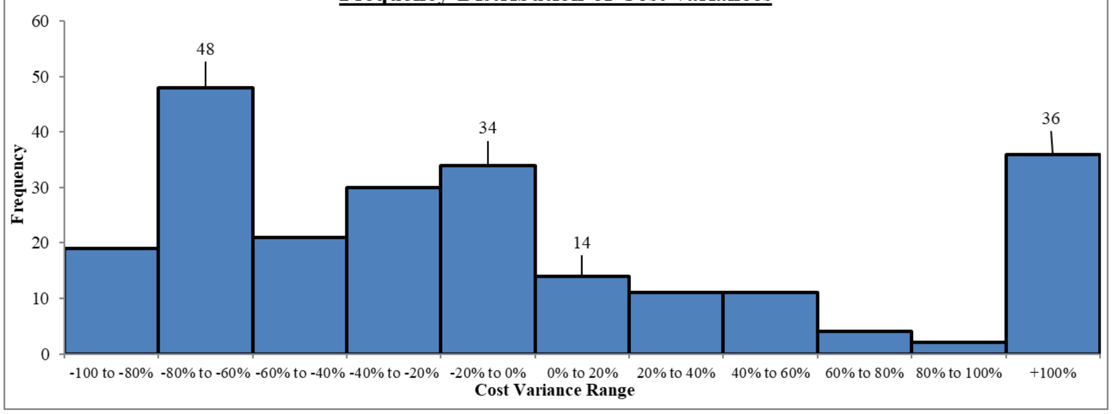
analysis of the 38 APRP projects that were completed demonstrates that these projects were approximately $400,000 over budget.[27] I note that this budget variance is above the Company's estimates which greatly exceeded historical spending rates.

**Q. DID THE COMPANY ESTIMATE AND MANAGE ITS BUDGETS EFFECTIVELY FOR LARGE PROJECTS?**

A. No. The average cost variance for all capital projects greater than $100,000 was 92%. I have shown the frequency of cost variances in Figure 2 below.

**Figure 2**

**Frequency Distribution of Cost Variances**




As can be seen from Figure 2, the largest frequencies of cost variances occurred in the -80% to -60% range (48 projects) and the over 100% range (36 projects). Less than 21% of all projects were completed within 20% of their budgeted cost (48 projects). This analysis demonstrates that the Company did not effectively develop or control the budgets of its large capital projects.

---

[27] Exhibit OPC (C)-8.

**Q. WHY IS UNDER-BUDGETING A CONCERN?**

A. This is a concern because capital is reserved for these projects and ratepayers are paying for significant capital outlay that was not needed due to over estimation of project scope and/or cost. These dollars could have been better deployed to other projects on the WGL distribution system. Moreover, it is difficult for stakeholders to track the Company's overall performance when the budgeted figures are so unreliable.

## V. <u>CLIMATE RELATED CONSIDERATIONS</u>

**Q. DO THE COMPANY'S EXPENDITURES IN THIS PROCEEDING DEMONSTRATE AN EFFORT BY THE COMPANY TO RESPOND TO THE DISTRICT'S CLIMATE OBJECTIVES?**

A. No. Based on my review of the Company's recent expenditures, WGL is taking a business-as-usual approach to distribution system planning. This observation is supported by WGL's response to OPC discovery in this proceeding in which WGL Witness Steffes' stated that "the Company is unaware of any District climate policy that has an impact on the Company's planned capital investments."[28]

**Q. WHAT DO YOU MAKE OF THAT RESPONSE FROM THE COMPANY?**

A. In my opinion, the response is not consistent with prior Commission findings with respect to the District's climate policies and how they affect regulated utilities. Specifically, in Order No. 22003 in Formal Case No. 1179, the Commission expressed concern about the potential for stranded investment in light of the District's climate

[28] Exhibit OPC (C)-9.

policies. In that proceeding, the Commission found that the Company's accelerated pipe replacement activity "must balance the need to replace leak-prone, highest-risk pipe segments to prevent dangerous cascading and potentially hidden 'super emitter' leaks before they happen while minimizing the stranded assets as the District continues to undergo the energy transition."[29]

**Q. ARE STRANDED ASSET CONCERNS PRESENTED BY THE COMPANY'S FILING IN THIS PROCEEDING?**

A. Yes. The majority of capital expenditures have continued to be focused on mains and services plant additions which have long expected useful lives. In order to meet the District's climate objectives, these assets might be abandoned prior to the end of their useful lives ("stranding the assets") and burdening future WGL customers to pay for infrastructure that is no longer used and useful. While I believe it is critical that the Company replace dangerous and leak prone pipe, this fact also underscores the critical need for the Company to efficiently spend ratepayer dollars given these stranded asset concerns.

## VI. <u>PIPES EXPENDITURES</u>

**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 PROJECT*pipes*-related plant into the development of base rates in this proceeding. Of

[29] Order No. 22003 at ¶ 48.

that amount, $118.5 million of that plant balance was included in the Company's PROJECT*pipes* surcharge, and $20.2 million was not eligible for collection in the PROJECT*pipes* surcharge due to the spend exceeding the Program 10 cap.[30] These figures do not consider the cost already recovered from ratepayers through the APRP surcharge for these PROJECT*pipes* projects.

**Q. WHAT IS THE COST PER MILE OF MAIN REPLACEMENT ACTIVITY FOR 2023 THAT THE COMPANY SEEKS TO INCLUDE IN RATE BASE?**

A. In 2023, the average cost of main replacement was approximately $8.0 million per mile of distribution main.

**Q. WHAT IS THE COST PER SERVICE REPLACEMENT FOR 2023 THAT THE COMPANY SEEKS TO INCLUDE IN RATE BASE?**

A. In 2023, the average cost of service replacement was approximately $25,000 per service replacement.

**Q. DO YOU BELIEVE THESE SPENDING RATES ARE REASONABLE?**

A. No. Not only are these costs well above WGL's own historical averages, they exceed national averages by significant margins.

**Q. HAVE YOU IDENTIFIED ANY APRP PROJECTS WITH SIGNIFICANT COST OVERRUNS?**

A. Yes. I have identified several projects where the cost variance between estimated and actual costs were excessive. I have shown some examples of these APRP projects in Table 3.

---

[30] Exhibit WG (I) (Morrow) at 6.

**Table 3**

**Summary of APRP Project Cost Variances**

| **Project** | **Actual Cost** | **Cost Variance %** |
|---|---|---|
| DC APRP 10 - 215 G ST NE - MCN BUILD - A002NE - WARD 6 | $251,517 | 298% |
| DC APRP 10 - AOP - Cleveland Park - Ward 3 - G007NW | $5,411,751 | 50% |
| DC F.O. - APRP 4 - 40TH ST - Ward 7 - OPT 362857 | $447,430 | 41% |

Source: WGL witness Morror Supplemental Direct Testimony, Exhibit (2I) - 1.

As can be seen from Table 3 above, there are several APRP projects with significant cost overruns. In addition, as discussed above, according to WGL's Year 9 Annual Project Reconciliation Report, WGL spent $8.2 million, or 12.3%, more than budgeted amounts in 2023.

**Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S PROJECT*PIPES* EXPENDITURES?**

A. I recommend the Commission disallow $16.7 million of APRP expenditures because the Company has not justified the significant cost increases from the historical cost of the PROJECT*pipes* program and other utilities. This figure represents a disallowance of approximately $2 million per mile for main replacement and $6,000 per service replacement activity conducted in 2023 because the Company has not demonstrated why its costs increased so severely on a cost per mile/service replacement basis in that year. I note that I have not proposed a disallowance for work performed in 2022, which, while above the historical costs for pipe replacement activity was much more in line with historical spending.

Given the cost overruns of specific projects the Company is seeking to recover in this proceeding, and the cost overruns discussed in WGL's Annual Reconciliation Report, customers should not be burdened with these expenses that exceeded the historical APRP spending without justification.

## VII. NON-PIPES EXPENDITURES

**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.

**Q. WHAT ARE THE LARGEST COST DRIVERS IN THE INCREASE IN DEPRECIABLE GPIS?**

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. I have shown increases in GPIS since the Company's last rate case in Table 4.

**Table 4**

**GPIS Increase from FC 1169 to FC 1180**

| | FC 1180 | FC 1169 | Increase (Decrease) | Percent Change |
|---|---|---|---|---|
| | $31,194,036 | $28,306,380 | $2,887,656 | 1.33% |
| Storage | 12,565,793 | 11,256,497 | 1,309,296 | 0.60% |
| Transmission Mains | 108,628,696 | 72,242,227 | 36,386,469 | 16.74% |
| Other Transmission | 56,200,255 | 54,982,642 | 1,217,613 | 0.56% |
| Distribution Mains | 561,591,227 | 468,460,036 | 93,131,191 | 42.85% |
| Distribution Services | 416,333,175 | 336,164,593 | 80,168,582 | 36.89% |
| Other Distribution | 82,534,531 | 84,137,237 | -1,602,706 | -0.74% |
| General | 72,889,990 | 69,066,220 | 3,823,770 | 1.76% |
| Total Depreciable GPIS | $1,341,937,704 | $1,124,615,831 | $217,321,872 | 100.00% |

Source: OPC Data Requenst No. 2, Question No. 2-1, Attachment 06.

The Company is requesting inclusion of approximately $108.6 million in transmission mains, a $36.4 million increase, or a 17%, from Formal Case No. 1169. The Company is also requesting approximately $561.6 million in distribution mains and $416.3 million in distribution services. This equals 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. As can be seen from Table 4 above, these three cost categories make up the vast majority of plant in service increase since the last rate case.

**Q. DO YOU HAVE ANY CONCERNS ABOUT THE SPECIFIC PROJECTS THE COMPANY IS REQUESTING TO TRANSFER TO RATE BASE?**

A. Yes. I have identified several projects where the cost variance between estimated and actual costs was excessive, and the Company has not provided adequate explanations demonstrating the cost increases were prudent expenditures. I have included the identified projects, along with the Company's explanation for cost variances below.

1. DC AOP - Reconstruction of Florida Ave NW - Ward 1 (133% Cost Variance): This project required additional paving and restoration that was not included in the original estimate.

2. ABAND GAS SERV AT MAIN === 705 4$^{TH}$ (952% Cost Variance): Additional paving and restoration was required by DDOT increasing the actual costs. Estimated cost was based on historical averages. The actual costs incurred on this project are the result of actual site conditions and work requirements.

3. DC AOP - Penn. Ave SE & Minn. Ave SE Intersection - Ward 7 (181% Cost Variance): This project required additional traffic control and timber shoring to perform 12" main offsets and required a longer offset than originally designed. The Company was also required to use bottom out line stoppers which added additional costs due to depth and material costs. This project also required armed security to ensure the safety of the crews working.

4. AOP - Cleveland Park Streetscape - G007NW - Ward 3 (490% Cost Variance): This job required the use of bottom out line stoppers which increased the depth and required additional shoring, backfill, etc. Furthermore, after the Company's completion of the offset at Porter St NW, DDOT revised their plans and required the Company to change the depth of the newly installed pipe. Finally, this project required the use of additional line stoppers in order to completely stop the flow of gas in order to perform the required work. The design estimated was created using average costs and, therefore, would not have accounted for these additional requirements. The actual costs incurred on this project are the result of actual site conditions and work requirements.

5. DC INT - Aspen St NW - A013NW - Ward 4 (Related to BCA 287799 & 283129) (108% Cost Variance): This project required a by-pass that was not originally estimated, increasing the costs of construction. Estimated cost was based on historical averages. The actual costs incurred on this project are the result of actual site conditions and work requirements.

6. ILI Readiness - Strip 24 – Launcher (67% Cost Variance): Project variance for this project were due to fees associated with the acquisition of the site development fine grading permit from Prince George's County.

7. Strip 7 Valve 8 (56% Cost Variance): Valve assembly (Strip 18 Valve 1 and 2) replaced in addition to replacing Strip 7 Valve 8.

8. Tools Field Ops (120% Cost Variance): Required to mass update the personnel gas monitors for below ground field operations personnel.

9. Strip 12 TIMP Dig (60% Cost Variance): Location of anomalies was difficult to find resulting in additional excavations.

The commonality among all the listed projects is that poor project planning resulted in project cost increases. In addition, better communication with WGL customers, other regulatory bodies, and the District Department of Transportation would have led to less work stoppages and improved project scheduling. I have summarized the Company's budget for the listed projects along with the actual project cost and variances in Table 5 below.

**Table 5**

**Summary of Non-Pipes Capital Expenditure Disallowances**

| Project | Budgeted | Actual | Variance | Variance % |
|---|---|---|---|---|
| DC AOP - Penn. Ave SE & Minn. Ave SE Intersection - Ward 7 | $1,245,871 | $3,500,174 | $2,254,303 | 181% |
| AOP - Cleveland Park Streetscape - G007NW - Ward 3 | $218,557 | $1,289,779 | $1,071,222 | 490% |
| DC AOP - Reconstruction of Florida Ave NW - Ward 1 | $44,656 | $104,079 | $59,423 | 133% |
| DC INT - Aspen St NW - A013NW - Ward 4 (Related to BCA287799 & 283129) | $224,405 | $466,069 | $241,664 | 108% |
| ABAND GAS SERV AT MAIN === 705 4TH | $10,392 | $109,274 | $98,882 | 952% |
| ILI Readiness - Strip 24 - Launcher | $1,380,000 | $2,306,027 | $926,027 | 67% |
| Strip 7 Valve 8 | $650,000 | $1,016,745 | $366,745 | 56% |
| Tools Field Ops | 275,060 | 605,869 | $330,809 | 120% |
| Strip 12 TIMP Dig | $438,000 | $699,439 | $261,439 | 60% |
| Total | $4,486,941 | $10,097,455 | $5,610,514 | 125% |

Source: WGL witness Morror Supplemental Direct Testimony, Exhibit (2I) - 1.

As can be seen from Table 5, WGL budgeted approximately $4.5 million for these non-PROJECT*pipes* expenditures, but actual expenditures more than doubled that amount ($10.1 million). This resulted in $5.6 million of cost overruns with a cost variance of 125%.

**Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THESE NON-PROJECT*PIPES* PROJECTS WITH SIGNIFICANT COST VARIANCES?**

A. I recommend the Commission disallow the $5,610,514 of cost variances associated with these non-PROJECT*pipes* projects. The Company has not adequately demonstrated the excess cost incurred in completing these projects was prudent and not the product of poor budgeting practices.

**Q. WHY IS IT REASONABLE TO DISALLOW COST VARIANCES ASSOCIATED WITH PROJECTS THAT ARE IN SERVICE AND CONSIDERED USED AND USEFUL?**

A. The rationale for using the cost variance in determining my proposed disallowance is to recognize that the project is in service and considered used and useful, but that a portion of the costs to place the project in service were imprudent. Specifically, the cost variance could represent excess project cost due to reasons such as extended project durations, poor project planning, labor cost overruns, or project scope creep. These would all be adequate explanations for a disallowance. In addition, with respect to the projects I have identified, the Company did not provide adequate explanations for the cost variances. The onus is on the utility to demonstrate the prudency of its investments and WGL has not met that burden in its application.

## **VIII. <u>CONCLUSION</u>**

**Q. WILL YOU PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS?**

A. WGL has continued to increase investment in distributions mains and services while doing so in an inefficient manner. This has resulted in the Company incurring excess project costs that are both imprudent, and unsupported by the Company. I recommend that the Commission disallow $16.7 million of PROJECT*pipes* expenditure cost overruns that exceeded the historical APRP spending rates and the $5,610,514 of cost variances associated with the non-PROJECT*pipes* projects identified in Table 5. This adjustment removes $22,321,552 from the Company's proposed rate base additions. The revenue requirement impact of this adjustment is included in the Direct Testimony of OPC witness Bion Ostrander.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

518122

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

| | | |
|---|---|---|
| **In the Matter of** | § | |
| | § | |
| **The Application of Washington Gas** | § | |
| **Light Company for Authority to** | § | **Formal Case No. 1180** |
| **Increase Existing Rates and** | § | |
| **Charges for Gas Service** | § | |

## AFFIDAVIT

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

Colin Fitzhenry

Colin T. Fitzhenry

Date: January 24, 2025

ADRIENNE JEAN NAVARRO
Notary Public - Notary Seal
STATE OF MISSOURI
Jefferson County
My Commission Expires: Mar. 22, 2025
Commission # 21989987

Adrienne J Navarro

**<u>Qualifications of Colin T. Fitzhenry</u>**

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. Colin Fitzhenry. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q. PLEASE STATE YOUR OCCUPATION.**

A. I am an Associate in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

**Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A. I received a Bachelor of Science in General Engineering from the University of Illinois Urbana-Champaign, which provided a broad background in mechanics and control systems. Prior to joining BAI, I served as an Engineer Intern for Dynegy Inc., where I was involved with generation operation at both Vermilion Power Station and Tilton Power Station.

Since joining BAI in January 2013, I have provided assistance in several regulated utility matters. Some of these include resource planning, transmission planning, fuel cost recovery, environmental compliance plans, mergers, asset transfers, electrical and commodity price forecasting, and power procurement.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of BAI was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, finance, mathematics, computer science and business.

BAI and its predecessor firm have participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 19

QUESTION NO. 19-1

**Q.** Referencing Exhibit WG(I) and the Direct Testimony of Frederick J. Morrow at 6, line 1-4, please address the following:

a. Please explain how Mr. Morrow calculated the 99.69% reliability percentage in the referenced testimony.

b. Explain the meaning of "service interruption" as used in the referenced testimony.

c. Did Mr. Morrow's calculation take into consideration the duration of the 141 unplanned service interruptions in calculating the reliability percentage?

d. Did Mr. Morrow take into consideration any reports of gas leaks from WGL customers in calculating the reliability percentage presented in the referenced testimony?

e. Provide the number of reported gas leaks from District customers for the twelve-months ended March 31, 2024.

**WASHINGTON GAS'S RESPONSE** 12/03/2024

**A.**

a. As stated in Company Witness Morrow's testimony, there were 141 unplanned service interruptions resulting in outages affecting 507 of 163,908 customers. Company Witness Morrow used the following equation: (163,908 – 507) ÷ 163,908 = 99.69%

b. A service interruption is when the supply of gas to a customer is temporarily unavailable.

c. No

d. No, an odor call does not necessarily equate to a leak nor an outage.

e. The Company files the reported odor calls in its LIDAROC quarterly filings in Formal Case No. 977.

SPONSOR: Frederick J. Morrow
Director, Construction

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 2

QUESTION NO. 2-7

**Q.** Please provide the capital and Operation and Maintenance (O&M) expense incurred for distribution main replacement for each calendar year for the past five-years.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** By definition, replacement work is not O&M expense.

See Attachment 1 for capital expenditures related to distribution main replacement for each calendar year for the past five-years.

SPONSOR: Donald Preston
Manager of Fixed Asset Accounting

FC 1180
OPC Data Request No 2
Question No. 2-7

**Capital Expenditure**
**Distribution Main Replacement**
**Calendar Yrs 2019-2023**

| **Years** | **Capital Expenditures** |
|---|---|
| 19 | 34,014,233.39 |
| 20 | 31,959,548.30 |
| 21 | 33,825,552.09 |
| 22 | 34,478,149.27 |
| 23 | 34,733,237.58 |
| **Grand Total** | **169,010,720.63** |

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 5

QUESTION NO. 5-9

**Q.** Regarding the publications mentioned in WGL's Response to OPC Question 2-35, please provide a copy of the full text (if not overly voluminous) or the relevant pages regarding the "commentary on graduating hazard rates" for each of the 7 publications.

**WASHINGTON GAS'S OBJECTION** 11/4/2024

Washington Gas objects to this request on grounds that it seeks publicly available information that OPC may obtain.

**Columbia Gas of Marvland. Inc.**
**2023 Eligible Main Replacement And Abandonment Status Update as of September 30, 2024**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | Actual Costs vs. Original Budget | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Project Location | Project Description | Original Job Order Estimate | Revised Job Order Estimate | WMS Booked Actual | In Service Date | Expenditures 8/1/23 - 9/30/24 | County | Planning & Scheduling Update | Estimated Install | Actual Install | Estimated # of Services | Actual # of Services | Estimated Bare Steel / Cast Iron Footage Retired | Estimated Pre-1971 Coated Steel | Estimated Pre-1982 Plastic | Estimated Post-1970 Coated Steel | Estimated Post-1981 Plastic | Actual Bare Steel Retired | Actual Cast Iron Retired | Actual Wrought Iron Retired | Actual Pre-1971 Coated Steel | Actual Pre-1982 Plastic | Actual Post-1970 Coated Steel | Actual Post-1981 Plastic | Completion / Execution | Variance - % | Variance - Explanation |
| 1 | Elgin Blvd | Install 4,235' - 6", 4", & 2" PMMP & Retest 1,854' P (in multiple sections) Justification: This project was identified for replacement using risk analysis software - Optimain / Uptime MRP. Also, approximately 327' of main on Elgin Blvd, between Washington and Lanvale, was included on our Active Corrosion Log on 7/11/22. The project includes replacing low pressure bare steel pipe with medium pressure plastic pipe on Elgin Blvd, along with multiple side streets. This project is located in Hagerstown. Please note the majority of Post-1981 Plastict to be abandoned is a vintage main (1980s) in which CMD does not typcially requalify - governed by our Standard or our common practice. | $1,573,723 | NA | $2,178,357 | NA | NA | Washington | Start Date - 3/15/23 Project Completed - 12/1/23 | 4,235 | 4,337 | 60 | 87 | 765 | 1,334 | 1,176 | 10 | 1,247 | 765 | 0 | 0 | 1,328 | 948 | 15 | 1,554 | Project Executed | 38.4% | There were increased expenses incurred as a result of rock being encountered at the underpass of the overhead railroad crossing and crossing underneath the City of Hagerstown's aquaduct system- thus extending the time needed for completion. Additional flagging and traffic control was required than what was estimated. Restoration is not 100% complete. |
| | | Elgin JO 22-0215787-00 | | | | 4/5/2023 | $63,927 | | | | | | | | | | | | | | | | | | | | | |
| | | Elgin JO 22-0215592-00 | | | | 11/28/2023 | $1,607,313 | | | | | | | | | | | | | | | | | | | | | |
| 2 | Memorial Boulevard / Antietam | Install 785' - 4" PMMP Justification: This project was identified for replacement using risk analysis software - Optimain / Uptime MRP. The project includes replacing segments of medium pressure bare steel pipe with medium pressure plastic pipe on Memorial Blvd, Antietam Street, and Baltimore Street. This project is located in Hagerstown, Md. | $352,441 | NA | $271,346 | 1/30/2023 | $93,615 | Washington | Start Date - 1/20/23 Project Completed - 11/1/23 | 785 | 672 | 5 | 1 | 601 | 1 | 9 | 18 | 216 | 469 | 0 | 0 | 23 | 0 | 17 | 180 | Project Executed | -23.0% | There was not as much footage that needed installed as originally planned. Also there was not the amount of hard surface restoration from what had been initially accounted for, thus the decrease in expenditures. A small portion of restoration still remains. |
| 3 | Bowling Green | Install 35,170' – 4" & 2" PMMP & Retest 4,930' P (in multiple sections) Justification: This project was identified for replacement using risk analysis software - Optimain / Uptime MRP. The project includes replacing low pressure bare steel pipe with medium pressure plastic pipe on Bowling Street along with multiple sides streets. This project is planned to be executed in conjunction with Allegany County's water / storm / road improvement work. This will allow CMD to abandon three of its low pressure District Regulator Stations and eliminate one of its low pressure systems in its entirety. This project is located in Cumberland, Md. Please note the majority of Post-1981 Plastict to be abandoned is due to the following reasons: Several segment are in casing and CMD will not requalify mainline as such (not having records of where the old services used to be - as a precaution in the event of any leak migration). Other segments are needed to maintain the integrty of the system as medium pressure is infiltrated. Other segments are just not large enough in size based on what is required to maintain reliable service. Also, there are some segments that are a vintage main (1980s) in which CMD does not typcially requalify - governed by our Standard or our common practice. | $7,853,229 | NA | $8,568,853 | 10/26/2023 | $5,321,281 | Allegany | Start Date - 1/9/23 Project Completed - 12/12/23 | 35,170 | 36,440 | 294 | 385 | 11,426 | 11,019 | 2,543 | 89 | 13,271 | 11,444 | 0 | 0 | 11,002 | 2,689 | 2,394 | 11,320 | Project Executed | 9.1% | NA |
| 4 | Winmer | Install 12,450' – 6", 4", & 2" PMMP & Retest 4,847' P (in multiple sections) Justification: This project was identified for replacement using risk analysis software - Optimain / Uptime MRP. The project includes replacing low pressure bare steel pipe with medium pressure plastic pipe on Waverly Terrace, Winmer Street, and multiple side streets. This will allow CMD to abandon two of its low pressure District Regulator Stations This project is located in Cumberland, Md. Please note the majority of Post-1981 Plastict to be abandoned is due to the following reasons: Several segment are in casing and CMD will not requalify mainline as such (not having records of where the old services used to be - as a precaution in the event of any leak migration). Other segments are needed to maintain the integrty of the system as medium pressure is infiltrated. Other segments are just not large enough in size based on what is required to maintain reliable service. | $3,059,038 | NA | $5,246,520 | 7/7/2023 | $3,573,243 | Allegany | Start Date - 1/6/23 Project Completed - 11/17/23 | 12,450 | 15,271 | 164 | 186 | 3,706 | 4,276 | 3,047 | 1,184 | 4,339 | 3,900 | 0 | 0 | 4,213 | 2,559 | 875 | 7,874 | Project Executed | 71.5% | A high volume traffic area, along with other congested utilities within the scope of the project, slowed construction considerably thus lengthening the duration of the project and increasing time sensitive units (e.g. labor, flaggers). There was an increase in footage installed due to some segments of main that were initally planned for requalifications (to be retested) that could not be, per our Standards, based on further investigations. Also, there was additional main that had to be installed, due to the terrain not permitting Columbia to replace in its existing location (main ran up a steep embankment in which Columbia basically had to reroute around). As a result, there was additonal hard surface restoration. Restoration is not 100% complete. |
| 5 | Green Street | Install 11,435' - 6", 4", & 2" PMMP & Retest 1,319' P (in multiple sections) Justification: This project was identified for replacement using risk analysis software - Optimain / Uptime MRP. The project includes replacing low pressure bare steel pipe with medium pressure plastic pipe on Green Street, along with multiple side streets. This will allow CMD to abandon one of its low pressure District Regulator Stations. This project is located in Cumberland, Md. Please note the majority of Post-1981 Plastict to be abandoned is in casing and CMD will not requalify mainline as such (not having records of where the old services used to be - as a precaution in the event of any leak migration). | $2,630,611 | NA | $4,700,281 | 7/31/2023 | $2,554,325 | Allegany | Start Date - 1/9/23 Project Completed - 8/28/23 | 11,435 | 11,208 | 147 | 169 | 2,739 | 1,979 | 2,876 | 2,091 | 2,812 | 2,744 | 0 | 0 | 2,194 | 2,925 | 1,820 | 3,079 | Project Executed | 78.7% | A high volume traffic area, congested utilities, along with the City of Cumberland's dated underground infrastructure (sewage / drainage was difficult to be well defined in the field), slowed the construction of this project lengthening the duration of the project and increasing time sensitive units (e.g. labor, flaggers). Also, there was some rock that had been encountered as well as additonal hard surface restoration, than what had initially been accounted for, thus the increase. Restoration is not 100% complete. |

# Exhibit OPC (C)-5
Page 2 of 3



**Columbia Gas of Marvland. Inc.**
**2023 Eligible Main Replacement And Abandonment Status Update as of September 30, 2024**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | Actual Costs vs. Original Budget | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Project Location | Project Description | Original Job Order Estimate | Revised Job Order Estimate | WMS Booked Actual | In Service Date | Expenditures 8/1/23 - 9/30/24 | County | Planning & Scheduling Update | Estimated Install | Actual Install | Estimated # of Services | Actual # of Services | Estimated Bare Steel / Cast Iron Footage Retired | Estimated Pre-1971 Coated Steel | Estimated Pre-1982 Plastic | Estimated Post-1970 Coated Steel | Estimated Post-1981 Plastic | Actual Bare Steel Retired | Actual Cast Iron Retired | Actual Wrought Iron Retired | Actual Pre-1971 Coated Steel | Actual Pre-1982 Plastic | Actual Post-1970 Coated Steel | Actual Post-1981 Plastic | Completion / Execution | Variance - % | Variance - Explanation |
| 6 | Henry Drive | Install 1,900' - 6" PMMP<br>Justification: This project was identified for replacement utilizing - Field Operation Leader input. The project includes replacing medium pressure bare steel pipe with medium pressure plastic pipe on Henry Drive between Cash Valley Rd and Falcon Ct. This will allow CMD to tie into exsiting protected steel main on all ends and eliminate an isolated section of bare steel main. This project is located in LaVale, Md. | $232,350 | NA | $590,079 | 10/16/2023 | $589,962 | Allegany | Start Date - 8/21/23<br>Project Completed - 8/21/23 | 1,900 | 1,940 | 10 | 16 | 1,808 | 0 | 0 | 0 | 0 | 1,833 | 0 | 0 | 102 | 0 | 0 | 0 | Project Executed | 154.0% | Due to the submission date of the 2023 STRIDE Roster and when the original Job Order estimates were needed, modifications to construction and restoration were required. It was initially planned for the installation of the main to be put in the grass, but after all was field marked, it had to be placed under pavement, thus the increase. Restoration is not 100% complete - some mill and overly remain. |
| 7 | Frantz Hollow Lane | Install 325' - 2" PMMP<br>Justification: This project was identified utilizing Field Operation Leader input. The project includes replacing medium pressure bare steel pipe with medium pressure plastic pipe on Frantz Hollow Lane off of US Highway 220. This will allow CMD to tie into existing plastic and eliminate an isolated section of bare steel main. This project is located in LaVale, Md. | $74,750 | NA | $53,698 | 5/3/2023 | NA | Allegany | Start Date -4/18/23<br>Project Completed - 5/9/23 | 325 | 382 | 3 | 4 | 295 | 0 | 0 | 0 | 0 | 286 | 0 | 0 | 0 | 0 | 0 | 0 | Project Executed | -28.2% | Due to good soil conditions and minimal impacts to construction, the main was able to be installed in a very proficient manner - saving on flaggers, and restoration from the original estimate. Restoration is complete. |
| 8 | Railroad | Install 5,770' - 4", & 2" PMMP & Retest 7,560' P (in multiple sections)<br>Justification: This project was identified for replacement using risk analysis software - Optimain / Uptime MRP. The project includes replacing low pressure bare steel pipe with medium pressure plastic pipe on Georges Creek Road along with multiple side streets. This will allow CMD to abandon two of its low pressure District Regulator Stations and eliminate one of its low pressure systems in its entirety. This will also allow CMD to abandon one of its medium pressure District Regulator Stations. This project is located in Midland, Md. Please note the majority of Post-1981 Plastict to be abandoned is due to the following reasons: Several segment are in casing and CMD will not requalify mainline as such (not having records of where the old services used to be - as a precaution in the event of any leak migration). There are some segments that are a vintage main (1980s) in which CMD does not typcially requalify - governed by our Standard or our common practice. Some segments to be abandoned are where we have dual main, thus keeping the the medium pressure, abandoning the low pressure. | $1,561,980 | NA | $2,014,740 | 10/24/2023 | $1,275,907 | Allegany | Start Date - 1/9/23<br>Project Completed - 12/18/23 | 5,770 | 7,338 | 91 | 72 | 1,780 | 511 | 699 | 211 | 5,032 | 1,780 | 0 | 0 | 514 | 932 | 181 | 7,039 | Project Executed | 29.0% | Increased expenditures on camera work involved with the portions of main lines needing requalified. |
| 9 | Prospect Str - Hagerstown (STRIDE) | Install 1,815' - 4" PMMP & 485'-4" PMLP<br>Justification:This project includes replacing 605' medium pressure bare steel pipe with medium pressure plastic, 1,210' low pressure bare steel with medium pressure plastic, and 485' low pressure bare steel with low pressure plastic. Such work will take place on Belview Ave, Prospect Str, and Park Place. This will allow CMD to abandon one of its low pressure District Regulator Stations This project is located in Hagerstown, Md. As of 1/1/22, only 1 mile of bare steel remains in the Hagerstown Area and is very wide spread and sporadic. | $650,000 | NA | $1,547,862 | NA | NA | Washington | Start Date - 9/6/23<br>Project Completed - 12/28/23 | 2,300 | 3,965 | 41 | 43 | 2,302 | 232 | 38 | 1,254 | 3,914 | 2,310 | 0 | 0 | 230 | 212 | 1,251 | 3,195 | Project Executed | 138.1% | Due to the submission date of the 2023 STRIDE Roster and when the original Job Order estimates were needed, modifications to construction and restoration were required. There was additonal footage that needed installed in order to maintain the integrity of our system, based on the recommendation of our Gas Systems Planing Department, thus the increase. There was also addional rock encountered, thus slowing construction, and increasing time sensitive units. Restoration is not 100% complete. |
| | | Prospect JO 22-0215647-00 | | | | 11/20/2023 | $1,537,965 | | | | | | | | | | | | | | | | | | | | | |
| | | Prospect JO 22-0215794-00 | | | | 12/20/2023 | $6,189 | | | | | | | | | | | | | | | | | | | | | |
| 10 | Wyoming (Non-STRIDE) | Install 560' - 4"PMLP Justification: This project includes replacing a segments of low pressure bare steel pipe with low pressure plastic pipe on Wyoming Ave, between Salem Ave and Connecticut Ave. This project is located in Hagerstown, Md and is part of the Hagerstown Downtown LP System. As of 1/1/22, only 1 mile of bare steel remains in the Hagerstown Area and is very wide spread and sporadic.<br>. | $247,000 | NA | $153,202 | 2/22/2023 | $3,392 | Washington | Start Date - 2/6/23<br>Project Completed - 3/1/23 | 560 | 571 | 5 | 3 | 347 | 156 | 23 | 0 | 8 | 347 | 0 | 0 | 156 | 23 | 0 | 0 | Project Executed | -38.0% | Due to the submission date of the 2023 STRIDE Roster and when the original Job Order estimates were needed, modifications to construction and restoration were required. There was less hard surface restoration from what had been initially accounted for. Also, not as much rock had been encountered based on what had been estimated, thus the decrease. Restoration is complete. |
| 11 | Welsh Hill (Non-STRIDE) | Install 3,685' – 4" PMMP & Retest 857' P (in multiple sections)<br>Justification: This project was identified with the assistance of Operation personel input. This project includes replacing low pressure bare steel pipe with medium pressure plastic pipe on Welsh Hill Road, Upper Georges Creek Road, Factory Lane, and Troutman Lane. This project is located in Frostburg, Md. | $1,106,000 | NA | $1,026,796 | 12/4/2023 | $1,026,182 | Allegany | Start Date - 10/9/23<br>Project Completed - 12/14/23 | 3,685 | 3,965 | 38 | 52 | 2,921 | 2,197 | 0 | 26 | 1,363 | 2,927 | 0 | 0 | 2,532 | 2 | 26 | 1,720 | Project Executed | -7.2% | Restoration is not 100% complete. Minimum concrete work remains as well as some mill and overlay. |
| 12 | Browning Street (Non-STRIDE) | Install 750' – 4" PMMP<br>Justification:This project was identified with the assistance of Operation personel input. This project includes replacing low pressure bare steel pipe with medium pressure plastic pipe on Browning Str between Oak Str and Virginia Ave. This project is located in Cumberland, Md. | $263,000 | NA | $220,632 | 6/30/2023 | $135,117 | Allegany | Start Date - 6/14/23<br>Project Completed - 7/31/23 | 750 | 845 | 20 | 22 | 664 | 0 | 0 | 0 | 0 | 664 | 0 | 0 | 101 | 0 | 0 | 5 | Project Executed | -16.1% | Due to good soil conditions and minimal impacts to construction, the main was able to be installed in a very proficient manner - saving on flaggers. Also, working in conjunction with the City of Cumberland, coordinating its hard surface restoration (performed by the municipality's contractor) - helped to reduce overall restoration expenditures.. |

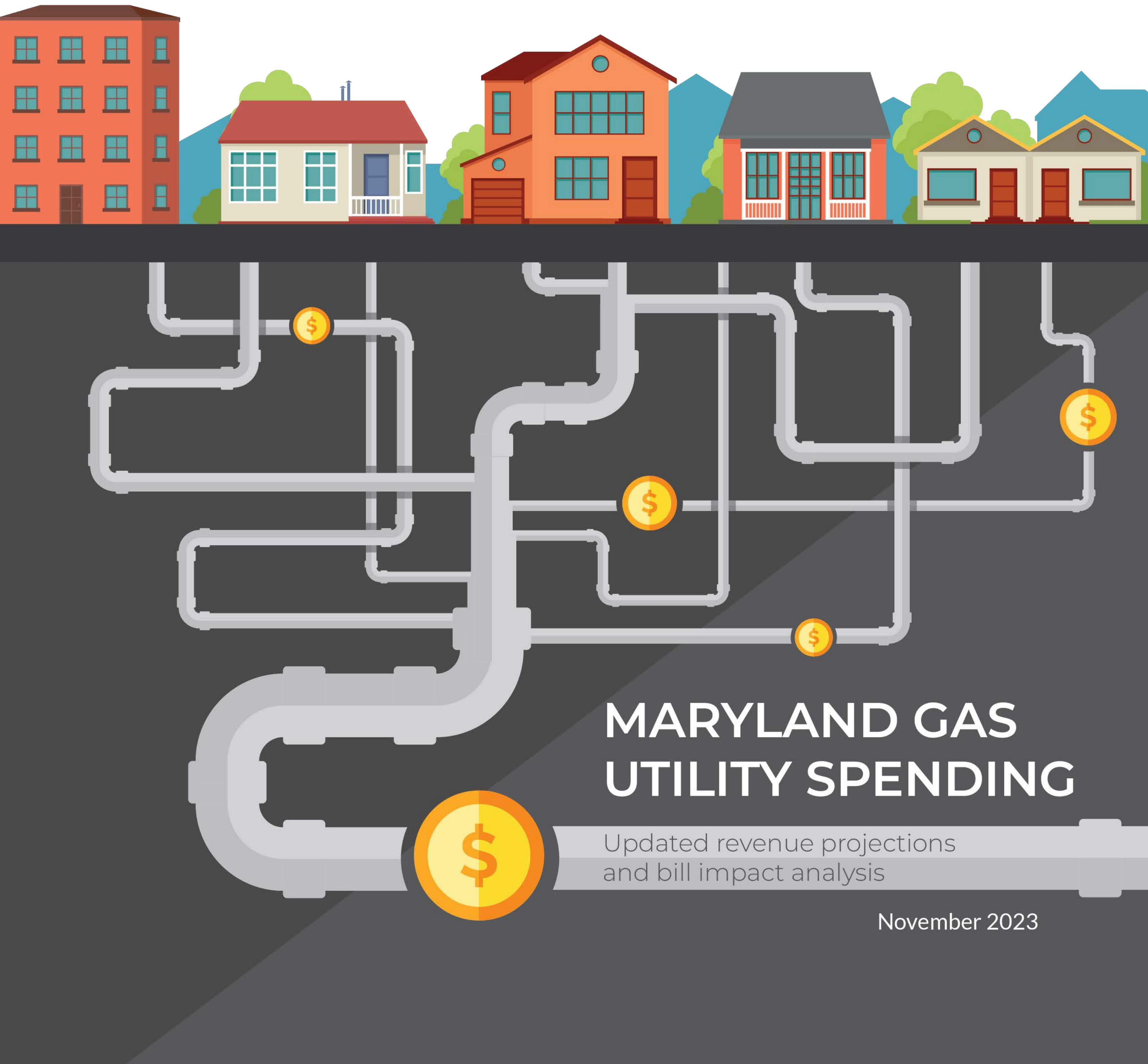
**Columbia Gas of Maryland. Inc.**
**2023 Eligible Main Replacement And Abandonment Status Update as of September 30, 2024**

| | | | | | | | | | | | | | | | | | | | | | | | | | | | Actual Costs vs. Original Budget | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Project Location | Project Description | Original Job Order Estimate | Revised Job Order Estimate | WMS Booked Actual | In Service Date | Expenditures 8/1/23 - 9/30/24 | County | Planning & Scheduling Update | Estimated Install | Actual Install | Estimated # of Services | Actual # of Services | Estimated Bare Steel / Cast Iron Footage Retired | Estimated Pre-1971 Coated Steel | Estimated Pre-1982 Plastic | Estimated Post-1970 Coated Steel | Estimated Post-1981 Plastic | Actual Bare Steel Retired | Actual Cast Iron Retired | Actual Wrought Iron Retired | Actual Pre-1971 Coated Steel | Actual Pre-1982 Plastic | Actual Post-1970 Coated Steel | Actual Post-1981 Plastic | Completion / Execution | Variance - % | Variance - Explanation |
| 13 | Dorsey Hotel Road (Non-STRIDE) | Install 500' - 4" PMMP<br>Justification: This project was identified with the assistance of Operation personel input. This project includes replacing medium pressure bare steel pipe with medium pressure plastic pipe on Dorsey Hotel Road from Miller Street to the dead end. This will allow CMD to tie into exsiting protected steel main and eliminate an isolated section of bare steel main. This project is located in Grantsville, Maryland, a somewhat remote location, which makes any emergency a challenge to respond to in a timely manner. | $175,000 | NA | $164,597 | 9/5/2023 | $132,087 | Garrett | Start Date - 7/25/23<br>Project Completed - 9/7/23 | 500 | 838 | 4 | 9 | 475 | 0 | 0 | 0 | 0 | 475 | 0 | 0 | 327 | 0 | 0 | 0 | Project Executed | -5.9% | NA |
| 14 | Fourth Street - Oakland (Non-STRIDE) | Install 3,114' - 4" PMMP<br>Justification: This project was identified with the assistance of Operation personel input. The project includes replacing 2,344' of various segments of medium pressure bare steel pipe with medium pressure plastic pipe on Totten Str between Mason Str and Aurora Rd, as well as Fourth Str between Center Str and Poplar Str. The project also includes replacing 770' of low pressure bare steel pipe with medium pressure plastic pipe on Reese Str between S. High Str and Seventh Str. This will allow CMD to tie into exsiting protected steel main and plastic main thus eliminating isolated sections of bare steel main. This project is located in Oakland, Maryland, a somewhat remote location, which makes any emergency a challenge to respond to in a timely manner. | $863,000 | NA | $1,474,099 | 7/23/2024 | $1,473,343 | Garrett | Start Date - 4/23/24<br>Project Completed - 9/10/24 | 3,114 | 4,190 | 15 | 29 | 3,112 | 0 | 20 | 0 | 124 | NA | NA | NA | NA | NA | NA | NA | Project Completed | 70.8% | This project was recently just Completed, not Executed, thus the actual footages of what had been retired, are not able to be updated just yet. |
| 15 | Bean Property (Non-STRIDE) | Install 5,150' - 4", & 2" PMIP<br>Justification: This project was identified with the assistance of Operation personel input. This project includes replacing intermediate pressure bare steel pipe with intermediate pressure plastic pipe on US Highway 220. This will allow CMD to eliminate all the bare steel within this small intermediate system. This project is located in McCoole, Maryland, a somewhat remote location, which makes any emergency a challenge to respond to in a timely manner. | $1,545,000 | $1,623,711 | $354,555 | NA | $354,555 | Allegany | Start Date - 7/29/24<br>Proposed Completion - Q4 | 5,150 | NA | 12 | 17 | 4,251 | 201 | 210 | 0 | 100 | NA | NA | NA | NA | NA | NA | NA | NA | -77.1% | This project is still in progress. |
| 16 | Longwood Ave (Non-STRIDE) | Install 2,225' - 4", & 2" PMMP<br>Justification: This project was identified with the assistance of Operation personel input. This project includes replacing medium pressure bare steel pipe with medium pressure plastic pipe on Longwood Ave between Nemacolin Ave and Braddock Road, as well as small segments on Seneca Ave and Braddock Rd. This will allow CMD to tie into exsiting protected steel main and eliminate an isolated section of bare steel main. This project is located in Cumberland, Md. | $612,000 | NA | $719,015 | 9/13/2023 | $717,375 | Allegany | Start Date - 8/2/23<br>Project Completed -10/27/23 | 2,195 | 2,171 | 15 | 19 | 2,033 | 149 | 0 | 0 | 42 | 2,034 | 0 | 0 | 149 | 0 | 21 | 45 | Project Executed | 17.5% | Due to the submission date of the 2023 STRIDE Roster and when the original Job Order estimates were needed, modifications to construction and restoration were required. There was additional hard surface restoration from what had been initially accounted for. Restoration is complete. |
| 17 | Gorman (Non-STRIDE) | Install 1,700 - 2" PMIP<br>Justification: This project was identified with the assistance of Operation personel input. This project includes replacing intermediate pressure bare steel pipe with intermediate pressure plastic pipe on US Highway 50 as well as Gorman Str and Gorman Rd. This will allow CMD to eliminate all the bare steel within this small intermediate system. This project is located in Gorman, Maryland, a somewhat remote location, which makes any emergency a challenge to respond to in a timely manner. | $510,000 | $574,633 | $653,040 | 5/22/2024 | $652,905 | Garrett | Start Date - 4/1/24 Project Completed - 6/4/24 | 1,700 | 1,395 | 8 | 9 | 1,519 | 0 | 140 | 0 | 0 | 1,519 | 0 | 0 | 69 | 2 | 0 | 4 | Project Executed | 28.0% | The necessary permits needed for this project were received late in 2023. As a result, this project will be completed in 2024 (as relayed in previous updates and data requests). |
| 18 | Thompson Ave (Non-STRIDE) | Install 500' - 4" PMMP<br>Justification: This project was identified with the assistance of Operation personel input. This project includes replacing medium pressure bare steel pipe with medium pressure plastic pipe on Thompason Ave between McKinley Ave and Rose Hill Ave as well Ridge Terrace between Thompson Ave and McKinley Terrace. This will allow CMD to tie into exsiting protected steel main and plastic main and eliminate an isolated section of bare steel main. This project is located in Cumberland, Md. | $175,000 | NA | $212,406 | 7/6/2023 | $102,559 | Allegany | Start Date - 6/14/23<br>Project Completed - 7/19/23 | 500 | 710 | 3 | 7 | 496 | 0 | 0 | 0 | 0 | 498 | 0 | 0 | 32 | 117 | 3 | 22 | Project Executed | 21.4% | Due to the submission date of the 2023 STRIDE Roster and when the original Job Order estimates were needed, modifications to construction and restoration were required, due to some additonal footage being added, thus the increase. Restoration is complete. |
| 19 | Locust Grove (Non-STRIDE) | Install 1,400' - 4", & 2" PMMP<br>Justification: This project was identified with the assistance of Operation personel input. This project includes replacing medium pressure bare steel pipe with medium pressure plastic pipe on Wabash Str between Bear Lane and Locust Grove Rd and from Bear Lane to a dead end, as well as a small segments on Bear Lane (much of which is in a wet / flood prone area). This will allow CMD to tie into exsiting plastic main and eliminate an isolated section of bare steel main. This project is located in Cumberland, Md. | $385,000 | NA | $79,632 | 7/27/2023 | $46,684 | Allegany | Start Date - 7/12/23<br>Project Completed - 8/21/23 | 1,400 | 1,276 | 8 | 14 | 1,139 | 0 | 0 | 2 | 208 | 1,144 | 0 | 0 | 12 | 420 | 2 | 244 | Project Executed | -79.3% | This project was estimated for the replacement of main to be installed under hard surface, when in fact, it was able to be installed all in the grass, saving on hard surface restoration. Also, due to good soil conditions and minimal impacts to construction, the main was able to be installed in a very proficient manner. Restoration is complete. |
| | | | $23,869,122 | | $30,229,710 | | $21,267,926 | | | 93,924 | 97,514 | 943 | 1,144 | 42,379 | 22,055 | 10,781 | 4,885 | 32,676 | 35,139 | 0 | 0 | 22,984 | 10,829 | 6,605 | 36,281 | | | |

OPC

OFFICE OF PEOPLE'S COUNSEL

State of Maryland



# MARYLAND GAS UTILITY SPENDING

## Updated revenue projections and bill impact analysis

November 2023

# TABLE OF CONTENTS

# CONTENTS

# LIST OF FIGURES



# LIST OF TABLES

SECTION ONE

# INTRODUCTION

The evolving regulatory landscape of gas infrastructure investment and its subsequent impact on costs for residential utility customers presents perhaps the most important issue facing Maryland utility customers. In October 2022, OPC released Maryland Gas Utility Spending: Projections and Analysis (the "2022 Gas Spending Report"), prepared by DHInfrastructure. This report provided critical information on current and future spending on gas capital projects by Maryland's three largest local gas distribution companies: Baltimore Gas and Electric (BGE), Columbia Gas of Maryland (CMD), and Washington Gas Light (WGL). Using information provided by the companies in regulatory filings and other publicly available information, the report presented projections on each company's capital investment expenditures from 2022 to 2100 under a business-as-usual scenario. These capital projections were then used to estimate how consumer bills would change over this period under this scenario.

The 2022 Gas Spending Report is an artifact of history in light of utility proposals over the past year that would substantially increase the scale of gas utility infrastructure investments. Despite this report only being a year old, the information relied on in 2022 has already proved stale. All three companies have submitted requests to the Maryland Public Service Commission ("PSC") for approval of new gas infrastructure capital investment plans, warranting a reevaluation and update of the previous analyses.[1] This report, also prepared by DHInfrastructure, updates the findings from our initial report based on the new filings and capital investment plans, providing a more comprehensive view of the current gas company business-as-usual plans in the absence of regulatory intervention.

**Under the gas companies' new proposals, spending goes up 60 percent from that projected one year ago.** The projected capital-related revenue requirements that customers of BGE, WGL, and CMD would be expected to pay from 2024 through 2100 goes from $125 billion in the 2022 study to $206 billion. Much of this customer impact is for the $20 billion in investments projected for the first 22-year period from 2024 to 2045, over the same period the State has set a goal to reach net-zero emissions.

At the proposed revised pace of investment, Maryland gas customers will be asked to spend $41.5 billion from 2024 through 2045 to pay for the gas companies' gas infrastructure spending: a $14.3 billion increase over the $27.2 billion in revenue requirements that we

1 BGE submitted a request for approval of its second three-year multi-year rate plan (BGE's "MRP 2") in Case Number ("CN") 9692 on February 17, 2023. WGL submitted a request for approval of its third five-year STRIDE plan (WGL's "STRIDE 3 plan") in CN 9708 on June 16, 2023. CMD submitted a request for approval of its third five-year STRIDE plan (CMD's "STRIDE 3 plan") in CN 9709 on June 23, 2023.

projected customers to pay for capital expenditures from 2024 to 2045 in the 2022 study.

The Strategic Infrastructure Development and Enhancement (STRIDE) statute, enacted by the Maryland General Assembly in 2013, continues to be a significant driver of the recent rapid increase in BGE, CMD, and WGL capital investments.[2] Under the STRIDE program, the gas companies plan wholesale replacements of most or all of their distribution systems that existed in 2014, the first year of the program. The 2022 report highlighted that gas customers in 2022 have paid only a fraction (about three percent) of the long-term customer costs of STRIDE investments—and because STRIDE remained a pivotal focus of each company's future capital investment plans, customers would continue paying for STRIDE investments until about the end of the century.

The updated capital spending and revenue requirement projections presented in this report show substantial increases from the corresponding projections in last year's report for each of the three gas companies:

- BGE's updated capital-investment revenue requirement projections—the amounts it must collect from customers to cover its distribution system cost—for 2024 through 2100 illustrate that BGE's capital spending plans have substantially increased. See Figure 2.2. BGE's average capital-investment revenue requirement from 2024 to 2100 ($1.97 billion) in the updated projections is 79 percent greater than the average ($1.09 billion) for this same period in the 2022 report.[3] This increase is driven by the significant jump in spending for work that is outside of the programs the utility has historically run through the STRIDE program.
- WGL's updated capital-investment revenue requirement projections for 2024 through 2100 show that its STRIDE 3 plan costs have increased by 33 percent compared to the 2022 projections.[4] See Figure 2.4. WGL's greatest change occurs in the 2040s, when the full impact of the completed STRIDE investments is reflected, increasing our previous projections by 60 percent. WGL's new forecasts show that its STRIDE program will not be complete until 2043—eight years later than last year's report showed it would be complete.
- CMD's updated capital-investment revenue requirement projections for 2024 through 2100 show the highest percentage increases, as its average revenue requirement from 2024 to 2100 ($89.2 million) is 87 percent greater than the average ($47.6 million) for this same period in the 2022 study.[5] See Figure 2.7. Previously, CMD's STRIDE investments were anticipated to end in 2026, but CMD is now proposing to add two new classes of pipes to its STRIDE program, potentially adding an additional 17 years of STRIDE investments.

CMD is now proposing to add two new classes of pipes to its STRIDE program, potentially adding an additional 17 years of STRIDE investments.

2 The STRIDE statute (MD Public Utilities Code § 4-210) enables utilities to recover eligible costs of approved STRIDE investments outside of a rate case through a STRIDE surcharge mechanism, allowing them to begin recovering costs when they are incurred, even before the infrastructure is in service, thereby effectively eliminating regulatory lag and accelerating the replacement of natural gas infrastructure.

3 When including OPEX (Figure 3.1), BGE's revenue requirement projections grow by 66 percent.

4 When including OPEX (Figure 3.2), WGL's revenue requirement projections still grow by 30 percent.

5 When including OPEX (Figure 3.3), CMD's revenue requirement projections grow by 70 percent.

The gas companies covered in this report may contend these projections are speculative. That criticism would incorrectly imply the purpose of the report is to predict precisely what gas investments will be in the future. The updated analysis presented in the report is instead provided to help Maryland policymakers and stakeholders understand how the new 2023 capital investment plans submitted by BGE, WGL, and CMD have altered the trajectory of gas investments and future revenue requirements.

The remainder of this document is organized as follows:

- Section 2 summarizes each of the companies' new investment plans that the PSC is currently evaluating and explains how the information in the filings supporting these investments has been used to develop new projections for STRIDE and non-STRIDE capital investments.
- Section 3 presents updated revenue requirement and bill impact forecasts based on new capital investment projections and other information presented in each company's 2023 base rate proposal.
- Section 4 concludes with a set of alternative results for how the statewide revenue requirement for the three companies would change over time under different investment pathways.

SECTION TWO

# NEW FILINGS AND CAPITAL INVESTMENT PLANS

This section provides updated capital spending projections for BGE, WGL, and CMD based on both their new capital plans submitted in 2023 and the latest information on actual capital expenditures released since the October 2022 report. Initially, we revisit the investment plans from our last report and establish a baseline for evaluating the new filings. Next, we discuss the specifics of the new capital plans submitted in 2023, and then describe how these plans have revised the projected spending forecasts.

The chapter is structured into four subsections: individual analyses for BGE, WGL, and CMD, followed by a summary section that synthesizes the findings into a statewide analysis of the revised updates in Maryland's gas utility sector.

## 2.1. BGE Capital Plans and Spending Projections

The year 2023 marks the end of two multi-year BGE capital investment plans: its five-year STRIDE 2 plan that the PSC approved in June 2018; and the pilot three-year multi-year rate plan ("MRP") that was approved in December 2020. Next, we summarize BGE's budgets and the actual/anticipated spend for these plans; identify the company's new capital plans for its MRP 2; and present updated projections on future capital spend based on the information in the new capital plans.

### 2.1.1. BGE's Previous Capital Plans: STRIDE 2 and MRP 1

BGE's approved STRIDE 2 plan included two programs: Operation Pipeline and the Service Replacement Program. The Operation Pipeline program targets replacing all remaining cast iron and bare steel main and bare steel and copper services. For this program under STRIDE 2, the PSC approved the replacement of 48 miles of main per year from 2019 through 2023 at a total five-year cost of approximately $486 million. The Service Replacement Program addressed the replacement of all pre-1970 ¾" high-pressure steel services. For STRIDE 2, the PSC approved BGE acceleration of the replacement of these services at the pace the company said was needed to replace the remaining population by the end of 2020, at a budgeted cost of $85 million. In total, the budget of BGE's approved STRIDE 2 plan was $571 million.

BGE's approved MRP 1 plan included a total of $1.26 billion in gas capital investments from 2021-2023. After removing the $489.7 million in STRIDE costs included in the MRP 1 budget, BGE's budget for non-STRIDE capital expenditures from 2021 to 2023 was $771.2 million.

As of October 2023, actual costs for both STRIDE 2 and the MRP 1 are available through the end of 2022, and more recent estimates on 2023 spending are available from the 2023 capital project lists submitted by BGE in 2022. This updated information shows that

BGE is on track to spend $804 million (141%) of the $571 million in planned STRIDE 2 costs, and $1.32 billion (104%) of the $1.26 billion in planned MRP 1 costs.

The data shows that BGE will exceed its budgeted costs for both STRIDE 2 and MRP 1. Therefore, when considering the new investment plans BGE has presented in 2023, the proposed budget should be viewed effectively to be expenditure floors, rather than limits on what will be spent.

### 2.1.2. BGE's New MRP 2 Gas Capital Plans from CN 9692

BGE submitted a request for approval of its second three-year MRP in CN 9692. The plan includes a total capital budget of $1.89 billion. This marks a $620 million or 50% increase in the overall gas capital budget from BGE's MRP 1 to MRP 2.

As for STRIDE, the company established in the MRP 2 filing that it does not intend to submit a third five-year STRIDE plan for 2024 to 2029. Instead, BGE stated in the MRP 2 filing its intent to recover its STRIDE investment activities under the MRP 2 base rates from 2024 to 2026 in place of the STRIDE surcharge mechanism. The budget to continue the company's STRIDE replacement activities in the MRP 2 is $459.3 million over three years. Because the replacements pursued through these projects are the same work BGE addressed through its STRIDE program, all updated 2023 projections in this report treat the work under these activities as the continuation of STRIDE investments.

### 2.1.3. Updated BGE Capital Projections

In its MRP 2 filing, BGE updated its capital projections for BGE's future STRIDE capital investments and non-STRIDE capital investments. These updates and the results are described below. Note that these updates rely on the information presented in BGE's CN 9692 filings, which have not yet been approved by the Commission. At the time this report was prepared, the Commission's final determination on BGE's MRP 2 is not expected until December 2023.

**Updated STRIDE Projections**

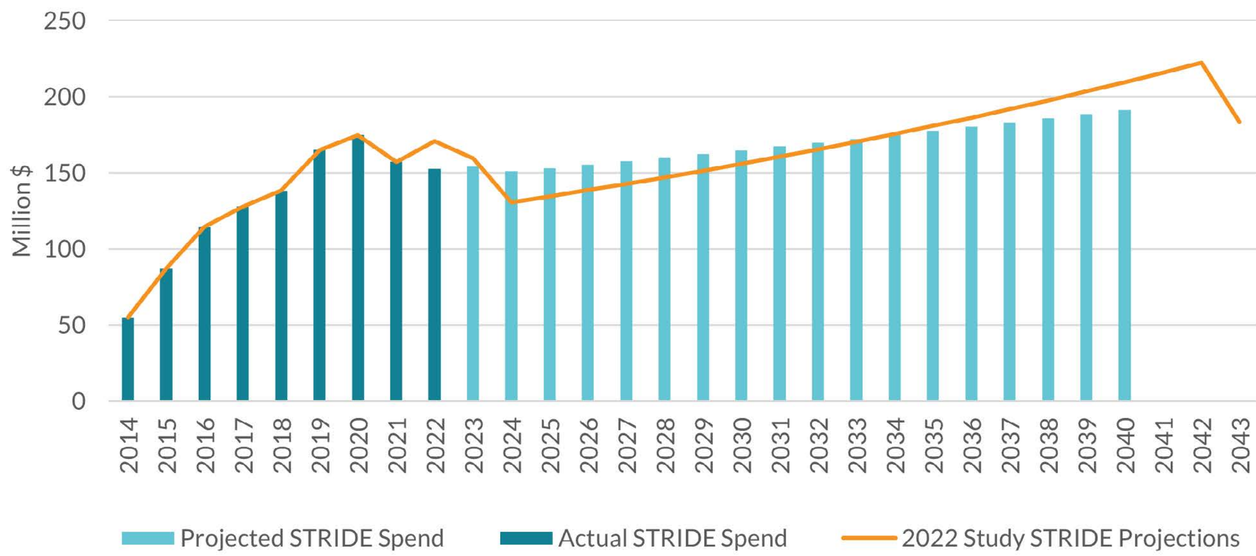
Projections for STRIDE expenditures in the 2022 Gas Spending Study relied on the remaining two years of budgeted costs for STRIDE 2 that were presented in the first MRP and then assumed that the 48 miles of main replaced each year under STRIDE 2 was continued from 2024 up until all bare steel and cast iron main would be replaced in 2043—when only 38.2 miles would need to be addressed.[6] Annual STRIDE costs were estimated by increasing the 2023 STRIDE budgeted cost per mile ($2.63 million / mile) by three percent each year—the same assumption BGE used in its STRIDE 2 plan—and multiplying by the assumed annual replacement miles.

For the updated 2023 projections, we used the same approach but revised the assumptions based on the new plan information provided by BGE in CN 9692. These changes include the following:

- Annual mains replaced per year were increased from 48 miles to 53 miles per year to match the company's plans to replace 53 miles per year under the STRIDE activities in the MRP 2.
- BGE's STRIDE replacement activities end in 2040 instead of 2043. This change is due to the faster replacement rate that achieves full replacement of bare steel and cast iron mains three years earlier.
- Budgeted costs for STRIDE replacement expenditures from 2024 to 2026 are the same as those presented in the MRP 2 filing.

6 This plan used a modified version of the projections that BGE presented for its accelerated STRIDE 2 plan in response to DR OPC 1-4 in CN 9468 that adjusts the number of miles replaced down from BGE's projections to the STRIDE 2 approved level of 48 miles per year.

Figure 2.1: BGE STRIDE Actual / Updated Projected Expenditures




- After 2026, the annual STRIDE expenditures estimated using the replacement cost per mile for the 2026 budget ($2,930,000/mile of main) increased by 1.5 percent per year. The 1.5 percent annual growth is the same rate of change in replacement cost per mile for the STRIDE replacements in MRP 2 program years 2025 to 2026.

The updated projections for BGE's STRIDE investments are presented in the figure below, which highlights the earlier end to the STRIDE investment activities.

**Updated Non-STRIDE Projections**

In the 2022 Gas Spending Study to project BGE's non-STRIDE costs, we used the planned capital budgets in the MRP 1 for 2022 and 2023, net of the budget for STRIDE activities. Then, for the post-MRP 1 period (2024-2100), the non-STRIDE capital expenditures were set at the average of the non-STRIDE gas capital expenditures in the MRP 1 for 2021 to 2023. This amounted to $263.26 million per year.

We used the same approach to update the non-STRIDE projections with new information from BGE's MRP 2 filing. For 2024 through 2026, we used the net budgets for non-STRIDE projects proposed for the MRP 2. The total of the three-year budget for non-STRIDE capital expenditures is $1.42 billion. We assumed the average of this non-STRIDE budget for the three years as the level of non-STRIDE investments from 2027 to 2100: $473.4 million. This amount is approximately 80 percent higher than the non-STRIDE spending projection in the 2022 study, representing a substantial shift in resources toward investments outside of STRIDE. Table 2.1 presents the derivation of the non-STRIDE capital investment assumption that is used to determine the average annual in the BGE capital projections.

The updated amount for non-STRIDE project spending is approximately 80 percent higher than the projection in the 2022 study.

Table 2.1: BGE Non-STRIDE Investment Projections

| Line | Description | Source | Projection |
|---|---|---|---|
| 1 | MRP Capital Budgets (2024-2026) | CN 9692, MRP 2 | $1,879.5 million |
| 2 | STRIDE Capital Budgets (2024-2026) | CN 9692, MRP 2 | $459.3 million |
| 3 | Non-STRIDE Plant Additions (2024-2026) | Line 1 – Line 2 | $1,420.2 million |
| 4 | Average Non-STRIDE Additions | Line 3 / 3 | **$473.4 million** |

**Combined Updated Capital Projections**

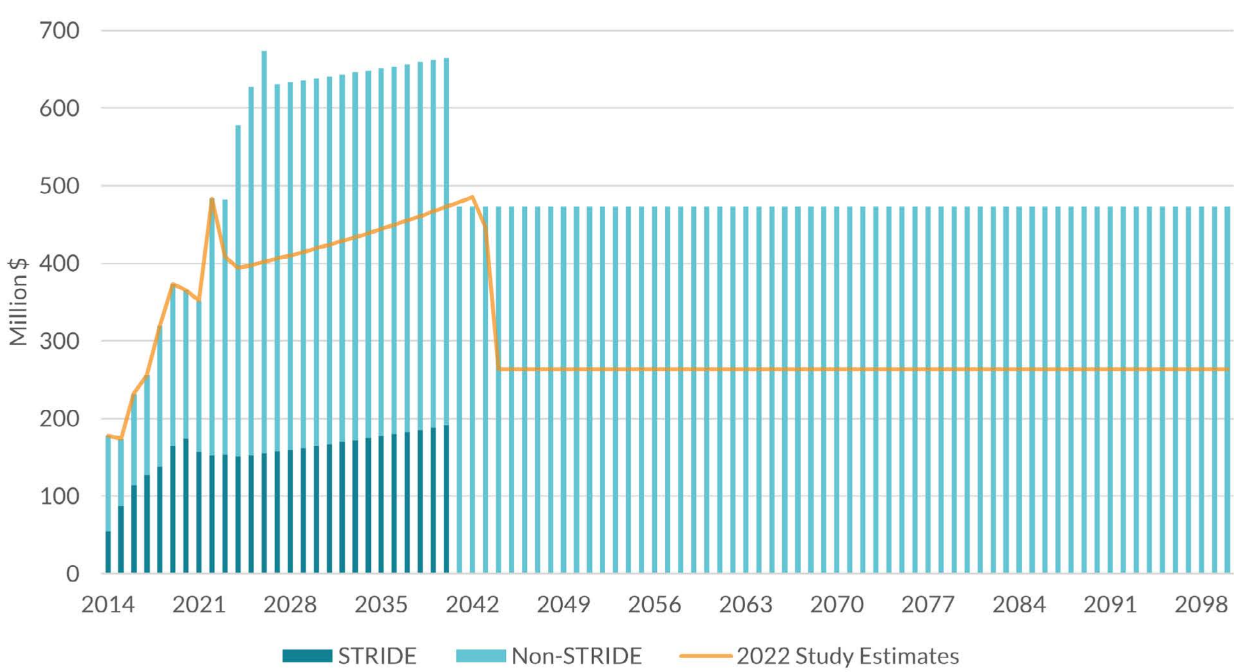
The combined investment projections for BGE, starting after the MRP 2 in 2026, represent the updated STRIDE projections through 2040 plus the base level of non-STRIDE additions of $473.4 million that is maintained over time.

Figure 2.2 shows the results of the revised capital investment projections for BGE through 2100 (bars) versus the previous projected expenditure path from the 2022 Gas Spending Study (line). Most evident is the substantial increase in non-STRIDE spending proposed in the MRP 2 gas capital plans that result in the non-STRIDE spending portion of our capital projections doubling from prior assumptions.

## 2.2. WGL Capital Plans and Spending Projections

WGL's current five-year STRIDE 2 plan ends in 2023. In this subsection, we summarize WGL's budgets and the actual or anticipated spend for the STRIDE 2 plan, identify the company's new STRIDE 3 plans presented for approval in CN 9708, and present updated projections on future capital spend based on the information in the STRIDE 3 plan.

Figure 2.2: BGE Capital Investment Actuals / Projections



### 2.2.1. WGL's Previous Capital Plan: STRIDE 2

The WGL STRIDE 2 program ending in 2023 includes five distribution and five transmission programs. These programs include:

- Distribution Program 1: a service-only replacement program split into components by material: bare and/or unprotected wrapped steel (1A); copper (1B); and pre-1982 plastic (1C);
- Distribution Program 2: bare and/or targeted unprotected wrapped steel main and affected services;
- Distribution Program 3: vintage mechanically coupled ("VMC") steel main, affected services, and independent services;
- Distribution Program 4: cast iron main and affected services;
- Distribution Program 5: a multi-asset program with three sub-categories: meter build-ups and risers (5A); shallow distribution main (5B); and steel gauge lines (5C);
- Transmission Program 1: U.S. Department of Transportation (DOT) Transmission and High-Pressure Pipe Replacement;
- Transmission Program 2: Remote Control Valve Installation;
- Transmission Program 3: DOT Transmission and High-Pressure Block Valve Replacement;
- Transmission Program 4: DOT Transmission and High-Pressure Valve Riser Replacement; and
- Transmission Program 5: Replacement of Components of DOT Transmission and High-Pressure Pipes to Enable the Use of In-line Inspection ("ILI") Tools.

The PSC approved $350.5 million for WGL's STRIDE 2 five-year budget plan across the ten programs.[7] Among the replacement activities WGL identified that would be completed over the course of the five-year period—from 2019 through 2023—was the replacement of an average of 24 miles of main per year, or a combined five-year total of 120 miles.[8]

As of October 2023, actual costs for WGL's STRIDE 2 activities are available through the end of 2022, and more recent estimates on 2023 spending are available from the 2023 STRIDE mid-year status report submitted in July 2023. This updated information shows that WGL is on track to spend $375.1 million (107%) of the $350.5 million budget approved in the STRIDE 2 plan.[9]

While the seven-percent budget overrun may appear relatively minor, WGL will be 107 percent over budget for only partial completion of the distribution replacement work included in the Commission-approved STRIDE 2 plan. If WGL completes all its ongoing 2023 main replacement projects, it will have only replaced 82.7 miles, or 69 percent, of the 120 miles in the approved plan. OPC's expert witness in WGL's ongoing STRIDE 3 case estimates that the cost for WGL to fully complete its proposed scope of STRIDE 2 replacements will be approximately $529 million—151 percent of the $350.5 million approved five-year budget.[10]

The uncompleted STRIDE 2 replacements only delay costs until later years and prolong the company's STRIDE plans. The corresponding impact of WGL's inability to complete both its STRIDE 1 and STRIDE 2 replacement work is evident in the company's updated long-term STRIDE timeline provided in its STRIDE 3 filing, described next.

7 Direct Testimony of WGL Witness Wayne Jacas in CN 9708 at page 6, line 17.

8 Exhibit WAJ-1: WGL's STRIDE 2 Distribution Program Application in CN 9486 at page 12.

9 Table 2, Errata Direct Testimony of OPC Witness Larkin-Connolly in CN 9708 at page 17.

10 Errata Direct Testimony of OPC Witness Larkin-Connolly in CN 9708 at page 18, line 11.

### 2.2.2. WGL's STRIDE 3 Plan Submitted in CN 9708

WGL's STRIDE 3 plan for 2024 through 2028 proposes to continue the identical set of five distribution and transmission programs in the STRIDE 2 plan. The one change in the overall STRIDE program design for STRIDE 3 is the addition of Distribution Program 6: low pressure main and services, which would be used to carry out the replacement of 58.6 of the remaining 63.5 miles of mains and associated services on the company's Maryland distribution system that still operates at low-pressure.[11] The 58.6 miles of mains targeted for replacement are made of materials technically already included under the existing distribution main replacement projects for bare/unprotected steel and cast iron.[12] This new program is proposed as part of a change in how WGL prioritizes replacement of low-pressure systems.

The company identifies that over the 2024 through 2028 STRIDE 3 period it plans to:

- Replace 79.6 miles of main through Distribution Programs 2, 3, 4, 5B, and 6;
- Replace 4,061 services and transfer another 3,051 services as part of the main replacement work to be carried out under Distribution Programs 2, 3, 4, 5B, and 6;
- Replace 6,879 services (independent of a main project) through Programs 1A, 1B, 1C, and 3;
- Complete meter buildups at 10,000 addresses, with 75 addresses to also include service riser replacements as part of this work, through Distribution Program 5A;
- Replace 425 steel gauge lines through Distribution Program 5C;
- Complete partial replacement of three (3) transmission pipeline strips through Transmission Program 1;
- Install six (6) new high-pressure rotary control valves (RCVs) through Transmission Program 2;
- Replace one (1) DOT transmission and high-pressure block valve through Transmission Program 3;
- Replace 12 valve risers on WGL's high-pressure transmission system through Transmission Program 4; and
- Replace components on portions of one (1) transmission strip to enable ILI through Transmission Program 5.[13]

These planned distribution replacements for STRIDE 3 are well below what was included in WGL's approved STRIDE 2 plan. The 79.6 planned main replacement miles for STRIDE 3 are approximately 40 miles (33%) below what it had proposed to complete under STRIDE 2, and the reduced main replacement means that services are reduced by 4,429 (24%) below the STRIDE 2 plan. Replacement plans for the other distribution assets under Distribution Programs 5A and 5C represent an even more significant drop in planned units. For Program 5A, the number of addresses where meter buildup and service riser work would be implemented over the course of STRIDE 3 is 16,500 addresses (62%) below the STRIDE 2 plan, and for Program 5C the steel gauge lines planned for replacement are 500 (54%) below the replacements planned for STRIDE 2.

The reduction in planned replacements has not led to a reduction in the five-year STRIDE budget. WGL's proposed budget for STRIDE 3 is $495 million: $89.4 million for 2024; $92.9 million for 2025; $99.7 million for 2026; $102.8 million for 2027; and $110.2 million

11 WGL Response to OPC DR 1-5, Att. 3 in CN 9708, attached to Direct Testimony of OPC witness Larkin-Connolly.

12 *Id.*

13 WGL's distribution targets are provided in Table 4 located in Exhibit WAJ-1 in CN 9708 at page 10.

for 2028.[14] This budget includes $483.1 million in planned distribution program spend and $11.9 million in transmission program spend.[15]

Another change for STRIDE 3 is clarification from WGL that the long-term duration of the distribution programs will be extended. When the STRIDE 1 plans were submitted in 2013 and 2014, the company presented them as part of an overall long-term plan to replace all targeted assets over 22 years, with individual program lengths ranging from 10 to 22 years.[16] The company extended the duration of some of the individual programs in the STRIDE 2 plan but kept the total long-term STRIDE duration to 22 years.[17] In its STRIDE 3 filing, as shown in Table 2.2, the 22-year plan for the WGL STRIDE distribution programs has now been extended another eight years. WGL's STRIDE program is now a 30-year replacement plan that is planned to end in 2043 instead of 2035.

### 2.2.3. Updated WGL Capital Projections

We updated the capital projections for WGL's future STRIDE capital investments and non-STRIDE capital investments based on the STRIDE 3 plan and new information from WGL's annual reports on capital expenditures and plant additions made in 2021 and 2022. These updates and the results are described below. As with BGE, these updates rely on the information presented in WGL's STRIDE 3 plan filed in CN 9708 that has not, as of October 2023, been approved by the Commission.

**Updated STRIDE Projections**

Projections for future STRIDE expenditures in the 2022 Gas Spending Study began with the remaining two years of 2022 and 2023 budgeted costs for STRIDE 2. Because the company had not provided a long-term plan for its future STRIDE replacements, other than the remaining years in each program,

Table 2.2: STRIDE 3 Distribution Programs and Updated Program Durations

| Program | Asset Category | STRIDE 1 Original Duration | OLD End Year | STRIDE 3 Remaining Duration | New End Year | Program Delay |
|---|---|---|---|---|---|---|
| 1A | Bare and/or Unprotected Wrapped Steel Services | 10 years | 2023 | 7 years | 2030 | +7 years |
| 1B | Targeted Copper Services | 10 years | 2023 | 10 years | 2033 | +10 years |
| 1C | Targeted Pre-1975 Plastic Services | 10 years | 2023 | 10 years | 2033 | +10 years |
| 2 | Bare and/or Targeted Unprotected Wrapped Steel Main and Affected Services | 14 years | 2027 | 15 years | 2038 | +11 years |
| 3 | Vintage Mechanically Coupled Steel Main and Services and Affected Services | 22 years | 2035 | 20 years | 2043 | +8 years |
| 4 | Cast Iron Main and Affected Services | 14 years | 2027 | 10 years | 2033 | +6 years |
| 5A | Meter Build ups and Service Risers | 15 years | 2029 | 10 years | 2033 | +4 years |
| 5B | Shallow Main | 15 years | 2029 | 10 years | 2033 | +4 years |
| 5C | 5C Steel Gauge Lines | 15 years | 2029 | 10 years | 2033 | +4 years |
| 6 | Low Pressure Main and Services | 14 years | 2027 | 15 years | 2038 | +11 years |

14 Table 4, Exhibit WAJ-1 in CN 9708 at page 10.

15 *Id.*

16 WGL Response to OPC DR 1-5 Att. 1 at 1; Att. 2 at 1.

17 WGL Response to OPC DR 1-5 Att. 3, WGL's STRIDE 2 filing at 2.

we used a simplified method to estimate the future distribution program spend after 2024. The budget for each distribution program is projected to increase by three percent each year until the program's final year. For example, the budget for Program 2 was $37.08 million in 2023 and was estimated to be $38.2 million in 2024 (3 percent higher). The budget for each year was increased accordingly until 2027, the previous planned end year of the program. An additional 14.7 percent was added to the 2022 to 2100 STRIDE distribution budgets to account for WGL's record under STRIDE 2 wherein its unit costs over the first three years of STRIDE 2 were shown to be on average 14.7 percent over the unit costs underlying the STRIDE 2 plan.

For the updated 2023 STRIDE capital projections, we took a different approach to account for new cost details, the change in program durations, and the estimated main replacement rate that would be needed to complete the expected mains remaining to be completed at the end of STRIDE 3 in 2028. This added information allows for a more accurate estimate of the budget required to complete the replacement WGL intends to complete over the next 20 years than the previous simplified approach. The new approach to the STRIDE capital spending projections can be summarized as follows:

- Proposed STRIDE 3 budgets for distribution and transmission as submitted in the CN 9708 initial filing are used for the assumed STRIDE capital spend in the five-year period from 2024 through 2028.
- Annual STRIDE spend for distribution main replacements and affected services under Distribution Programs 2, 3, 4, 5C, and 6 for 2029 to 2043 were estimated by first assuming annual main replacements of 25.5 miles for STRIDE 4 (2029-2033); 28 miles for STRIDE 5 (2034-2038); and 32 miles for STRIDE 6 (2039-2043).[18] Next, the annual replacement cost per mile for these replacements from 2029 to 2100 was assumed to be the $4,313,823 budgeted cost per mile for main replacement in the final year of STRIDE 3 (2028), grown by six percent each year.[19] Finally, the spend for each year was derived by multiplying the assumed miles replaced by the annual replacement unit costs.
- STRIDE spend for the independent service programs (1A, 1B, 1C, and 3) and other distribution programs (5A and 5C) from 2029 through 2043 was set at the budget for each program in 2028, the final year of STRIDE 3, grown by six percent each year until the year that WGL has indicated the program will end.
- No transmission budgets are included after 2028 because WGL has not identified its plans for future STRIDE transmission investments beyond 2028.

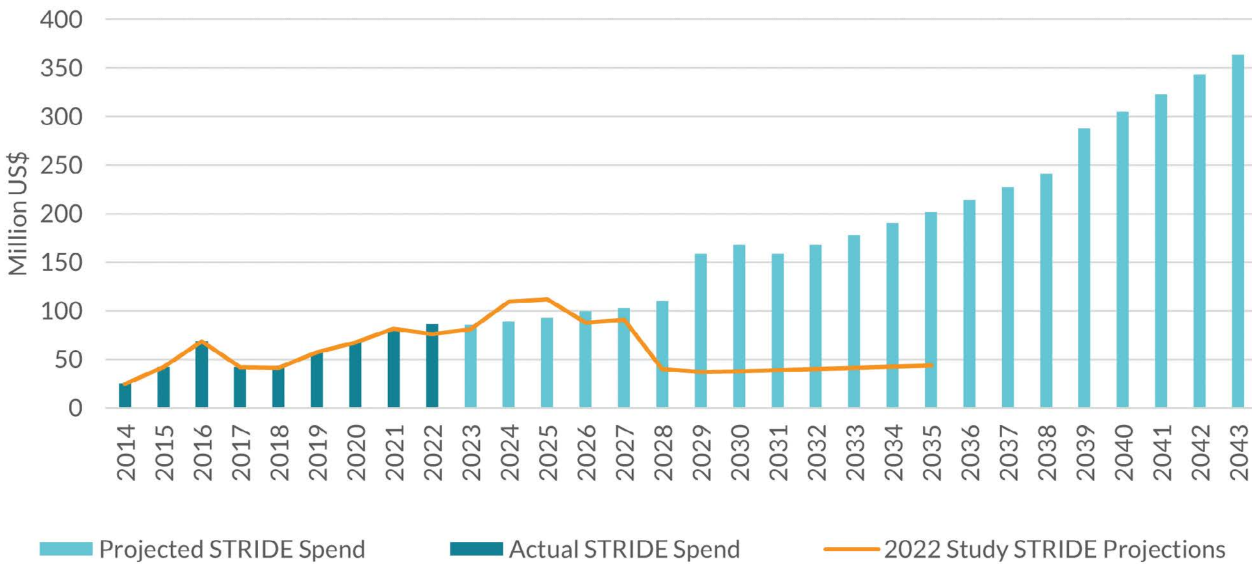
Based on this approach, we estimate the total expenditures for WGL's remaining STRIDE activities after 2023 to be $4.0 billion. This is more than $3 billion, or five times the $720 million projected after 2023 we had estimated in the previous study based on WGL's previous STRIDE plans and unit cost estimates. As shown in Figure 2.3 below, the new STRIDE expenditure path reflects the increased replacement costs and extended duration of STRIDE.

> The total expenditures for WGL's remaining STRIDE activities after 2023 are projected to be $4.0 billion, more than five times last year's projection.

18 These replacement rates were developed based on an estimate that at the end of STRIDE 3 the remaining miles of main to be replaced over the final 15 planned years for WGL's STRIDE program would be approximately 427.5 miles, which would require an average of 28.5 miles replaced per year.

19 This six-percent growth rate in unit costs is the same rate used by WGL in its STRIDE 3 plan.

Figure 2.3: WGL STRIDE Actual (2014-2022) / Updated Projected Expenditures (2023-2043)




**Updated Non-STRIDE Projections**

We used a different approach to calculate WGL's non-STRIDE projections in the 2022 Gas Spending Study than for BGE because WGL was not operating under an MRP. WGL's non-STRIDE capital expenditures for 2021 through 2100 were estimated by first aggregating the annual plant additions listed for WGL in the three most recent annual reports available (2018-2020): $1.2 billion. This three-year plant-additions amount was for plant additions across all WGL's service areas (MD, VA, and DC) because the company submits a combined annual report to the Maryland PSC. To arrive at the MD portion of the three-year plant additions, the jurisdictional plant allocator for Maryland of 38.2%—presented in WGL's 2020 base rate filing, CN 9651—was applied to arrive at an estimated total of $473.1 million in plant additions in Maryland from 2018 through 2020. STRIDE spending of $166.0 million for the years 2018 to 2020 was then subtracted from this amount to arrive at an estimated $307.5 million in non-STRIDE plant additions for the three-year period. The assumed non-STRIDE capital expenditures for 2021 through 2100 was then the three-year average of this amount, or $102.5 million per year.

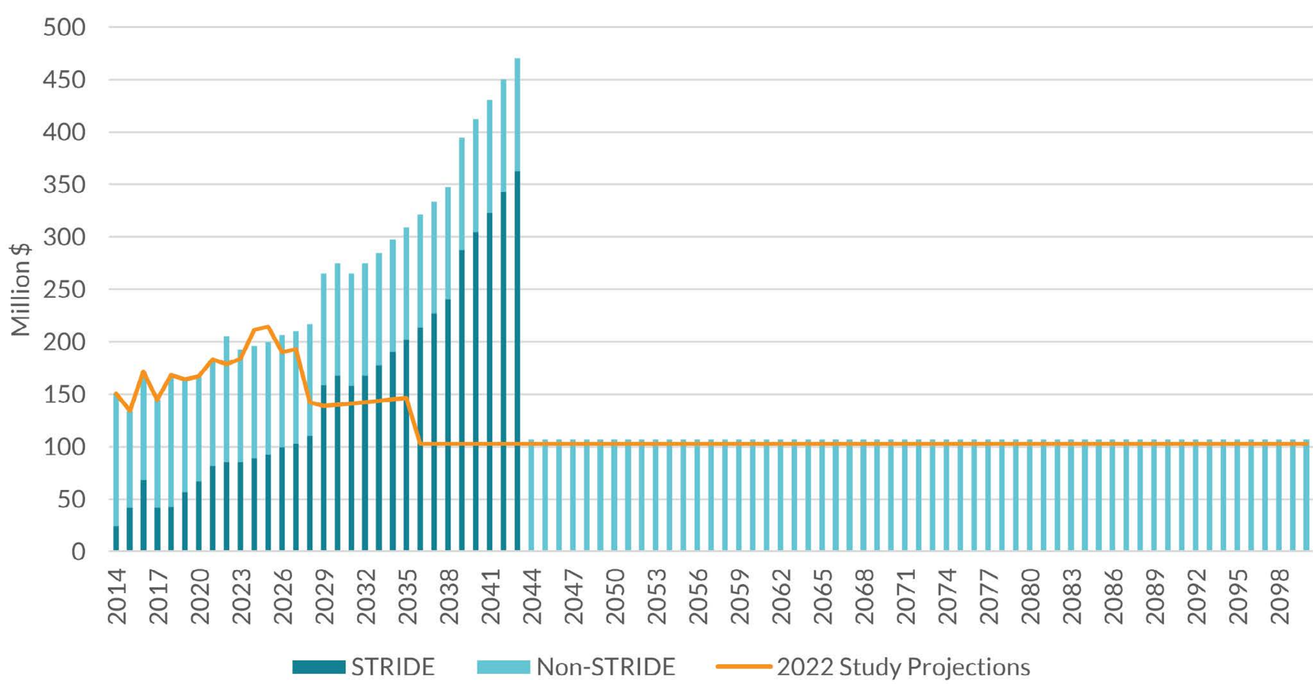
The 2023 updated non-STRIDE projections reflect the most recent three years of information in WGL's 2020 through 2022 annual reports and the jurisdictional plant allocation factor included in the cost-of-service study submitted in WGL's 2023 base rate case (CN 9704). Beyond these informational updates, we made one modification to the prior approach to derive the WGL non-STRIDE expenditure assumption—the addition of the net change in capital work in progress (CWIP) to the three-year plant-additions amount. This change intends to capture the fact that amounts on annual STRIDE spend do not necessarily represent only plants in-service but also include CWIP not yet placed into service. Excluding these amounts from the previous projections likely underestimated WGL's non-STRIDE spend.

Table 2.3 presents the derivation of the non-STRIDE capital investment assumptions that are used in the updated WGL capital projections for 2023 to 2100.

Table 2.3: WGL Non-STRIDE Investment Projections

| Line | Description | Source | Projection |
|---|---|---|---|
| 1 | WGL Plant Additions (2020-2022) | Annual Reports | $1,363 million |
| 2 | WGL Net Change in CWIP (2020-2022) | Annual Reports | $92.20 million |
| 3 | Total WGL Plant Additions + CWIP | Line 1 + Line 2 | $1,455 million |
| 4 | MD Plant Allocator | CN 9704, Exh. RET-6 | 38.2% |
| 5 | Estimated MD Capital Expenditures | Line 3 * Line 4 | $566.1 million |
| 6 | STRIDE Expenditures (2020-2022) | STRIDE filings | $235.1 million |
| 7 | Non-STRIDE Expenditures (2020-2022) | Line 5 – Line 6 | $307.5 |
| 8 | Average Non-STRIDE Expenditures | Line 7 / 3 | **$107.0 million** |

Figure 2.4: WGL Capital Investment Actual / Projections




**Combined Updated Capital Projections**

The combined investment projections for WGL, starting in 2023, represent the STRIDE projections through 2043 plus a base level of $107.0 million that we maintain for the entire evaluation period. Figure 2.4 shows the results of our capital investment projections for WGL through 2100.

## 2.3. CMD Capital Plans and Spending Projections

Like we did for WGL, we updated the capital projections for CMD's future STRIDE capital investment and non-STRIDE capital investments based on the STRIDE 3 plan and new information from CMD's annual reports on capital expenditures and plant additions made in 2021 and 2022. These updates and the results are described below. These CMD updates rely on the information presented in the company's STRIDE 3 plan filed in CN 9709, which has not, as of October 2023, been approved by the Commission.

### 2.3.1. CMD's Previous Capital Plan: STRIDE 2

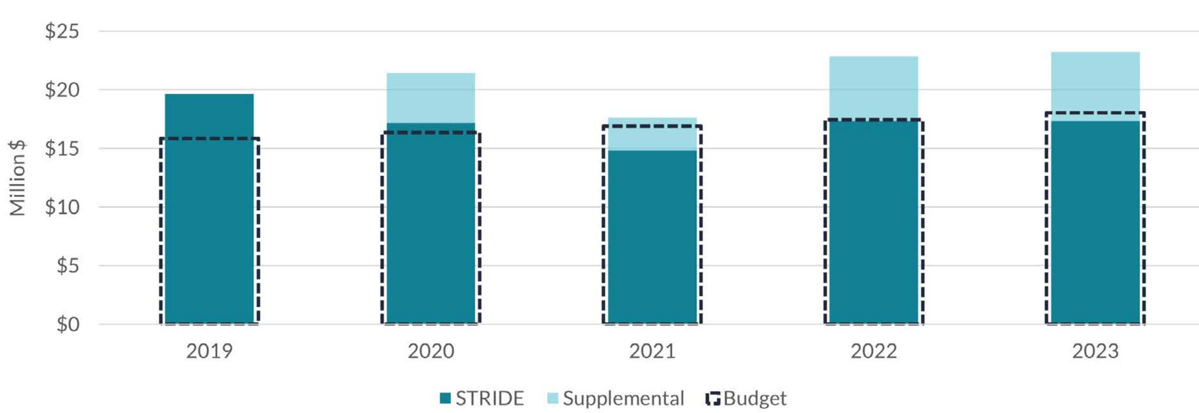
The STRIDE 2 plan that CMD is operating under in 2023 remains relatively the same as the original STRIDE 1 plan approved by the PSC in CN 9332. CMD's approved first five-year plan included an average replacement of 7.56 miles of bare steel, wrought-iron, or cast-iron main per year with a goal to complete replacement of all mains made of these materials by the end of 2026. The STRIDE 2 plan that was agreed upon through a settlement agreement in CN 9479 stipulated that CMD would replace eight miles per year of the same three main materials from 2019 through 2023 for a budgeted cost of $84.6 million over the five years.

CMD completed its replacement of all remaining cast- and wrought-iron mains on CMD's distribution system in 2020. This milestone meant that the remaining three years of STRIDE 2 targeted replacement of only eight miles of bare steel main per year. Over the remaining three years CMD was unable to put together lists of projects that both included eight miles of bare steel main and fit within the agreed upon budget for the year because the remaining bare steel on the system is located more sporadically and in between other older main materials, such as older plastic and coated steel pipes, which were not prioritized for replacement through STRIDE. The company replaces these other materials at the same time it replaces the STRIDE-targeted bare steel. The replacement of these other materials adds to the overall cost to replace each mile of bare steel. For CMD to both achieve the mileage replacement and incur costs close to the budget agreed to in the settlement agreement, the company has put forward supplemental non-STRIDE replacement projects from 2020 through 2023 to address any gap between the eight miles target and the miles of bare steel main prioritized for replacement through STRIDE.

Although the company has not pursued collection of the cost of these supplemental projects through the STRIDE surcharge mechanism, these additional STRIDE-related investment costs are still contributing to higher base rates when the company comes in for its annual base rate filing. For this reason, it is appropriate to include these supplemental costs when evaluating CMD's STRIDE 2 results. Evident in Figure 2.5 below is that these supplemental projects have resulted in CMD incurring costs well above the amounts budgeted to replace the eight miles of main per year.

As of October 2023, actual costs for CMD's STRIDE 2 activities are available through the end of 2022, and more recent estimates on 2023 spend are available

Figure 2.5: CMD STRIDE 2 Budget vs. Actual Annual Expenditures



from the 2023 STRIDE project list submitted in November 2022.[20] This updated information shows that CMD is on track to spend $86.4 million on STRIDE projects and another $18.5 million on supplemental projects. In total, CMD will have spent $104.3 million, or 124 percent, of the $84.6 million budget to replace the 40 miles of bare steel or cast iron mains over the five-year STRIDE 2 period.

### 2.3.2. CMD's New STRIDE 3 Plan from CN 9709

CMD's STRIDE 3 plan for 2024 through 2028 proposes to continue the replacement of the remaining bare steel mains prioritized in the STRIDE 2 plan, along with the replacement of two new priority main materials: coated steel mains installed prior to 1971 ("pre-1971 coated steel") and plastic mains installed prior to 1982 ("pre-1982 plastic"). CMD has proposed to replace a combined eight miles per year of bare steel main and the two new material types—40 miles total—from 2024 through 2028 at a five-year budget of $101.7 million.

The proposed addition of pre-1971 coated steel and pre-1982 plastic has implications on the duration of not only STRIDE 3 but CMD's long-term STRIDE plans. We expect that CMD will have approximately 17.4 miles of bare steel mains remaining at the end of 2023. That means that at the eight-mile-per-year replacement rate, the company is currently on track to complete the replacement of bare steel main by the end of 2026. In other words, if only bare steel was included in the new plan, then the duration of STRIDE 3 proposed would be at most three years long.

> Replacing the entire population of pre-1971 coated steel and pre-1982 plastic mains would add another 17 years to the company's STRIDE plans.

Including additional priority material types enables CMD to add two more years to the STRIDE 3 plan—because there are enough priority mains to replace to fill up an entire five-year plan of replacement projects.

CMD is unclear on its long-term plans for replacement of pre-1971 coated steel and pre-1982 plastic after STRIDE 3. The company does not specify if the intention is to replace every single mile of pre-1971 coated steel and pre-1982 plastic or if it will only target replacement where there is evidence that the mains are performing poorly. At the current pace of eight miles per year, replacing the entire population of pre-1971 coated steel and pre-1982 plastic mains would add another 17 years to the company's STRIDE plans, extending CMD's STRIDE program from a single three-year STRIDE 3 plan up to potentially four five-year plans.[21]

### 2.3.3. Updated CMD CApital Projections

The capital projections for CMD's future STRIDE capital investment and non-STRIDE capital investments were updated based on the STRIDE 3 plan and other new information from the 2021 and 2022 annual reports. These updates and the results are described below. These updates rely on the

20 Annual reconciliation filings: ML#s 229077 (2019); 234156 (2020); 239568 (2021); and 301824 (2022). The 2023 Project List is ML#300394.

21 In 2023, Columbia said it will replace a combined 5.6 miles of pre-1971 coated steel and pre-1982 plastic through the replacement projects it is pursuing under the STRIDE mechanism (Att. C to Columbia's 2023 STRIDE Project List, ML 242872) and 0.62 miles through the projects on its supplemental STRIDE list (Supplemental STRIDE 2023 Project List, ML 300745). That puts the company on track to have 141.48 miles in pre-1981 coated steel and pre-1982 plastic remaining by the end of 2023. The 141.48 pre-1972 coated steel and pre-1982 plastic plus the 17.4 miles of remaining bare steel at the start of 2024 equals a combined 158.9 miles of main that would take 19.9 years (158.9 miles / 8 miles per year) to complete at a rate of eight miles per year. The additional 17 years is found by removing the three years remaining in CMD's original STRIDE completion timeline that ends in 2026 (19.9 years – 3 years = 16.9 years).

information presented in CMD's STRIDE 3 plan filed in CN 9709, which has not, as of October 2023, been approved by the Commission.

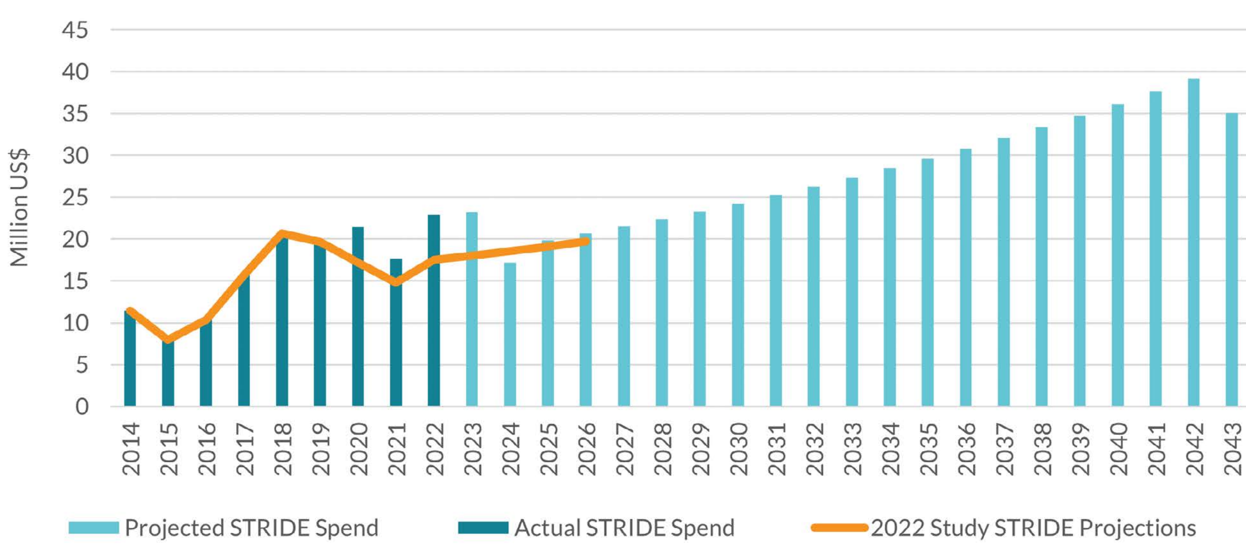
**Updated STRIDE Projections**

The projections for CMD's STRIDE spend in the 2022 Gas Spending Report relied on the budgeted costs for the remaining two years of STRIDE 2 (2022 and 2023) and then assumed that there would only be 17.5 miles of bare steel main replacement from 2024 through 2026. We assumed that a total of 24 miles would need to be replaced over this three-year period. The additional 6.5 miles in other mains included were meant to represent the high number of other main materials the company had shown it would need to complete the removal of the remaining bare steel mains on its system. The expenditure on these replacements were estimated by using the same unit rate for 2023 in the company's STRIDE 2 plan grown by three percent per year.

The proposed STRIDE 3 budgets submitted by CMD in the CN 9709 initial filing are used for the assumed STRIDE capital spend from 2024 through 2028. To model the company's future STRIDE investment activities after 2028, we adjusted the approach used in the previous study to reflect the new priority pipe and unit costs in CMD's STRIDE 3 plan. While the company has not stated its intention explicitly, we assume the goal for these new asset categories is to eventually replace all pre-1971 coated steel and pre-1982 plastic mains. We assume that the company would continue the same replacement pace of eight miles per year in 2029 and keep that pace until all remaining miles of pre-1971 coated steel and pre-1982 plastic are fully replaced in 2043. When estimating the costs of these annual replacements, we again use the unit costs from the final year of the existing five-year STRIDE plan—the unit cost of $2.8 million per mile for 2028—and grow it each year by 4.07 percent—the same growth rate CMD used between 2027 and 2028 in the STRIDE 3 budget.

Based on this approach, we estimate that the total expenditures for CMD's remaining STRIDE activities after 2023 will be $565.2 million. This estimated STRIDE spending is $507.8 million greater than the $57.4 million the 2022 study projected CMD would spend on STRIDE after 2023. As shown in Figure 2.6 below, the new STRIDE expenditure path reflects the additional 17 years of new STRIDE investments that will occur if CMD is permitted to fully replace the population of the two new asset categories starting in STRIDE 3.

Figure 2.6: CMD STRIDE Actual (2014-2022) / Updated Projected Expenditures (2023-2043)



### Updated Non-STRIDE Projections

We used the same approach for CMD's non-STRIDE projections in the 2022 Gas Spending Study as for WGL, wherein the non-STRIDE investments were assumed to be the three-year average plant additions identified in the company's annual reports for 2018 through 2020 minus the three-year average of the company's STRIDE expenditures for this same period. The one difference for CMD is that we have exact numbers for CMD plant additions because CMD's annual report only covers its Maryland jurisdiction. This approach results in an assumed $10.7 million per year in non-STRIDE capital expenditures from 2022 through 2100 in the 2022 Gas Spending Study.

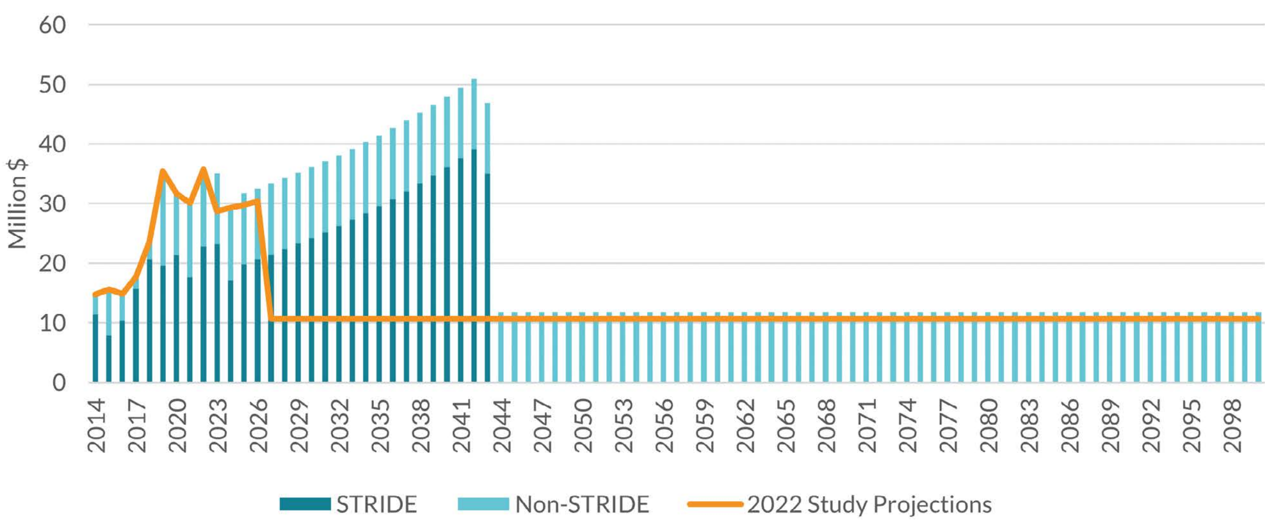
We based the updated non-STRIDE projections for CMD in 2023 on the most recent three years of information in the 2020 through 2022 annual reports. The revised assumptions for CMD also incorporate an adjustment for net CWIP and another adjustment for completed construction not classified (CCNC)[22] to better reflect the three-year average annual expenditures on capital investments.

Table 2.4 presents the derivation of the non-STRIDE capital investment assumptions that are used in the updated CMD capital projections for 2023 to 2100.

Table 2.4: CMD Non-STRIDE Investment Projections

| Line | Description | Source | Projection |
|---|---|---|---|
| 1 | CMD Plant Additions (2020-2022) | Annual Reports | $87.26 million |
| 2 | CMD Net Change in CCNC (2020-2022) | Annual Reports | $10.28 million |
| 3 | CMD Net Change in CWIP (2020-2022) | Annual Reports | -$0.05 million |
| 4 | Total CMD Plant Additions + CWIP | Line 1 + Line 2 | $97.49 million |
| 5 | STRIDE Expenditures (2020-2022) | STRIDE filings | $61.95 million |
| 6 | Non-STRIDE Expenditures (2020-2022) | Line 4 – Line 5 | $35.54 million |
| 7 | Average Non-STRIDE Expenditures | Line 6 / 3 | **$11.85 million** |

Figure 2.7: CMD Capital Investment Actual / Projections




22 The adjustment for CCNC was not included for WGL because this item is not included in its annual reports.

**Combined Updated Capital Projections**

The combined investment projections for CMD, starting in 2023, represent the STRIDE projections through 2043 plus a base level of $11.85 million that we maintain for the entire evaluation period. Figure 2.7 shows the results of our capital investment projections for CMD through 2100.

## 2.4. Combined Investment Projections

The updated projections in STRIDE and non-STRIDE capital expenditures for each of the companies result in substantial increase from our previous study. Below, the updated combined spend for the evaluation time period (2024-2100) and the changes in projected statewide spending are presented for STRIDE investments and cumulative gas infrastructure investments.

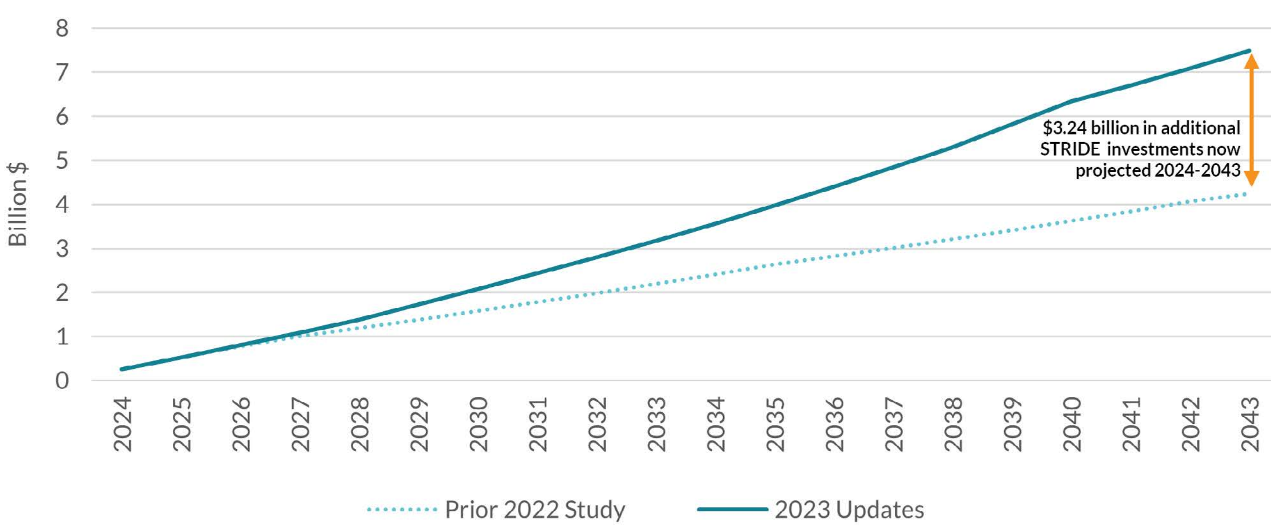
### 2.4.1. Combined STRIDE Investments

Table 2.5 below summarizes the updated projections for all-time STRIDE expenditures for BGE, WGL, and CMD. Then Figure 2.8 shows how the cumulative trajectory of STRIDE spending from 2024 to 2100 changed.

Table 2.5: All-Time STRIDE Investment Projections

| | BGE | WGL | CMD | THREE-COMPANY TOTAL |
|---|---|---|---|---|
| Total spent STRIDE I (actual 2014-2018) | $522.7 | $220.8 | $66.2 | |
| Actual/Anticipated spend STRIDE II (2019-2023) | $803.9 | $377.9 | $104.8 | |
| Estimated STRIDE III (2024-2028) budget | $776.9 | $495.2 | $101.7 | |
| Estimated STRIDE IV (2029-2033) budget | $836.7 | $830.7 | $126.4 | |
| Estimated STRIDE V (2034-2038) budget | $901.4 | $1,074.7 | $154.3 | |
| Estimated STRIDE VI (2039-2043) budget | $379.8 | $1,622.7 | $182.7 | |
| **All-Time Total STRIDE I – VI** | **$4,221.4** | **$4,622.0** | **$736.2** | **$9,579.6** |
| **Future Total = STRIDE III to STRIDE VI** | **$2,894.8** | **$4,023.3** | **$565.1** | **$7,483.2** |

Figure 2.8: Changes in STRIDE Expenditure Projections



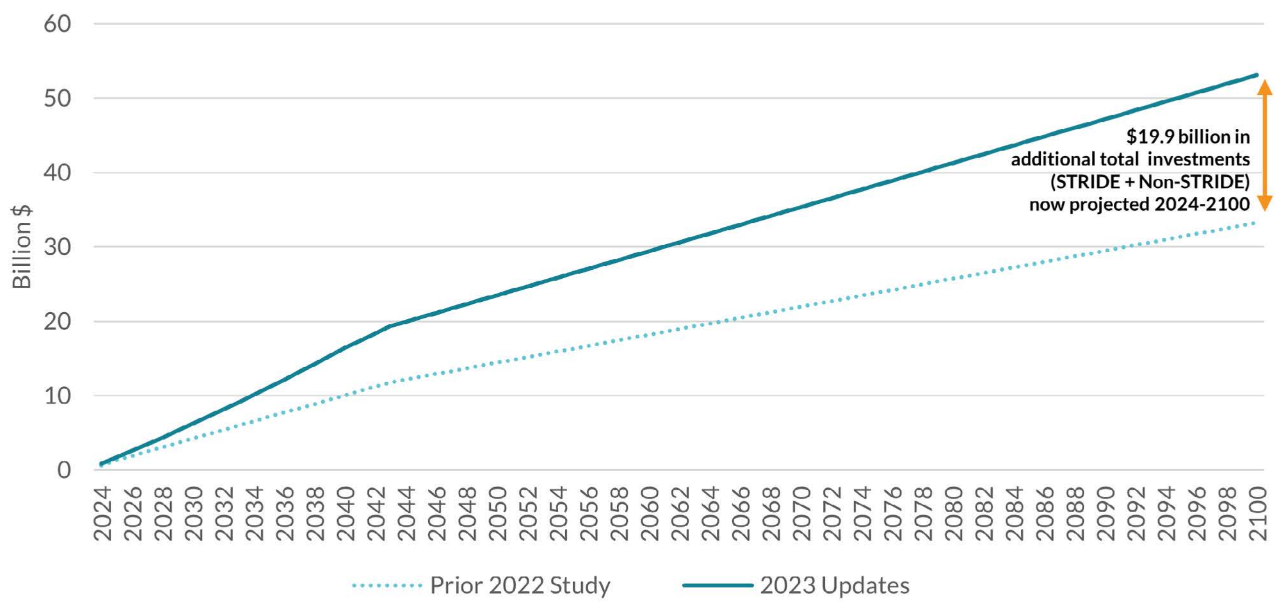
### 2.4.2. Combined All Capital Investments

Table 2.6 summarizes the updated projections for capital expenditures for BGE, WGL, and CMD from 2024 to 2100. Then Figure 2.9 shows how the cumulative trajectory of capital spending from 2024 to 2100 has changed.

Table 2.6: Total Maryland Capital Investment Projections ($ million)

| Utility | STRIDE (2024-2043) | Non-STRIDE (2024-2043) | Non-STRIDE (2044-2100) | Total (2024-2100) | Changes from 2022 Gas Spending Study ($) | (%) |
|---|---|---|---|---|---|---|
| BGE | $2,895 | $9,468 | $26,984 | $39,347 | + $15,612 | ↑ 66% |
| WGL | $4,023 | $2,140 | $6,099 | $12,262 | + $3,648 | ↑ 42% |
| CMD | $565 | $237 | $675 | $1,477 | + $596 | ↑ 68% |
| Total | $7,483 | $11,845 | $33,758 | $53,086 | + $19,856 | ↑ 60% |

Figure 2.9: Changes in Total Capital Expenditure Projections



SECTION THREE

# UPDATED REVENUE REQUIREMENT AND BILL IMPACT FORECASTS

This section provides updated revenue requirement and customer bill forecasts that incorporate the revised capital projections for each company, as well as other information from each company's 2023 base rate filing.

## 3.1. Methodology and Revised Assumptions

For the 2022 Gas Spending Study, we developed a revenue requirement model to understand the impact of the capital investment projections on customer rates. The model used capital projections and other assumptions to estimate the capital-related components of the annual revenue requirement for the forecast period. The revenue requirement for the capital investment components included:

- Return on rate base
- Depreciation
- Property taxes
- Gross-up for income taxes, bad debt, franchise taxes, and PSC assessment

We used a variation of this model to forecast the revenue requirements for the updated capital projections developed in Section 2. There is one notable change in the 2023 model. The approach to estimated plant retirements was revised to improve the steps for removal of a retired plant from both the plant in service and accumulated depreciation balances. The result of this change is evident in the more gradual decline in revenue requirements over time without the drops in revenue requirements seen in the 2022 results.

To calculate the annual revenue requirement in future years, based on publicly available information, we developed certain assumptions on depreciation, retirements, cost of capital, property taxes, and the gross-conversion factor. The updated 2023 projections rely on the most recent information available for these same assumptions presented in the company's 2023 base rate filings. Table 3.1 presents the 2023 versions of the assumptions used to calculate the capital-related revenue requirements for each company.

As stated in the 2022 Gas Spending Study, we want to emphasize again the updated projections and revenue requirement analysis presented in this report are solely intended to show the general impact that current capital investment trends will have on future revenue requirements and therefore utility customer rates. We do not attempt to identify the precise future revenue requirements that will be developed through the regulatory process.

Table 3.1: CAPEX Revenue Requirement Assumptions

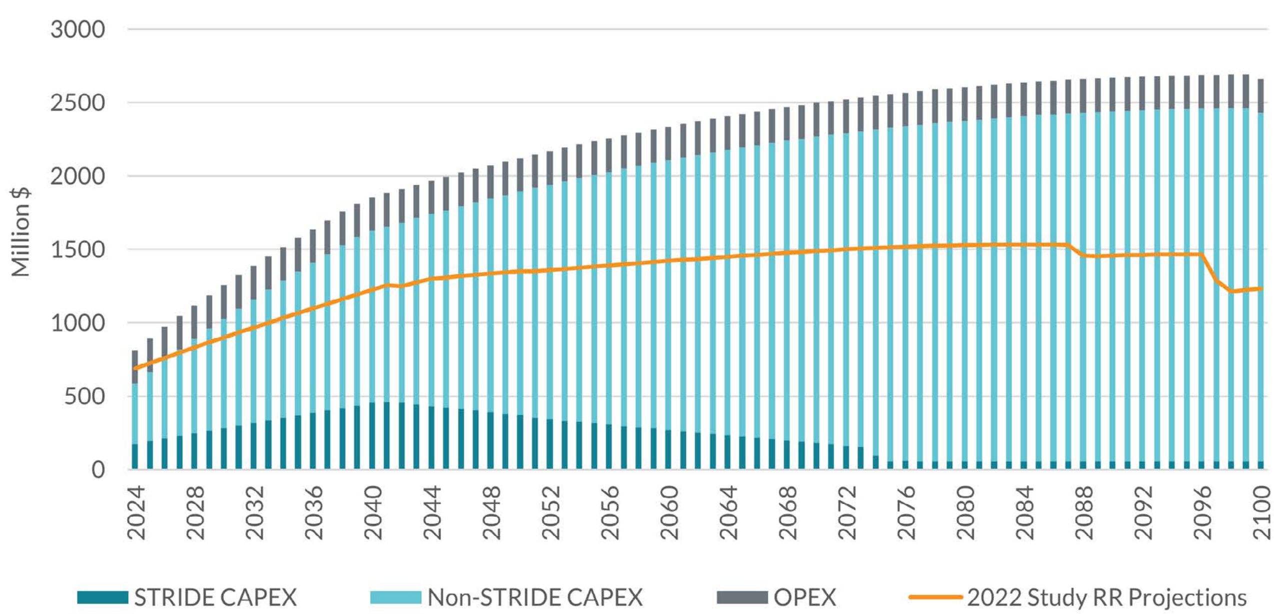
| | BGE | WGL | CMD |
|---|---|---|---|
| **Depreciation Rates** | 2.23% (mains)<br>3.52% (services)<br>2.92% (non-STRIDE) | 1.65% (distribution)<br>1.91% (transmission)<br>1.88% (non-STRIDE) | 2.00% (STRIDE)<br>2.31% (non-STRIDE) |
| **Retirement Rate (% of plant in service)** | -0.91% | -0.91% | -0.91% |
| **Weighted Average Cost of Capital** | 2024: 7.39%<br>2025: 7.45%<br>2026+: 7.56% | 7.73% | 7.20% |
| **Gross-Conversion Factor** | 70.56% | 70.36% | 70.36% |
| **Property Tax Rate** | 1.37% | 1.12% | 1.40% |
| **Tax Treatment of STRIDE Plant Additions** | Tax Repairs: 80%<br>MACRS: 20% | Tax Repairs: 80%<br>MACRS: 20% | Tax Repairs: 80%<br>MACRS: 20% |

## 3.2. Annual Revenue Requirement Projections

### 3.2.1. BGE

BGE's updated revenue requirement projections for 2024 through 2100 (bars) are presented in Figure 3.1, illustrating that BGE's updated capital plans presented in its MRP 2 have substantially increased its expected future revenue requirements. BGE's average revenue requirement from 2024 to 2100 ($2.19 billion) in the updated projections is 66 percent greater than the average ($1.32 billion) for this same period in the 2022 study. This increase is driven by the significant jump in non-STRIDE spending that had not been captured in the previous study.

Figure 3.1: BGE Revenue Requirement Projections (2024-2100)



### 3.2.2. WGL

WGL's updated revenue requirement projections for 2024 through 2100 (bars) are presented in Figure 3.2, showing that WGL's STRIDE 3 plans have increased its expected future revenue requirements by 30 percent compared to the 2022 projections. The greatest change in the projection for WGL is in the 2040s, when the full impact of the completed STRIDE investments is reflected in the revenue requirement. This results in a 60 percent increase in the amount to be collected from customers compared to what had previously been projected for this same decade.

The increases in revenue requirements related to the STRIDE investments is due to a combination of the higher unit costs and updated information on the company's long-term STRIDE plans, as well as our revised approach to projecting WGL's future STRIDE costs that better captures the full replacement work the company continues to state it will complete over this period.

### 3.2.3. CMD

CMD's updated revenue requirement projections for 2024 through 2100 (bars) are presented in Figure 3.3. The percentage increases in revenue requirements projected for CMD are the highest among the three utilities, as the average revenue requirement for CMD from 2024 to 2100 ($102.57 billion) in the updated 2023 projections is 70 percent greater than the average ($60 million) for this same period in the 2022 study. These results are not surprising, considering that in the previous study, CMD's STRIDE investments were anticipated to end in 2026. CMD's proposal to add two new classes of main to be replaced through STRIDE in the company's STRIDE 3 plan has added an additional 17 years of investments that were not previously considered.

Updates to long-term STRIDE plans increase WGL's expected future revenue requirements by 30 percent and CMD's by 70 percent compared to the 2022 projections.

Figure 3.2: WGL Revenue Requirement Projections (2024-2100)

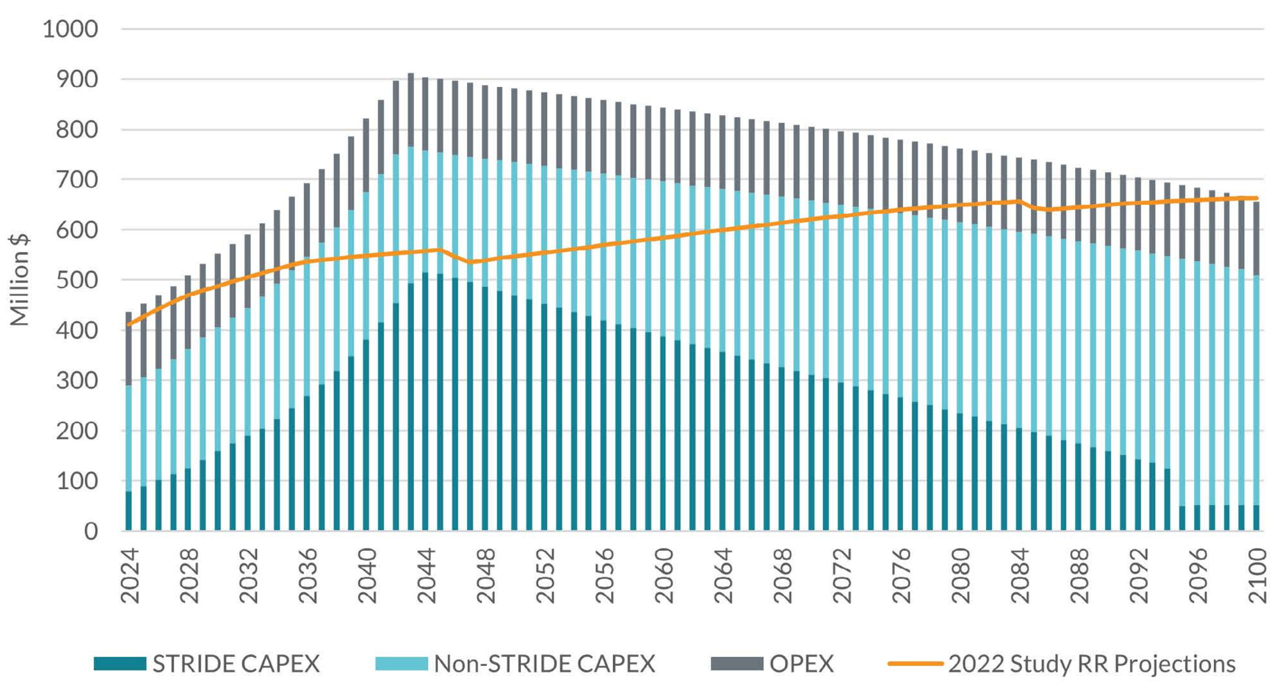
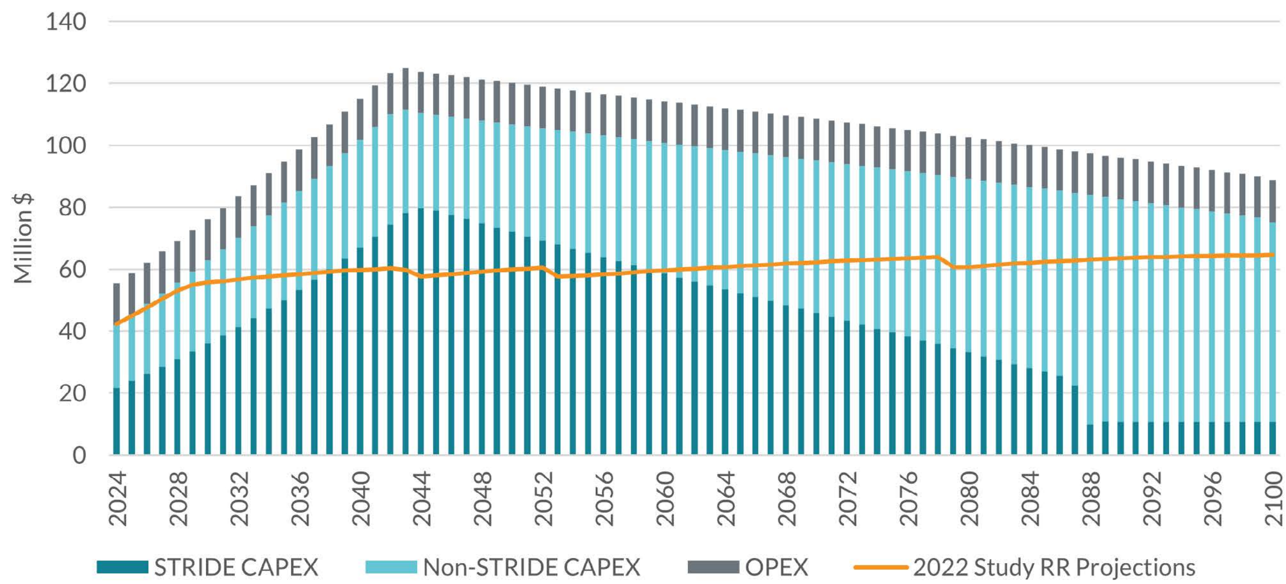


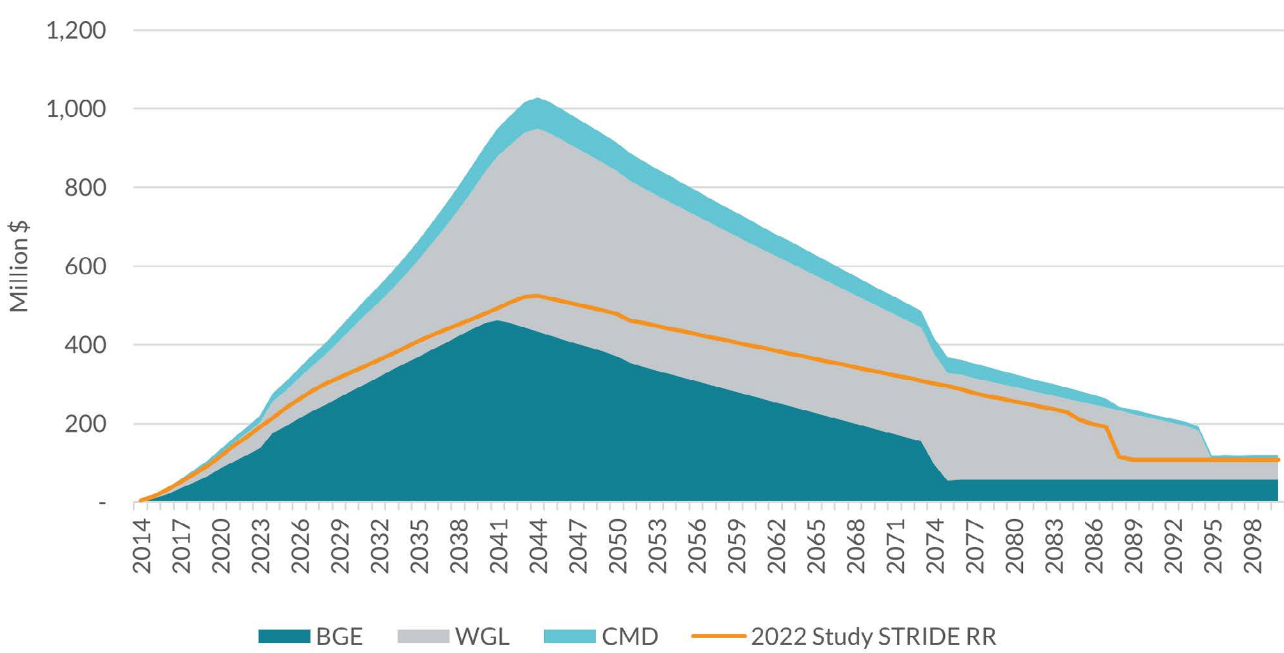
Figure 3.3: CMD Revenue Requirement Projections (2024-2100)




### 3.2.4. Combined Revenue Requirements for Maryland's Three Largest Gas Utilities

To provide a picture of the statewide level of planned utility spending, the 2022 Gas Spending Study provided figures that aggregate the projected revenue requirements of the three companies. We update two of these figures below.

Figure 3.4: STRIDE Revenue Requirements



**Total Customer CAPEX Payments**

Overall, the projected capital-related revenue requirements that customers of BGE, WGL, and CMD would be expected to pay from 2024 through 2100 has increased by 60 percent from $125 billion in the 2022 study to $206 billion in the updated 2023 projection. Much of these payments will be for the $20 billion in investments that are projected to be made in the first 22-year period from 2024 to 2045—meaning that 38 percent of spending is projected to take place in 28 percent of the forecast period. These $20 billion in investments would be made over the same period the State has set a goal to reach net-zero emissions.

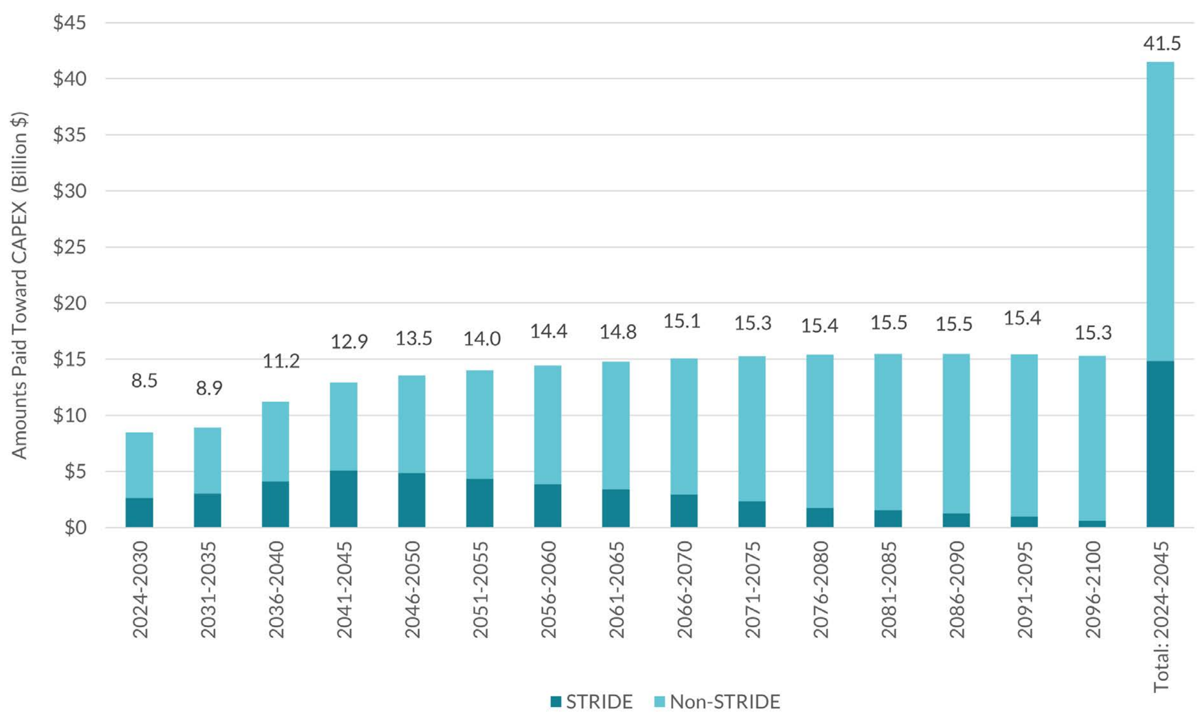
Figure 3.5 below illustrates that at this revised pace of investment, Maryland gas customers will be asked to spend $41.5 billion from 2024 through 2045 to compensate the gas companies for their gas infrastructure spending: a $14.3 billion increase over the $27.2 billion in revenue requirements that customers were expected to pay for CAPEX from 2024 to 2045 in the 2022 study. Current capital investment proposals from the three gas companies show an additional $14 billion in payments from gas customers over a period when State policy suggests that investment should focus on zero-emission technologies. Section 4 compares the spending projects from this investment path to alternatives.

The projected capital-related revenue requirements that customers would be expected to pay increases by 60 percent from $125 billion in the 2022 study to $206 billion.

## 3.3. Rate Impacts

The revenue requirements forecasted in the previous subsection were used to estimate what the future winter bill would be for the typical residential customer at BGE, WGL, and CMD. The projected trajectory of residential bills from 2024 to 2100 and

Figure 3.5: Projected Gas Customer Payments Toward CAPEX (Billion $), 2022-2100



the previous historical bills from 2014 to 2023 are provided for each company below.

*Importantly, these bill impacts assume that the gas companies do not experience a decline in gas consumption. With declines in their numbers of customers who decrease gas consumption, rates must increase to meet the utilities' revenue requirements. If gas consumption drops substantially, rates would increase substantially.*

### 3.3.1. BGE

The updated estimated winter bill for a BGE customer using 160 therms a month from 2024 to 2100 is presented in Figure 3.6. Our projections show that if BGE continues investing in capital at the proposed levels, a customer's typical winter bill will grow from an average of $220 in 2021-2023 to $450 by 2035 (a 104 percent increase) and $580 by 2050 (a 63 percent increase). These estimates assume commodity prices stay around the most recent five-year average. If gas prices go back up to the levels experienced in 2021-2022, then the typical residential customer's winter bill would increase by another $56 per month.

### 3.3.2. WGL

The updated estimated winter bill for a WGL customer using 160 therms a month from 2024 to 2100 is presented in Figure 3.7. Our projections show that if WGL continues investing in capital at the proposed levels, a customer's typical winter bill will grow from an average of $187 in 2021-2023 to $268 by 2035 (a 43 percent increase) and $333 by 2050 (a 78 percent increase). These estimates assume commodity prices stay around the most recent five-year average. If gas prices go back up to the levels experienced in 2021-2022, then the typical residential customer's winter bill would increase by another $68 per month.

Figure 3.6: BGE Typical Winter Bill, 2014-2100

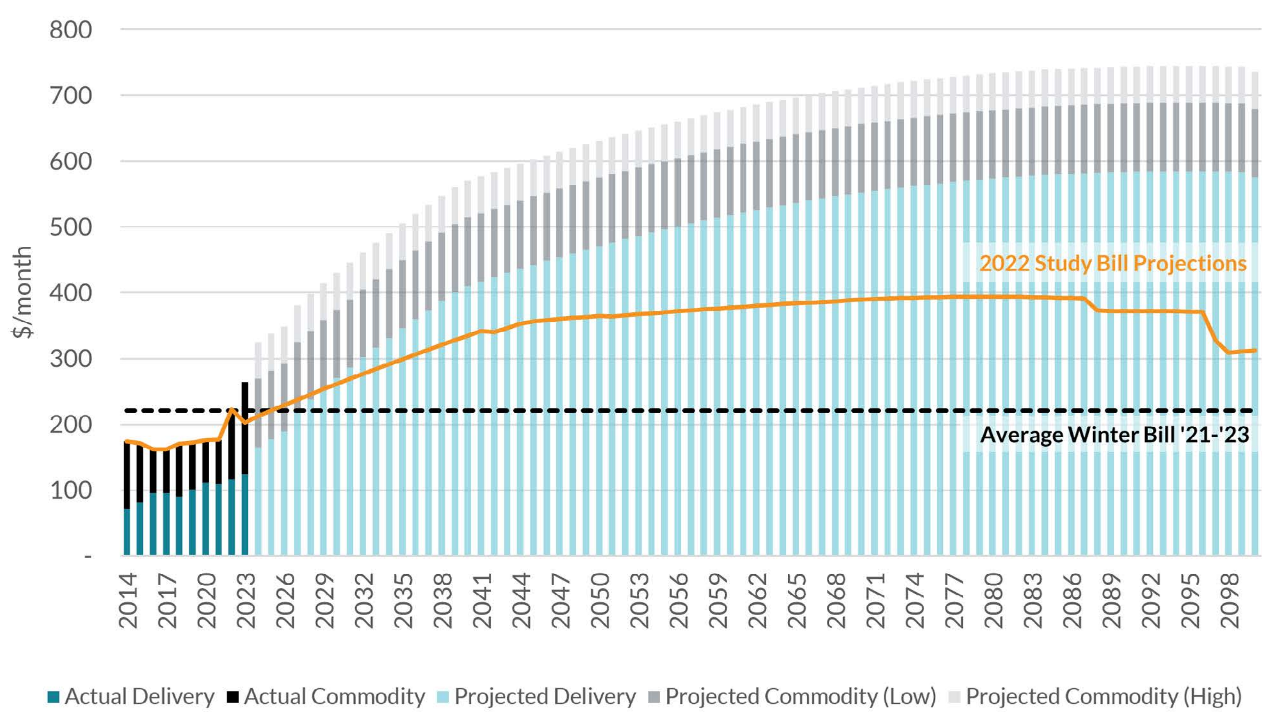
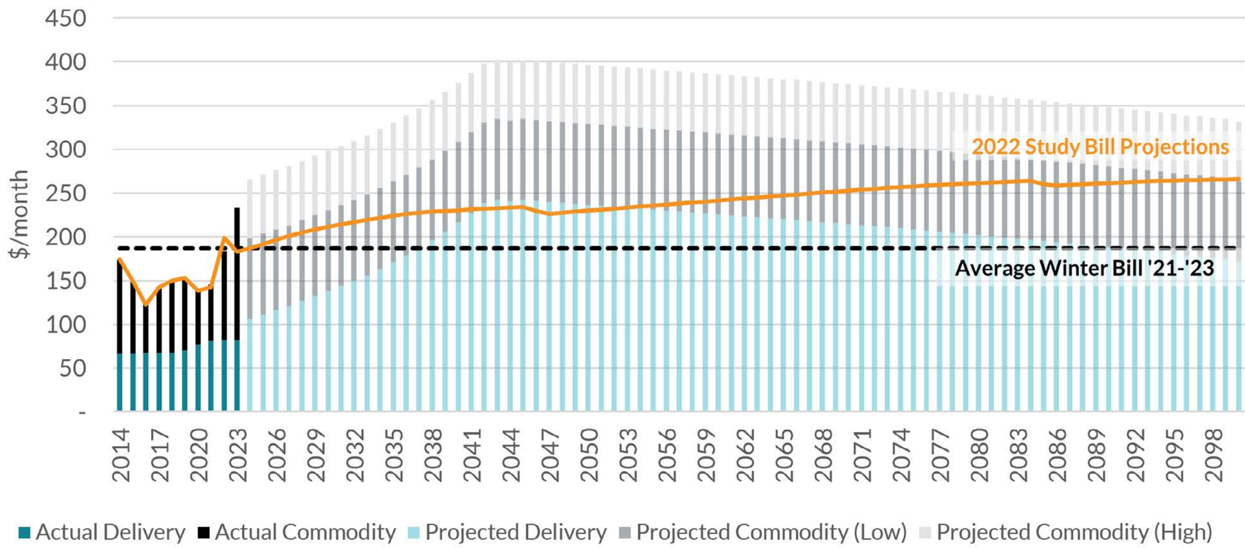


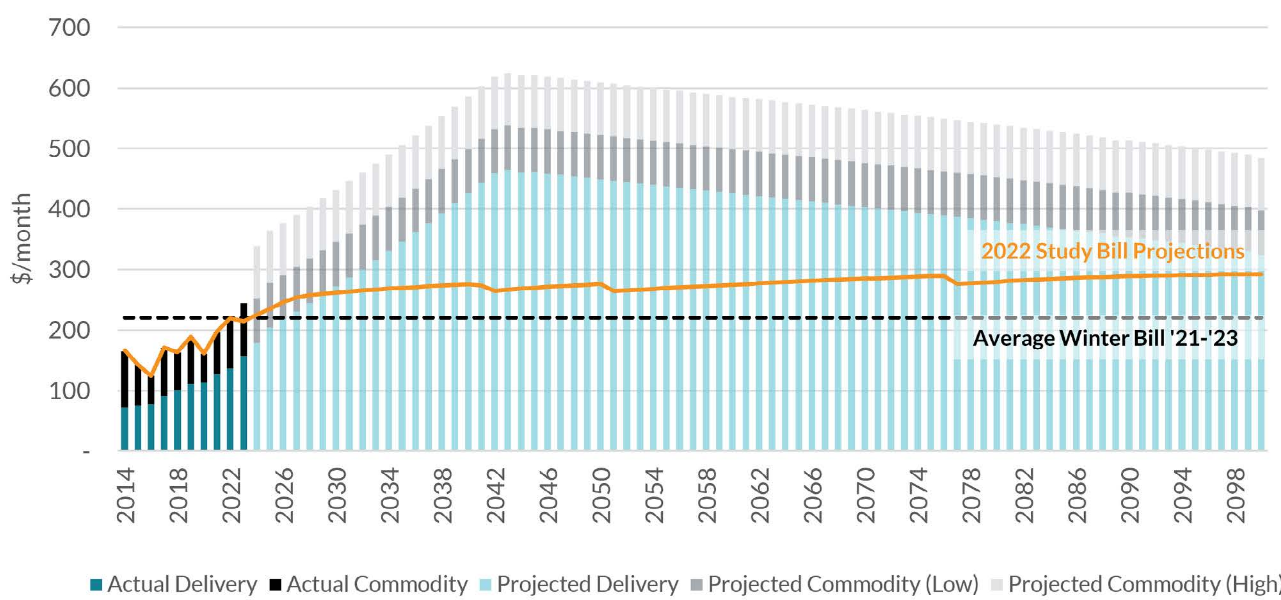
Figure 3.7: WGL Typical Winter Bill, 2014-2100




### 3.3.3. CMD

The updated estimated winter bill for a CMD customer using 160 therms a month from 2024 to 2100 is presented in Figure 3.8. Our projections show that if CMD continues investing in capital at the proposed levels, a customer's typical winter bill will grow from an average of $221 in 2021-2023 to $419 by 2035 (a 90 percent increase) and $523 by 2050 (a 137 percent increase). These estimates assume commodity prices stay around the most recent five-year average. If gas prices go back up to the levels experienced in 2021-2022, then the typical residential customer's winter bill would increase by another $87 per month.

Figure 3.8: CMD Typical Winter Bill, 2014-2100



SECTION FOUR

# ALTERNATIVE PATHWAYS

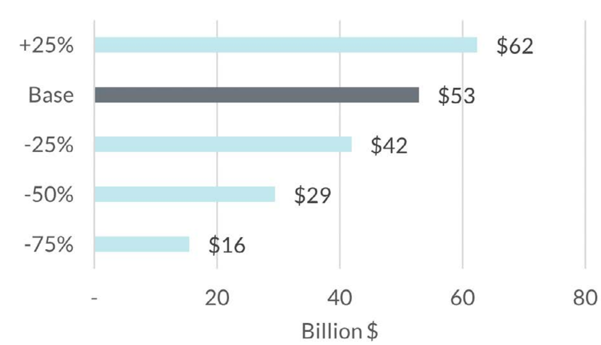
The forecasting approach relied on for this analysis is what forecasters might call a naïve method, where the last observed or known values are used to predict future outcomes. Put another way, the capital expenditure pathways presented are the status quo expenditure paths the companies are presently shown to be on. The trajectory of this status quo path is for BGE, WGL, and CMD to make $53 billion in gas infrastructure investments in Maryland from 2024 through 2100. Inclusive of the utilities' pre-tax return on those investments, from just 2024 to 2045, Maryland gas customers will be asked to pay $41.2 billion to compensate the gas companies for this gas infrastructure spending.

A relevant issue to consider when evaluating the reasonableness of $53 billion in investments in gas infrastructure is that they would take place over a period when Maryland has goals to substantially reduce its greenhouse gas (GHG) emissions. In 2022, the General Assembly passed the Climate Solutions Now Act (CSNA), increasing the State's GHG emissions reduction goal to a 60 percent reduction by 2031 and requiring net-zero statewide GHG emissions by 2045.[23] The CSNA also declared the "intent of the General Assembly that the State move toward broader electrification of both existing buildings and new construction." These State policy goals suggest that the State's limited financial and construction capacity resources might be better used for electrification or other solutions that support the State's net-zero goals.

These policy goals represent a challenge to the long-term viability of the natural gas industry, where there is a spectrum of possible futures. Based on the State's energy policy, it is fair to assume that the future of gas will not remain at the status quo, and gas consumption will decline.[24] This means that current investment approaches need to adapt and consider how reduced gas demand will affect future investment needs.

Figure 4.1 shows how the cumulative spend across the companies would be different if the entire projected spend for each company from 2024 through 2100 was increased or decreased proportionally.

Figure 4.1: Alternative Capital Expenditure Pathways, Cumulative Expenditures 2024-2100



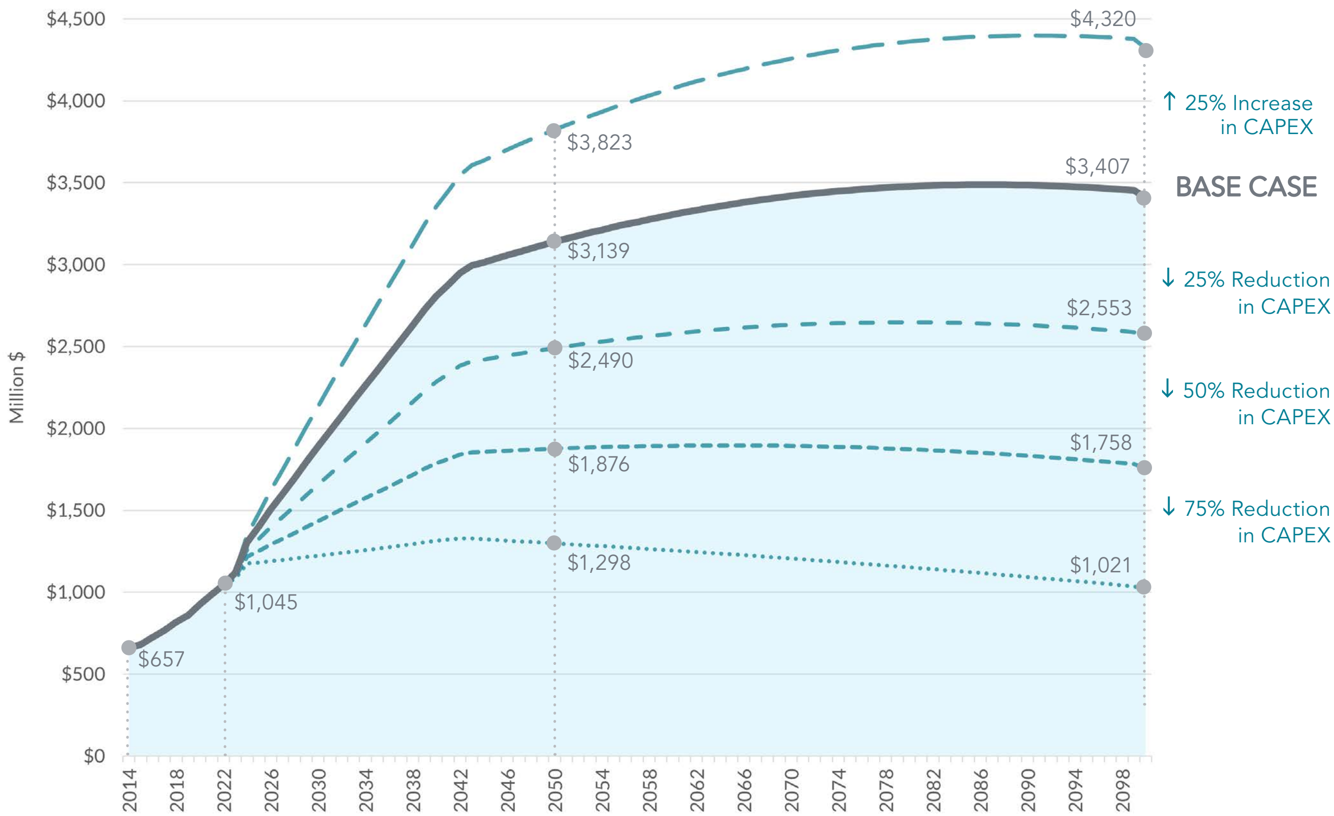

23 S.B. 528, 2022 Reg. Sess., at 29 (Md. 2022), https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0528?ys=2022RS.

24 OPC's November 2022 report, Climate Policy for Maryland's Gas Utilities: Financial Implications, further suggests that advances in electric appliance technologies will also be a factor contributing to declining gas consumption.

Figure 4.2 shows the changes in the future revenue requirements from moving to one of the alternative investment pathways, demonstrating that reductions in capital investments lower the revenue requirement that needs to be collected from gas customers.[25]

Reductions in capital investments lower the revenue requirement that needs to be collected from gas customers.

Figure 4.2: Alternative Combined Revenue Requirement Pathways




25 In OPC's October 24, 2023, filing in CN 9707, slide 12 showing "Potential Avoided Customer Costs From Reduced Gas Utility Spending" has slightly different figures because it reflects avoided costs related to capital expenditures only, without accounting for operational costs.

OPC
OFFICE OF PEOPLE'S COUNSEL
State of Maryland

OPC@maryland.gov

www.opc.maryland.gov

6 St Paul St #2102, Baltimore, MD 21202

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 19

QUESTION NO. 19-2

**Q.** Referencing Exhibit WG(I) at page 8, lines 13 through 17 and the statement that "[t]he Company relies on qualified contractor crews to perform construction and replacement services and has multi-year contract, with these contractors, through competitive bidding and negotiated unit pricing to obtain the most competitive unit prices in the market."

a. What percentage of WGL construction and replacement services were performed by external contractors for the twelve-months ended March 31, 2024?

b. Has the Company performed any analyses of the cost of having WG employee crews perform this work relative to the cost associated with outside contractors?

c. How does the Company ensure availability of outside contractors to address critical replacement or repair activity through the contracting process?

**WASHINGTON GAS'S RESPONSE** 12/03/2024

**A.**

a. Approximately 91% of service replacements in the District of Columbia were replaced by external contractor crews for the twelve-months ended March 31, 2024.

b. Washington Gas, at various intervals, has evaluated the utilization of internal versus external crew resources. The decision to proceed with external crew resources has granted the Company the maximum flexibility to increase or decrease resources with the fluctuation of the accelerated pipeline replacement work.

c. The Company will work with existing qualified contractors to verify their ability to add resources based on the Company's resource plan including system betterment, accelerated replacement, and new business. If the current contractors cannot provide the resources needed, the Company's Supply Chain Group will work in conjunction with the Construction Group to send out a request for pricing (RFP) to other natural gas contractors. The Company will then select external contractor(s) based on various considerations, such as safety, historical performance, and qualifications in order to meet the resources needed. Once a contractor is brought onto the Company's system, they are trained on Washington Gas specific processes, procedures, and Operation Qualifications by Washington Gas personnel.

SPONSOR: Frederick J. Morrow
Director, Construction

| 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 OPT76865 | 2 | Program 2 | 6. Closed | 622 | 606 | 635 | 597 | 20 | 19 | 1,225,564 | $1,338,640 | 109% |
| 146223 | DC APRP 1 L ST NW WARD 2 D003NW3 | 2 | Program 1 | 6. Closed | 0 | 0 | 0 | 0 | 8 | 5 | 267,676 | $250,399 | 94% |
| 169566 | DC APRP 1 17TH ST NW WARD 2 E004NW4 | 2 | Program 1 | 6. Closed | 0 | 0 | 0 | 0 | 49 | 39 | 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 | 962,222 | $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% |
| 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 | 10,866,603 | $9,543,896 | 88% |
| 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 | $2,597,369 | 163% |
| 292561 | DC APRP 2 F.O. Mass Ave NW L008NW Ward 3 | 3 | Program 2 | 6. Closed | 2,276 | 2,299 | 1,775 | 932 | 15 | 15 | 3,634,329 | $3,788,107 | 104% |
| 294323 | DC F.O. APRP 2 Massachusetts Ave NW Ward 3 I006NW | 3 | Program 2 | 6. Closed | 1,691 | 1,408 | 1,740 | 1,930 | 9 | 5 | 6,606,798 | $4,227,197 | 64% |
| 294341 | DC APRP 10 AOP PA Ave NW Streetscape (17th22nd) FAP2017043 Ward 2 | 2 | Program 10 | 6. Closed | 5,502 | 1,783 | 2,810 | 1,455 | 8 | 5 | 4,127,430 | $3,170,995 | 77% |
| 295350 | DC F.O. APRP 2 49th ST NW M009NW WARD 3 OPT 77626 | 3 | Program 2 | 6. Closed | 408 | 432 | 420 | 438 | 3 | 3 | 766,546 | $756,760 | 99% |
| 295352 | DC F.O. APRP 4 W PL NW I005NW WARD 3 OPT 53273 | 3 | Program 4 | 6. Closed | 1,304 | 1,305 | 1,090 | 1,076 | 66 | 67 | 2,195,740 | $2,372,099 | 108% |
| 295824 | DC F.O. APRP 4 Massachusetts Ave NW Ward 3 I006NW | 3 | Program 4 | 6. Closed | 2,435 | 2,438 | 570 | 566 | 10 | 10 | 991,696 | $360,467 | 36% |
| 299376 | DC APRP 2 Sedgwick ST NW M008NW Ward 3 OPT 77625 | 3 | Program 2 | 6. Closed | 804 | 801 | 690 | 690 | 19 | 19 | 1,242,786 | $980,557 | 79% |
| 299388 | DC APRP 2 34th St NWI006NW Ward 3 OPT111567 | 3 | Program 2 | 6. Closed | 355 | 458 | 375 | 433 | 5 | 5 | 608,978 | $681,532 | 112% |
| 299392 | DC APRP 4 Lamont St NWC006NW1 Ward 1 OPT 55301 | 1 | Program 4 | 6. Closed | 692 | 666 | 615 | 627 | 32 | 34 | 1,058,889 | $1,155,135 | 109% |
| 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 362857 | 7 | Program 4 | 6. Closed | 482 | 465 | 595 | 633 | 16 | 15 | 1,068,398 | $1,683,129 | 158% |
| 300159 | DC APRP 3 Division Ave NE L001NE Ward 7 | 7 | Program 3 | 6. Closed | 0 | 0 | 0 | 0 | 16 | 16 | 565,941 | $373,538 | 66% |
| 300162 | DC APRP 3 Kennedy St NE B010NE Ward 5 | 5 | Program 3 | 6. Closed | 0 | 0 | 0 | 0 | 17 | 17 | 716,165 | $564,243 | 79% |
| 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% |
| 300773 | DC APRP 1 L St NE A003NE Ward 6 | 6 | Program 1 | 6. Closed | 0 | 0 | 0 | 0 | 14 | 13 | 608,135 | $462,955 | 76% |
| 301131 | DC APRP 1 UNDERWOOD PL NE A012NE Ward 4 | 4 | Program 1 | 6. Closed | 0 | 0 | 0 | 0 | 8 | 4 | 410,185 | $133,461 | 33% |
| 301132 | 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% |
| 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% |
| 301163 | DC APRP 1 MARNE PL NE J003NE Ward 7 | 7 | Program 1 | 6. Closed | 0 | 0 | 0 | 0 | 15 | 14 | 447,576 | $222,354 | 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% |
| 301190 | DC APRP 3 A ST SE L001SE Ward 7 | 7 | Program 3 | 6. Closed | 0 | 0 | 0 | 0 | 12 | 10 | 433,725 | $375,105 | 86% |
| 301193 | DC APRP 3 3RD ST SE A001SE Ward 6 | 6 | Program 3 | 6. Closed | 0 | 0 | 0 | 0 | 9 | 9 | 245,553 | $399,363 | 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% |
| 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% |
| 303116 | DC APRP 2 Prospect St NW I003NW4 Ward 2 OPT 70851 | 2 | Program 2 | 6. Closed | 271 | 271 | 0 | 0 | 0 | 0 | 154,049 | $70,277 | 46% |
| 303646 | DC F.O. APRP 2 Luzon Ave NW D012NW Ward 4 | 4 | Program 2 | 6. Closed | 2,812 | 2,907 | 2,290 | 2,521 | 37 | 38 | 2,847,854 | $2,606,913 | 92% |
| 303974 | DC APRP 1 CHANNING ST NE B005NE1 Ward 5 | 5 | Program 1 | 6. Closed | 0 | 0 | 0 | 0 | 10 | 1 | 377,163 | $9,791 | 3% |
| 9202301 | Scattered | Various | Program 1 | 6. Closed | 0 | 0 | 0 | 0 | 190 | 316 | 4,325,000 | $7,570,216 | 175% |
| 9202303 | Scattered | Various | Program 3 | 6. Closed | 0 | 0 | 0 | 0 | 33 | 106 | 580,000 | $2,389,547 | 412% |
| 9202305 | Scattered | Various | Program 5 | 6. Closed | 0 | 0 | 0 | 0 | 88 | 220 | 1,670,400 | $4,302,114 | 258% |
| | | | | | | | | | | | $ 65,450,793.00 | $ 65,845,355.56 | **$ 394,562.56** |

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 16

QUESTION NO. 16-1

**Q.** With respect to witness Steffes' supplemental direct testimony, Exh. WG (2A) at 6:13, please identify with specificity the "District's climate policies" to which you refer.

**WASHINGTON GAS'S RESPONSE** 11/27/2024

**A.** At this time, the Company is unaware of any District climate policy that has an impact on the Company's planned capital investments, expected life assets, or depreciation rates.

SPONSOR: James D. Steffes
Senior VP, Regulatory Policy

**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** |

**DIRECT TESTIMONY**
**AND SUPPORTING EXHIBITS OF**
**AARON L. ROTHSCHILD**

**Exhibit OPC (D)**

**On Behalf of the**
**Office of the People's Counsel**
**for the District of Columbia**

**JANUARY 24, 2025**

## TABLE OF CONTENTS

# EXHIBIT LIST

| | |
|---|---|
| Exhibit OPC (D)-1 | Listing of Prior Testimony of Aaron L. Rothschild |
| Exhibit OPC (D)-2 | Resumé of Aaron L. Rothschild |
| Exhibit OPC (D)-3 | Overall Rothschild Recommended Cost of Capital |
| Exhibit OPC (D)-4 | Rothschild Cost of Equity Summary |
| Exhibit OPC (D)-5 | Constant Growth Discounted Cash Flow (DCF) - Indicated Cost of Equity with Calculations and Analysis |
| Exhibit OPC (D)-6 | Capital Asset Pricing Model (CAPM) – Indicated Cost of Equity Calculations and Analysis |
| Exhibit OPC (D)-7 | Rothschild Gas Proxy Group and Financial Data (including Capital Structure) |
| Exhibit OPC (D)-8 | CAPM-Implied Cost of Equity for Rothschild Gas Proxy Group over time since onset of COVID Pandemic |
| Exhibit OPC (D)-9 | Market-to-Book Ratios and the Market-Based COE |
| Exhibit OPC (D)-10 | Future-oriented “B X R” Method |
| Exhibit OPC (D)-11 | Non-Constant Growth Form of the DCF Model Overview |
| Exhibit OPC (D)-12 | Capital Asset Pricing Model Overview |
| Exhibit OPC (D)-13 | Detailed Analysis of Current Capital Market Conditions |
| Exhibit OPC (D)-14 | WGL Response to OPC Data Request No. 7-12 |
| Exhibit OPC (D)-15 | WGL Response to OPC Data Request No. 7-9 |
| Exhibit OPC (D)-16 | WGL Response to OPC Data Request No. 7-11 |

# I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.**

**A.** My name is Aaron L. Rothschild. My title is President, and my business address is 15 Lake Road, Ridgefield, CT.

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

**A.** I am President of Rothschild Financial Consulting ("RFC").

**Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?**

**A.** I am testifying on behalf of the Office of the People's Counsel for the District of Columbia ("OPC" or "Office") in this proceeding pertaining to Washington Gas Light Company's ("WGL", "Washington Gas", or "Company") Application to the Public Service Commission of the District of Columbia ("Commission" or "DC PSC") for authority to increase existing rates and charges for gas service.[1]

**Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.**

**A.** I have a B.A. degree in mathematics from Clark University (1994) and an M.B.A. from Vanderbilt University (1996).

---

[1] *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* ("*Formal Case No. 1180*"), Washington Gas's Application, Direct Testimony and Supporting Exhibits, filed August 5, 2024 ("WGL Application"). As a general matter, for the remainder of my testimony, any references to WGL's "Application" include WGL's Supplemental Direct Testimony and Supporting Exhibits.

**Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.**

**A.** I performed financial analysis in the telecom industry in the United States and Asia Pacific from 1996 to 2001, investment banking consulting in New York, complex systems science research regarding the power sector at an independent research institute, and I have prepared rate of return testimonies since 2002. See Exhibit OPC (D)-2 for my resume.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE DC PSC, OR OTHER STATE COMMISSIONS? IF SO, WHICH COMMISSIONS?**

**A.** Yes. I submitted pre-filed surrebuttal testimony on behalf of OPC in WGL's last rate case before the DC PSC, Formal Case No. 1169. My expert witness experience also includes testifying in about 100 cost of capital proceedings before the following state commissions: California; Colorado; Connecticut; Delaware; Florida; Maryland; New Hampshire; New Jersey; North Dakota; Pennsylvania; South Carolina; Tennessee; and Vermont. See Exhibit OPC (D)-1 for the list of dockets for each of my testimonies.

**Q. WERE YOUR TESTIMONY AND ACCOMPANYING EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?**

**A.** Yes.

**Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF EACH OF YOUR EXHIBITS, INCLUDING THE SOURCE MATERIALS.**

**A.** My list of prior testimonies is provided in Exhibit OPC (D)-1 and my resumé is provided in Exhibit OPC (D)-2. I also provide six exhibits containing my analyses and calculations.

Specifically, in Exhibit OPC (D)-3 (Overall Rothschild Recommended Cost of Capital), I provide the results of my calculation of WGL's overall cost of capital. In Exhibit OPC (D)-4 (Rothschild Cost of Equity Summary), I provide a summary of the results of my application of the cost of common equity ("COE")[2] models applied to a proxy group consisting of the same six companies as used in WGL Witness D'Ascendis' Utility Proxy Group ("Rothschild Gas Proxy Group"). In Exhibit OPC (D)-5 (Constant Growth Discounted Cash Flow (DCF) - Indicated Cost of Equity with Calculations and Analysis), I provide the results of my Discounted Cash Flow ("DFC") analysis to determine the indicated cost of equity for WGL. In Exhibit OPC (D)-6 (Capital Asset Pricing Model (CAPM) – Indicated Cost of Equity Calculations and Analysis), I provide the results of my Capital Asset Pricing Model ("CAPM") analysis and an overview of my calculations to determine the indicated cost of equity for WGL. In Exhibit OPC (D)-7 (Rothschild Gas Proxy Group and Financial Data (including Capital Structure)), I provide the financial information such as market prices of the stock, book value, and capital structure of the Rothschild Gas Proxy Group). In Exhibit OPC (D)-8 (CAPM-Implied Cost of Equity for the Rothschild Gas Proxy Group over time since onset of COVID Pandemic), I provide the CAPM-Implied Cost of Equity for the Rothschild Gas Proxy Group over time since the COVID pandemic. As more specifically referenced in the exhibits, I used various investment sources such as The Value Line Investment Survey ("Value Line"), End of Day

[2] COE is the market-based return investors expect to earn on the market value of any given stock (i.e., the market price of equity).

Data; Charles Schwab and JP Morgan investment reports, Federal Reserve Bank of Atlanta; and the U.S. Department of the Treasury.

In addition, I provide five exhibits containing detailed explanations of certain technical topics addressed in my testimony, which also include citations to sources used for those exhibits. Specifically, in Exhibit OPC (D)-9 (Market-to-Book Ratios and Market-Based COE), I provide an explanation of the relevance of market-to-book ratios (i.e., a metric that compares a company's market value to its book value) and the relevance of such ratios to a utility's marked-based COE. In Exhibit OPC (D)-10 (Future-Oriented "B x R" Method), I discuss the importance of using a reasonable growth rate component in calculating a DCF-indicated cost of equity. In Exhibit OPC (D)-11 (Rothschild Non-Constant Growth Form DCF), I provide an overview of the Non-Constant Growth Form of my DCF Model. In Exhibit OPC (D)-12 (Capital Asset Pricing Model Overview), I provide a technical description and rationale for my methodology for computing the CAPM. In Exhibit OPC (D)-13 (Detailed Analysis of Current Capital Market Conditions), I provide a detailed analysis of current capital market data to supplement the summary of capital market conditions discussed in my testimony.

Finally, in Exhibits OPC (D)-14 through OPC (D)-16, I attach WGL's Responses to certain Data Requests referenced in my Direct Testimony.

## II. SCOPE AND SUMMARY OF TESTIMONY

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

**A.** The purpose of my testimony in this proceeding is to present my findings and recommendations to the Commission as to the allowed rate of return ("ROR") for WGL that should be applied for ratemaking purposes, including an appropriate authorized return on equity ("ROE"), authorized cost of debt, and authorized capital structure.

**Q. PLEASE DESCRIBE THE STRUCTURE OF YOUR TESTIMONY.**

**A.** *First*, I provide a summary of WGL's requested rate of return and my primary findings and recommendations. *Second*, I provide an overview of cost of capital concepts, including how a utility's cost of equity and capital structure is determined and discuss certain precedent relevant to the calculation of WGL's rate of return. *Third*, I critique the Company's rate of return analysis and testimony. *Fourth*, I summarize current capital market conditions. *Fifth*, I provide my cost of equity calculations, including the selection of a risk-comparable proxy group and calculation of WGL's cost of equity using the DCF and CAPM models. *Sixth*, I provide my capital structure and cost of debt recommendations. *Seventh*, I discuss how WGL's proposed Weather Normalization Adjustment ("WNA") impacts its cost of equity.

**Q. WHAT RATE OF RETURN DID WGL RECOMMEND THE COMMISSION ACCEPT?**

**A.** WGL recommended that the Commission accept an overall rate of return of 7.874% as supported by WGL Witness Janet Burrows, Exhibit WG (B), including a return on common equity of 10.50%, as supported by WGL Witness Dylan D'Ascendis, Exhibit WG (C).[3] WGL Witness Burrows states that WGL's proposed overall rate of return of 7.874% is based on the following capital structure and cost rate:[4]

**TABLE 1: WGL Requested Cost of Capital**
**Formal Case No. 1180**

| | Capital Structure Ratios | Cost Rate | Weighted Cost Rate |
|---|---|---|---|
| **Long-Term Debt** | 42.881% | 4.840% | 2.075% |
| **Short-Term Debt** | 4.634% | 6.202% | 0.287% |
| **Preferred Equity** | 0.000% | 0.000% | 0.000% |
| **Common Equity** | 52.486% | 10.500% | 5.511% |
| **Rate of Return** | | | 7.874% |

WGL's proposed rate of return of 7.874% is based on a total capitalization of $2,122,063 (of which $1,915,107 is the long-term debt component, $206,956 is the short-term debt component, and $2,344,085 is the common equity component).[5]

---

3 *See* WGL Application at 3-4.

4 *See* Exhibit WG (B) 2 (Burrows) at 2:9-18; Exhibit WG (B)-1. *See also* Exhibit WG (C) (D'Ascendis) at 3:2-7 (recommending a 10.50% ROE); *id.* at 3:10-15 (Table 1 of Witness D'Ascendis' Direct Testimony summarizing the recommended weighted average cost of capital for WGL using rounded figures).

5 *See* Exhibit WG (B) (Burrows) at 2:12-18. *See also* Exhibit WG (B)-1.

**Q. DO YOU AGREE WITH WGL'S RATE OF RETURN REQUEST?**

**A.** No. I disagree with WGL's requested overall rate of return, including WGL's proposed ROE and the common equity and long-term debt ratio used in WGL's proposed capital structure.

**Q. PLEASE SUMMARIZE YOUR PRIMARY FINDINGS AND RECOMMENDATIONS IN THIS CASE?**

**A.** My primary findings and recommendations in this case are as follows:

- WGL's proposed rate of return on common equity is not an accurate measure of WGL's cost of capital, including because Witness D'Ascendis' methodologies for computing the cost of equity are flawed and his proposed ROE is inappropriately inflated based on the use of a non-utility proxy group.
- WGL's proposed capital structure, which includes a recommended 52.49% common equity ratio, is not appropriate because it includes significantly more expensive capital (equity) than corporations use to fund regulated gas distribution operations. The Commission should set WGL's capital structure based on the capital structure ratios used by gas utility holding companies.
- The cost of capital for WGL's gas operations should be based on the following:

- An overall cost of capital of 6.58% (with a reasonable range of 5.84% - 6.58%).
- An ROE of 8.22% (with a reasonable range of 6.73% - 8.22%).
- A capital structure containing 49.76% common equity, 45.61% long-term debt and 4.63% short-term debt.
- A long-term debt cost rate of 4.84%.
- A short-term debt cost rate of 6.20%.

A summary of my cost of capital recommendations for WGL's gas operations are presented in Table 2 below:

**TABLE 2: ALR RECOMMENDED - WASHINGTON GAS LIGHT COMPANY**
**Formal Case No. 1180**

| | Capital Structure Ratios | Cost Rate | Weighted Cost Rate |
|---|---|---|---|
| **Long-Term Debt** | 45.61% | 4.84% | 2.21% |
| **Short-Term Debt** | 4.63% | 6.20% | 0.29% |
| **Preferred Equity** | 0.00% | 0.00% | 0.00% |
| **Common Equity** | 49.76% | 8.22% | 4.09% |
| **Rate of Return** | | | 6.58% |

Exhibit OPC (D)-3

In addition, if the Commission decides to use WGL's requested capital structure of 52.49% common equity and 42.88% debt instead of my recommended capital structure, I recommend a reduced authorized ROE of 8.11% (6.62% - 8.11%) to account for the lower financial risk of a capital structure with more equity.

Furthermore, if a WNA mechanism is approved for WGL, I recommend that the Commission make a downward adjustment to the ROE from my recommended 8.22% ROE and an associated adjustment to the overall rate of return.

**Q. ARE YOU RECOMMENDING A SPECIFIC ROE OF 8.22% OR AN ROE RANGE OF 6.73% TO 8.22%?**

**A.** I recommend both a range of appropriate ROEs and a specific point within that range that I consider to be the most appropriate. It is not possible to measure WGL's cost of equity with the precision of measuring temperature with a thermometer. However, my recommended ROE range of 6.73% to 8.22% already eliminates the extreme ends of the results of my models and provides the Commission with a range of ROEs that will allow WGL to raise the capital it needs to provide safe and reliable service, fairly compensate investors, and balance the interests of investors and ratepayers. I also recommend a specific point of 8.22% which is conservatively on the high end of my COE model results so the Commission can be confident that WGL's parent will be able to raise equity capital, particularly when considering the equity return expectations of major financial institutions.

**Q. HOW DOES YOUR COST OF EQUITY RECOMMENDATION COMPARE TO THE RETURN EXPECTATIONS OF MAJOR FINANCIAL INSTITUTIONS?**

**A.** As shown in Table 3, major financial institutions are informing their clients to expect returns on the overall market (S&P 500)[6] of 6.0% to 8.5%. As I explain in detail in my testimony, WGL's authorized ROE should be based on investors' expectations as indicated by a large set of capital market data, not the opinions of a small range of financial analysts

---

[6] The S&P 500 is a stock market index that includes 503 of the largest U.S. companies, including 11 sectors to show the health of the U.S. stock market and broader economy. The Dow Jones Industrial Average, 30 of the largest U.S. companies, is another commonly used measure of equity markets in general. https://stockanalysis.com/list/sp-500-stocks/.

or institutions. However, I chose to include the equity return expectations of major financial institutions to demonstrate why Witness D'Ascendis' 10.50% ROE is significantly higher than the equity return expectations of major financial institutions.

| TABLE 3: U.S. EQUITY RETURN EXPECTATIONS AMONG MAJOR FINANCIAL INSTITUTIONS | |
|---|---|
| **J.P. Morgan Asset Management - Equity Long-Term Returns (2025) [1]** | **6.7%** |
| **Charles Schwab - 10-year U.S. Large Cap Returns (January 2025) [2]** | **6.0%** |
| **Horizon Actuarial Services, LLC Survey - 20 Year Horizon (August 2024) [3]** | |
| *U.S. Equity - Large Cap (5.6-10.2%, 50% Percentile - 7.3%)* | **7.3%** |
| *U.S. Equity - Small / Mid Cap (5.1-10.9%, 50% Percentile - 7.6%)* | **7.6%** |
| **Duff & Phelps / Kroll (June 2024) [4]** | **8.5%** |

Sources:
[1] J.P. Morgan Asset Management - 2025 Long-Term Capital Market Assumptions, 2024, page 30.
https://am.jpmorgan.com/us/en/asset-management/adv/insights/portfolio-insights/ltcma/
[2] Schwab's 2025 Long-Term Capital Market Expectations, January 3, 2025.
https://www.schwab.com/learn/story/schwabs-long-term-capital-market-expectations
[3] Horizon Actuarial Services, LLC, Survey of Capital Market Assumptions Survey, August 2024, page 19.
Survey participants Include: Bank of New York Mellon, BlackRock, Goldman Sachs Asset Management, J.P. Morgan Asset Management, Merrill, Morgan Stanley Wealth Management, Royal Bank of Canada, UBS.
[4] Kroll Recommended U.S. ERP and Corresponding RFR to be Used in Computing Cost of Capital: January 2008 - Present.
https://www.kroll.com/en/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates
Note: Duff & Phelps acquired Kroll in 2021 and rebranded itself as Kroll.
Note: J.P. Morgan's 2025 Long-Term Capital Market Assumptions is an annual report.

The returns on equity shown in Table 3 are anticipated equity returns across the broader stock market, including sectors such as "US Large Cap," which are generally referred to as U.S. companies with the highest market value (e.g., those listed on the S&P 500, such as Tesla and Amazon).[7] The return expectations of these large companies would be expected to be higher than those for utility stocks because most companies that make up the S&P 500 operate in highly competitive markets whereas regulated utility companies like WGL do not operate in a highly competitive market and are generally considered safer

[7] The S&P 500 consists of 503 companies that are considered large cap companies by most definitions and is widely regarded as a gauge of large-cap U.S. equities. https://stockanalysis.com/list/sp-500-stocks/.

investments that commonly provide a regular dividend to their shareholders. Therefore, Witness D'Ascendis' recommendation of an ROE (10.50%), which is significantly higher than financial professionals expect to earn on investments in companies that are operating in highly competitive markets, is unreasonable. Indeed, as I address further in my Direct Testimony below, prices of gas utility stocks remain attractive to investors, significantly outperforming the overall market (e.g., S&P 500), and the COE for gas utility stocks, as indicated by extensive market data, has been trending down in recent months.

Even my cost of equity recommendation of 8.22% (6.73% to 8.22%) for WGL, which is based on my COE model results, is in the upper part of the range of the major financial institution expectations. This should give the Commission more confidence that, if it adopts my ROE recommendation, WGL will be able to raise the capital it needs to maintain its credit rating, attract capital, and perform its utility obligations, including the provision of safe and reliable service.

## III. COST OF CAPITAL CONCEPTS

**Q. PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY" (COE).**

**A.** A utility's COE is the expected return that investors require on an investment in the utility based on current capital markets. Since investors must pay the market price of a stock to make an investment, investors' required returns are based on the return they expect to receive on the market price of stocks. In other words, a utility's COE is forward-looking and "market-based." As it applies to this proceeding, it is the return investors require to provide equity capital to WGL.

**Q. PLEASE DESCRIBE THE LEGAL FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.**

**A.** In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the United States Supreme Court: *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. VA.,* 262 U.S. 679 (1923) ("*Bluefield*") and *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"). While I am not a lawyer, based on my experience in utility ratemaking, I understand that in these two often cited seminal decisions, the United States Supreme Court found that a fair rate of return for a public utility is one that will permit the utility to earn a return on its investments that is comparable to the returns available in other investments of corresponding risks and which is sufficient to support the utility's credit and allows it to raise funds to carry out its utility mission.[8] However, the Court in *Bluefield* made clear that a utility "has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."[9] The Court also explained that the

---

[8] *See Bluefield*, 262 U.S. at 692 (stating the "public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties . . . .". *See also Hope*, 320 U.S. at 603 (stating "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 credit and attract capital.").

[9] *Bluefield*, 262 U.S. at 692-693.

measure of whether a utility's return is adequate is premised on the expectation that the utility is "using efficient and economical management."[10] These standards reflect the need to balance the utility's and ratepayer interests in determining a fair rate of return for a utility.

**Q. DOES THE COMMISSION ADHERE TO THE *HOPE* AND *BLUEFIELD* STANDARDS IN DETERMINING A UTILITY'S RATE OF RETURN?**

**A.** Yes, the Commission adheres to the *Hope* and *Bluefield* standards referenced above.[11] The Commission has stated that it "must consider both the interests of ratepayers and the needs of a private investor-owned utility to attract investors and raise capital."[12] Similarly, the Commission has explained the importance of ensuring the zone of reasonableness in its rate determinations to safeguarding the interests of both investors and consumers.[13] The

---

10 *Id.* at 693.

11 *See, e.g., Formal Case No. 1139, In the Matter of Potomac Electric Power Co. for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, ("*Formal Case No. 1139*")*,* Order No. 18846 ¶ 250, rel. July 25, 2017 (stating that the Commission adheres to the standards set in *Hope* and Bluefield); *Formal Case No. 1176, In the Matter of Potomac Electric Power Co. for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service*, ("*Formal Case No. 1176*"*),* Order No. 22328 ¶ 165 rel. November 26, 2024 (same). *See also 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,* ("*Formal Case No. 922*"), Order No. 10307, page 14, rel. October 8, 1993 (stating that the Commission would adhere to the standards derived from the *Hope* and *Bluefield* decisions as set forth in Washington Gas Light Co., 450 A.2d 1187 at 1209-1215 (D.C. 1982)).

12 *Formal Case No. 1139*, Order No. 18846 ¶ 2.

13 *See, e.g.*, *Formal Case No. 1176*, Order No. 22328 ¶ 198 (quoting *Metropolitan Board of Trade v. Public Service Comm'n,* 432 A.2d. 343, 350 (D.C. 1981), which in pertinent part states that approving rates within the zone of reasonableness "assures that the Commission is safeguarding the public interest that is, the interests of both investors and consumers. *** From the investor standpoint, courts have defined the lower boundary of this zone of reasonableness as 'one which is not confiscatory in the constitutional sense.' *** From the consumer standpoint, the upper boundary cannot be so high that the rate would be classified as 'exorbitant'.") (citations omitted).

Commission has also stated that "[i]t is assumed that the cost of capital, when competently computed, is essentially and practically the equivalent of a fair rate of return."[14]

**Q. WHAT IS A UTILITY'S CAPITAL STRUCTURE?**

**A.** Capital structure is the percentage of equity and debt that makes up the finances of a utility. For example, if a utility raises $1 million of equity capital and $1 million of debt capital, we say it has a capital structure containing 50% equity and 50% debt.

**Q. IS A UTILITY'S CAPITAL STRUCTURE ALWAYS REPRESENTATIVE OF HOW THE REGULATED UTILITY WAS FINANCED?**

**A.** No. As discussed in further detail below in my Direct Testimony, the reported capital structure of a regulated subsidiary is often not representative of how the regulated utility was financed. For example, the parent of a regulated utility can report funds raised through debt financing at the holding company level as equity financing on the books of its regulated utility subsidiary. Therefore, it is important to make sure WGL's authorized capital structure would not overcharge consumers by including a higher common equity ratio than is appropriate.[15]

---

[14] *Formal Case No. 922*, Order No. 10307, page 15. *See also, e.g.*, *Formal Case No. 1169, In the Matter of Washington Gas Light Company for Authority to Increase Existing Rates and Natural Gas Service*, ("*Formal Case No. 1169*"), Order No. 21939 ¶ 39, rel. December 22, 2023 (similar statement to the one in Order No. 10307).

[15] A higher authorized common equity ratio, all else equal, results in higher rates for consumers because equity is more expensive than debt.

**Q. HOW DOES THE COMMISSION DETERMINE A UTILITY'S CAPITAL STRUCTURE?**

**A.** In Order No. 21939 pertaining to WGL's last rate case, the Commission stated "[a] balanced utility capital structure (consisting of an optimized ratio of debt and equity) is essential to maintaining a strong investment grade credit rating in both favorable and unfavorable capital market conditions."[16] The Commission also explained its aim "to ensure that WGL's approved capital structure enables the Company to adequately maintain its credit ratings with an opportunity to earn its allowed rate of return," while also striving to ensure that "ratepayers are being charged reasonable rates of return, using the appropriate capital structure."[17] The Commission explained its methodology by first examining WGL's actual capital structure, next reviewing common equity ratios and cost of common equity of the peer groups, and noting that the Commission also considers the capital structure and cost of equity for utilities with reasonably comparable investment grade credit ratings.[18]

**Q. PLEASE EXPLAIN HOW YOU BELIEVE A UTILITY'S COST OF DEBT SHOULD BE DETERMINED?**

**A.** A utility's cost of debt can be described as the actual interest rate paid by the utility to source its credit. For example, if a utility has a bond with a 3% interest rate three years

---

16 *Formal Case No. 1169*, Order No. 21939 ¶ 53.

17 *Id.* ¶ 54.

18 *Id.*

ago, its authorized cost of debt should be 3% even if interest rates are currently higher or lower than 3%.

**Q. HAS THE COMMISSION EXPLAINED HOW IT DETERMINES A UTILITY'S RATE OF RETURN (ROR)?**

**A.** Yes. As an example, in the recently issued Order No. 22328 concerning Pepco's Multiyear Rate Plan, the Commission stated as follows:

> The Commission determines the Company's authorized overall ROR by the "cost of capital" method. The cost of capital method seeks to determine what return the Company must offer its investors to attract the capital investment in its stocks and bonds necessary to finance its construction and operations. The overall cost of a utility's capital is calculated by determining the cost of each component in the company's capital structure. A weighted cost for each component is derived by multiplying its cost by its ratio to total capital. The sum of these weighted costs then becomes the utility's overall ROR, multiplied by Pepco's rate base to determine the Company's required return.[19]

As indicated in the above-quoted Commission Order, the appropriate Rate of Return for a utility is generally based upon the weighted overall cost of capital ("WACC") of the current costs of debt and equity at the time of the proceeding. The weighted cost rate is calculated by multiplying the capital structure ratios of the sources of capital (debt, preferred equity, and common equity) times their respective cost rates.

WACC = Cost of Debt X Debt Ratio + COE X Common Equity Ratio + Cost of Preferred Equity X Preferred Equity Ratio.

---

[19] *Formal Case No. 1176*, Order No. 22328 ¶ 166 (internal citations and footnotes omitted).

**Q. DID WGL AND/OR ITS PARENT, ALTAGAS, LTD. ("ALTAGAS") AGREE TO ANY COMMITMENTS RELEVANT TO WGL'S RATE OF RETURN AS PART OF THEIR MERGER IN FORMAL CASE NO. 1142?[20]**

**A.** Yes. The Order approving the merger contained several merger commitments that are relevant to WGL's rate of return, including among others, the following:

- Commitment 27 (WGL will not include in its debt or credit agreements any financial covenants or rating agency triggers related to AltaGas or any other AltaGas affiliates, nor assume liability for nor issue any guarantees of the debt of any other entities);
- Commitment 32 (WGL will maintain its own separate debt, preferred stock, and debt securities and will maintain its own corporate and debt credit ratings as well as ratings for long term debt and preferred stock; WGL will maintain a separate capital structure to finance activities and operations of WGL; WGL will maintain a 12-month rolling average common equity ratio of not less than 48% and no more than 55%, provided that this range is consistent with future orders that address capital structure for Washington Gas; WGL to report within 30 days of the end of each quarter certain credit metrics, including debt/capitalization; AltGas acknowledges the

[20] *See Formal Case No. 1142*, *In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.*, ("*Formal Case No. 1142*"), Order No. 19396, rel. June 29, 2018 (approving, with conditions, a Settlement Agreement pertaining to AltaGas and WGL's merger)). Appendix A of Order No. 19396 contains the Merger Commitments.

Commission's preference for maintaining WGL's credit rating at least at the minimum investment grade level of BBB+ as rated by S&P and Fitch or Baa1 as rated by Moody's, assuming a reasonable regulatory environment and reasonable capital market conditions);

- Commitment 35 (AltaGas to issue separate debt and maintain separate credit ratings for WGL; Applicants shall maintain a separate capital structure to finance WGL activities and use reasonable efforts to ensure credit ratings remain at or above investment-grade);
- Commitment 37 (WGL will not make any dividend payments to its parent that would result in drop of WGL's common equity level below 48% of its total capitalization provided that this common equity level is consistent with future capital structure orders, or it rates below investment grade by any of the three major credit rating agencies); and
- Commitment 38 (WGL shall demonstrate that "customers of [WGL] are held harmless from adverse rate impacts due to an increase in [WGL's] cost of debt that is caused by the Merger with AltaGas, or the ongoing affiliation with AltaGas and its affiliates after the Merger. Nothing in this condition will restrict the Commission's authority in setting [WGL's] rates or [WGL's] responsibility to support its cost of capital.").[21]

---

[21] *Id.,* Appendix A at 11-15.

## IV. CRITIQUE OF WGL'S EXCESSIVE PROPOSED ROE

**Q. DO YOU AGREE WITH WGL'S REQUESTED ROE OF 10.50%?**

**A.** No. I find that WGL's 10.50% ROE recommendation as supported in Witness D'Ascendis' direct testimony is excessive, because it is based on a flawed cost of equity analysis. If used to set rates, WGL's proposed ROE will significantly overcharge WGL's customers.

**Q. BEFORE WE TURN TO A DETAILED CRITIQUE OF WGL WITNESS D'ASCENDIS' COE ANALYSES, PLEASE SUMMARIZE HOW YOUR ANALYTICAL APPROACH DIFFERS FROM WITNESS D'ASCENDIS' AND WHY YOUR APPROACH BETTER REFLECTS WGL'S COST OF EQUITY IN TODAY'S CAPITAL MARKETS.**

**A.** My approach for calculating a cost of equity differs fundamentally from that of Witness D'Ascendis' in several ways:

- **Reliance on Market Data**. I focus on using market data (e.g., stock prices, bond yields, stock option prices) to measure investors' expectations as much as possible. On the other hand, Witness D'Ascendis relies extensively on analyst forecasts[22], which can be biased, even when it is possible to measure investors' equity return expectations using market data (stock and

---

[22] Witness D'Ascendis explains that he used analyst's five-year forecasts for the growth rate component of his DCF analysis because these forecasts are widely available, and he claims that investors realize that analysts have significant insights. *See, e.g.*, Exhibit WG (C) (D'Ascendis) at 18:9-17.

option prices).[23] Market data is more reliable than analyst forecasts. Market data aggregates the expectations of a diverse group of participants who utilize a range of quantitative models and economic indicators (including analysts forecasts). This distributed intelligence is inherently more robust than an individual or small group of analysts, regardless of expertise, and because market data includes thousands of participants, it is better equipped to capture the complex market interactions and nonlinear dynamics. My use of market data more accurately captures investor expectations in real-time, providing a market-based COE that reflects current capital conditions. Witness D'Ascendis, however, utilizes more analyst-driven data and interest rate forecasts, which can diverge from the immediate expectations investors demonstrate through market behavior. By relying on current market data over analyst forecasts, my DCF and CAPM analyses offer a real-time reflection of capital market expectations. This aligns COE closer to what investors are actually willing to pay based on prevailing economic and market conditions, eliminating the speculative bias introduced by forecasted rates.

- **Growth Rate Assumptions in DCF Analysis**. The growth rate component of Witness D'Ascendis' DCF model is based on relatively short-term

[23] *See, e.g.*, *id.* at 18:11-17.

analyst growth rates without adjusting for sustainable, long-term growth.[24] This can inflate COE estimates because short-term growth is not a reliable measure over the long-term, particularly in regulated utilities with modest growth expectations. My DCF analysis counters this by using sustainable growth rates, aligning growth assumptions with longer-term investor expectations. This method avoids overreliance on optimistic analyst projections that may not reflect future, consistent cash flows. Using a sustainable growth approach in the DCF model ensures that growth rates are realistic and more in line with utility sector norms. This stabilizes COE estimates and reduces overstatement, providing a more accurate long-term indicator of WGL's financial needs.

- **CAPM**. Witness D'Ascendis' CAPM incorporates an inflated market risk premium (7.17% - 10.78%).[25] The risk premium he uses is higher than what equity investors would typically expect to earn when investing in equities, leading to an overstated COE.[26] The risk premium portion of my CAPM analysis (3.34% to 3.96%)[27] is based on a direct measure of investors' return expectations based on stock option prices. I calculate my risk premium component based on both spot and historical averages to provide a more

---

[24] *See, e.g.*, *id.* at 17:11-19:8.

[25] *See, e.g.*, *id.* at 38:12-23 (Table 10).

[26] The equity risk premium is related to the overall market (e.g., the companies in the S&P 500). In order to equate this to the cost of equity for a utility company, it is required to make additional calculations.

[27] *See* Exhibit OPC (D)-6 at 4 & 5.

stable COE that aligns accounts for changing capital market conditions without being overly influenced by short-term capital market turmoil. Incorporating both short-term and long-term risk-free rates in the CAPM smooths out fluctuations from daily market shifts, creating a more comprehensive view of investor expectations. My balanced market risk premium also reduces the influence of historical extremes, delivering a COE grounded in both recent and past market conditions. Witness D'Ascendis' approach significantly relies on the personal opinions of equity analysts in both his CAPM and DCF analysis instead of the supply and demand of stocks and bonds as indicated by market data. Calculating the cost of equity should rely on market data to measure investors' expectations, as Witness D'Ascendis did in some parts of his testimony, rather than relying on the opinions of, in comparison, a relatively small group of analysts (e.g., interest rate forecasts instead of investors' expectations as revealed in the market yield).

- **Risk Premium Model (RPM).** Witness D'Ascendis' RPM produces inflated results for a number of reasons. One reason for the inflated results is that the historical market risk premium portion of Witness D'Ascendis' RPM is based on historical equity return measures (11.91%)[28] that are above investors' expectations, which are reflected in my model results

---

[28] *See* Exhibit WG (C) (D'Ascendis) at 23:11-13.

(7.02%)[29] and equity return expectations of major US financial institutions shown on Table 3 (6.0% to 8.5%). Another reason for Witness D'Ascendis' inflated RPM results is that the projected equity risk premium portion of his RPM is based on unrealistically high measures of equity return expectations (12.05%)[30] because it is highly influenced by upwardly biased analyst projections.

- **Avoidance of Business Risk Adjustments**. Witness D'Ascendis claims that it is appropriate to make an upward adjustment of 0.19% to his indicated range of ROEs due to the regulatory risk and smaller size of WGL as compared to his Utility Proxy Group.[31] However, he does not specifically add this adjustment to his COE calculations and neither should the Commission because these claimed higher risks are unfounded as I discuss in more detail further in this Direct Testimony.

- **Non-Price Regulated Proxy Group COE Analysis**. The companies in Witness D'Ascendis' Non-Price Regulated Proxy Group are not comparable in risk to WGL because of significant differences in operational characteristics, ongoing legal exposure, radically different capital structure ratios, and differing regulatory or political risks. Consistent with the *Hope* and *Bluefield* standards and Commission precedent, the results of WGL's

---

29 *See* Exhibit OPC (D)-8 at 1.

30 *See* Exhibit WG (C) (D'Ascendis) at 26:19-22.

31 *See id.* at 5:4-9.

COE analysis based on non-regulated utilities should be disregarded because the results do not represent an accurate measure of WGL's COE.[32]

- **Proposed Weather Normalization Adjustment ("WNA")**. If WGL's recommendation for a WNA is approved, it would be appropriate for the Commission, consistent with Commission precedent,[33] to adjust WGL's ROE downward to reflect WGL's reduced risk in attracting investors and obtaining credit.[34] Witness D'Ascendis does not make any specific adjustments to his cost of equity recommendation to account for the proposed Weather Normalization Adjustment because according to him, most of the companies in his Utility Proxy Group have similar mechanisms.[35] However, even if the regulated operations of the companies in his proxy group do have similar risk reducing mechanisms, these companies have significant unregulated operations that are riskier by nature

---

32 *See, e.g.*, *Formal Case No. 1139,* Order No. 18846 ¶ 280 (finding that companies that have non-utility operations are not an appropriate proxy or point of comparison to Pepco).

33 *See, e.g.*, *Formal Case No. 1156*, Order No. 20755 ¶ 242, rel. June 8, 2021 (noting that the Commission reduced Pepco's proposed ROE to account for the Commission's approval of the Modified Enhanced Multiyear Rate Plan).

34 *See, e.g.*, Value Line Natural Gas Utility Industry Report, November 22, 2024 (stating that "investors interested in utilities with more-stable earrings" should consider buying utility stocks with weather adjustment mechanisms.). *See also* WGL Response to OPC Data Request No. 7-12 (Exhibit OPC (D)-14) (where WGL Witness D'Ascendis states that "[a]ll else being equal, a weather normalization mechanism, such as the Company's proposed WNA, will reduce some of the company-specific business risks related to the recovery of its authorized return."); WGL Response to OPC Data Request No. 7-9 (Exhibit OPC (D)-15) (where WGL Witness Burrows states that the WNA "would help maintain the Company's current credit ratings").

35 *See* Exhibit WG (C) (D'Ascendis) at 48:13-18. *See also* WGL Response to OPC Data Request No. 7-11 (Exhibit OPC (D)-16) (where Witness D'Ascendis concedes he has not conducted an analysis to compare the characteristics of the various rate constructs and decoupling mechanisms used by the companies in Witness D'Ascendis' Utility Proxy Group to WGL's proposed WNA).

than WGL and their unregulated operations do not have any risk reducing mechanisms.

### A. Evaluation of Witness D'Ascendis' COE Models

**Q. WHAT COE MODELS DID WITNESS D'ASCENDIS USE IN HIS DIRECT TESTIMONY TO DETERMINE HIS RECOMMENDED ROE OF 10.50% FOR WGL?**

**A.** Witness D'Ascendis arrived at his ROE recommendation of 10.50% based upon his own versions of the Discounted Cash Flow model, Risk Premium Model, and Capital Asset Pricing Model applied to the market data of a Utility Proxy Group, as well as a Cost of Equity analysis applied to a proxy group of non-price regulated companies.[36] Witness D'Ascendis testified that, "[u]sing multiple models adds reliability to the estimated common equity cost rate."[37]

Below are the results of Witness D'Ascendis' cost of equity methods.

---

36 *See* Exhibit WG (C) (D'Ascendis) at 4: 3-9.

37 *See id.* at 42:19-20.

| TABLE 4: WITNESS D'ASCENDIS' COST OF EQUITY RESULTS | |
|---|---|
| **METHOD** | **Model Results** |
| **Discounted Cash Flow Model** | 9.99% |
| **Risk Premium Model** | 10.82% |
| **CAPM** | 11.57% - 11.63% |
| **COE Models Applied to Non-Price Regulated Companies** | 12.01% - 12.02% |
| | |
| **Indicated Range** | 9.99% - 11.63% |
| | |
| **Business Risk Adjustment** | 0.00% |
| **Flotation Cost Adjustment** | 0.00% |
| | |
| **Recommended Range** | **9.99% - 11.63%** |
| | |
| **Recommended Common Equity Cost Rate** | **10.50%** |

[1] Witness D'Ascendis's Direct Testimony, Exhibit WG (C), page 2 of 2.

## B. Critique of WGL's DCF Analysis

**Q. IS WITNESS D'ASCENDIS' DCF RESULT OF 9.99% (RANGE OF 8.40% - 11.44%)[38] REASONABLE?**

**A.** No. The primary flaw in Witness D'Ascendis' DCF analysis lies in his use of analysts' five-year earnings per share ("EPS") growth rate forecasts as the sole basis for the growth rate component.[39] His approach is overly simplistic and ignores the fact that the constant growth DCF model requires a growth rate that can reasonably be expected to be the same in perpetuity.[40] Perpetuity is far longer than five years, and short-term EPS projections reflect transient factors such as cyclical economic conditions or company-specific events.

---

38 Exhibit WG (C)-3 at 1.

39 *See, e.g.*, *id.*; Exhibit WG (C) (D'Ascendis) at 16:1-2.

40 *See, e.g.*, Exhibit WG (C) (D'Ascendis) at 16:1-2.

Without addressing how these short-term forecasts relate to sustainable long-term growth, his DCF model results are not reliable.

A company's ability to grow in perpetuity depends not just on its earnings growth but also on the portion of earnings it retains to reinvest in future growth.[41] Witness D'Ascendis' method does not assess whether the high EPS growth rates he includes are consistent with the utility's retention of earnings, dividend payout practices, and reinvestment opportunities. Additionally, analysts' forecasts are often overly optimistic.[42] Using these analyst forecasts without accounting for this over-optimism, contributes to upward bias in Witness D'Ascendis' DCF model results.

**Q. DO MAJOR FINANCIAL INSTITUTIONS UNDERSTAND THAT IT IS NOT APPROPRIATE TO USE UNADJUSTED EPS GROWTH RATES AS A PROXY FOR LONG-TERM GROWTH?**

**A.** Yes. J.P. Morgan explained that its equity assumptions methodology considers five return drivers (including earnings growth and dividends).[43] Pertinently, J.P. Morgan explained that its equity return assumptions methodology:

---

[41] The retention rate is the portion of earnings a company keeps after paying dividends. The higher the retention rate, the more funds are available for reinvestment, which supports growth.

[42] McKinsey Consulting stated that "analysts' near-term forecasts are often overly optimistic and don't always correctly reflect operating performance." David Kohn, Vartika Gupta, Tim Koller, Werner Rehm, *Prime Numbers: Do consensus estimates accurately reflect operating performance?*, May 16, 2022, available at: https://www.mckinsey.com/capabilities/strategy-and-corporate-finance/our-insights/the-strategy-and-corporate-finance-blog/do-consensus-estimates-accurately-reflect-operating-performance.

[43] *See* J.P. Morgan Asset Management, *2019 23rd Annual Edition Long-Term Capital Market Assumptions*, available at: https://am.jpmorgan.com/content/dam/jpm-am-aem/global/en/insights/portfolio-insights/ltcma/archive/LTCMA-2019.pdf, pages 62-63.

> ties together complex interrelationships among these factors to ensure that retained earnings and gross dilution imply a future book value that is consistent with projected return on equity and future earnings. This framework – analogous to Robert Higgins' sustainable growth rate (SGR) concept – ensures that higher shareholder payouts, for instance, would come at the expense of slower earnings growth, all else the same. Our methodology uses trailing, not forward, earnings, which tend to be more stable.[44]

As J.P. Morgan's equity return methodology illustrates, a robust DCF analysis should tie growth rates to sustainable factors such as reinvestment and return on equity, not rely solely on analysts' five-year projections. By failing to address these elements, Witness D'Ascendis' method is woefully incomplete and produces unreasonable results, ranging from 8.40% to 11.44%.[45]

**Q. ARE YOUR DCF MODEL RESULTS MORE RELIABLE THAN WITNESS D'ASCENDIS'?**

**A.** Yes. My DCF results are more reliable than Witness D'Ascendis' because they are not as influenced by overly-optimistic analysts' forecasts as would have been the case had I merely used analysts' five-year earnings growth rate forecasts as a proxy for long-term growth. This is because the DCF methods I use compute sustainable growth rates, rather than growth rates that can exaggerate the growth rate due to assuming that a relatively short-term forecast (5 years) will remain indefinitely.

---

44 *Id.*

45 Exhibit WG (C)-3 at 1.

**Q. ARE YOU SAYING THAT ANALYSTS' CONSENSUS EARNINGS PER SHARE GROWTH RATES ARE USELESS AS AN AID TO PROJECTING THE FUTURE?**

**A.** No. Analysts' EPS growth rates are, however, very dangerous if used in a simplified DCF without proper interpretation. They are not useful if used in their "raw" form but can be useful in computing estimates of what earned return on equity investors expect will be sustained in the future if other factors also encompassed in the analysis, such as retained earnings.

**Q. HOW DO YOU ACCOUNT FOR RETAINED EARNINGS IN YOUR SUSTAINBLE GROWTH DCF MODEL?**

**A.** I account for the retention rate when calculating the growth component of sustainable growth DCF model by taking the following steps:

1. **Start with Dividend Yield on Market Price:**
   This is the dividend as a percentage of the stock's market price, which is available from numerous data sources (e.g., Yahoo Finance).
2. **Relate to Book Value:**
   Using the relationship between the market price of a stock and its accounting book value (market-to-book ratio), I adjust this dividend yield to express it as a percentage of book value. This step bridges the market valuation with the company's accounting figures.
3. **Integrate Expected Return on Book Equity and Expected Dividend Yield on Book Equity to Calculate Retention Rate:**
   I use Value Line's forecasted accounting returns (future expected return on book equity) to calculate how much of the percentage of earnings that are likely to be retained.

The key point is that the constant growth DCF model is biased if it is based only on EPS growth forecasts, as Witness D'Ascendis has done, because it ignores the mechanics of how growth is funded—whether through retained earnings or other means. This leads to an unsustainable growth estimate that does not reflect the company's true capacity to grow.

**Q. HOW DO THE RESULTS OF YOUR DCF MODELS COMPARE TO WITNESS D'ASCENDIS' DCF MODEL RESULTS?**

**A.** My sustainable growth DCF and option-implied growth DCF methods produce cost of equity results of 8.22% - 8.32% and 7.83% - 8.51% respectively, based on growth rate components of 4.22% and 4.81%.[46] The differences between Witness D'Ascendis' and my DCF results range between -11 basis points (8.40% - 8.51%) and 361 basis points (11.44% - 7.83%).

### C. Critique of WGL's CAPM Analysis

**Q. DOES WITNESS D'ASCENDIS' CAPM ANALYSIS PROVIDE REASONBLE COE RESULTS??**

**A.** No. Witness D'Ascendis' CAPM result of 11.57% to 11.63% is unreasonably high because his market risk premium component of 7.17% to 10.78% is higher than indicated by current capital market data and higher than justified based on a closer examination of his own

---

46 *See* Exhibit OPC (D)-4 and -5.

sources. He uses an average beta coefficient of 0.81,[47] which is highly impacted by capital market conditions during the peak of the COVID-19 pandemic that are no longer representative of current capital markets as explained more fully in my Exhibit OPC (D)-8.

**Q. PLEASE DESCRIBE WITNESS D'ASCENDIS' CAPM METHOD.**

**A.** Witness D'Ascendis explains that the CAPM theory "defines risk as the co-variability of a security's returns with the market's returns as measured by the beta (β)."[48] He states that beta less or greater than 1.0 indicates a lower or higher variability than the market as a whole respectively.[49] He says that the traditional CAPM model is expressed as:

| | | |
|---|---|---|
| Rs | = | Rf+ β (Rm-Rf). Where: |
| R | = | Return rate on the common stock |
| Rf | = | Risk-free rate of return |
| Rm | = | Return rate on the market as a whole |
| β | = | adjusted beta (volatility of the security relative to the market as a whole)[50] |

---

47 Exhibit WG (C) (D'Ascendis) at 28:16-20; Exhibit WG (C)-5 at 1.

48 *See* Exhibit WG (C) (D'Ascendis) at 32:21-22.

49 *See id.* at 32:22-33:2.

50 *See id.* at 33:10-17.

**Q. WHAT RISK-FREE RATE DOES WITNESS D'ASCENDIS USE IN HIS CAPM?**

**A.** He used the following two risk-free rates: (1) 4.41% - the average of the Blue Chip consensus forecast of the expected yields on 30-year U.S. Treasury bonds, (2) 4.55% - the three-month average as of May 2024.[51]

**Q. WHAT BETA COEFFICIENT DID WITNESS D'ASCENDIS USE IN HIS CAPM ANALYSIS?**

**A.** Witness D'Ascendis used the following two historical beta coefficients of each of the companies in his proxy group: (1) Bloomberg 2-year weekly return relative to the S&P 500 index, and (2) Value Line 5-year historical weekly return relative to the New York stock exchange composite index.[52]

**Q. WHAT RISK PREMIUM DOES WITNESS D'ASCENDIS USE IN HIS CAPM?**

**A.** The risk premium portion of his CAPM analysis is 8.59% (using prospective interest rates) and 8.51% (using current interest rates)[53] which is derived from an average of the following components:

**Measure 1:** *Kroll Arithmetic Mean MRP* | 7.17%[54] (for both prospective and current interest rates)

---

51 *See id.* at 36:14-21.

52 *See id.* at 36:6-13.

53 *See* Exhibit WG (C)-5 at 1 & 2.

54 This is the difference between the Arithmetic Mean Monthly Returns for Large Stocks 1926-2023 (12.16%) and the Arithmetic Mean income Returns on Long-Term Government Bonds (4.99%).

**Measure 2:** *Application of a Regression Analysis to Kroll Historical Data* | 7.93% (using prospective interest rates) and 7.79% (using current interest rates)

**Measure 3:** *Application of Predictive Risk Premium Model ("PRPM")*[55] *to Kroll Historical Data* | 9.44% (for both prospective and current interest rates)

**Measure 4:** *Value Line MRP* | 7.64%[56] (using prospective interest rates) and 7.50%[57] (using current interest rates)

**Measure 5:** *Bloomberg, Value Line, and S&P Capital IQ Projected Return on the Market based on the S&P 500* | 10.78%[58] (using prospective interest rates) and 10.64% (using current interest rates).[59]

**Q. DOES WITNESS D'ASCENDIS USE AN APPROPRIATE RISK-FREE RATE IN HIS CAPM?**

**A.** In principle, no. The risk-free rate component of Witness D'Ascendis' CAPM is not appropriate because it is based considerably on economist published projections and not investors' expectations as indicated by market yields. Interest rates have increased since Witness D'Ascendis filed his testimony, and the forecasted yields he used in his CAPM

---

55 See description of Witness D'Ascendis' PRPM in my critique of his Risk Premium Method above.

56 The MRP based on Value Line Summary & Index using prospective interest rates (7.64%) is the difference between the total projected return on the market 3-5 years hence (12.05%) and the Risk-Free Rate (4.41%).

57 The MRP based on Value Line Summary & Index based on current interest rates (7.50%) is based on the difference between the total projected return on the market 3-5 years hence (12.05%) and the Risk-Free Rate (4.55%).

58 The MRP based on Bloomberg, Value Line, and S&P Capital IQ data using prospective interest rates (10.78%) is the difference between the total return on the market based on the S&P 500 (15.19%) and the risk-free rate (4.41%)

59 The MRP based on Bloomberg, Value Line, and S&P Capital IQ data using current interest rates (10.64%) is the difference between the total return on the market based on the S&P 500 (15.19%) and the risk-free rate (4.55%).

are now lower than the market-based risk-free rates that I used in my CAPM analysis. As outlined in Exhibit OPC (D)-6, page 2, my spot and weighted average short-term risk-free rates are 4.58% and 4.64%, respectively. My spot and weighted average long-term risk-free rates are 4.36% and 4.34%, respectively. These four rates average 4.48%. The risk-free rate component of Witness D'Ascendis' CAPM analysis is between 4.41% for the prospective yield on 30-year U.S. Treasury bonds and 4.55% for the current 30-day average market yield.[60]

Witness D'Ascendis' use of interest rate forecasts is wrong in principle because market yields on U.S. Treasury bonds indicate market expectations. As discussed above, WGL's authorized ROE should be market-based because investors provide the capital. In this case, Witness D'Ascendis' use of interest rate forecasts to determine the risk-free rate component does not inflate his CAPM result. However, the Commission should be wary of using his CAPM method as it could produce inaccurate cost of equity results (too high or too low) in different capital market conditions.

**Q. DO WITNESS D'ASCENDIS' BETA COEFFICIENTS CONTRIBUTE TO HIS EXCESSIVE CAPM RESULT?**

**A.** Yes. Witness D'Ascendis' beta coefficients contribute to an overstatement of the cost of equity because he relies, in part, on outdated historical data. Specifically, his analysis uses

60 *See* Exhibit WG (C) (D'Ascendis) at 36:14-21.

five-year historical beta coefficients from Value Line, averaging 0.89.[61] These betas are based on data still influenced by the financial turmoil caused by the COVID-19 pandemic when utility betas spiked, rendering them less reflective of market conditions.

By contrast, the Bloomberg betas that he uses are based on only two years of historical beta coefficients, averaging 0.72, and provide a more current and reasonable estimate of investors' risk expectations.[62] Using an average of both the five-year and two-year betas, as he has done, results in an inflated beta and excessive CAPM indicated cost of equity.

It would have been more appropriate for Witness D'Ascendis to give more weight to the results of the more current two-year historical beta from Bloomberg. Over the past 3 months, my forward-looking option-implied betas have had a weighted average of 0.68[63] and my 6-month and 2-year historical betas for the Rothschild Gas Proxy Group have had a weighted average of 0.544 and 0.703, respectively.[64] My analysis, like Bloomberg's 2-year historical betas in this case, are better measure of WGL's indicated cost of equity.

**Q. UPON CLOSER EXAMINATION OF WITNESS D'ASCENDIS' SOURCES AND OTHER PROMINENT SOURCES, DO YOU BELIEVE THAT THE EQUITY RISK**

---

[61] *See* Exhibit WG (C)-5 at 1, column [1]. The Value Line betas for Witness D'Ascendis' proxy group companies average to 0.89 ((0.85+1.00+0.95+0.85+0.85+0.85)/6 = 0.89).

[62] *See* Exhibit WG (C)-5 at 1, column [2]. The Bloomberg betas for Witness D'Ascendis' proxy group companies average to 0.72 ((0.76+0.74+0.77+0.63+0.64+0.79)/6 = 0.72).

[63] Exhibit OPC (D)-6 at 3.

[64] *Id.*

**PREMIUM PORTION OF WITNESS D'ASCENDIS' CAPM ANALYSIS IS REASONABLE?**

**A.** No, I believe Witness D'Ascendis' equity risk premium component of between 8.51% and 8.59%[65] is excessive and leads to an inflated CAPM result. The CAPM indicates a COE averaging about 7% using a reasonable equity risk premium component. As explained in the discussion of my CAPM analysis, I determined that investors are demanding a significantly lower equity risk premium of between 3.34% and 3.93%. Closer examination shows that Witness D'Ascendis' own sources (Kroll and Bloomberg) and other prominent sources arrive at substantially lower numbers than those of Witness D'Ascendis.

**Kroll**

Witness D'Ascendis uses data from Kroll, Value Line, Bloomberg, and S&P Capital IQ to calculate the market risk premium component of his CAPM analysis.[66] His decision to rely on this data is not appropriate. First, it is not reasonable to conclude that investors expect that equity returns will be as high in the future as in the past. Kroll calculates a supply-side equity risk premium to account for evidence that equity returns may be lower in the future than they were since 1926. Witness D'Ascendis' equity risk premium is inflated because he does not conduct a comprehensive analysis to consider if historical equity returns are sustainable or not. Second, Witness D'Ascendis bases his analysis on a one-year timeframe, which is problematic. The cost of equity should be

---

65 Exhibit WG (C)-5 at 2.

66 *Id.*

measured over long periods, not just yearly returns. A one-year view is arbitrary and inconsistent with the long-term perspective needed, especially when juxtaposed with the 30-year treasury bonds used as a risk-free rate benchmark. Ideally, a five-year rolling return average, or better yet, a 30-year period, should be used to align with the long-term investment horizon we are trying to measure.

**<u>Other Prominent Sources</u>**

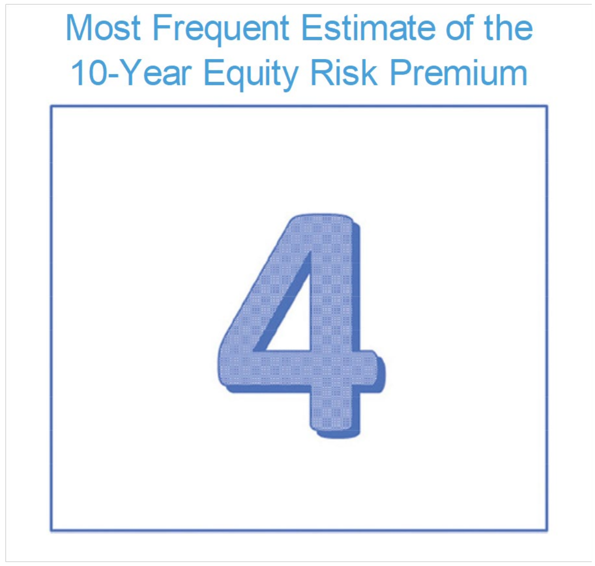
This discrepancy is evident even when consulting other respected sources, like Professor Aswath Damodaran from NYU (who finds an equity risk premium of 4.00% as of January 1, 2025),[67] and further supports the argument that Witness D'Ascendis' equity risk premium estimation is excessively high.

Additionally, based on calculations by P. Brett Hammond and Martin L. Leibowitz, which were based on a literature survey and estimates from participants in the 2001 Equity Risk Premium Forum, they found the most frequent estimate of the 10-year equity risk premium to be 4.0%. Some attendees at the Equity Risk Premium Forum in 2012 found the following slide regarding the equity risk premium to be most memorable.[68]

---

[67] Aswath Damodaran, PhD., Stern School of Business, New York University, *Damodaram Online*, at https://pages.stern.nyu.edu/~adamodar/.

[68] Brett Hammond & Martin L. Leibowitz, CFA Institute Research Foundation, Revisiting the Equity Risk Premium*, Introduction: Three Decades of Equity Risk Premium Forums,* page vi, *(2023)* available at: https://www.cfainstitute.org/-/media/documents/article/rf-brief/Revisiting-the-Equity-Risk-Premium.pdf.




The authors of *Revisiting the Equity Risk Premium* noted "[d]espite radically different market environments, it is striking that the estimates in all three forums were so similar. They tended to be in the 3%–5% range, and notably and notably, in comparison to historical returns, none of them included estimates above 7% or below zero."[69] The three forums were in 2001, 2011, and 2021.[70]

In summary, Witness D'Ascendis' CAPM results are unreasonably high because his equity risk premium component is above current market-based indicators as reflected in the stock option prices used in my own analysis, the sources he uses (e.g., Kroll), and the conclusions of other prominent research cited above (e.g., the CFA Research Institute).

---

69 *Id.*

70 *Id.*

**Q. DO WITNESS D'ASCENDIS' CAPM RESULTS OVERSTATE THE COE BECAUSE THE MARKET RISK PREMIUM PORTION OF HIS ANALYSIS IS HIGHER THAN INVESTORS' EXPECTATIONS?**

**A.** Yes. Witness D'Ascendis' CAPM uses a market risk premium of 8.51% to 8.59% based on an expected market return on the S&P 500 as high as 15.19%[71] The equity risk premium portion of my CAPM, which is based on a direct measure of investors' expectations, is significantly lower than Witness D'Ascendis'. The market risk premia I use in my Weighted Average CAPM analysis with short- and long-term risk-free rates are 3.64% and 3.93%, respectively.[72] The market risk premia I use in my Spot CAPM analysis with short- and long-term risk-free rates are 3.34% and 3.56%, respectively.[73]

## D. Critique of WGL's Risk Premium Analysis

**Q. IS WITNESS D'ASCENDIS' RISK PREMIUM MODEL RESULT OF 10.82%[74] REASONABLE?**

**A.** No. Witness D'Ascendis' RPM result of 10.82% directly contradicts the investor return expectations indicated by the results of properly applied market-based models by myself (DCF, CAPM) and major financial institutions (See Table 3). As discussed earlier, current stock option prices indicate that investors expect there is less than a 40% chance of a 10.5%

---

[71] *See* Exhibit WG (C)-5 at 2.

[72] *See* Exhibit OPC (D)-6 at 1.

[73] *See id*. at 5.

[74] *See* Exhibit WG (C) (D'Ascendis) at 32:13-18 (Table 9 of Witness D'Ascendis' Direct Testimony); Exhibit WG (C)-2 at 2; Exhibit WG (C)-4 at 1.

equity return on the companies in the Utility Proxy Group. This means that the market expects there is an even lower probability of achieving a 10.82% return. Therefore, Witness D'Ascendis' RPM results are unreliable and significantly overstate WGL's cost of equity.

## E. Critique of WGL's Business Risk Claims

**Q. PLEASE SUMMARIZE WITNESS D'ASCENDIS' PROPOSAL RELATED TO WGL'S PURPORTED BUSINESS RISKS ASSOCIATED WITH ITS SIZE AND ITS REGULATORY RISKS.[75]**

**A.** Witness D'Ascendis claimed that a 0.19% adjustment would be appropriate because of WGL's smaller size and heightened regulatory risk as compared to the companies in his Utility Proxy Group but did not apply such an adjustment to his ROE recommendation at this time. [76]

**Q. PLEASE RESPOND TO WITNESS D'ASCENDIS' CLAIM THAT WGL'S SMALLER SIZE RELATIVE TO COMPANIES IN HIS PROXY GROUP INDICATES GREATER BUSINESS RISK.**

**A.** The evidence indicates that investors do not demand a higher expected return on equity to invest in small companies as compared to larger ones. The Stocks, Bonds, Bills, and

---

[75] *See* Exhibit WG (C) (D'Ascendis) at 43:3-49:14.

[76] *See id.* at 5:7-9.

Inflation ("SBBI") 2021 Summary Edition states the following regarding the theory that investors require higher returns to invest in smaller firms:

> The size effect is not without controversy, nor is this controversy something new. Traditionally, small companies are believed to have greater required rates of return than large companies because smaller companies are inherently riskier. It is not clear, however, whether this is due to size itself, or to other factors closely related to or correlated with size . . . .[77]

Many scholars have expressed concerns with the results of older studies (1980s and 1990s) that found that smaller companies have higher required returns. Professor Aswath Damodaran said the following regarding the supposed "small cap premium:"

> Even if you believe that small cap companies are more exposed to market risk than large cap ones, this is a sloppy and lazy way of dealing with that risk, since risk ultimately has to come from something fundamental (and size is not a fundamental factor). [78]

**Q. HAVE RECENT STUDIES FOUND THAT THE RELATIONSHIP BETWEEN SIZE AND EXPECTED RETURN IS WEAK?**

**A.** Yes. A 2018 study conducted by scholars at AQR Capital Management and Yale University found that "the size effect diminished shortly after its discovery and

---

[77] Roger G. Ibbotson, James P. Harrington, Stocks, Bonds, Bills, and Inflation (SBBI), 2021 Summary Edition, at 99, available at: https://rpc.cfainstitute.org/sites/default/files/-/media/documents/book/rf-publication/2021/sbbi-summary-edition-2021.pdf.

[78] Aswath Damodaran, New York University, Stern School of Business, *Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – the 2022 Edition*, pp. 53-54 (Updated March 23, 2022) at https://pages.stern.nyu.edu/~adamodar/pdfiles/papers/ERP2022Formatted.pdf.

publication."[79] The authors of this research found that data errors plagued the early studies regarding the relationship between firm size and return. They found that the data in the earlier studies did not include delisted companies and since smaller firms are delisted more often than larger stocks, the biased data (referred to as a "delisting bias") made the returns of smaller stocks look higher than reality.[80] In light of this recent data, Witness D'Ascendis' claim that WGL's smaller size justifies an upward adjustment to WGL's ROE is unjustified and should be disregarded.

**Q. PLEASE RESPOND TO WITNESS D'ASCENDIS' CLAIM THAT IT WOULD BE APPROPRIATE TO INCREASE WGL'S ROE, IN PART, TO ACCOUNT FOR THE RELATIVELY RISKY REGULATORY ENVIRONMENT IN THE DISTRICT OF COLUMBIA.**

**A.** This Commission should base WGL's authorized ROEs on objective financial evidence, not on speculation regarding how decisions might be perceived. The purpose of regulation is to make decisions grounded in sound financial analysis and established regulatory principles—not to chase perceived grades assigned by external agencies like Regulatory Research Associates. The fact that the Commission just over a year ago significantly

---

[79] Ron Alquist, Ronen Israel, and Tobias Moskowitz, Fact, Fiction, and the Size Effect, *The Journal of Portfolio Management*, Fall 2018, at 3, available at: https://www.aqr.com/-/media/AQR/Documents/Whitepapers/Fact-Fiction-and-the-Size-Effect.pdf.

[80] *See id*. at 5-6.

increased WGL's authorized ROE from 9.25% to 9.65% in Order No. 21939 in Formal Case No. 1169 belies Witness D'Ascendis' claims in this regard.[81]

### F. Critique of WGL's Non-Price Regulated Proxy Group

**Q. SHOULD THE COST OF EQUITY FOR WGL BE BASED UPON WITNESS D'ASCENDIS' "NON-PRICE REGULATED PROXY GROUP"?[82]**

**A.** No. Witness D'Ascendis' Non-Price Regulated Proxy Group of 52 companies[83] should not be used because the companies in this group are not comparable in risk to WGL. As a regulated utility, WGL has accepted an obligation to serve within its service territory in exchange for the opportunity to recover its costs and earn a return on its investments. Non-price regulated companies have a different business model and are exposed to different risks. Non-price regulated companies face the risk that their customers will no longer purchase their product if they raise prices to cover increasing costs. WGL, on the other hand, can file for a rate increase to address increasing costs.

The companies in Witness D'Ascendis' Non-Price Regulated Proxy Group are exposed to lawsuits, political risk, international markets, among many other risks to which WGL is not exposed. For example, one of his non-price regulated companies, Booz Allen Hamilton operates in the defense and government contracting sectors. Booz Allen

---

[81] *See Formal Case No. 1169*, Order No. 21939 at ¶¶ 2, 60, 83, 94, & 95.

[82] *See, e.g.*, Exhibit WG (C) (D'Ascendis) at 40:5-12 (explaining that Witness D'Ascendis used a non-price regulated proxy group of 52 domestic companies). *See also* Exhibit WG (C)-6; Exhibit WG (C)-7.

[83] *See, e.g.*, Exhibit WG (C)-7 at 1.

Hamilton's revenue often depends on government defense spending and specific project contracts, exposing them to unique political and operational risks. Utilities, in contrast, provide essential services with regulated rates, creating a different risk profile not influenced by federal defense budgets or competitive contract bidding

Additionally, Pfizer, Inc. is a pharmaceutical and biomedical company; its primary activities involve drug discovery, development, and commercialization. These activities are vastly different from utility services. Pharmaceutical companies typically have high research and development costs and face regulatory risks distinct from those encountered by utilities (e.g., FDA approval processes), and their earnings are also subject to market demand for specific drugs, rather than the stable demand typical for utilities.

Regulated gas utilities, including WGL, are not impacted by many of these factors at all, or are impacted to a significantly lower degree because WGL does not have international operations and if its earnings decline, it is impacted for a limited period of time because it can apply for a rate increase. None of the companies in Witness D'Ascendis' Non-Price Regulated Proxy Group can file for a rate case if there is political unrest in one of their international, for example, harms earnings.

**Q. IS WITNESS D'ASCENDIS' USE OF A NON-PRICE REGULATED PROXY GROUP CONSISTENT WITH *HOPE* AND *BLUEFIELD*?**

**A.** No, Witness D'Ascendis' use of a non-price regulated proxy group is not consistent with *Hope* and *Bluefield* because the companies in his non-price regulated proxy group are not utilities of commensurate risk to WGL. As explained above, many of the companies are riskier than WGL and could be considered highly profitable enterprises or speculative ventures. *Bluefield* states that a public utility "has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."[84]

The reliance on these results would thus not reflect the adequate balance between ratepayers and investors as the *Hope* and *Bluefield* standards, as well as the Commission's precedent, require. Therefore, the results of WGL's non-price regulated proxy group should be disregarded.

### G. Reasonableness Tests of Witness D'Ascendis' COE Model Results

**Q. WITNESS D'ASCENDIS STATES ON PAGE 4 OF HIS DIRECT TESTIMONY THAT THE RESULTS OF HIS MODELS BASED ON THE NON-PRICE REGULATED PROXY GROUP SERVE AS A CHECK ON THE REASONABLENESS OF HIS OTHER ANALYTICAL MODELS.[85] DOES WITNESS D'ASCENDIS' NON-PRICE REGULATED PROXY GROUP RESULTS SERVE AS A REASONABLE CHECK OF WITNESS D'ASCENDIS' UTILITY PROXY GROUP-BASED COE MODELS?**

**A.** No. Stock options traded on the S&P 500 Index imply a probability distribution which represents the growth scenarios investors currently see as plausible for the market in aggregate. Using this probability distribution along with the risk-free rate and betas of the Utility Proxy Group (i.e., the proxy group of 6 gas utility companies relied on by Witness

---

[84] *Bluefield*, 262 U.S. at 692-693.

[85] *See* Exhibit WG (C) (D'Ascendis) at 4:9-11.

D'Ascendis and me), I calculated that Witness D'Ascendis 10.50% ROE recommendation means that market growth would have to exceed 69.9% of all such scenarios deemed plausible by investors, considerably more than the median market consensus at 50%.[86] To put this into perspective, it is important to note that values on the tails of the probability distribution function get increasingly separated, requiring an ever-increasing growth rate for every additional percentage in the cumulative probability, and making it impossible to ever arrive at 100%.

Using exactly the same methodology, my COE result of 8.22% implies a cumulative probability of 56.0%, very much in line with the median market consensus at 50%.

## V. COST OF EQUITY IN TODAY'S FINANCIAL MARKETS

**Q. YOU PREVIOUSLY MENTIONED THAT YOUR ROE RECOMMENDATION OF 8.22% IS CONSISTENT WITH CURRENT CAPITAL MARKET CONDITIONS. WHAT TYPES OF CAPITAL MARKET FACTORS DO YOU RELY ON IN DETERMINING CURRENT CAPITAL MARKET CONDITIONS?**

**A.** My conclusion that a 8.22% ROE is sufficient for WGL to be able to raise capital is primarily based on the interplay between the following four capital market factors: (A) inflation and interest rates, (B) the relative risk/cost of equity for gas utility companies

---

86 *See* Exhibit OPC (D)-3.

(including WGL), (C) the cost of equity for the overall market, and (D) investors' volatility expectations. I discuss each of these components in detail in Exhibit OPC (D)-13. First, however, I will provide a summary of the individual issues.

**Q. PLEASE SUMMARIZE WHY THESE FOUR CAPITAL MARKET FACTORS SUPPORT YOUR 8.22% ROE RECOMMENDATION FOR WGL.**

**A.** The following summary of each of these market factors or developments shows how they impact the COE:

**Inflation and Interest Rates.** It is reasonable to ask how interest rates are impacting the cost of equity. All else equal, higher interest rates mean a higher cost of equity. However, as discussed below, all else is not equal and we must look beyond inflation and interest rates. The Federal Reserve ("the Fed") has increased short-term interest rates (the Federal Funds Rate) from near 0% to a high of 5.25% - 5.50%, but has decreased the range to 4.5% to 4.7% as November 30, 2024.[87] As shown on Chart 2 in Exhibit OPC (D)-13, investors expect the Federal Reserve to continue lowering the Federal Funds Rate in 2025. Long-term interest rates have decreased since October 31, 2023, as well, with the yield on the 30-year U.S. Treasury bond (which both Witness D'Ascendis and I use in our respective CAPM analyses) decreasing from about 5.04% to about 4.4% as of November 30, 2024. Chart 2 shows that as of July 9, 2024, investors expected the Fed to reduce the Federal Funds Rate to about 3.6% by June 2026. As of October 2024, investors expected the Fed to reduce this rate to about 3.2%. As shown on Chart 3 in

[87] Federal Reserve Bank of New York, *Effective Federal Funds Rate*, available at: https://www.newyorkfed.org/markets/reference-rates/effr.

Exhibit OPC (D)-13, investors expect inflation to decrease over the next few years. These recent changes in inflation and interest rate expectations is likely putting more downward pressure on WGL's cost of equity, as gas utility stocks have outperformed the overall market over the past year ending November 30, 2024.

**Relative risk/cost of equity of gas utility stocks.** Capital market data indicates that the cost of equity for gas utility companies remains below that of the overall market. There are many cross currents in today's capital markets. However, I would like to emphasize that since the end of 2022 there has been a downward trend in the cost of equity of both the overall market and gas utility stocks, specifically. Indeed, as shown in Chart 12 in Exhibit OPC (D)-13, despite relatively high volatility expectations for the companies in the Rothschild Gas Proxy Group, investors' expectations regarding the chance of a large drop in utility stock prices, or investors' perceived downside risk, remain significantly below those for the overall market, which indicates that the relative cost of equity for gas utility companies remains below the overall market.[88] Additionally, the beta coefficients[89] of gas utility stocks have declined sharply since March 2024, also indicating that the cost of equity for gas utility stocks has been decreasing compared to the overall market.

---

88 Option-implied skewness represents investors' expectations regarding the asymmetry of the probability distribution for stock price movements. Option-implied skewness is further discussed in Exhibit OPC (D)-13 in the section titled Investor-Perceived Downside Risk (Option-Implied Skewness).

89 As discussed in Section E. Capital Asset Pricing Model, a beta coefficient measures the type of risk that most impacts a firm's cost of equity, i.e., systematic risk. As also equal, the higher the beta the higher the cost of equity.

**Cost of equity for the overall market.** Global stock markets have been increasing in recent years, with the S&P 500 rising about 31% since December 2023.[90] An Economist article published in July reported that "[a]ll around the world, stock markets have been rising at a breakneck pace" and "[v]aluations, or the multiples by which underlying earnings are scaled up to generate share prices, have risen from expensive to alarming."[91] Stock prices have increased at a faster clip than earnings, leading to higher price-to-earnings ratios. In other words, investors have been willing to pay a higher premium for earnings. This rise in price-to-earnings ratios (among other market data) indicates that the cost of equity for the overall market (e.g. S&P 500) has been declining over the last two years and is at historical lows. J.P. Morgan's 3Q 2024 Guide to the Markets reported that the forward price-to-earnings ratio of the S&P 500 is significantly higher as of August 31, 2024 (21.2) than over the 20-year average (15.7). The utility section, according to J.P. Morgan, has as higher than average price-to-earnings ratio, 17.9 currently compared to a 20-year average of only 15.7.[92]

**Stock price volatility.** As shown on Chart 10 in Exhibit OPC (D)-13, investors' volatility expectations for the overall market decreased considerably between October 2022 and November 2024. Despite a spike in late September and early October 2023, market volatility expectations remain significantly lower than the highs of October 2022.

---

[90] S&P 500 was 4,954.63 on the first trading day of December 2023 and $6,032.38 on the last trading day of November 2024. (6,032.38-4,594.63)/4,594.63 = 31.29%.

[91] The Economist, "*Stocks are on an astonishing run. Yet threats lurk*", (published July 16, 2024), https://www.economist.com/finance-and-economics/2024/07/16/stocks-are-on-an-astonishing-run-yet-threats-lurk.

[92] J.P. Morgan Asset Management, *U.S. 3Q 2024 Guide to The Markets, As of August 31, 2024*, page 15.

Like high price-to-earnings ratios, the relatively low market volatility expectations of investors indicate a lower cost of equity. However, as discussed above, the volatility expectations for the companies in the Rothschild Gas Proxy Group have declined in recent months but as of November 30, 2024, the average volatility expectations of the companies in the Rothschild Gas Proxy Group remain higher than the overall market.

I elaborate on each of the above points in Exhibit OPC (D)-13.

## VI. COST OF EQUITY CALCULATIONS

**Q. HOW DID YOU ARRIVE AT YOUR COE RECOMMENDATION?**

**A.** To arrive at my recommendation, I applied the DCF, including a Constant Growth and a Non-Constant Growth method, and a CAPM analysis to the same group of companies used in WGL Witness' Utility Proxy Group (referred to in my testimony as the "Rothschild Gas Proxy Group")[93] using data available through November 30, 2024, as discussed below. In all of my models, I use both historical averages and the most recently available spot data for the inputs wherever it is possible and applicable.

---

[93] See Table 6 for a list of the companies in the Rothschild Gas Proxy Group This is the same proxy group as Witness D'Ascendis**.** This is not surprising as there is a small pool of commensurate companies that are also evaluated by Value Line.

**Q. PLEASE SUMMARIZE HOW YOU DETERMINED YOUR 8.22% COST OF EQUITY RECOMMENDATION FOR WGL.**

**A.** To arrive at my recommendations, I applied the Constant Growth form of the Discounted Cash Flow Model[94] to the Rothschild Gas Proxy Group using data available through November 30, 2024. I also used a CAPM analysis both as a check on the DCF results and to ensure the Commission is able to consider how inflation and interest rates are impacting WGL's cost of equity. I use a proxy group to calculate WGL's cost of equity because WGL does not have publicly traded stock data needed for COE models. Additionally, using a proxy group provides more reliable results because it is less likely to be skewed by specific circumstances or anomalies faced by any individual company.

As shown in Table 5 on page 52, Cost of Equity Model Results, the high-end results of my three cost of equity models, including eight variations of the CAPM, range between 6.73% and 9.03%, with an upper percentile of 8.22%. The low-end results of my three cost of equity models, including eight variations of the CAPM, range between 6.65% and 8.22%, with a lower percentile of 6.73%.

---

[94] The constant growth DCF model is a variant, or version, of the single-stage DCF model that uses a consistent, never-changing growth rate component in perpetuity.

| TABLE 5: COST OF EQUITY MODEL RESULTS | | |
|---|---|---|
| **DCF** | **Low** | **High** |
| Constant Growth - Sustainable Growth | 8.22% | 8.32% |
| Constant Growth - Option-Implied Growth | 7.90% | 9.03% |
| Non-Constant Growth | 7.32% | 7.82% |
| **CAPM** | | |
| **Spot (Nov. 30, 2024)** | | |
| Risk Free Rate - 3-Month T Bill | 6.73% | 6.80% |
| Risk Free Rate - 30-Yr T Bond | 6.65% | 6.73% |
| **3-Mo. Weighted Average (Sep. to Nov. 2024)** | | |
| Risk Free Rate - 3-Month T Bill | 6.98% | 7.12% |
| Risk Free Rate - 30-Yr T Bond | 6.87% | 7.03% |
| **Outer Percentile Range** | **6.73%** | **8.22%** |
| **Midpoint of Range** | **7.47%** | |

Exhibit OPC (D)-4

**Q. ARE YOUR COE MODELS BASED ON ESTABLISHED METHODOLOGIES?**

**A.** Yes. My constant growth DCF model is used by major financial institutions. J.P. Morgan Chase uses the sustainable growth form of the DCF method, as I do, in its 2019 Long-Term Capital Market Assumptions publication.[95] *Principles of Corporate Finance*, a leading financial textbook used in business schools and investment banks around the world, recommends using the very same method I use to calculate the cost of equity for regulated energy utility companies.[96] As discussed in Section E, Capital Asset Pricing Model, my CAPM is based on methodologies used by Value Line, the Chicago Board of Options Exchange ("CBOE"), and published in peer-reviewed academic journals (e.g., The Review

---

[95] 23rd Annual Edition, Long-Term Capital Market Assumptions - Time-tested projections to build stronger portfolios, pp. 62-63.

[96] Brealey, Myers, and Allen (2017), Principles of Corporate Finance, 12th Edition, McGraw-Hill Irwin, New York, page 86-87.

of Financial Studies). My CAPM method has also been recognized by state utility commissions. For instance, on April 9, 2020, the Public Service Commission of South Carolina stated the following:

> Amongst the three witnesses, Consumer Affairs Rothschild's approach was unique in that he included the use of both historical and forward-looking, market-based data in his analysis. Based on the testimony and facts presented, the Commission therefore adopts the recommended ROE of 7.46% proposed by witness Rothschild.[97]

**Q. PLEASE EXPLAIN WHY IT IS IMPORTANT FOR WGL'S AUTHORIZED ROE TO BE BASED ON CAPITAL MARKET DATA.**

**A.** As explained below, I use current market prices (e.g., stocks, bonds, options), which measure investors' expectations directly, instead of relying solely on historical data and analyst forecasts.

A COE based on current market prices (market-based) is superior to a COE based on historical data (non-market-based) for two reasons:

1. The COE that WGL has to pay investors is based on capital markets. Inflation and interest rate developments are not a secret and therefore market-based COE models will reflect investors' changing expectations.
2. Capital markets are unpredictable. Regarding capital markets' unpredictability, investment guru Warren Buffet gave the following advice

---

[97] *Application of Blue Granite Water Company for Approval to Adjust Rate Schedules and Increase Rates*, Order Ruling on Application for Adjustment in Rates, Public Service Commission of South Carolina Docket No. 2019-290-WS, Order No. 2020-306, rel. April 9, 2020, p. 43, available at: https://dms.psc.sc.gov/Attachments/Order/6bc32f94-f706-4d01-bd64-7be95ae75612.

> to investors: "[t]hey should not listen to a lot of the jabbering about what the market is going to do tomorrow, or next week or next month because nobody knows."[98]

Current capital markets are our best source of investors' expectations regarding future capital markets. Current market prices of stocks and bonds reflect investors' forecasts for long-term interest rates and capital markets in general.

**Q. CONSIDERING THAT STOCK AND OPTION PRICES AND BOND YIELDS CHANGE DAILY, WOULD IT NOT BE BETTER TO USE HISTORICAL AVERAGES EXCLUSIVELY FOR THE INPUTS IN YOUR MODELS?**

**A.** Not necessarily. Most people would agree that the use of spot market data, the value of a particular input on a particular day, can lead to COE results that can vary over short periods of time. It may therefore be tempting to find a more stable value based on historical averages that are not overly influenced by short-term fluctuations in capital markets. When doing a forward-looking analysis, however, it is equally important to look at the most recent market data as an indication of trends and where a given value is more likely to be in the future. This is a broad and generally accepted principle, as made clear in the following example.

Using historical stock prices to make the point clear, if Company A's stock price were to go up linearly over the course of one year from $50 to $100, its average stock price

---

[98] PBS News Hour, June 26, 2017, Part 1 – *America should stand for more than just wealth, says Warren Buffett*, available at: https://www.pbs.org/newshour/show/america-stand-just-wealth-says-warren-buffett (video time stamp: 8:00-8:08).

over that year would be $75. If Company B's stock price declined linearly from $100 to $50 over the same year, it would have the same exact average stock price of $75. But most people would agree that predicting both stock prices at $75 over the near future would be overly simplistic and leave readily accessible data unused. Without relying on any additional data, at the very least, it would stand to reason that in the near future, Company A's stock price is more likely to be between $75 and $100 than Company B's stock price, and that Company B's stock price is more likely to be between $50 and $75 than Company A's stock price. These observations cannot be made by looking at the yearly averages alone and must take the most recent data into special consideration.

This does not eliminate concerns regarding the effect of daily fluctuations in market data, especially during periods of volatility. As a result, it is important to consider both averages and recent spot values when using market data for forward-looking analyses. That is precisely my approach when using market data that are expected to continue to fluctuate, such as stock prices, dividend yields, betas, and market risk premia.

**Q. CAN A DIFFERENCE OF ONE DAY IN THE SELECTION OF SPOT DATA HAVE A SIGNIFICANT POSITIVE OR NEGATIVE EFFECT ON ROE RESULTS? IF SO, HOW DO YOU GO ABOUT CHOOSING WHICH DAY TO USE FOR MARKET-BASED SPOT DATA?**

**A.** Daily fluctuations in stock prices, resulting dividend yields, betas, etc., all have an impact on resulting ROE calculations, especially when using recent spot values for market data. Such is the nature of market data, which changes from day to day. This is rightfully noted as a potential risk of using spot data, but given the stated benefits of using recent spot data for forward-looking analyses, there are ways to address such potential pitfalls.

For instance, it is very important to establish consistent methodologies that eliminate the possibility of personal bias, especially when using spot market data. I consistently use the last trading day of the last full calendar month before my schedule preparations for all market-based spot data and as the last day for all historical market-data averages. It is also important to keep in mind that even averages fluctuate over time, and all responsible data analysts must find a consistent and reproducible way to "freeze time" to work with such fluctuations while eliminating bias. In this regard, I believe it is important to point out once again that I use recent spot market data to establish one benchmark for market-based inputs, which are balanced by the use of historical averages, as stated previously.

## A. Proxy Group Selection

**Q. WHAT PROXY GROUPS DID YOU USE TO CALCULATE WGL'S COE?**

**A.** My comparable proxy group, shown on Table 6 on page 57 and referred to as the Rothschild Gas Proxy Group, consists of the following 6 publicly traded gas utility companies covered by Value Line:

**TABLE 6: ROTHSCHILD GAS PROXY GROUP COMPOSITION**

| | Company Name | Ticker |
|---|---|---|
| 1 | Atmos Energy Corporation | ATO |
| 2 | NiSource, Inc. | NI |
| 3 | New Jersey Resource Corporation | NJR |
| 4 | Northwest Natural Holding Company | NWN |
| 5 | ONE Gas, Inc. | OGS |
| 6 | Spire, Inc. | SR |

## B. Discounted Cash Flow

**Q. PLEASE SUMMARIZE THE RESULTS OF YOUR DCF MODELS.**

**A.** I used both the constant growth form of the DCF method, which determines growth based on the sustainable retention growth procedure, and a non-constant growth DCF method. The results of my constant growth DCF model range between 8.22% and 8.32% when using a sustainable growth rate and between 7.90% and 9.03% when using an option-implied growth rate.[99] The results of my non-constant growth DCF method indicate a COE of between 7.32% and 7.82% for the Rothschild Gas Proxy Group.[100]

**Q. WHAT IS THE DISCOUNTED CASH FLOW METHOD?**

**A.** The DCF method is an approach to determine the COE. The method recognizes that investors purchase common stock to receive future cash payments. These payments come from: (a) current and future dividends, and (b) proceeds from selling stock. A rational

---

99 Exhibit OPC (D)-5 at 1.

100 *Id.* at 3 and 4.

investor will buy stock to receive dividends and ultimately to sell the stock to another investor at a gain. The price the new owner is willing to pay for stock is related to that buyer's expectation of future flow of dividends and the future expected selling price. The value of the stock is the discounted value of all future dividends until the stock is sold plus the value of proceeds from the sale of the stock.

### C. Constant Growth Form of the DCF Model

**Q. YOU STATE YOU USED THE CONSTANT GROWTH FORM OF THE DCF MODEL. WHAT IS THE CONSTANT GROWTH FORM OF THE DCF MODEL?**

**A.** The constant growth form of the DCF model is a form of the DCF method that can be used in determining the COE when investors can reasonably expect that the growth of retained earnings and dividends will be constant.

Retained earnings are funds that a company keeps in its treasury, so that they are available for future needs, such as capital expenditures, debt payments, and new investments. These retained earnings show investors whether the company is growing, which, in turn, is a measure of the future indicator of dividends and the value of a company's stock.

**Q. DESCRIBE HOW THE CONSTANT GROWTH MODEL WORKS.**

**A.** The constant growth model is described by this equation $k = D/P + g$, where: [101]

k= cost of equity (COE);

[101] M. Gordon, *Cost of Capital to a Public Utility*, p. 32-33 (MSU Public Utility Studies 1974).

D=Dividend; and
P=Market price of stock at time of the analysis

and where:

g=the growth rate, where g= br + sv;
b=the earnings retention rate;
r=return on common equity investment (referred to below as "book equity");
v=the fraction of funds raised by the sale of stock that increases the book value of the existing shareholders' common equity; and
s=the rate of continuous new stock financing

The constant growth model is therefore correctly recognized to be:

k=D/P + (br +sv)

The COE demanded by investors is the sum of two factors. The first factor is the dividend yield. The second factor is growth (dividends and stock price). The logical relationship among these factors is as follows: the dividend yield is calculated based on current dividend payments while growth indicates what dividends and stock price will be in the future.

**Q. WHAT OTHER FACTORS IMPACT HOW ONE USES THE CONSTANT GROWTH FORM OF THE DCF MODEL?**

**A.** Sufficient care must be taken to be sure that the growth rate "g" is representative of the constant sustainable growth. To obtain an accurate constant growth DCF result, the mathematical relationship between earnings, dividends, book value and stock price must be respected.

The basic difference between the use of an analysts' earnings per share growth rate in the constant growth DCF formula and using the "br" (b (the earnings retention rate) X r (rate of return on common equity investment)) approach is that the "br" form, if properly applied, eliminates the mathematical error caused by an inconsistency between the expectations for earnings per share growth and dividends per share growth. Because it eliminates that error, the results of a properly applied "br" approach will be superior to the answer obtained from other approaches to the constant growth form of the DCF model. This is not to say that even a properly applied "br" approach will be perfect. The self-correcting nature of a properly applied "br" to forecasted differences in earnings per share and dividends per share growth rates helps to mitigate the resultant error but should not be viewed as the perfect way to quantify the impact of expected non-constant growth rates.

**Q. HOW HAVE YOU IMPLEMENTED THE CONSTANT GROWTH FORM OF THE DCF MODEL IN THIS CASE?**

**A.** I have applied the constant growth form of the DCF model by staying true to the mathematically derived "k=D/P + (br + sv)" form of the DCF model. I have also taken care to fully allocate all future expected earnings to either future cash flow in the form of dividends ("D") or to retained earnings (the retention rate, "b"). This extra accuracy is obtained only when the retention rate "b" is derived from the values used for "D" and "r," rather than independently.

**Q. PLEASE EXPLAIN HOW YOU OBTAINED THE VALUES YOU USED IN THE CONSTANT GROWTH FORM OF THE DCF METHOD.**

**A.** The DCF model generally calls for the use of the dividend expected over the next year. A reasonable way to estimate next year's dividend rate is to increase the quarterly dividend rate by half of the current actual quarterly dividend rate. This is a good approximation of the rate that would be obtained if the full prior year's dividend were escalated by the entire growth rate.[102]

I obtained the stock price—"P"—used in my DCF analysis from the closing prices of the stocks on November 30, 2024. I also obtained an average stock price for the 12 months ending November 30, 2024 by averaging the high and low stock prices for the year.

I based the value of the future expected return on equity— "r" —on the average return on book equity expected by Value Line, adjusted in consideration of recent returns. I also made a computation that was based on a review of both the earned return on equity consistent with analysts' consensus earnings growth rate expectations and on the actual earned returns on equity. For a stable industry such as utility companies, investors will typically look at actual earned returns on equity as one meaningful input into what can be expected for future earned returns on book equity.[103]

This return on book equity expectation used in the DCF method to compute growth must *not* be confused with the COE. Since the stock prices for the comparative companies are substantially higher than their book value, the return investors expect to receive on their

---

[102] For example, assume a company paid a dividend of $0.50 in the first quarter a year ago, and has a dividend growth rate of 4 % per year. This dividend growth rate equals (1.04)^4-1=0.00985 % per quarter. Thus, the dividend is $0.5049 in the second quarter, $0.5099 in the third quarter, and $0.5149 in the fourth quarter. If that 4 % per annum growth continues into the following year, then the dividend would be $0.5199 in the 1st quarter, $0.5251 in the 2nd quarter, $0.5303 in the 3rd quarter, and $0.5355 in the 4th quarter. Accordingly, the total dividends for the following year equal $2.111 (0.5199 + 0.5251 + 0.5303 + 0.5355). I computed the dividend yield by taking the current quarter (the $0.5149 in the 4th quarter in this example) and multiplying it by 4 to get an annual rate of $2.06. I then escalated this $2.06 by half the 4 % growth rate, which means it is increased by 2 %. $2.06 x 1.02= $2.101, which is within one cent of the $2.111 obtained in the example.

[103] *See* Exhibit OPC (D)-5 at 1.

market price investment is considerably less than the anticipated return on book value. If the market price is low relative to book value, the COE will be higher than the future expected return on book equity, and if the market price is high, then the return on book equity will be less than the COE.

In addition to growing through the retention of earnings, utility companies also grow by selling new common stock. Selling new common stock increases a company's growth. I quantified this growth caused by the sale of new common stock by multiplying the amount that the actual market-to-book ratio exceeds 1.0, by the compound annual growth rate of stock that Value Line forecasts. The results of that computation are shown on line 4 of Exhibit OPC (D)-5, page 1.

Pure financial theory prefers concentrating on the results from the most current price because investors cannot purchase stock at historical prices. There is a legitimate concern, however, about the potential distortion of using just a single price. I present DCF results based on the most recent stock pricing data available when performing my analysis (November 30, 2024) as well as the average of the high and low stock price over the past 12 months to obtain a range of reasonable values. As shown in Exhibit OPC (D)-5, page 1, the DCF result based on the average of the high and low stock price for the year ending November 30, 2024 is 8.22%. The DCF result based on the stock price as of November 30, 2024 is 8.32%. Exhibit OPC (D)-5, page 1, shows more of the specifics of how I implemented the constant growth form of the DCF model for the Rothschild Gas Proxy Group.

**Q. PLEASE EXPLAIN HOW YOU DETERMINED WHAT VALUE TO USE FOR "r" WHEN COMPUTING GROWTH IN YOUR CONSTANT GROWTH FORM OF THE DCF MODEL.**

**A.** The inputs I considered are shown in Footnote [C] of Exhibit OPC (D)-5, page 1. The value of "r" that is appropriate to use in the DCF formula is the value anticipated by investors to be maintained on average in the future. This Exhibit shows that the average future return on equity forecasted by Value Line for the Rothschild Gas Proxy Group between 2024 and 2027-29 is 9.25%. The same footnote also shows that the future expected return on equity derived from the Zacks consensus forecast is 8.03%, and that the actual returns on equity earned by the Rothschild Gas Proxy Group on average were 10.01% in 2021, 9.85% in 2022, and 9.24% in 2023. Based on the combination of the forecasted return on equity derived from the Zacks consensus, the recent historical actual earned returns, and Value Line's forecast, I made the DCF growth computation using a 8.80%[104] value of "r".

**Q. PLEASE EXPLAIN HOW YOU DETERMINED WHAT VALUE TO USE FOR "sv" WHEN COMPUTING GROWTH IN YOUR CONSTANT GROWTH FORM OF THE DCF MODEL.**

**A.** The inputs I considered are shown in Exhibit OPC (D)-5, page 5. The value of "sv" that is appropriate to use in the DCF formula is the average growth in common shares outstanding

---

[104] I used 8.80% in consideration of historical returns, Zacks' projections, and Value Line projected returns for the Rothschild Gas Proxy Group. *See* Exhibit OPC (D)-5 at 1.

on average in the future. This Exhibit shows that the average growth rate in outstanding shares forecasted by Value Line for the Rothschild Gas Proxy Group between 2019 and 2028 is 2.59%. The same exhibit also shows that the average expected growth in shares outstanding forecasted by Value Line is 2.00% between 2023 and 2028 and this growth rate was 3.34% between 2019 and 2023. Based on the combination of the forecasted and recent historical actual growth in common stock outstanding, I made the DCF growth computation using a 2.59%[105] value of "sv".

**Q. WHAT COE IS INDICATED BY THE CONSTANT GROWTH FORM OF THE DCF METHOD THAT YOU RELY ON FOR YOUR RECOMMENDATION?**

**A.** The result of my DCF analysis using the Constant Growth form of the DCF indicates a COE range of between 8.22% and 8.32% for the Rothschild Gas Proxy Group.[106] Since these DCF findings use analysts' forecasts to derive sustainable growth (in part) and on analysts' forecasts of dividend growth and book value growth in the non-constant form of the DCF method, the results should be considered as conservatively high. This is because, as previously mentioned above, analysts' forecasts of such growth have been notoriously overstated.

My results are not as influenced by overly optimistic analysts' forecasts as would have been the case had I merely used analysts' five-year earnings growth rate forecasts as a proxy for long-term growth. This is because the DCF methods I use compute sustainable

---

[105] *See* Exhibit OPC (D)-5 at 1.

[106] *See* Exhibit OPC (D)-5 at 1.

growth rates, rather than growth rates that can exaggerate the growth rate due to assuming that a relatively short-term forecast (5 years) will remain indefinitely.

## D. Non-Constant Growth Form of the DCF Model

**Q. PLEASE EXPLAIN HOW YOU IMPLEMENTED THE NON-CONSTANT GROWTH FORM OF THE DCF MODEL.**

**A.** The non-constant growth form of the DCF model determines the return on investment expected by investors based on an estimate of each separate annual cash flow the investor expects to receive. For the purpose of this computation, I have incorporated Value Line's detailed annual forecasts to arrive at the specific non-constant growth expectations that an investor who trusts Value Line would expect. This implementation is shown on Exhibit OPC (D)-5, page 3 and Exhibit OPC (D)-5, page 4. In the first stage, cash flow entry is the cash outflow an investor would experience when buying a share of stock at the market price. The subsequent years of cash flow are equal to the dividends per share that Value Line forecasts. For the intermediate years of the forecast period in which Value Line does not provide a specific dividend, the annual dividends were obtained by estimating that dividend growth would persist at a compound annual rate. The cash flow at the conclusion of the forecast period includes both the final year's dividend as projected by Value Line and the proceeds from selling the stock. The stock price used to determine the proceeds from selling the stock was obtained by estimating that the stock price would grow at the same rate at which Value Line forecasts book value to grow.

**Q. WHY DID YOU USE BOOK VALUE GROWTH TO PROVIDE THE ESTIMATE OF THE FUTURE STOCK PRICE?**

**A.** For any given earned return on book equity, earnings are directly proportional to the book value. Furthermore, book value growth is the net result after the company produces earnings, pays a dividend and also, perhaps, either sells new common stock at market price or repurchases its own common stock at market price.

Once these cash flows are entered into an Excel spreadsheet, the compound annual return an investor would achieve as a result of making this investment was obtained by using the Internal Rate of Return ("IRR") function built into the spreadsheet. As shown on Exhibit OPC (D)-5, page 3 and Exhibit OPC (D)-5, page 4, this multi-stage DCF model produced an average indicated COE of 7.32% based on the year-end stock price, and 7.82% based on average prices for the year ending November 30, 2024 for the Rothschild Gas Proxy Group.

**Q. WHAT COST OF EQUITY DOES YOUR NON-CONSTANT GROWTH DCF METHOD INDICATE?**

**A.** My non-constant growth DCF method indicates a cost of equity of between 7.32% and 7.82%.[107]

[107] *See id*. at 3 & 4.

## E. Capital Asset Pricing Model

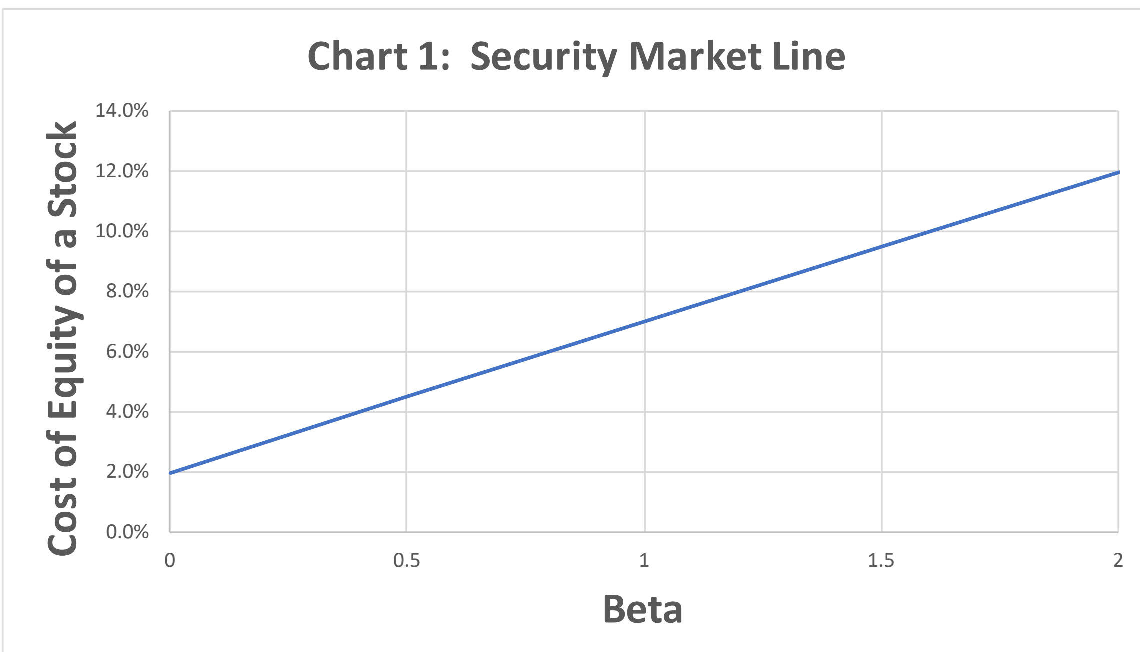
**Q. PLEASE DESCRIBE THE CAPM.**

**A.** CAPM stands for "Capital Asset Pricing Model." The CAPM relates return to risk; specifically, it relates the expected return on an investment in a security to the risk of investing in that security. The riskier the investment, the greater the expected return (i.e., the cost of equity) investors require to make that investment.

Investors in a firm's equity face two types of risks: (1) firm-specific risk and (2) market risk (financial analysts refer to this market risk as systematic risk). Firm-specific risk refers to risks unique to the firm, such as management performance and losing market share to a new competitor. Investors can reduce firm-specific risk by purchasing stocks as part of a diverse portfolio of companies if they construct the portfolio to cause the firm-specific risk of individual companies to balance out. Market-related risk refers to potential impacts from the overall market, such as a recession or interest rate changes. This risk cannot be removed by diversification, so the investor must bear it no matter what. Because the investor has no option but to bear market risk, the investor's cost of equity will reflect that risk.

The price of a stock with a beta of 1 tends to move with the market. If the market increases by 1%, the stock is also expected to increase by about 1%, and vice versa. The price of a stock with a beta greater than 1 tends to be more volatile than the market. For example, a stock with a beta of 1.5 will on average be 50% more volatile than the market. If the market rises by 1%, the price of a stock with a beta of 1.5 is expected to rise by 1.5%, and if the market falls by 1%, the stock price is expected to decrease by 1.5%. The price of a stock with a beta less than 1 tends to be less volatile than the market.

The CAPM predicts that for a given equity security, the cost of equity has a positive linear relationship to how sensitive the stock's returns are to movements in the overall market (e.g., S&P 500). A security's market sensitivity is measured by its beta.[108] As shown in Chart 1, the higher the beta of a stock, the higher the company's cost of equity—the return required by the investor to invest in the stock.




Here is the standard CAPM formula:

$$K = Rf + \beta_{i} * (Rm - Rf)$$

Where:

K is the cost of equity;
Rf is the risk-free interest rate;

108 The covariation of the return on an individual security with the return on the market portfolio.

Rm is the expected return on the overall market (e.g., S&P 500);
[Rm – Rf] is the premium investors expect to earn above the risk-free rate for investing in the overall market ("equity risk premium" or "market risk premium"); and
βí (Beta) is a measure of non-diversifiable, or systematic, risk.

**Q. PLEASE EXPLAIN HOW YOU IMPLEMENTED THE CAPM.**

**A.** First, I determined appropriate values or ranges for each of the three model inputs: (a) Risk-Free Rate, (b) Beta, and (c) Equity Risk Premium. Second, I used the equation above to calculate the cost of equity implied by the model. Below I will explain how I calculated the three model inputs and summarize the CAPM cost of equity numbers resulting from those inputs. Table 7 and Table 8 show the results of my CAPM.

**<u>Risk-Free Rate</u>**

**Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPM?**

**A.** It is generally preferable to use the market yield on short-term U.S. Treasury yields as the risk-free rate because these bonds have a beta close to zero. *Principles of Corporate Finance* states: "The CAPM… calls for a short-term interest rate."[109] However, I chose to use a risk-free rate based on both long- and short-term Treasury yields because it is reasonable to consider a risk-free rate that would apply to both long- and short-term investors. My short-term risk-free rate is based on the yield of 3-month U.S. Treasury bills and my long-term risk-free rate is based on the yield of 30-year U.S. Treasury bonds. In line with my Spot and Weighted Average CAPM approaches, I use both spot values as of

---

[109] Brealey, Myers, and Allen, *Principles of Corporate Finance*, p. 228, (McGraw-Hill Irwin, New York, 12th ed. 2017).

November 30, 2024 and weighted averages over the 3 months ending on that date for these two yields.

As outlined in Exhibit OPC (D)-6, page 2, my spot and weighted average short-term risk-free rates are 4.58% and 4.64%, respectively. My spot and weighted average long-term risk-free rates are 4.36% and 4.34%, respectively.

U.S. government bonds are reasonable to use as a risk-free rate because they have a negligible risk of default. The value of short-term U.S. Treasury bills has a relatively low exposure to swings in the overall market. The value of long-term U.S. Treasury bonds is relatively more exposed to the market and therefore must be used with caution.

**Q. WHAT IS YOUR RESPONSE TO ANALYSTS WHO CLAIM THAT THE CAPM SHOULD BE IMPLEMENTED WITH A RISK-FREE RATE BASED ON A LONG-TERM INTEREST RATE (E.G., YIELD ON 30-YEAR TREASURY BOND) AND/OR BASED ON INTEREST RATE FORECASTS INSTEAD OF MARKET YIELDS?**

**A.** As discussed in Section VI.E, a CAPM analysis that uses a risk-free rate based only on long-term interest rates may overstate the COE because these bonds do not have a zero beta. It is not appropriate to use a risk-free rate based on interest rate forecasts because it often does not represent investors' expectations.

**Q. CURRENTLY YOUR RISK-FREE RATE BASED ON SHORT-TERM INTEREST RATES IS HIGHER THAN YOUR RISK-FREE RATE BASED ON LONG-TERM INTEREST RATES. HOW DOES THIS IMPACT YOUR CAPM RESULTS?**

**A.** It is rare for short-term interest rates to be higher than long-term interest rates because, as stated above, they are less risky than long-term bonds. At first, it seems nonsensical for an investor to accept an interest rate that is over 1% less (4.36% vs. 4.58% as of November 30, 2024). However, as shown in Chart 2 in Exhibit OPC (D)-13, the Federal Reserve Bank of Atlanta estimated that as of February 29, 2024, investors expect short-term interest rates to decrease in 2024 and 2025. This means that it is rational for investors to lock in a 4.36% interest rate on long-term bonds now if they expect short-term interest rates to decline below 4.36% in the near future. It is like a homeowner deciding to lock in a 30-year mortgage at a higher rate (e.g., 5%) than to take an adjustable-rate mortgage rate with a lower interest rate (e.g., 4%) because if short-term rates increase above 5% in the future, they could end up paying more over the life of the mortgage.

As this relates to CAPM results, this is one of the rate circumstances when a short-term risk-free rate likely overstates the COE because investors expect the relatively higher short-term interest rate to be temporary. Another way to put it is the following: investors expect that the interest income from short-term treasuries (3-months) will be lower than the interest income from long-term treasuries (30-years) over the long-term.

**<u>Beta</u>**

**Q. WHAT BETA DID YOU USE IN YOUR CAPM?**

**A.** Since the cost of equity should be based on investor expectations, I chose to use two betas. My “forward beta” is based on forward-looking investor expectations of non-diversifiable risk. My “historical blended” is based on historical return data over 6-month, 2-year, and 5-year periods.

Most published betas are based exclusively on historical return data. For example, Value Line publishes a 5-year historical beta for each of the companies it covers. However, it is also possible to calculate betas based on investors’ expectations of the probability distribution of future returns. This probability distribution of future returns expected by investors can be calculated based on the market prices of stock options.

**Q. WHAT IS A STOCK OPTION?**

**A.** A stock option is the right to buy or sell a stock at a specific price for a specified amount of time. A call option is the right to buy a stock at a specified exercise or strike price on or before a maturity date. A put option is the right to sell a stock at a specified exercise or strike price on or before a maturity date. For example, a call option to purchase 100 shares of Apple Computer stock for $230 on January 17, 2020, allows the owner the option (not the obligation) to buy Apple stock for $230 on that date. At the end of July 2019, Apple stock was trading at about $215 per share. Why would anyone pay for the right to buy a stock higher than the current price? Investors who purchased those call options thought there was a chance Apple stock would be trading higher than $230 on January 17, 2020, and those options gave those investors the right to buy Apple stock for $230 and profit by selling it at the market price on that date, if it was higher. The price of Apple's stock was $317.98 at the close of trading on January 17, 2020. Therefore, the investor who purchased this call option for $635 on July 31, 2019, earned a profit of $8,163[110] at expiry on January 17, 2020. On the other hand, the investor who purchased an Apple put option with the same expiration date and strike price on July 31, 2019, would have lost the price of the option ($2,248) and gained nothing on the expiration date because the right to sell Apple stock for $230 when the price is over $300 is worthless.

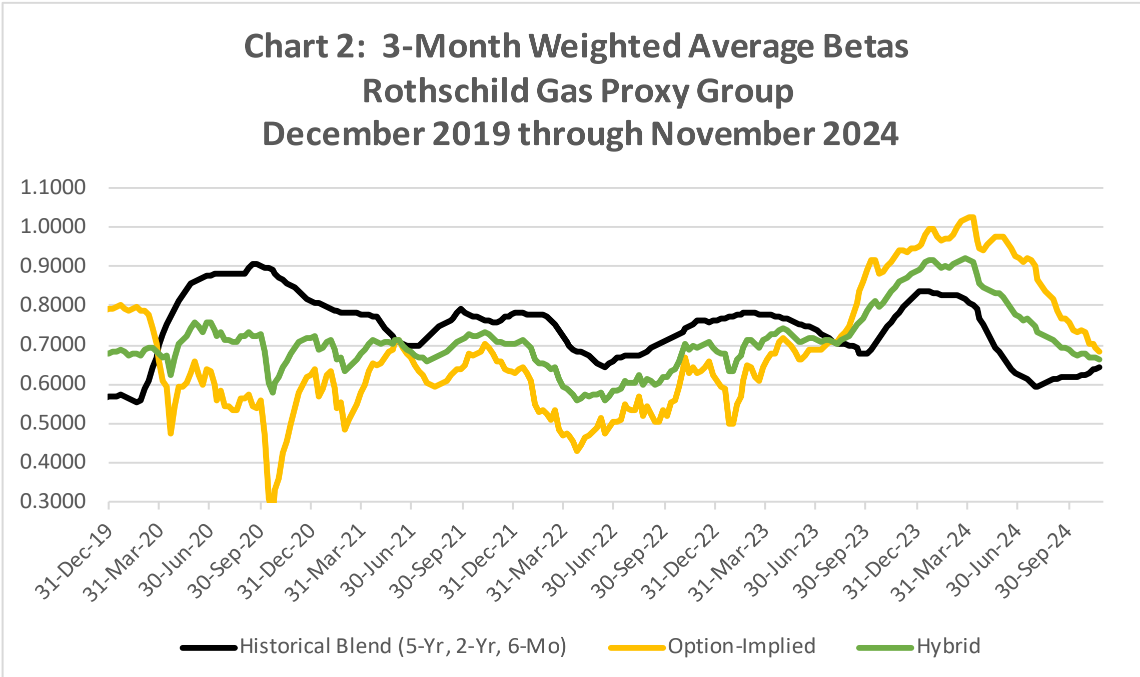
The market prices of put options and call options provide information regarding the probability distribution of future stock prices expected by investors. Using established techniques, I am able to use price data for stock options of my Rothschild Gas Proxy Group companies and the S&P 500 Index to determine investors' return expectations, including the relationship (covariance) between the return expectations for individual Rothschild Gas Proxy Group companies and those for the overall market (S&P 500). This covariance between the expected returns for my Rothschild Gas Proxy Group and for the S&P 500 indicates what investors expect betas will be in the future. I refer to betas based on option price calculations as "option-implied betas."

[110] $8,163 profit from exercising call option ($31,798 from selling at $317.98 market price - $23,000 cost to purchase at $230) - $635 ($6.35 X 100) option purchase price. Note: Each call option is the right to purchase 100 shares.

**Q. PLEASE EXPLAIN HOW YOU CALCULATED THE BETAS USED IN YOUR CAPM.**

**A.** Traditionally, the betas used in CAPM calculations are calculated from historical returns. This approach has strengths and weaknesses. An alternative way to calculate betas is to incorporate investors' return expectations by calculating option-implied betas as explained in the previous paragraph. As discussed below, I have chosen to use both historical and option-implied betas in my CAPM analysis. I chose to use option-implied betas in my CAPM analysis because, among other reasons, studies have found that betas calculated based on investor expectations (option-implied) provide information regarding future perceived risks and expectations.[111]

[111] Bo-Young Chang & Peter Christoffersen & Kris Jacobs & Gregory Vainberg, *Option-Implied Measures of Equity Risk*, Review of Finance, Vol. 16, Issue 2, pp. 385-428 (April 2012) available at: https://academic.oup.com/rof/article/16/2/385/1584560.




As shown in Chart 2 above, stock option prices indicate that investors likely expect higher historical betas for the Rothschild Gas Proxy Group in the future.

Exhibit OPC (D)-6, page 3 contains the last three months of data used in creating Chart 2 above, which is what I use in my CAPM analysis. Specifically, I use the following two betas in my CAPM analysis:

1. **Historical Blend:** 50% (6 months) + 30% (2 years) + 20% (5 years).
2. **Forward Beta:** 100% Option-Implied Beta (6 months).

**Q. WHY DO YOU USE PERIODS OF 6 MONTHS, 2 YEARS, AND 5 YEARS FOR YOUR HISTORICAL BETA CALCULATIONS, AS OPPOSED TO RELYING EXCLUSIVELY ON THE 5-YEAR PERIOD USED BY VALUE LINE?**

**A.** Using shorter periods for the return regression analysis portion of the historical beta calculation allows me to see if the correlation between the returns of each of the companies in my Rothschild Gas Proxy Group and those of the S&P 500 Index has changed in the last 2 years or 6 months. Using a 5-year period exclusively tends to make recent changes in the correlation more difficult to identify because of the weight of 5 years of data.

**Q. WOULD YOU AGREE THAT CHANGES IN MARKET DYNAMICS WILL HAVE A LARGER EFFECT ON 6-MONTH HISTORICAL BETAS THAN THEY WILL ON 2-YEAR OR 5-YEAR HISTORICAL BETAS?**

**A.** Yes. As with other historical metrics based on a given time period, say, average stock prices, the longer the time horizon under consideration, the more data points are considered, and the smaller the effect of any one given change in the data set.

**Q. IS THIS LARGER EFFECT ON 6-MONTH HISTORICAL BETAS FROM CHANGES IN MARKET DYNAMICS A GOOD OR A BAD THING?**

**A.** The answer depends on what the beta will be used for. I would argue that in any attempt to forecast the beta coefficient of a company for any forward-looking analysis such as the cost of capital calculations in this proceeding, more recent historical data should be given more relevance than data from 5 or 10 years ago. The weight of 10 years of data can make a beta coefficient react extremely slowly to market developments. Even pronounced permanent market changes can take more than 6 months to have a detectable effect on a 10-year beta.

As with using spot values and averages of historical market data, I believe the right answer is not to use *either* 6-month historical betas or historical betas with longer horizons, but to consider *both*. For this reason, I have created my historical blended betas, which take into consideration 6-month, 2-year, and 5-year historical betas.

**Q. DO YOU THINK IT IS A GOOD IDEA TO RELY ON 6-MONTH HISTORICAL BETAS DESPITE MARKET DEVELOPMENTS IN THE PAST YEAR THAT SOME WOULD CALL "MARKET DISLOCATIONS?"**

**A.** Financial markets are constantly in flux due to the influence of countless factors. So-called "market dislocations," are just some of the numerous factors that are constantly affecting markets. To attempt to separate any one specific factor from "real" underlying market dynamics would be an exercise in futility.

Furthermore, predicting the duration and impact of any single influencing factor on financial markets is extremely challenging, if not impossible. In 2008, when interest rates plummeted to unprecedented lows, numerous analysts deemed this a temporary anomaly. Contrary to these expectations, rates not only persisted at these low levels for more than ten years but dropped even further in response to the unforeseen COVID-19 pandemic, which significantly affected the global economy and financial markets.

So, in response, yes, I think it is a good idea to use 6-month historical betas to measure recent and current market dynamics regardless of recent developments. I use them as part of my historical blended betas in conjunction with longer-term historical betas and forward-looking, option-implied betas to achieve the most reasonable result.

**Q. GIVEN THE SHORTER PERIOD COVERED BY 6-MONTH HISTORICAL BETAS, CAN THEY STILL BE CONSIDERED STATISTICALLY SIGNIFICANT? HOW MANY DATA POINT PAIRS ARE USED IN THE CALCULATION OF YOUR 6-MONTH HISTORICAL BETA COEFFICIENTS?**

**A.** A 6-month historical beta based on weekly returns calculated weekly is calculated using 26 closing price points for a company and for its corresponding market index, in this case the S&P 500 Index. This translates into 25 pairs of return data that are then used in the regression analysis. This is most certainly enough data to achieve statistical significance as addressed further below.

Furthermore, as stated above, the recent improvement in my calculation of historical betas of using weekly returns on every day of the week as opposed to using only one day of the week, as Value Line does, has the added benefit of providing significantly more data pairs to be used in the regression analysis used to calculate beta. For 6-month historical betas, instead of relying on 25 return pairs, the regression is performed on 117 return pairs.

**Q. PLEASE EXPLAIN HOW YOU CALCULATED OPTION-IMPLIED BETAS.**

**A.** Calculating option-implied betas of a company requires (1) obtaining stock option data for that company and a market index, (2) filtering the stock option data, (3) calculating the option-implied volatility for the company and for the index, (4) calculating the option-implied skewness for the company and for the index, and (5) calculating option-implied betas for the company based on implied volatility and skewness for the company and for the index. There are various ways one could choose to perform the steps above, but I chose to filter stock option data and calculate option-implied volatility[112] and skewness[113] following the same methodology used by the Chicago Board of Options Exchange ("CBOE") in the calculation of their widely-used VIX (or Volatility Index) and SKEW Index, respectively.

I start my process with publicly available trading information for all the options for a given security (company or index) for a complete trading day. I then filter the option data as described by the CBOE using the following guidelines:

1. Use the mid-quote or mark (average of bid and ask) as the option price.
2. Use only out-of-the-money call and put options.
    - Determine the "moneyness" threshold where absolute difference between call and put prices is smallest (using CBOE "Forward Index Price" formula).
    - Include "at-the-money" call and put options and use average of call and put prices as price for "blended" option.
3. Exclude all zero bids.

---

[112] CBOE Volatility Index White Paper (2018) available at: https://cdn.cboe.com/resources/indices/srvix-white-paper.pdf. Please note that the cover page says, "proprietary information." However, this document has been in the public domain for over 3 years.

[113] The CBOE SKEW Index (2010) available at: https://cdn.cboe.com/resources/indices/documents/SKEWwhitepaperjan2011.pdf. Please note that the cover page says, "proprietary information." However, this document has been in the public domain for over 3 years.

4. Exclude remaining (more out-of-the-money) options when two sequential zero bids are found.

I then apply the series of formulas clearly described in both of the CBOE's white papers to the remaining options to calculate Option-Implied Volatility and Option-Implied Skewness. In the words of the CBOE, each of its two indices is "an amalgam of the information reflected in the prices of all of the selected options." To be clear, Implied Volatility is not exactly the same as the VIX Index, and Implied Skewness is not exactly the same as the SKEW Index, but both indices are directly based on their corresponding statistical value.

After calculating the daily option-implied values as discussed above, I calculate the weekly average of these daily values.[114] This approach results in stable weekly data points due to the weekly averaging. Even the most recent "spot" option-implied beta value represents an average of a full week of option-implied beta values.

Option-Implied Volatility reflects investors' expectations regarding future stock price movements. Option-Implied Skewness reflects investors' expectations on how implied volatility changes for strike prices that are closer and further to the current value of the underlying stock price.

The CBOE calculates Times to Expiration by the minute—as do I. The Time to Expiration of traded options cannot be changed and varies from day to day. For the sake

---

[114] I interpolate option-implied beta values for a given company in the rare instances where all daily values for a given company are not available for a given week. This has the effect of maintaining a constant representation of all companies in the proxy group across all periods, thus further improving the stability of proxy group option-implied betas over time.

of consistency, the CBOE calculates the VIX and SKEW indices on a "30-day" basis by interpolating for two sets of options with Times to Expiration closest to the 30-day mark. I prefer to focus on as long of a time horizon as possible for forecasting purposes. Option Times to Expiration vary significantly for various stocks but can consistently be found to go out to 6 months (180 days) for utility companies. Therefore, for the sake of consistency, I have chosen to calculate 6-month volatility and skewness where possible. Occasionally, Times to Expiration for a given stock do not go out to 180 days. If the greatest Time to Expiration available is 171 days (95%) or greater, I use the volatility and skewness for that group of options as a proxy for the 180-day volatility and skewness, respectively.

Finally, once I have calculated the option-implied volatility and skewness for each company and index using the methodology described above, I calculate option-implied betas using the following formula developed by Christoffersen, Chang, Jacobs and Vainberg (2011): [115]

$$\beta_i = \left(\frac{SKEW_i}{SKEW_m}\right)^{1/3} \left(\frac{VAR_i}{VAR_m}\right)^{1/2}$$

Where:

$\beta_i$: $option - implied\ beta\ of\ security\ (e.g.\, stock, fund)$;
$SKEW_i$: $skewness\ of\ security$;
$SKEW_m$: $skewness\ of\ overall\ market\ (S\&P\ 500)$;
$VAR_i$: $variance\ of\ company$;
$VAR_m$: $variance\ of\ overall\ market\ (S\&P\ 500)$.

---

115 Bo-Young Chang & Peter Christoffersen & Kris Jacobs & Gregory Vainberg, *Option-Implied Measures of Equity Risk*, Review of Finance, Volume 16, Issue 2, at 385-428 (April 2012), available at: https://academic.oup.com/rof/article/16/2/385/1584560.

**Q. YOU CALCULATE YOUR OPTION-IMPLIED BETAS BASED ON A 6-MONTH HORIZON. WOULD IT NOT BE BETTER TO USE A LONGER FORECASTING HORIZON?**

**A.** The methodology I use to calculate my option-implied betas "allows for the computation of a complete term structure of beta for each company so long as the options data are available,"[116] so there is nothing inherent in the methodology that limits it to a certain time horizon.

For many applications, including cost of capital, one could argue that the longer the time horizon for the option-implied betas, the better. However, the limitation on the forecasting horizon is always set by the longest expiration period of the options currently traded in the market. Some companies trade options with expiration periods up to 2 or 3 years into the future. As evidenced by the exhaustive option data in my working papers, the maximum expiration period for the options of the companies in my Rothschild Gas Proxy Group is approximately 8 months. None of the 6 companies ever trade options with expiration periods of more than 8 months. New options are issued roughly every 3 months for all of these companies, so the maximum expiration period on any given trading day is somewhere between 5 and 8 months. For consistency across companies in my proxy group and across dates within the 3-month period on which my analysis is focused (September through November 2024), I chose to use 6 months for the time horizon of my option-implied betas. If the maximum expiration period for the options of a given company on a

[116] Peter Christoffersen, Kris Jacobs, and Gregory Vainberg, *Forward-Looking Betas*, at 24 (April 25, 2008) available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=891467.

given day is less than 6 months, I use the maximum expiration period as an approximation for the target 6-month horizon.

Simply because some may argue that it may be preferable to use longer time horizons in place of or in addition to a 6-month horizon, it does not mean that a 6-month option-implied beta is of no relevance or cannot be used. That would be tantamount to saying you cannot use a 1-year Value Line Earnings Per Share estimate, or that the minimum relevant forecast is 2 or 3 years. In fact, for purposes of option-implied betas, it would be difficult to say if a time horizon of 1 year, for instance, is necessarily always better than a time horizon of 6 months. An option-implied forward-looking beta, even with a time horizon of less than 6 months, is still a useful tool in interpreting the current expectations of investors at any given time.

A final strong argument in support of using 6-month option-implied betas in a cost of capital calculation looking years into the future is that the authors of the paper on which I based my option-implied betas concluded that their predictive powers are not limited to 6 months into the future. In fact, they conclude that 6-month option-implied betas have stronger predictive power than 6-month, 1-year, or 5-year historical betas when attempting to forecast betas 1 or 2 years into the future.

**Market Risk Premium**

**Q. PLEASE EXPLAIN HOW YOU CALCULATED THE EQUITY RISK PREMIUM USED IN YOUR CAPM.**

**A.** Traditionally, the risk premium used in CAPM calculations is derived from historical returns and/or equity analyst projections. The former approach is historically accurate but does not take into account investors' expectations for future market risks and returns. The latter approach is based on analyst projections, which are not appropriate since they do not reflect investor expectations. A superior market-based way to calculate the equity risk premium is to use option-implied return expectations, which is the approach I have used.

My equity risk premium is the expected return on the S&P 500 minus the risk-free rate. I calculate an expected return on the S&P 500 by using stock options traded on this index. To begin with, I use exactly the same methodology used by the Chicago Board of Options Exchange to filter stock option data and calculate option-implied volatility and skewness,[117] as described in detail in the Beta section. The volatility and skewness calculated in this way describe a probability function representing the possible trajectories for the S&P 500 implied by the options market. The resulting skewed probability function can be closely approximated by a log-normal function using established statistical formulas, which then make it straightforward to calculate the expected growth for the S&P 500 for any given cumulative probability. A cumulative probability of 50% represents the

[117] As used in the calculation of their widely-used VIX (or Volatility Index) and SKEW Index, respectively.

median of the probability distribution, or the option-implied market consensus, which is how I arrive at my calculation of expected market growth.

Once the option-implied growth rate of the S&P 500 has been estimated as described above, I add the dividend yield and subtract the risk-free rate to arrive at the market risk premium, as laid out in Exhibit OPC (D)-6, page 4 and Exhibit OPC (D)-6, page 6.Once the option-implied growth rate of the S&P 500 has been estimated as described above, I add the dividend yield and subtract the risk-free rate to arrive at the market risk premium, as laid out in Exhibit OPC (D)-6, page 4 and Exhibit OPC (D)-6, page 6. In line with my Spot and Weighted Average CAPM approaches, I use both spot values as of November 30, 2024 and weighted averages over the 3 months ending on that date for option-implied growth, dividend yields, and short- and long-term risk-free rates in these calculations to arrive at a total of 4 estimated values for the market risk premium. The market risk premia I use in my Weighted Average CAPM analysis with short- and long-term risk-free rates are 3.64% and 3.93%, respectively. The market risk premia I use in my Spot CAPM analysis with short- and long-term risk-free rates are 3.34% and 3.56%, respectively.

**Q. DID YOU TAKE INTO CONSIDERATION THE DIFFERENCE IN VOLATILITIES ACROSS EXPIRATION PERIODS IN THE OPTIONS TRADED ON THE S&P 500?**

**A.** Yes. The volatility implied by the options market changes over time as investors' perception of risk changes. For example, during a crisis, implied volatility generally increases as investors expect that stock market prices have a greater chance of large swings compared to times when there is no crisis. As discussed earlier, investors also often have different volatility expectations over different time periods. For example, on any given day, investors might expect volatility to be relatively high over the next 30 days and to decrease over the next year or longer. The same holds true for skewness, even though it is less intuitive to understand changes in skewness than in volatility. Because of these changes across option expiration periods, I take a weighted average of the entire term structure of the option-implied volatility and skewness, which for the S&P 500 typically goes out to 54 to 61 months[118], interpolating where necessary, and giving the most weight to the option expiration period of 12 months.

**CAPM Results**

**Q. PLEASE SUMMARIZE THE RESULTS OF YOUR CAPM.**

**A.** Table 7 and Table 8 on page 87show the results of my Weighted Average CAPM and Spot CAPM Analyses, respectively.

[118] Prior to November 2021, the longest expiration period for stock options traded on the S&P 500 was 36 months.

Weighted Average CAPM

**TABLE 7: CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY**
**WEIGHTED - All Inputs Weighted From September to November 2024**

| | 3-Month Treasury Bill | | 30-Year Treasury Bond | |
|---|---|---|---|---|
| | Historical Blended Beta | Forward Beta | Historical Blended Beta | Forward Beta |
| Risk-Free Rate | 4.64% | 4.64% | 4.34% | 4.34% |
| Beta | 0.64 | 0.68 | 0.64 | 0.68 |
| Risk Premium | 3.64% | 3.64% | 3.93% | 3.93% |
| CAPM | 6.98% | 7.12% | 6.87% | 7.03% |

Source: Exhibit OPC (D)-6, page 1

Spot CAPM

**TABLE 8: CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY (SPOT)**
**SPOT - All Inputs Based on Last Available Data as of November 30, 2024**

| | 3-Month Treasury Bill | | 30-Year Treasury Bond | |
|---|---|---|---|---|
| | Historical Blended Beta | Forward Beta | Historical Blended Beta | Forward Beta |
| Risk-Free Rate | 4.58% | 4.58% | 4.36% | 4.36% |
| Beta | 0.67 | 0.64 | 0.67 | 0.64 |
| Risk Premium | 3.34% | 3.34% | 3.56% | 3.56% |
| CAPM | 6.80% | 6.73% | 6.73% | 6.65% |

Source: Exhibit OPC (D)-6, page 5

Please see Exhibit OPC (D)-8 for a chart showing how the results of my CAPM analysis applied to the Rothschild Gas Proxy Group have changed over time since the onset of the COVID pandemic.

## VII. CAPITAL STRUCTURE AND COST OF DEBT RECOMENDATION

**Q. PLEASE DEFINE CAPITAL STRUCTURE AND HOW WGL'S AUTHORIZED CAPITAL STRUCTURE WILL IMPACT RATES.**

**A.** The authorized capital structure of WGL, or any regulated utility company, is an important component of the rates it charges customers, as it reflects the proportion of equity, debt, and other financing methods used to fund its operations and investments. Equity financing, while necessary, is more expensive than debt due to the higher returns required by equity investors. In contrast, the cost of debt financing is generally less expensive than equity because debt securities like utility bonds are less risky to investors.[119] Thus, the utility's capital structure has a direct impact on the overall cost of service to customers.

**Q. WHY SHOULD THE COMMISSION CAREFULLY CONSIDER THE REASONBLENESS OF WGL'S REQUESTED AUTHORIZED CAPITAL STRUCTURE?**

**A.** Allowing a utility to adopt a capital structure that is disproportionately equity-heavy as a result of the utility's reliance in part on unrepresentative peer group analysis (e.g., inclusion of the capital structure ratios of the regulated subsidiaries of the peer holding companies as Witness Burrows did in this case)[120] would impose an unjustified financial burden on ratepayers. Regulators should carefully consider the capital structure ratios used by the

---

[119] Debt financing is less risky than equity financing because debt holders have a legal claim to fixed payments (interest and principal) and are prioritized over equity holders in case of bankruptcy.

[120] *See* Exhibit WG (B)-5 at 1 (where Witness Burrows includes regulated subsidiaries such as Spire Missouri, Inc. in her peer group analysis).

publicly traded utility companies in peer groups because they are a more reliable measure of how WGL's utility operations should and or are actually funded. Additionally, the Commission can protect consumers by exploring the cost-benefit of the utility's proposed capital structure. For example, a higher authorized common equity ratio may provide benefits such as lowering WGL's cost of debt, but it may lead to a higher overall cost of capital in the short and long run as compared to a lower common equity ratio and a slightly higher cost of debt.

**Q. WHAT CAPITAL STRUCTURE IS WGL REQUESTING FOR RATEMAKING PURPOSES?**

**A.** Witness Burrows recommends a capital structure with 52.49% common equity, 42.88% long-term debt and 4.63% short-term debt.[121]

**Q. WHAT IS THE BASIS OF WITNESS BURROWS CAPITAL STRUCTURE RECOMMENDENDATION?**

**A.** Witness Burrows justifies her capital structure recommendation by indicating that her capital structure recommendation is: 1) consistent with the actual capital structure used by WGL;[122] 2) in line with capital structure ratios used by a peer group of gas utility

---

121 *See* Exhibit WG (B) (Burrows) at 2:11-18; Exhibit WG (B)-1. Numbers rounded.

122 *See, e.g.*, Exhibit WG (B) (Burrows) at 15:19-25.

companies;[123] and 3) includes just enough common equity to avoid a credit downgrade as evidenced by the financial data in her peer group.[124]

**Q. IS WITNESS BURROWS' CAPITAL STRUCTURE RECOMMENDATION APPROPRIATE FOR RATEMAKING PURPOSES?**

**A.** No. As noted above, Witness Burrows inappropriately includes the capital structure ratios of the regulated subsidiaries of the peer group holding companies in her peer comparison – credit metrics and capital structure analysis in Exhibit WG (B)-5. The capital structure ratio at the holding company is what matters because it reflects the actual percentages of capital chosen by the companies to raise capital. The capital structure ratios at the operating level, on the hand, are subject to capital structure manipulation and if used to set rates could significantly overcharge consumers.

In addition, Witness Burrows does not show that increasing the common equity ratio above 48% (as required by Merger Commitment 32) results in any net savings to ratepayers. Given that equity costs more than debt, one cannot assume that maintaining a capital structure with a common equity above 52% to protect the purported bond downgrade (as claimed by Witness Burrows)[125] is worth the extra cost associated with a ratemaking capital structure with a common equity ratio above my recommended common equity ratio of 49.76%.

---

123 *See, e.g., id.* at 16:19-22.

124 *See, e.g., id.* at 17:21-18:2.

125 *Id.* at 17:18-18:2.

**Q. PLEASE ELABORATE MORE ON WHY IT IS INAPPROPRIATE TO BASE WGL'S AUTHORIZED CAPITAL STRUCTURE ON THE CAPITAL STRUCTURE RATIOS OF REGULATED SUBSIDIARIES OF THE PEER GROUP HOLDING COMPANIES AS WITNESS BURROWS HAS DONE IN HER ANALYSIS?**

**A.** Many company witnesses argue that the capital structure ratios at the holding company should not be used to determine the appropriate regulatory capital structure for many reasons. The most common reason is that regulated operations have a different level of risk than the operations at the holding company level. I would agree that operations at the holding company level are not completely comparable to a regulatory subsidiary like WGL. However, common equity ratios at the holding company level are relevant to this proceeding. These holding companies include unregulated operations that are generally riskier than those of regulated subsidiaries. But where an analysis includes the capital structure ratios of the peer group holding companies' regulated subsidiaries, it can inappropriately increase the equity ratios, particularly where the holding company is able to infuse equity into the regulated subsidiary. For example, WGL recently submitted a Notice of Equity Infusion and Change in Equity Infusion Plans to the Commission, in which it stated that it will receive a higher equity infusion from WGL's parent holding companies than previously reported.[126] This evidences that even if WGL issues its own

---

[126] *Formal Case No. 1177*, In the Matter of the Application of Washington Gas Light Company for a Certificate of Authority Authorizing it to Issue Debt Securities, Washington Gas Light Company's Notice of Equity Infusion and Change in Equity Infusion Plans, filed December 23, 2024 at 3.

debt, it relies on its parent for equity capital and such equity infusions have the effect of increasing its common equity ratio.

**Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND AND WHY IS IT MORE APPROPRIATE FOR RATEMAKING PURPOSES THAT THE CAPITAL STRUCTURE REQUESTED BY WGL?**

**A.** I recommend using a capital structure consisting of 49.76% equity, 45.61% long-term debt and 4.63% short-term debt, based on the average common equity ratios of the companies in the Rothschild Gas Proxy Group. A common equity ratio of 49.76% is on the high side of reasonableness because it is above the mean (45.9%) and median (46.2%) common equity ratio of the 6 gas distribution companies in the Rothschild Gas Proxy Group when short-term debt is included.[127] I believe absent evidence from WGL in support of the need for a different capital structure, using the capital structure that more closely aligns with that of the proxy group is consistent in setting just and reasonable rates that consider both the utility and its investor's needs as well as the needs of ratepayers.

**Q. WHAT WOULD BE THE CONSEQUENCES OF AUTHORIZING A CAPITAL STRUCTURE WITH A COMMON EQUITY RATIO HIGHER THAN OTHER COMPARABLE UTILTIY COMPANIES?**

**A.** Authorizing a regulatory capital structure for WGL with a common equity ratio higher than other comparable utility companies without justification will result in unreasonably high

---

[127] Exhibit OPC (D)-7 at 4.

rates. As shown in Table 2, my recommendations, including my capital structure recommendation, result in an overall rate of return of 6.58%. WGL's recommendations result in an overall rate of return of 7.87%. Capital structure has a major impact on revenue requirement. If the Commission adopts an equity component of the capital structure ratio that is higher than I've recommended, there should be an additional reduction to the authorized ROE.

It can't be overlooked that the authorized capital structure can have a large impact on the utility company's revenue requirement. If my cost of equity recommendation is applied to WGL's recommended capital structure it will require a significantly larger revenue requirement.

If WGL's capital structure recommendations are adopted it is important to make an adjustment the overall ROR to account for the financial risk difference between WGL's capital structure recommendation and that of the companies in the Rothschild Gas Proxy Group[128] which have a significantly lower average common equity ratio (49.76%) than the common equity ratios recommend by WGL. A higher common equity ratio means less debt, a lower chance of financial stress (financial risk), and therefore a lower COE. On the other hand, a lower common equity ratio means more debt, a higher chance of financial stress (financial risk), and therefore a higher COE. Based on a regression analysis of dozens of utility companies, I found a 0.04% reduction in the cost of equity results for every 1% increase in the common equity ratio. Therefore, if the Commission

[128] Witness Burrows started with the same peer group used by Witness D'Ascendis which includes all the companies in the Rothschild Gas Proxy Group.

authorizes a capital structure with a higher common equity ratio than 49.76% for WGL, then its authorized ROE should be reduced by 0.04% for every 1% its authorized common equity ratio exceeds that of the proxy group, resulting in an ROE of 8.11%.[129]

## VIII. CONCLUSION

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.**

**A.** Based on the evidence presented in my testimony, I conclude that the cost of equity allowed for WGL should be between 6.73% to 8.22% (recommended at 8.22%). Based on my recommended common equity ratio of 49.76%, my resulting overall cost of capital is between 5.84% and 6.58% (recommended at 6.58%).

If the Commission decides to use WGL' requested capital structure of 52.49% common equity and 42.88% debt instead of my recommended capital structure, I recommend a reduced authorized ROE of 8.11% (6.62% - 8.11%) to account for the lower financial risk of a capital structure with more equity. In addition, if the Commission grants the Company's proposed WNA, it should further reduce WGL's authorized ROE to reflect the reduction in WGL's financial risks while, as explained by OPC Witness Dismukes, failing to adequately balance the shifted risks to ratepayers.

My recommendations satisfy the requirements of *Hope* and *Bluefield* that regulated utility companies should have the opportunity to earn a return commensurate with returns

---

129 *See* Exhibit OPC (D)-3 (Capital Structure Risk Adjustment).

on investments in other enterprises having corresponding risks. My recommendations are also supported by market data and will allow WGL to raise capital on reasonable terms to allow it to fulfill its obligation to provide safe, reliable, and affordable service. Accordingly, consistent with Commission precedent, if adopted, my recommendations would appropriately balance investors' and ratepayers' interests.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

**A.** Yes.

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

| | | |
|---|---|---|
| **In the Matter of**<br><br>**THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE** | §<br>§<br>§<br>§<br>§<br>§<br>§ | **Formal Case No. 1180** |

**AFFIDAVIT**

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

Aaron L. Rothschild

Date: 1-21-25

Subscribed and sworn to before me

This 21st day of January, 2025.

State of Connecticut

County of Fairfield

Vida M. Rothschild
Notary Public

My Commission expires: VIDA M. ROTHSCHILD NOTARY PUBLIC My Commission Expires May 31, 2027

VIDA M. ROTHSCHILD NOTARY PUBLIC CONNECTICUT

# Listing of Prior Testimony of Aaron L. Rothschild

## Filed Rate of Return Testimonies:

### California

- Pacific Gas and Electric, Application 22-04-008 et al, Rate of Return/Cost of Capital Mechanism, January 2024
- Liberty Utilities, Application A.23-05-004, Rate of Return, August 2023
- San Gabriel Water Company, Application 23-05-001, Rate of Return, August 2023
- Suburban Water Company, Application 23-05-003, Rate of Return, August 2023
- Great Oaks Water Company, Application 23-05-002, Rate of Return, August 2023
- Incumbent Local Exchange Carriers (ILECs), Application 22-09-003, Rate of Return, May 2023
- Pacific Gas and Electric Company, Application 22-04-008, Rate of Return, August 2022
- Southern California Edison, Application 22-04-009, Rate of Return, August 2022
- San Diego Gas & Electric Company, Application 22-04-012, Rate of Return, August 2022
- California American Water Company, Application 21-05-001, Rate of Return, January 2022
- California Water Service Company, Application 21-05-002, Rate of Return, January 2022
- Golden State Water Company, Application 21-05-003, Rate of Return, January 2022
- San Jose Water Company, Application 21-05-004, Rate of Return, January 2022
- Southern California Edison, Application 21-08-013, Rate of Return/Cost of Capital Mechanism, January 2022
- San Diego Gas & Electric Company, Application 21-08-014, Rate of Return/Cost of Capital Mechanism, January 2022
- Pacific Gas and Electric Company, Application 21-08-015, Rate of Return/Cost of Capital Mechanism, January 2022
- Pacific Gas and Electric Company, Application 21-01-004, Securitization, February 2021
- Pacific Gas and Electric Company, Application 20-04-023, Securitization, October 2020
- Southern California Edison, Application 20-07-008, Securitization, September 2020
- San Diego Gas & Electric Company, Application 19-04-017, Rate of Return, August 2019
- Southern California Gas Company, Application 19-04-016, Rate of Return, August 2019
- Pacific Gas and Electric Company, Application 19-04-015, Rate of Return, August 2019
- Southern California Edison, Application 19-04-014, Rate of Return, August 2019
- Liberty Utilities, Application A.18-05-006, Rate of Return, August 2018
- San Gabriel Water Company, Application 18-05-005, Rate of Return, August 2018
- Suburban Water Company, Application 18-05-004, Rate of Return, August 2018
- Great Oaks Water Company, Application 18-05-001, Rate of Return, August 2018
- California Water Service Company, Application 17-04-006, Rate of Return, August 2017
- California American Water Company, Application 17-04-003, Rate of Return, August 2017

- Golden State Water Company, Application 17-04-002, Rate of Return, August 2017
- San Jose Water Company, Application 17-04-001, Rate of Return, August 2017

**Colorado**
- Public Service Company of Colorado, Docket No. 11AL-947E, Rate of Return, March 2012

**Connecticut**
- Connecticut Natural Gas Corporation, Docket No. 23-11-02, February 2024
- The Southern Connecticut Gas Company, Docket No. 23-11-02, February 2024
- United Illuminating Company, Docket No. 22-08-08, Rate of Return, December 2022
- Aquarion Water Company of Connecticut, Docket No. 22-07-01, Rate of Return, October 2022
- Eversource and United Illuminating, Docket No. 17-12-03RE11, Rate of Return / Interim Rate Reduction, April 2021
- United Water Connecticut, Docket No. 07-05-44, Rate of Return, November 2008
- Valley Water Systems, Docket No. 06-10-07, Rate of Return, May 2007

**Delaware**
- Tidewater Utilities, Inc., PSC Docket No. 11-397, Rate of Return, April 2012

**District of Columbia**
- Washington Gas Light Company, Formal Case No. 1169, Rate of Return, May 2023

**Florida**
- Florida Power & Light (FPL), Docket No. 070001-EI, October 2007
- Florida Power Corp., Docket No. 060001 Fuel Clause, September 2007

**New Jersey**
- Aqua New Jersey, Inc., BPU Docket No. WR11120859, Rate of Return, April 2012

**Maryland**
- Delmarva Power & Light, Case No. 9317, Rate of Return, June 2013
- Columbia Gas of Maryland, Case No. 9316, Rate of Return, May 2013
- Potomac Electric Power Company, Case No. 9286, Rate of Return, March 2012
- Delmarva Power & Light, Case No. 9285, Rate of Return, March 2012

**New Hampshire**
- Liberty Utilities (EnergyNorth Natural Gas) Corp., Docket No. DG-23-23-067, Rate of Return, February 2024
- Liberty Utilities (Granite State Electric) Corp., Docket No. DE-23-05-039, Rate of Return, December 2023

**North Dakota**
- Montana-Dakota Utilities Co., Case No. PU-20-379, Rate of Return, January 2021
- Otter Tail Power Company, Case No. PU-17-398, Rate of Return, May 2018

- Montana-Dakota Utilities Co., Case No. PU-15-90, Rate of Return, August 2015
- Northern States Power, Case No. PU-400-04-578, Rate of Return, March 2005

**Pennsylvania**

- Aqua Pennsylvania, Inc., Docket No. R-2024-3047822, Rate of Return, August 2024
- Peoples Natural Gas Company LLC, Docket No. R-2023-304459, Rate of Return, March 2024
- UGI Utilities, Inc. – Electric Division, Docket No. R-2022-3037368, Rate of Return, April 2023
- Pennsylvania American Water Company, Docket No. R-2022-3031672 and R-2022-3031673, Rate of Return, July 2022
- UGI Utilities, Inc. – Electric Division, Docket No. R-2021-3023618, Rate of Return, May 2021
- Pennsylvania American Water Company, Docket No. P-2021-3022426, Rate of Return, February 2021
- Audubon Water Company, Docket No. R-2020-3020919, Rate of Return, November 2020
- Pennsylvania American Water Company, Docket No. R-2020-3019369 and R-2020-3019371, Rate of Return, September 2020
- Twin Lakes Utilities, Inc., Docket No. R-2019-3010958, Rate of Return, October 2019
- City of Lancaster Sewer Fund, Docket No. R-2019-3010955, Rate of Return, October 2019
- Community Utilities of Pennsylvania Inc. Wastewater Division, Docket No. R-2019-3008948, Rate of Return, July 2019
- Community Utilities of Pennsylvania Inc. Water Division, Docket No. R-2019-3008947, Rate of Return, July 2019
- Newtown Artesian Water Company, Docket No. R-20019-3006904, Rate of Return, May 2019
- Hidden Valley Utility Services, L.P. – Wastewater Division, Docket No. R-2018-3001307, Rate of Return, September 2018
- Hidden Valley Utility Services, L.P. – Water Division, Docket No. R-2018-3001306, Rate of Return, September 2018
- The York Water Company, Docket No. R-2018-3000019, Rate of Return, August 2018
- SUEZ PA Pennsylvania, Inc., Docket No. R-2018-000834, Rate of Return, July 2018
- UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058, Rate of Return, April 2018
- Wellsboro Electric Company, Docket No. R-2016-2531551, Rate of Return, December 2016
- Citizens' Electric Company of Lewisburg, PA, Docket No. R-2016-2531550, Rate of Return, December 2016
- Columbia Gas of Pennsylvania, Inc., Docket No. R-2016-2529660, Rate of Return, June 2016
- Columbia Gas of Pennsylvania, Inc., Docket No. R-2015-2468056, Rate of Return, June 2015
- Pike County Light & Power Company, Docket No. R-2013-2397353 (gas), Rate of Return, April 2014
- Pike County Light & Power Company, Docket No. R-2013-2397237 (electric), Rate of Return, April 2014
- Columbia Water Company, Docket No. R-2013-2360798, Rate of Return, August 2013
- Peoples TWP LLC, Docket No. R-2013-2355886, Rate of Return, July 2013
- City of Dubois – Bureau of Water, Docket No. R-2013-2350509, Rate of Return, July 2013
- City of Lancaster – Sewer Fund, Docket No. R-2012-2310366, Rate of Return, December 2012

- Wellsboro Electric Company, Docket No. R-2010-2172665, Rate of Return, September 2010
- Citizens' Electric Company of Lewisburg, PA, Docket No. R-2010-2172662, Rate of Return, September 2010
- T.W. Phillips Gas and Oil Company, Docket No. R-2010-2167797, Rate of Return, August 2010
- York Water Company, Docket No. R-2010-2157140, Rate of Return, August 2010
- Joint Application of The Peoples Natural Gas Company, Dominion Resources, Inc. and Peoples Hope Gas Company LLC, Docket No. A-2008-2063737, Financial Analysis, December 2008
- York Water Company, Docket No. R-2008-2023067, Rate of Return, August 2008

**South Carolina**
- Dominion Energy South Carolina, Inc., Docket No. 2024-34-E, Rate of Return, June 2024
- Duke Energy Carolinas, LLC., Docket No. 2023-388-E, Rate of Return, April 2024
- Duke Energy Progress, LLC., Docket No. 2023-89-E, Securitization, September 2023
- Dominion Energy South Carolina, Inc., Docket No. 2023-170-G, Rate of Return, July 2023
- Duke Energy Progress, LLC., Docket No. 2022-254-E, Rate of Return, December 2022
- Daufuskie Island Utility Company, Inc., Docket No. 22-142-WS, Rate of Return, September 2022
- Piedmont Natural Gas Company, Inc., Docket No. 22-89-G, Rate of Return, July 2022
- Kiawah Island Utility, Inc., Docket No. 2021-324-WS, Rate of Return, February 2022
- Palmetto Wastewater Reclamation, Inc., Docket No. 2021-153-S, Rate of Return, September 2021
- Dominion Energy South Carolina, Inc., Docket No. 2020-125-E, Rate of Return, November 2020
- Palmetto Utilities, Inc., Docket No. 2019-281-S, Rate of Return, May 2020
- Palmetto Utilities, Inc., Docket No. 2019-281-S, Accounting, May 2020
- Blue Granite Water Company, Docket No. 2019-290-WS, Rate of Return, January 2020

**Tennessee**
- Limestone Water Utility Operating Company., Docket No. 24-00044, Rate of Return, December 2024
- Tennessee American Water Company, Inc., Docket No. 24-00032, Rate of Return, September 2024
- Kingsport Power Company D/B/A AEP Appalachian Power, Docket No. 21-00107, Rate of Return, March 2022

**Vermont**
- Central Vermont Public Service Corp., Docket No. 7321, Rate of Return, September 2007

**Wisconsin**
- American Transmission Company, LLC, ITC, Midwest, LLC, Case No. 19-CV-3418, financial and regulatory analysis regarding requested temporary injunction to halt the construction in Wisconsin of the proposed Cardinal-Hickory Creek transmission line, October 2021

# Resumé of Aaron L. Rothschild

## SUMMARY

Financial professional providing U.S. public utility commissions financial tools and expert testimony to assist in rate setting for regulated utility companies (e.g., regulated electric distribution providers, natural gas pipelines). Relevant experience includes developing and applying methodologies that directly measure investors' equity return expectations based on stock option prices, applied mathematics research for utility industry as an affiliate of the New England Complex Systems Institute, and serving as Head of Business Analysis for a major U.S. telecom firm in Asia Pacific.

## EXPERIENCE

**Rothschild Financial Consulting, Ridgefield, CT** **November 2001- present**
Independent consulting firm specializing in utility sector
***President***

- Provide financial expert testimony (e.g., rate of return and M&A) to regulators, policy makers, foundations, and consumer groups in utility rate case proceedings
- Developed cost of equity models that have been used by public utility commissions for rate setting purposes in many states around the country
- Present at utility regulation conferences (NARUC/NASUCA and MARC) regarding rate of return, power purchase agreements, complex systems science, and subsidy auctions

**360 Networks, Hong Kong** **January 2001 - October 2001**
Pioneer of the fiber optic telecommunications industry
***Senior Manager***

- Business development and investment evaluation
- Negotiated landing rights and formed local partnerships in Korea, Japan, Singapore, and Hong Kong for $1 billion undersea cable project
- Structured fiber optic bandwidth swapping agreement with Enron and Global Crossing
- Established relationships with Hong Kong based Investment Bankers to communicate Asia Pacific objectives and accomplishments to Wall Street

**Dantis, Chicago, IL** **July 2000- December 2000**
Start-up managed data-hosting services provider
***Director***

- Built capital raise valuation models and negotiated with potential investors
- Team raised $100M from venture capital firm through valuation negotiations and internal strategic analysis

**MFS, MCI-WorldCom, Chicago, Hong Kong, Tokyo** **September 1996- July 2000**
American Telecommunications Company
***Head of Business Analysis for Japan operations***

- Managed staff of 5 business development analysts
- Raised $80M internally for Japanese national fiber network expansion plan by conducting an investment evaluation and presenting findings to CEO of international operations in London, UK
- Built financial model for local fiber optic investment evaluation that was used by business development offices in Oak Brook, IL and Sydney, Australia

## EDUCATION

**Vanderbilt University, Nashville, TN** **1994-1996**
***MBA, Finance***

- Completed business plan for Nextlink Communications in support of their national fiber optic network expansion, including identifying opportunities from passage of Telecom Act of 1996
- Developed analytical framework to evaluate predictability of rare events
- Provided financial and accounting analysis to Chicago's consumer advocate, the Citizens Utility Board (CUB) as a summer intern

**Clark University, Worchester, MA** **1990 - 1994**
***BA, Mathematics***

# Overall Rothschild Recommended Cost of Capital

| | Ratios | | Cost Rate | | Weighted Cost Rate |
|---|---|---|---|---|---|
| | | | | | [D] |
| **Long-Term Debt** | 45.61% | [A] | 4.84% | [B] | 2.21% |
| **Short-Term Debt** | 4.63% | [B] | 6.20% | [B] | 0.29% |
| **Preferred Equity** | 0.00% | [B] | 0.00% | [B] | 0.00% |
| **Common Equity** | 49.76% | [A] | 8.22% | [C] | 4.09% |
| | 100.00% | | | | **6.58%** |

**RECOMMENDED RANGES**

| | | Low | | High |
|---|---|---|---|---|
| **Proxy Group Cost of Equity Range** | | 6.73% | | 8.22% |
| **Proxy Group Cost of Equity** | | | 7.47% | |
| **Based on Rothschild Capital Structure Recommendation** | | | | |
| **Capital Structure Risk Adjustment** | [E] | | 0.00% | |
| **Adjusted Recommended Cost of Equity Range** | | **6.73%** | | **8.22%** |
| **Company Specific Cost of Equity Recommendation** | | | **8.22%** | |
| **Cost of Capital Range** | | 5.84% | | 6.58% |
| **Based on Witness D'Ascendis's Capital Structure Recommendation** | | | | |
| **Capital Structure Risk Adjustment** | [F] | | -0.11% | |
| **Adjusted Recommended Cost of Equity Range** | | **6.62%** | | **8.11%** |
| **Company Specific Cost of Equity Recommendation** | | | **8.11%** | |
| **Cost of Capital Range** | | 5.84% | | 6.62% |
| **Comprehensive Cost of Capital Range** | | | | |
| **Cost of Debt Range** | | 4.84% | | 0.00% |
| **Common Equity Ratio Range** | | 49.76% | | 45.86% |
| **Comprehensive Cost of Capital Range** | | 5.84% | | 4.06% |

Sources:
[A] Recommendation based on the Rothschild Gas Proxy Group capital structures
[B] Exhibit WG (C) (D'Ascendis) at 3:1-15 (Table 1)
[C] Company Specific Cost of Equity Recommendation based on Rothschild Capital Structure Recommendation
[D] Ratios times Cost Rate
[E] Not applicable because of recommended Capital Structure within Proxy Group range.
[F] Based on estimate of 0.04% change in Cost of Equity for each 1% difference in Common Equity Ratio compared to the Rothschild Gas Proxy Group (Exhibit OPC (D)-3 vs. Exhibit OPC (D)-7, page 4).

# Rothschild Cost of Equity Summary

**Rothschild Gas Proxy Group (6 Companies)**

| | | Low | | High |
|---|---|---|---|---|
| **DCF** | | | | |
| **Constant Growth - Sustainable Growth** | [A] | 8.22% | | 8.32% |
| **Constant Growth - Option-Implied Growth** | [B] | 7.90% | | 9.03% |
| **Non-Constant Growth** | [C] | 7.32% | | 7.82% |
| **CAPM** | | | | |
| **3-Mo. Weighted Average (Sep. to Nov. 2024)** | | | | |
| 3-Month Treasury Bill Risk-Free Rate | [D] | 6.98% | | 7.12% |
| 30-Year Treasury Bond Risk-Free Rate | [D] | 6.87% | | 7.03% |
| **Spot (Nov. 30, 2024)** | | | | |
| 3-Month Treasury Bill Risk-Free Rate | [E] | 6.73% | | 6.80% |
| 30-Year Treasury Bond Risk-Free Rate | [E] | 6.65% | | 6.73% |
| **Full Range** | | **6.65%** | | **9.03%** |
| **Outer Percentile Range** | | **6.73%** | | **8.22%** |
| **Proxy Group Cost of Equity** | | | **7.47%** | |

# Constant Growth Discounted Cash Flow (DCF) - Indicated Cost of Equity with Calculations and Analysis

## CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY
### Rothschild Gas Proxy Group (6 Companies)

| | | Based on Average Market Price For Year Ending 11/30/2024 | Based On Market Price As Of 11/30/2024 |
|---|---|---|---|
| 1 Dividend Yield On Market Price | [A] | 3.91% | 3.43% |
| 2 Retention Rate: | | | |
| a) Market-to-Book Ratio | [A] | 1.50 | 1.67 |
| b) Dividend Yield on Book | [B] | 5.88% | 5.71% |
| c) Expected Return on Equity | [C] | 8.80% | 8.80% |
| d) Retention Rate | [D] | 33.23% | 35.16% |
| 3 Reinvestment Growth | [E] | 2.92% | 3.09% |
| 4 New Financing Growth | [F] | 1.30% | 1.72% |
| 5 Total Estimate of Investor Anticipated Growth | [G] | 4.22% | 4.81% |
| 6 Increment to Dividend Yield for Growth to Next Year | [H] | 0.08% | 0.08% |
| **7 Indicated Cost of Equity** | **[I]** | **8.22%** | **8.32%** |

Sources:
[A] Exhibit OPC (D)-7, page 1
[B] Line 1 x Line 2a
[C] Some of the considerations for determining Future Expected Return on Equity:

| | Median | Mean | From |
|---|---|---|---|
| Value Line Expectation | **8.50%** | **9.25%** | Exhibit OPC (D)-7, page 2 |
| Return on Equity to Achieve Zacks Growth | 8.11% | 8.03% | Exhibit OPC (D)-7, page 3 |
| Average Historical Growth | 9.15% | 9.70% | |
| Earned Return on Equity in 2023 | 8.69% | 9.24% | Exhibit OPC (D)-7, page 2 |
| Earned Return on Equity in 2022 | 8.93% | 9.85% | Exhibit OPC (D)-7, page 2 |
| Earned Return on Equity in 2021 | 9.82% | 10.01% | Exhibit OPC (D)-7, page 2 |

[D] 1 - Line 2b / Line 2c
[E] Line 2c x Line 2d
[F] S x V = (Ext. Fin Rate) x (Line 2a - 1) — Ext. Fin. Rate = 2.59% — From: Exhibit OPC (D)-5, page 5
S = rate of continuous new stock financing
V = fraction of funds raised by sale of stock that increases the book value of existing shareholders' common equity
[G] Line 3 + Line 4
[H] Line 1 x one-half of Line 5
[I] Line 1 + Line 5 + Line 6

**CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY**
**Rothschild Gas Proxy Group (6 Companies)**

| | | Based On Weighted Averages As Of 11/30/2024 | Based On Spot Market Values As Of 11/30/2024 |
|---|---|---|---|
| 1 Dividend Yield On Market Price | [A] | 3.91% | 3.43% |
| 2 Total Estimate of Investor Anticipated Growth | [B] | 5.02% | 4.40% |
| 3 Increment to Dividend Yield for Growth to Next Year | [C] | 0.10% | 0.08% |
| **4 Indicated Cost of Equity** | **[D]** | **9.03%** | **7.90%** |

Sources:
[A] Exhibit OPC (D)-7, page 1
[B] 6-Month Option-Implied Growth
[C] Line 1 x one-half of Line 2
[D] Line 1 + Line 2 + Line 3

**NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY**
**(BASED ON VALUE LINE FORECASTS AND CLOSING STOCK PRICE)**
**Rothschild Gas Proxy Group**

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Forecasted Dividends per Share | | | | | Growth | Book Value | | Closing Stock Price | | Cash Flow From Buying and Selling Stock (At Closing Price) | | | | | |
| | | 2024 | 2025 | 2026 | 2027 | 2028 | 2025-28 | 11/30/24 | 11/30/28 | 11/30/2024 | 11/30/2028 | 2024 | 2025 | 2026 | 2027 | 2028 | IRR / DCF |
| | | [A] | [A] | [B] | [B] | [A] | [B] | [C] | [C] | [D] | [E] | [F] | [F] | [F] | [F] | [F] | [G] |
| Atmos Energy Corporation | ATO | $3.22 | $3.48 | $3.72 | $3.98 | $4.25 | 6.89% | $80.10 | $88.49 | $151.32 | $167.16 | ($150.52) | $3.48 | $3.72 | $3.98 | $170.35 | 4.96% |
| New Jersey Resource Corp | NJR | $1.71 | $1.76 | $1.82 | $1.88 | $1.95 | 3.48% | $22.15 | $28.16 | $51.58 | $65.57 | ($51.15) | $1.76 | $1.82 | $1.88 | $67.04 | 9.52% |
| NiSource, Inc. | NI | $1.06 | $1.12 | $1.15 | $1.17 | $1.20 | 2.33% | $22.56 | $26.06 | $38.09 | $44.00 | ($37.83) | $1.12 | $1.15 | $1.17 | $44.90 | 6.58% |
| Northwest Natural Holding C | NWN | $1.95 | $1.96 | $1.97 | $1.97 | $1.98 | 0.34% | $37.14 | $38.73 | $43.82 | $45.69 | ($43.33) | $1.96 | $1.97 | $1.97 | $47.18 | 5.54% |
| ONE Gas, Inc. | OGS | $2.64 | $2.68 | $2.74 | $2.79 | $2.85 | 2.07% | $51.52 | $59.94 | $77.97 | $90.70 | ($77.31) | $2.68 | $2.74 | $2.79 | $92.84 | 7.25% |
| Spire, Inc. | SR | $3.02 | $3.16 | $3.30 | $3.45 | $3.60 | 4.44% | $52.55 | $65.80 | $73.19 | $91.64 | ($72.44) | $3.16 | $3.30 | $3.45 | $94.34 | 10.08% |
| Maximum | | $3.22 | $3.48 | $3.72 | $3.98 | $4.25 | 6.89% | $80.10 | $88.49 | $151.32 | $167.16 | ($37.83) | $3.48 | $3.72 | $3.98 | $170.35 | 10.08% |
| Minimum | | $1.06 | $1.12 | $1.15 | $1.17 | $1.20 | 0.34% | $22.15 | $26.06 | $38.09 | $44.00 | ($150.52) | $1.12 | $1.15 | $1.17 | $44.90 | 4.96% |
| Median | | $2.30 | $2.32 | $2.35 | $2.38 | $2.42 | 2.90% | $44.33 | $49.33 | $62.39 | $78.14 | ($61.79) | $2.32 | $2.35 | $2.38 | $79.94 | 6.92% |
| **Average** | | $2.27 | $2.36 | $2.45 | $2.54 | $2.64 | 3.26% | $44.34 | $51.20 | $72.66 | $84.13 | ($72.10) | $2.36 | $2.45 | $2.54 | $86.11 | **7.32%** |

Sources:
[A] Value Line: Most current data available at time of schedule preparation. 2028 data is VL forecast for 2027-29.
[B] Straight line interpolation based on Value Line data, assuming constant dividend growth for 2025-28.
[C] Straight line interpolation based on Value Line data, assuming constant book value growth for 2025-28.
[D] EOD Data: Market Data as of November 30, 2024.
[E] Stock Price projected assuming constant Market to Book Ratio (Exhibit OPC (D)-7, page 1) and using VL projected Book Value.
[F] Cash Flow from purchasing stock on December 1, 2024, receiving dividends through 2028, and selling on November 30, 2028.
Negative number in 2024 reflects cash outflow required to purchase stock.
Cash flow sources are 1) dividends and 2) proceeds of stock sale.
1 of 4 dividends assumed received in 2024 and 3 of 4 in 2028 based on purchase and sale date.
[G] Total return on equity to investor who purchased, held, and sold stock as described above,
assuming Value Line projections of Dividends and Book Value are correct and
assuming Stock Price grows at same rate as Book Value.
DCF result is an Internal Rate of Return computation made using the "IRR" function built into Microsoft Excel
based on projected cash flows from 2024 to 2028.

**NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY**
**(BASED ON VALUE LINE FORECASTS AND LTM AVERAGE STOCK PRICE)**
**Rothschild Gas Proxy Group**

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Forecasted Dividends per Share | | | | | Growth | LTM Avg. Book Value | | LTM Avg. Stock Price | | Cash Flow From Buying and Selling Stock (At LTM Average Price) | | | | | |
| | | **2024** | **2025** | **2026** | **2027** | **2028** | **2025-28** | **2024** | **2028** | **11/30/24** | **11/30/28** | **2024** | **2025** | **2026** | **2027** | **2028** | **IRR / DCF** |
| | | [A] | [A] | [B] | [B] | [A] | [B] | [C] | [C] | [D] | [E] | [F] | [F] | [F] | [F] | [F] | [G] |
| Atmos Energy Corporation | ATO | $3.22 | $3.48 | $3.72 | $3.98 | $4.25 | 6.89% | $76.40 | $84.40 | $131.56 | $145.33 | ($130.75) | $3.48 | $3.72 | $3.98 | $148.52 | 5.32% |
| New Jersey Resource Corp | NJR | $1.71 | $1.76 | $1.82 | $1.88 | $1.95 | 3.48% | $21.22 | $26.97 | $45.69 | $58.09 | ($45.27) | $1.76 | $1.82 | $1.88 | $59.55 | 9.96% |
| NiSource, Inc. | NI | $1.06 | $1.12 | $1.15 | $1.17 | $1.20 | 2.33% | $22.25 | $25.71 | $31.68 | $36.60 | ($31.42) | $1.12 | $1.15 | $1.17 | $37.50 | 7.18% |
| Northwest Natural Holding C | NWN | $1.95 | $1.96 | $1.97 | $1.97 | $1.98 | 0.34% | $35.59 | $37.11 | $39.54 | $41.23 | ($39.05) | $1.96 | $1.97 | $1.97 | $42.71 | 6.03% |
| ONE Gas, Inc. | OGS | $2.64 | $2.68 | $2.74 | $2.79 | $2.85 | 2.07% | $50.13 | $58.31 | $67.19 | $78.16 | ($66.53) | $2.68 | $2.74 | $2.79 | $80.30 | 7.80% |
| Spire, Inc. | SR | $3.02 | $3.16 | $3.30 | $3.45 | $3.60 | 4.44% | $51.37 | $64.33 | $65.00 | $81.39 | ($64.25) | $3.16 | $3.30 | $3.45 | $84.09 | 10.63% |
| Maximum | | $3.22 | $3.48 | $3.72 | $3.98 | $4.25 | 6.89% | $76.40 | $84.40 | $131.56 | $145.33 | ($31.42) | $3.48 | $3.72 | $3.98 | $148.52 | 10.63% |
| Minimum | | $1.06 | $1.12 | $1.15 | $1.17 | $1.20 | 0.34% | $21.22 | $25.71 | $31.68 | $36.60 | ($130.75) | $1.12 | $1.15 | $1.17 | $37.50 | 5.32% |
| Median | | $2.30 | $2.32 | $2.35 | $2.38 | $2.42 | 2.90% | $42.86 | $47.71 | $55.35 | $68.13 | ($54.76) | $2.32 | $2.35 | $2.38 | $69.93 | 7.49% |
| **Average** | | $2.27 | $2.36 | $2.45 | $2.54 | $2.64 | 3.26% | $42.83 | $49.47 | $63.44 | $73.47 | ($62.88) | $2.36 | $2.45 | $2.54 | $75.44 | **7.82%** |

Sources:

[A] Value Line: Most current data available at time of schedule preparation. 2028 data is VL forecast for 2027-29.
[B] Straight line interpolation based on Value Line data, assuming constant dividend growth for 2025-28.
[C] Straight line interpolation based on Value Line data, assuming constant book value growth for 2025-28.
[D] EOD Data: Market Data as of November 30, 2024.
[E] Stock Price projected assuming constant Market to Book Ratio (Exhibit OPC (D)-7, page 1) and using VL projected Book Value.
[F] Cash Flow from purchasing stock on December 1, 2024, receiving dividends through 2028, and selling on November 30, 2028.
Negative number in 2024 reflects cash outflow required to purchase stock.
Cash flow sources are 1) dividends and 2) proceeds of stock sale.
1 of 4 dividends assumed received in 2024 and 3 of 4 in 2028 based on purchase and sale date.
[G] Total return on equity to investor who purchased, held, and sold stock as described above,
assuming Value Line projections of Dividends and Book Value are correct and
assuming Stock Price grows at same rate as Book Value.
DCF result is an Internal Rate of Return computation made using the "IRR" function built into Microsoft Excel
based on projected cash flows from 2024 to 2028.

## COMMON SHARES OUTSTANDING AND EXTERNAL FINANCING RATE
## Rothschild Gas Proxy Group

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Common Stock Outstanding (Millions of Shares) | | | | | | | | Annual Growth Rate | | |
| | | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2028 | 2019-23 | 2023-28 | 2019-28 |
| | | [A] | [A] | [A] | [A] | [A] | [A] | [A] | [A] | [B] | [B] | [B] |
| Atmos Energy Corporation | ATO | 119.3 | 125.9 | 132.4 | 140.9 | 148.5 | 155.0 | 158.0 | 175.0 | 5.62% | 3.34% | 4.35% |
| New Jersey Resource Corporatioı | NJR | 89.3 | 95.8 | 95.0 | 95.6 | 97.6 | 100.0 | 100.0 | 100.0 | 2.23% | 0.49% | 1.26% |
| NiSource, Inc. | NI | 382.1 | 391.8 | 404.3 | 411.1 | 446.4 | 465.0 | 465.0 | 475.0 | 3.96% | 1.25% | 2.45% |
| Northwest Natural Holding Compa | NWN | 30.5 | 30.6 | 31.1 | 35.5 | 37.6 | 40.0 | 42.0 | 45.0 | 5.42% | 3.64% | 4.43% |
| ONE Gas, Inc. | OGS | 52.8 | 53.2 | 53.6 | 55.4 | 56.6 | 56.5 | 56.5 | 57.0 | 1.74% | 0.16% | 0.86% |
| Spire, Inc. | SR | 51.0 | 51.6 | 51.7 | 52.5 | 53.2 | 58.0 | 60.0 | 62.0 | 1.08% | 3.11% | 2.20% |
| Maximum | | 382.1 | 391.8 | 404.3 | 411.1 | 446.4 | 465.0 | 465.0 | 475.0 | 5.62% | 3.64% | 4.43% |
| Minimum | | 30.5 | 30.6 | 31.1 | 35.5 | 37.6 | 40.0 | 42.0 | 45.0 | 1.08% | 0.16% | 0.86% |
| Median | | 71.1 | 74.5 | 74.3 | 75.5 | 77.1 | 79.0 | 80.0 | 81.0 | 3.09% | 2.18% | 2.32% |
| **Average** | | 120.8 | 124.8 | 128.0 | 131.8 | 140.0 | 145.8 | 146.9 | 152.3 | 3.34% | 2.00% | 2.59% |
| | | | | | | | | | **Sustainable Growth [C]** | | | **2.59%** |

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Annualized Growth Rate calculation.
[C] Estimated Sustainable Growth in Common Stock based on analysis of historical and projected growth rates.

# Capital Asset Pricing Model (CAPM) – Indicated Cost of Equity Calculations and Analysis

## CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY

WEIGHTED - All Inputs Weighted From September to November 2024
Rothschild Gas Proxy Group

| | 3-Month Treasury Bill | | 30-Year Treasury Bond | |
|---|---|---|---|---|
| | Historical Blended Beta | Forward Beta | Historical Blended Beta | Forward Beta |
| Risk-Free Rate | 4.64% | 4.64% | 4.34% | 4.34% |
| Beta | 0.64 | 0.68 | 0.64 | 0.68 |
| Risk Premium | 3.64% | 3.64% | 3.93% | 3.93% |
| CAPM (Weighted) | 6.98% | 7.12% | 6.87% | 7.03% |

## CAPITAL ASSET PRICING MODEL (CAPM) - RISK-FREE RATE

| | |
|---|---|
| **Spot (Nov. 30, 2024)** | |
| 3-Month Treasury Bill | 4.58% |
| 30-Year Treasury Bond | 4.36% |
| | |
| **3-Mo. Weighted Average (Sep. to Nov. 2024)** | |
| 3-Month Treasury Bill | 4.64% |
| 30-Year Treasury Bond | 4.34% |

Source: www.treasury.gov

**CAPITAL ASSET PRICING MODEL (CAPM) - BETAS**
(BASED ON HISTORICAL AND OPTION-IMPLIED RETURNS)
Rothschild Gas Proxy Group

| **Betas** | 08/27/2024 | 09/03/2024 | 09/10/2024 | 09/17/2024 | 09/24/2024 | 10/01/2024 | 10/08/2024 | 10/15/2024 | 10/22/2024 | 10/29/2024 | 11/05/2024 | 11/12/2024 | 11/19/2024 | 11/26/2024 | Average | Time Avg. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forward (6 months) | 0.79 | 0.77 | 0.65 | 0.66 | 0.78 | 0.73 | 0.67 | 0.71 | 0.81 | 0.71 | 0.55 | 0.71 | 0.65 | 0.64 | 0.703 | 0.682 |
| Historical (6 months) | 0.51 | 0.50 | 0.50 | 0.52 | 0.51 | 0.50 | 0.49 | 0.50 | 0.50 | 0.52 | 0.56 | 0.61 | 0.57 | 0.59 | 0.526 | 0.544 |
| Historical (2 yrs) | 0.73 | 0.73 | 0.73 | 0.70 | 0.71 | 0.71 | 0.70 | 0.69 | 0.70 | 0.70 | 0.69 | 0.70 | 0.70 | 0.71 | 0.707 | 0.703 |
| Historical (5 yrs) | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.801 | 0.802 |
| **Weighting** | | | | | | | | | | | | | | | | |
| Forward (6 months) | 50% | 50% | 50% | 50% | 50% | 50% | 50% | 50% | 50% | 50% | 50% | 50% | 50% | 50% | | |
| Historical (6 months) | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | | |
| Historical (2 yrs) | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | 15% | | |
| Historical (5 yrs) | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | | |
| **Historical Blended Beta** | **0.63** | **0.63** | **0.63** | **0.63** | **0.63** | **0.62** | **0.62** | **0.62** | **0.62** | **0.63** | **0.65** | **0.68** | **0.66** | **0.67** | 0.635 | 0.643 |
| **Slope** | 15% | | | | | | | | | | | | | | | |
| **Points** | 0.00 | 1.00 | 1.15 | 1.32 | 1.52 | 1.75 | 2.01 | 2.31 | 2.66 | 3.06 | 3.52 | 4.05 | 4.65 | 5.35 | | |
| **Time Weight** | 0.0% | 2.9% | 3.3% | 3.8% | 4.4% | 5.1% | 5.9% | 6.7% | 7.7% | 8.9% | 10.2% | 11.8% | 13.5% | 15.6% | | |

| **CAPM Betas** | Spot (Nov 26, 2024) | Weighted (Sep - Nov 2024) |
|---|---|---|
| Forward | 0.64 | 0.68 |
| Historical Blended | 0.67 | 0.64 |

Note: Historical betas are calculated on Tuesdays, following Value Line's methodology. Forward (option-implied) betas are also calculated on Tuesdays for the sake of compatibility.

# CAPITAL ASSET PRICING MODEL (CAPM) - MARKET RISK PREMIUM

WEIGHTED - All Inputs Weighted From September to November 2024

| | | |
|---|---|---|
| Cumulative Probability | 50.00% | |
| S&P 500 Option-Implied Growth Rate | 6.98% | |
| S&P 500 Dividend Yield | 1.30% | |
| S&P 500 Market Return | 8.28% | |
| | **3-Month Treasury Bill** | **30-Year Treasury Bond** |
| Risk-Free Rate | 4.64% | 4.34% |
| Option-Implied Market Risk Premium (Weighted) | 3.64% | 3.93% |

# CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY

SPOT - All Inputs Based on Last Available Data as of November 30, 2024

Rothschild Gas Proxy Group

| | 3-Month Treasury Bill | | 30-Year Treasury Bond | |
|---|---|---|---|---|
| | Historical Blended Beta | Forward Beta | Historical Blended Beta | Forward Beta |
| Risk-Free Rate | 4.58% | 4.58% | 4.36% | 4.36% |
| Beta | 0.67 | 0.64 | 0.67 | 0.64 |
| Risk Premium | 3.34% | 3.34% | 3.56% | 3.56% |
| CAPM (Spot) | 6.80% | 6.73% | 6.73% | 6.65% |

## CAPITAL ASSET PRICING MODEL (CAPM) - MARKET RISK PREMIUM

SPOT - All Inputs Based on Last Available Data as of November 30, 2024

| | | |
|---|---|---|
| Cumulative Probability | 50.00% | |
| S&P 500 Option-Implied Growth Rate | 6.64% | |
| S&P 500 Dividend Yield | 1.28% | |
| S&P 500 Market Return | 7.92% | |
| | **3-Month Treasury Bill** | **30-Year Treasury Bond** |
| Risk-Free Rate | 4.58% | 4.36% |
| Option-Implied Market Risk Premium (Spot) | 3.34% | 3.56% |

# Rothschild Gas Proxy Group Financial Data (including Capital Structure)

**MARKET TO BOOK RATIO AND DIVIDEND YIELD**
**Rothschild Gas Proxy Group**

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Book Value per Share** | | | | | | | | | | | | | | | |
| | | **Actual** | | | | **Estimated** | | | **Market Price** | | | **Mkt. to Book Ratio** | | **Dividend Rate** | | **Dividend Yield** | |
| | | **12/31/20** | **12/31/21** | **12/31/22** | **12/31/23** | **11/30/23** | **11/30/24** | **12/31/24** | **11/30/24** | **LTM High** | **LTM Low** | **11/30/24** | **LTM Avg.** | **MRQ** | **Annual** | **11/30/24** | **LTM Avg.** |
| | | [A] | [A] | [A] | [A] | [B] | [B] | [A] | [C] | [C] | [C] | [D] | [D] | [A] | [E] | [F] | [F] |
| Atmos Energy Corporation | ATO | $53.95 | $59.71 | $66.85 | $73.20 | $72.69 | $80.10 | $80.70 | $151.32 | $152.65 | $110.46 | 1.89 | 1.72 | $0.870 | $3.480 | 2.30% | 2.65% |
| New Jersey Resource Corp | NJR | $19.26 | $17.18 | $19.00 | $20.40 | $20.29 | $22.15 | $22.30 | $51.58 | $51.95 | $39.44 | 2.33 | 2.15 | $0.450 | $1.800 | 3.49% | 3.94% |
| NiSource, Inc. | NI | $12.44 | $13.33 | $13.14 | $22.71 | $21.94 | $22.56 | $22.55 | $38.09 | $38.56 | $24.80 | 1.69 | 1.42 | $0.265 | $1.060 | 2.78% | 3.35% |
| Northwest Natural Holding C | NWN | $29.05 | $30.04 | $33.08 | $34.12 | $34.04 | $37.14 | $37.40 | $43.82 | $44.25 | $34.82 | 1.18 | 1.11 | $0.490 | $1.960 | 4.47% | 4.96% |
| ONE Gas, Inc. | OGS | $42.01 | $43.81 | $46.69 | $48.91 | $48.73 | $51.52 | $51.75 | $77.97 | $78.89 | $55.50 | 1.51 | 1.34 | $0.660 | $2.640 | 3.39% | 3.93% |
| Spire, Inc. | SR | $44.19 | $46.74 | $49.08 | $50.29 | $50.19 | $52.55 | $52.75 | $73.19 | $73.64 | $56.36 | 1.39 | 1.27 | $0.755 | $3.020 | 4.13% | 4.65% |
| Maximum | | $53.95 | $59.71 | $66.85 | $73.20 | $72.69 | $80.10 | $80.70 | $151.32 | $152.65 | $110.46 | 2.33 | 2.15 | $0.870 | $3.480 | 4.47% | 4.96% |
| Minimum | | $12.44 | $13.33 | $13.14 | $20.40 | $20.29 | $22.15 | $22.30 | $38.09 | $38.56 | $24.80 | 1.18 | 1.11 | $0.265 | $1.060 | 2.30% | 2.65% |
| Median | | $35.53 | $36.93 | $39.89 | $41.52 | $41.38 | $44.33 | $44.58 | $62.39 | $62.79 | $47.47 | 1.60 | 1.38 | $0.575 | $2.300 | 3.44% | 3.93% |
| **Average** | | $33.48 | $35.14 | $37.97 | $41.61 | $41.31 | $44.34 | $44.58 | $72.66 | $73.32 | $53.56 | 1.67 | 1.50 | $0.582 | $2.327 | 3.43% | 3.91% |

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Straight-line interpolation of Actual and Estimated VL year-end values.
[C] EOD Data: Market Data as of November 30, 2024.
[D] Market Price divided by Book Value per Share.
[E] Most Recent Quarterly Dividend multiplied by 4.
[F] Dividend Rate divided by Market Price.

## EARNINGS PER SHARE AND RETURN ON EQUITY
**Rothschild Gas Proxy Group**

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] |
|---|---|---|---|---|---|---|---|---|---|
| | | **Earnings per Share** | | | | **Return on Equity** | | | |
| | | **2020** | **2021** | **2022** | **2023** | **2021** | **2022** | **2023** | **VL Future Exp.** |
| | | [A] | [A] | [A] | [A] | [B] | [B] | [B] | [A] |
| Atmos Energy Corporation | ATO | $4.72 | $5.12 | $5.60 | $6.10 | 9.01% | 8.85% | 8.71% | 9.50% |
| New Jersey Resource Corporation | NJR | $2.07 | $2.16 | $2.50 | $2.70 | 11.86% | 13.82% | 13.71% | 12.50% |
| NiSource, Inc. | NI | $1.32 | $1.37 | $1.47 | $1.60 | 10.63% | 11.11% | 8.93% | 8.50% |
| Northwest Natural Holding Company | NWN | $2.30 | $2.56 | $2.54 | $2.59 | 8.66% | 8.05% | 7.71% | 8.00% |
| ONE Gas, Inc. | OGS | $3.68 | $3.85 | $4.08 | $4.14 | 8.97% | 9.02% | 8.66% | 8.50% |
| Spire, Inc. | SR | $1.44 | $4.96 | $3.95 | $3.85 | 10.91% | 8.24% | 7.75% | 8.50% |
| Maximum | | $4.72 | $5.12 | $5.60 | $6.10 | 11.86% | 13.82% | 13.71% | 12.50% |
| Minimum | | $1.32 | $1.37 | $1.47 | $1.60 | 8.66% | 8.05% | 7.71% | 8.00% |
| Median | | $2.19 | $3.21 | $3.25 | $3.28 | 9.82% | 8.93% | 8.69% | 8.50% |
| **Average** | | $2.59 | $3.34 | $3.36 | $3.50 | 10.01% | 9.85% | 9.24% | 9.25% |

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Earnings per Share divded by average Book Value. Book Values shown on Exhibit OPC (D)-7, page 1.

## RETURN ON EQUITY IMPLIED BY ZACKS GROWTH RATES
**Rothschild Gas Proxy Group**

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Annual | Analyst | Analyst-Implied | | Analyst-Implied | | Implied | Analyst- |
| | | Book Value | EPS | Dividend | 5 Year | Book Value before SV | | Book Value Incl. SV | | EPS | Implied |
| | | 12/31/23 | 2023 | Rate | Growth Rate | 12/31/2027 | 12/31/2028 | 12/31/2027 | 12/31/2028 | 2028 | ROE |
| | | [A] | [A] | [A] | [B] | [C] | [C] | [C] | [C] | [C] | [C] |
| Atmos Energy Corporation | ATO | $73.20 | $6.10 | $3.480 | 7.00% | $85.65 | $89.32 | $107.39 | $118.52 | $8.56 | 7.57% |
| New Jersey Resource Corporation | NJR | $20.40 | $2.70 | $1.800 | NA | NA | NA | NA | NA | NA | NA |
| NiSource, Inc. | NI | $22.71 | $1.60 | $1.060 | 7.00% | $25.28 | $26.03 | $26.20 | $27.23 | $2.24 | 8.40% |
| Northwest Natural Holding Company | NWN | $34.12 | $2.59 | $1.960 | NA | NA | NA | NA | NA | NA | NA |
| ONE Gas, Inc. | OGS | $48.91 | $4.14 | $2.640 | NA | NA | NA | NA | NA | NA | NA |
| Spire, Inc. | SR | $50.29 | $3.85 | $3.020 | 5.00% | $54.05 | $55.11 | $59.29 | $61.87 | $4.91 | 8.11% |
| Maximum | | $73.20 | $6.10 | $3.480 | 7.00% | $85.65 | $89.32 | $107.39 | $118.52 | $8.56 | 8.40% |
| Minimum | | $20.40 | $1.60 | $1.060 | 5.00% | $25.28 | $26.03 | $26.20 | $27.23 | $2.24 | 7.57% |
| Median | | $41.52 | $3.28 | $2.300 | 7.00% | $54.05 | $55.11 | $59.29 | $61.87 | $4.91 | 8.11% |
| **Average** | | $41.61 | $3.50 | $2.327 | 6.33% | $54.99 | $56.82 | $64.29 | $69.20 | $5.24 | 8.03% |

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Zacks: Data as of December 03, 2024.
[C] Analyst-Implied Book Value and Return on Equity is obtained by escalating both Dividends and Earnings per Share by the stated Analyst Growth Rate and adding Earnings and subtracting Dividends for each projected year.
"SV" = S X V, where S = rate of continuous new stock financing and V = rate of return on common equity investment.

**CAPITAL STRUCTURE WITH SHORT TERM DEBT**
**Rothschild Gas Proxy Group**

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | % Common Equity | | | | | ($ millions) | | | | | | Percentage | | | |
| | | **2019** | **2020** | **2021** | **2022** | **2023** | **Total Debt** | **LT Debt** | **ST Debt** | **Pfd Stock** | **Equity** | **Total Capital** | **LT Debt** | **ST Debt** | **Pfd Stock** | **Equity Ratio** |
| | | [A] | [A] | [A] | [A] | [A] | [A] | [A] | [A] | [A] | [A] | [A] | [B] | [B] | [B] | [B] |
| Atmos Energy Corporation | ATO | 62.0% | 60.0% | 61.6% | 62.1% | 62.1% | $ 7,876.1 | $ 7,866.5 | $ 9.6 | $ - | $ 12,889.4 | $ 20,765.5 | 37.9% | 0.0% | 0.0% | 62.1% |
| New Jersey Resource Corpo | NJR | 50.2% | 44.9% | 43.0% | 42.2% | 41.8% | $ 3,246.0 | $ 2,793.7 | $ 452.3 | $ - | $ 2,006.5 | $ 5,252.5 | 53.2% | 8.6% | 0.0% | 38.2% |
| NiSource, Inc. | NI | 36.9% | 32.5% | 33.5% | 31.6% | 45.5% | $ 13,614.5 | $ 12,086.3 | $ 1,528.2 | NA | NA | $ 13,614.5 | 88.8% | 11.2% | NA | NA |
| Northwest Natural Holding Cc | NWN | 51.8% | 50.8% | 47.2% | 48.5% | 47.4% | $ 1,654.7 | $ 1,574.8 | $ 79.9 | $ - | $ 1,419.1 | $ 3,073.8 | 51.2% | 2.6% | 0.0% | 46.2% |
| ONE Gas, Inc. | OGS | 62.3% | 58.5% | 38.9% | 49.3% | 56.2% | $ 3,365.3 | $ 2,384.9 | $ 980.4 | $ - | $ 3,060.1 | $ 6,425.4 | 37.1% | 15.3% | 0.0% | 47.6% |
| Spire, Inc. | SR | 49.7% | 46.1% | 43.2% | 44.6% | 41.3% | $ 4,500.3 | $ 3,422.3 | $ 1,078.0 | $ 242.0 | $ 2,578.1 | $ 7,320.4 | 46.8% | 14.7% | 3.3% | 35.2% |
| Maximum | | 62.3% | 60.0% | 61.6% | 62.1% | 62.1% | $ 13,614.5 | $ 12,086.3 | $ 1,528.2 | $ 242.0 | $ 12,889.4 | $ 20,765.5 | 88.8% | 15.3% | 3.3% | 62.1% |
| Minimum | | 36.9% | 32.5% | 33.5% | 31.6% | 41.3% | $ 1,654.7 | $ 1,574.8 | $ 9.6 | $ - | $ 1,419.1 | $ 3,073.8 | 37.1% | 0.0% | 0.0% | 35.2% |
| Median | | 51.0% | 48.5% | 43.1% | 46.6% | 46.5% | $ 3,932.8 | $ 3,108.0 | $ 716.4 | $ - | $ 2,578.1 | $ 6,872.9 | 49.0% | 9.9% | 0.0% | 46.2% |
| **Average** | | 52.2% | 48.8% | 44.6% | 46.4% | 49.1% | $ 5,709.5 | $ 5,021.4 | $ 688.1 | $ 48.4 | $ 4,390.6 | $ 9,408.7 | 52.5% | 8.7% | 0.7% | **45.9%** |

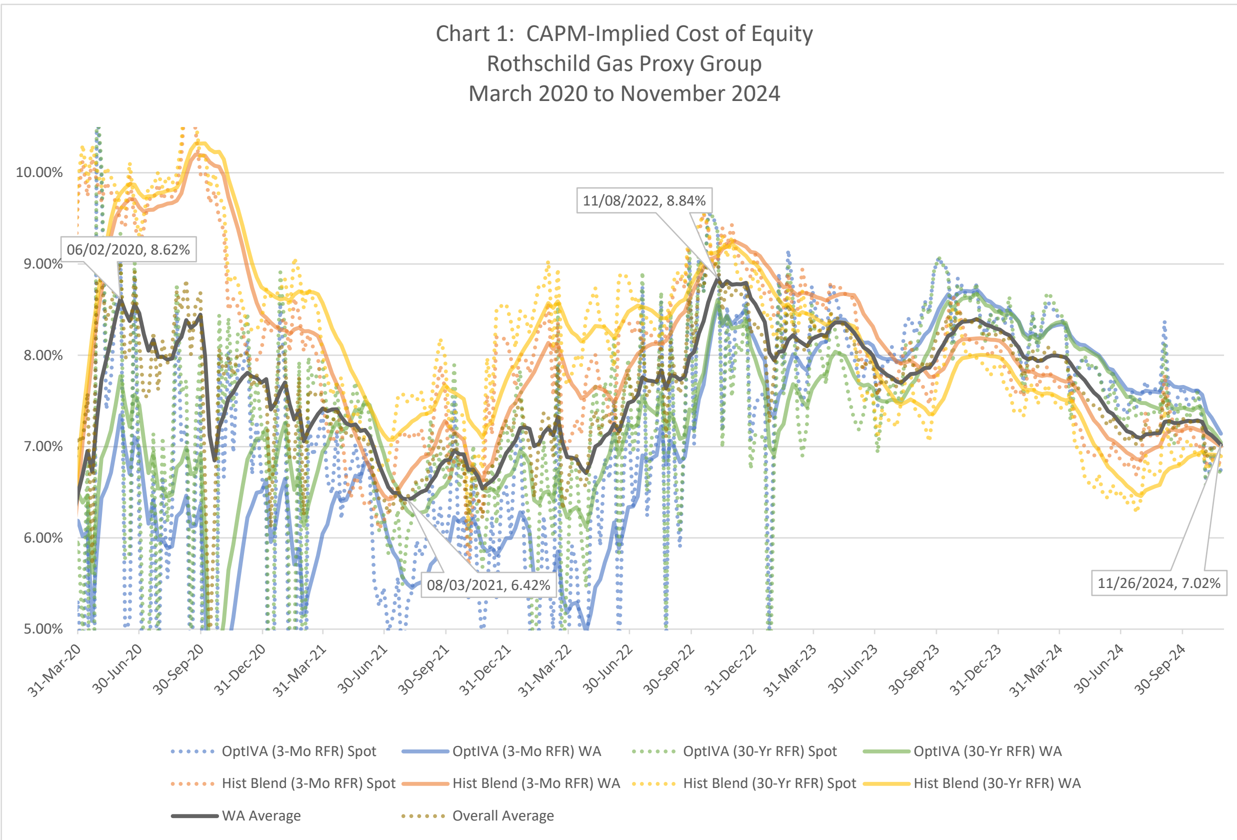
Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Percentage calculated on Total Capital including Short Term Debt.

**CAPITAL STRUCTURE WITHOUT SHORT TERM DEBT**
**Rothschild Gas Proxy Group**

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | % Common Equity | | | | | ($ millions) | | | | | | Percentage | | | |
| | | **2019** | **2020** | **2021** | **2022** | **2023** | **Total Debt** | **LT Debt** | **ST Debt** | **Pfd Stock** | **Equity** | **Total Capital** | **LT Debt** | **ST Debt** | **Pfd Stock** | **Equity Ratio** |
| | | [A] | [A] | [A] | [A] | [A] | [A] | [A] | [B] | [A] | [A] | [A] | [B] | [B] | [B] | [B] |
| Atmos Energy Corporation | ATO | 62.0% | 60.0% | 61.6% | 62.1% | 62.1% | $ 7,876.1 | $ 7,866.5 | | $ - | $ 12,889.4 | $ 20,755.9 | 37.9% | 0.0% | 0.0% | 62.1% |
| New Jersey Resource Corpoi | NJR | 50.2% | 44.9% | 43.0% | 42.2% | 41.8% | $ 3,246.0 | $ 2,793.7 | | $ - | $ 2,006.5 | $ 4,800.2 | 58.2% | 0.0% | 0.0% | 41.8% |
| NiSource, Inc. | NI | 36.9% | 32.5% | 33.5% | 31.6% | 45.5% | $ 13,614.5 | $ 12,086.3 | | NA | NA | $ 12,086.3 | 100.0% | 0.0% | NA | NA |
| Northwest Natural Holding Co | NWN | 51.8% | 50.8% | 47.2% | 48.5% | 47.4% | $ 1,654.7 | $ 1,574.8 | | $ - | $ 1,419.1 | $ 2,993.9 | 52.6% | 0.0% | 0.0% | 47.4% |
| ONE Gas, Inc. | OGS | 62.3% | 58.5% | 38.9% | 49.3% | 56.2% | $ 3,365.3 | $ 2,384.9 | | $ - | $ 3,060.1 | $ 5,445.0 | 43.8% | 0.0% | 0.0% | 56.2% |
| Spire, Inc. | SR | 49.7% | 46.1% | 43.2% | 44.6% | 41.3% | $ 4,500.3 | $ 3,422.3 | | $ 242.0 | $ 2,578.1 | $ 6,242.4 | 54.8% | 0.0% | 3.9% | 41.3% |
| Maximum | | 62.3% | 60.0% | 61.6% | 62.1% | 62.1% | $ 13,614.5 | $ 12,086.3 | | $ 242.0 | $ 12,889.4 | $ 20,755.9 | 100.0% | 0.0% | 3.9% | 62.1% |
| Minimum | | 36.9% | 32.5% | 33.5% | 31.6% | 41.3% | $ 1,654.7 | $ 1,574.8 | | $ - | $ 1,419.1 | $ 2,993.9 | 37.9% | 0.0% | 0.0% | 41.3% |
| Median | | 51.0% | 48.5% | 43.1% | 46.6% | 46.5% | $ 3,932.8 | $ 3,108.0 | | $ - | $ 2,578.1 | $ 5,843.7 | 53.7% | 0.0% | 0.0% | 47.4% |
| **Average** | | 52.2% | 48.8% | 44.6% | 46.4% | 49.1% | $ 5,709.5 | $ 5,021.4 | | $ 48.4 | $ 4,390.6 | $ 8,720.6 | 57.9% | 0.0% | 0.8% | **49.8%** |

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Percentage calculated on Total Capital excluding Short Term Debt.

# CAPM-Implied Cost of Equity for the Rothschild Gas Proxy Group Over Time Since Onset of COVID Pandemic




***Notes regarding the content of this chart:***

- *The information in this chart is the property of Rothschild Financial Consulting ("RFC") and may not be used for any purpose without the express written consent of RFC. Even when the underlying data are publicly available from another source, the results of analyses performed by RFC and the way of presenting the data are and remain the property of RFC.*

- *The data presented herein may not agree 100% with past recommendations by RFC for numerous reasons, including differences in the underlying proxy group and the fact that this chart represents only results based on the CAPM, whereas RFC usually bases recommendations on the CAPM and other models, such as various forms of the DCF.*

## Market-to-Book Ratios and the Market-Based COE

**Q. PLEASE EXPLAIN WHY A MARKET TO BOOK RATIO OF SIGNIFICANTLY ABOVE ONE INDICATES THAT THE COST OF EQUITY FOR GAS UTILITY COMPANIES IS LOWER THAN THE EXPECTED RETURN ON BOOK EQUITY?**

**A.** Calculating the cost of equity (investors' equity return expectations) is more complicated than calculating the return on a rental property, but the same concept applies regarding the relationship between market returns and book returns. If an investor purchases an apartment for $100,000 and expects to receive $500 per month ($500 X 12 = $6,000 per year) in rent, he or she will expect an annual return of 6% ($6,000/$100,000) on their investment. When the investor purchases the apartment, he would record the book value as $100,000 and the market value as $100,000 unless he determined that the purchase price was higher or lower than the market value. If the value of the apartment increases to $350,000, for example, the market to book ratio would increase to approximately 3.5, and therefore, his return on book value would remain at about 6% while his return on the market value of the apartment would decrease to about 1.7%.

In this rental property example, an increasing market value results in a lower expected return on market (1.7%) compared to expected return on book (6%) if the rent price remains constant. Rent prices do not increase to maintain an expected 6% return on book value; they are set by what the rental market reasonably can bear. The same is true of utility stocks. An ROE is not established based on a constant return on book (accounting) returns, it is set based on what investors in the market expect that market to return. In the case of a utility stock, an increasing market value results in a lower return on the market price of a stock for the same expected return on book. As this rental property example demonstrates, there is nothing inconsistent about investors expecting a lower return on the market price of an investment than on the book value of an investment. In fact, with market to book ratios of gas utility companies significantly above one, it would be surprising if investors expected a return on market equal, or anywhere close, to return on book.

**Q. ARE YOU AWARE OF ANY PUBLICATIONS THAT EXPLAIN HOW MARKET-TO-BOOK RATIOS RELATE TO THE COST OF EQUITY?**

**A.** Yes. In his 1970 book *The Economics of Regulation: Principles and Institutions*, regulatory economist Alfred Kahn wrote on why the cost of equity is lower than authorized returns when market to book ratios are significantly above one, saying:[1]

> [T]he sharp appreciation in the prices of public utility stocks, to one and half and then two times their book value during this period, reflected ... a growing recognition that the companies in question were in fact being permitted to earn considerably more than their cost of capital. ... The source of the discrepancy between market and book value has been that commissions have been allowing r's [returns on equity] in excess of k [market cost of equity]; if instead they had set r equal to k, or proceeded at some point to do so ... the discrepancy between market and book value ... would have disappeared, or would never have arisen.

---

1 Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, Mass. Inst. Tech. at 48 (fn. 69), 50 (1970).

A utility company's COE should not be based on authorized ROEs, which are accounting returns. The COE is set based on what investors in the market expect for a given risk profile. In the case of a utility stock, an increasing market value results in a lower return on market for the same expected return on book, all else equal.

## Future-Oriented "B X R" Method

**Q. ARE YOU AWARE OF CLAIMS ALLEGING THAT THE "BR"[2] APPROACH TO THE CONSTANT GROWTH DCF MODEL IS FLAWED BECAUSE IT RELIES ON THE VALUE OF THE FUTURE EXPECTED RETURN ON BOOK EQUITY ("R") TO ESTIMATE WHAT THE EARNED RETURN ON EQUITY SHOULD BE?**

**A.** Yes. One common criticism is that it is not reasonable for the DCF to indicate a COE (market return) that is different (lower or higher) than the expected return on book equity (accounting). There are multiple reasons why this concern is unfounded:

1. The constant growth form of the equation using "br" is:

   $$k= D/P + (br + sv)$$

   In this equation, "k" is the variable for the COE, and "r" is the future expected return on equity. The COE, "k," is not the same variable as the future expected earned return on equity, "r." In fact, there often is a large difference between the two.

2. The correct value to use for "r" is the return on book equity expected by investors as of the time the stock price and dividend data are used to quantify the D/P term in the equation. Therefore, even if future events occur that may change what investors expect for "r," the computation of the COE "k" remains correct as of the time the computation was completed.

[2] B=the earnings retention rate, R=return on common equity investment.

3. The ability of a commission's ROE decision to influence future cash flow expectations is not unique to the retention growth DCF approach. The five-year analysts' earnings per share growth rate is a computation that is directly influenced by what earnings per share will be in 5 years. Allowed ROEs impact earning – higher allowed returns lead to higher earnings growth because the higher allowed returns the more earnings are available for reinvestment.

**Q. CAN CHANGES IN THE ACTUAL EARNED RETURNS IMPACT GROWTH ABOVE AND BEYOND WHATEVER GROWTH RESULTS FROM EARNINGS RETENTION?**

**A.** Yes, but large short-term changes in earnings per share caused by a perceived change in the future expected earned returns are unsustainable. The new perceived earned return on book equity should be part of the computation, but the one-time growth spurt to get there is no more indicative of the sustainable growth required in the constant growth DCF formula than the temporary negative growth that occurs when a company has a bad year.

**Q. CAN YOU PLEASE SUMMARIZE WHY A FUTURE-ORIENTED "B X R" METHOD IS SUPERIOR TO A FIVE-YEAR EARNINGS PER SHARE GROWTH RATE FORECAST IN PROVIDING A LONG-TERM SUSTAINABLE GROWTH RATE?**

**A.** The primary cause of sustainable earnings growth is the retention of earnings. A company is able to create higher future earnings by retaining a portion of the prior year's earnings in the business and purchasing new business assets with those retained earnings. There are many factors that can cause short-term swings in earnings growth rates, but the long-term sustainable growth is caused by retaining earnings and reinvesting those earnings. Factors that cause short-term swings include anything that causes a company to earn a return on book equity at a rate different from the long-term sustainable rate. Assume, for example, that a particular utility company is regulated so that it is provided with a reasonable opportunity to earn 9% on its equity. Should the company experience an event such as the loss of several key customers, or unfavorable weather conditions, which cause it to earn only 6% on equity in a given year, the drop from a 9% earned return on equity to a 6% earned return on equity would be concurrent with a very large drop in earnings per share. In fact, if a company did not issue any new shares of stock during the year, a drop from a 9% earned return on book equity to a 6% earned return on book equity would result in a 33.3% decline in earnings per share over the period.[3] However, such a drop in earnings would not be an indication of what is a long-term sustainable earnings per share growth rate. If the drop were caused by weather conditions, the drop in earnings would be immediately offset once normal weather conditions return. If the drop were from the loss of some key customers, the company would replace the lost earnings by filing for a rate increase to bring revenues up to the level required for the company to be given a reasonable opportunity to recover its cost of equity.

For the reasons above, changes in earnings per share growth rates that are caused by non-recurring changes in the earned return on book equity are inconsistent with long-

[3] By definition, earned return on equity is earnings divided by book value. Therefore, whatever level of earnings is required to produce earnings of 6% of book would have to be 33.3% lower than the level of earnings required to produce a return on book equity of 9%.

term sustainable growth, but changes in earnings per share because of the reinvestment of additional assets is a cause of sustainable earnings growth. The "b x r" term in the DCF equation computes sustainable growth because it measures only the growth which a company can expect to achieve when its earned return on book equity "r" remains in equilibrium. If analysts have sufficient data to be able to forecast varying values of "r" in future years, then a complex, or multi-stage DCF method must be used to accurately quantify the effect. Averaging growth rates over sub-periods, such as averaging growth over the first five years with a growth rate expected over the subsequent period, will not provide an appropriate representation of the cash flows expected by investors in the future and, therefore, will not provide an acceptable method of quantifying the cost of equity using the DCF method. The choices are either a constant growth DCF, in which one growth rate derived using "b x r" should be used, or a complex DCF method in which the cash flow anticipated in each future year is separately estimated. Witness D'Ascendis has done neither. Instead, he mechanically adds analysts' five-year earnings per share growth rate to the dividend yield.

**Q. WHY ARE ANALYSTS' FIVE-YEAR CONSENSUS GROWTH RATES NOT INDICATIVE OF LONG-TERM SUSTAINABLE GROWTH RATES?**

**A.** Analysts' five-year earnings per share growth rates are earnings per share growth rates that measure earnings growth from the most currently completed fiscal year to projected earnings five years into the future. These growth rates are not indicative of future sustainable growth rates in part because the sources of cash flow to an investor are dividends and stock price appreciation. While both stock price and dividends are impacted in the long run by the level of earnings a company is capable of achieving, earnings growth over a period as short as five years is rarely in synchronization with the cash flow growth from increases in dividends and stock prices. For example, if a company experiences a year in which investors perceive that earnings temporarily dipped below normal trend levels, stock prices generally do not decline at the same percentage that earnings decline, and dividends are usually not cut just because of a temporary decline in a company's earnings. Unless both the stock price and dividends mirror every down swing in earnings, they cannot be expected to recover at the same growth rate that earnings recover. Therefore, growth rates such as five-year projected growth in earnings per share are not indicative of long-term sustainable growth rates in cash flow. As a result, they are not applicable for direct use in the simplified DCF method.

**Q. IS THE USE OF FIVE-YEAR EARNINGS PER SHARE GROWTH RATES IN THE DCF MODEL ALSO IMPROPER?**

**A.** Yes. A raw, unadjusted, five-year earnings per share growth rate is usually a poor proxy for either short-term or long-term cash flow growth that an investor expects to receive. When implementing the DCF method, the time value of money is considered by equating the current stock price of a company to the present value of the future cash flows that an investor expects to receive over the entire time that he or he owns the stock. The discount rate required to make the future cash flow stream, on a net present value basis, equal to the current stock price is the cost of equity. The only two sources of cash flow to an investor are dividends and the net proceeds from the sale of stock at whatever time in the future the investor finally sells. Therefore, the DCF method is discounting future cash flows that investors expect to receive from dividends and from the eventual sale of the stock. Five-year earnings growth rate forecasts are especially poor indicators of cash flow growth, even over the five years being measured by the five-year earnings per share growth rate number.

**Q. WHY IS A FIVE-YEAR EARNINGS PER SHARE GROWTH RATE A POOR INDICATOR OF THE FIVE-YEAR CASH DIVIDEND GROWTH EXPECTATIONS?**

**A.** The board of directors of a company changes dividend rates based upon long-term earnings expectations combined with the capital needs of a company. Most companies do not decrease dividends simply because a company has a year in which earnings were below sustainable trends, and similarly they do not increase dividends simply because earnings for one year happened to be above long-term sustainable trends. Therefore, over any given five-year period, earnings growth is frequently very different from dividend growth. In order for earnings growth to equal dividend growth, at a minimum, earnings per share in the first year of the five-year earnings growth rate period would have to be exactly on the long-term earnings trend line expected by investors. Since earnings in most years are above or below the trend line, the earnings per share growth rate over most five-year periods is different from what is expected for dividend growth.

**Q. WHY IS THE FIVE-YEAR EARNINGS PER SHARE GROWTH RATE A POOR INDICATION OF FUTURE STOCK PRICE GROWTH?**

**A.** If a company happens to experience a year in which earnings decline below what investors believe is consistent with the long-term trend, then the stock price does not drop anywhere near as much as earnings drop. Similarly, if a company happens to experience a year in which earnings are higher than the investor-perceived long-term sustainable trend, the stock price will not increase as much as the earnings. In other words, the P/E ratio of a company will increase after a year in which investors believe earnings are below sustainable levels, and the P/E ratio will decline in a year in which investors believe earnings are higher than expected. Since stock price is one of the important cash flow sources to an investor, a five-year earnings growth rate is a poor indicator of cash flow, both because it is a poor indicator of stock price growth over the five years being examined, and because it is equally a poor predictor of dividend growth over the period.

## Non-Constant Growth Form of the DCF Model

**Q. YOUR NON-CONSTANT GROWTH DCF MODEL USES ANNUAL EXPECTED CASH FLOWS. SINCE DIVIDENDS ARE PAID QUARTERLY RATHER THAN ANNUALLY, HOW DOES THIS SIMPLIFICATION IMPACT YOUR RESULTS?**

**A.** I used the annual model because it is easier for observers to visualize what is happening. Modeling cash flows to be annual rather than when they are actually expected to occur causes a small overstatement of the COE.

**Q. WHY IS IT A SMALL OVERSTATEMENT OF THE COE IF YOU HAVE MODELED DIVIDENDS TO BE RECEIVED SOME MONTHS AFTER INVESTORS ACTUALLY EXPECT TO RECEIVE THEM?**

**A.** The process of changing from an annual model to a quarterly model would require two changes, not just one. A quarterly model would show dividends being paid sooner and would also show earnings being available sooner. A company that receives its earnings sooner, rather than at the end of the year, has the opportunity to compound them. Since revenues, and therefore earnings, are essentially received every day, a company that is supposed to earn an annual rate of 9.00% on equity would have to earn only 8.62% if the return were compounded daily.[1] This reduction from 9.00% to 8.62% would then be partially offset by the impact of the quarterly dividend payment to bring the result of switching from the simplifying annual model closer to, but still a bit below 9.00%.

---

1 $(1+.0862/365)^{365}=1.09 = 9.00\%$.

**Q. WHEN USING CASH FLOW EXPECTATIONS AS THE VALUATION PARAMETER, DOES THE NON-CONSTANT DCF MODEL STILL RELY ON EARNINGS?**

**A.** Yes. It relies on an expectation of future cash flows. Future cash flows come from dividends during the time the stock is owned and capital gains from the sale of the stock once it is sold. Since earnings impact both dividends and stock price, the non-constant DCF model still relies on earnings.

Every dollar of earnings is used for the benefit of stockholders, either in the form of a dividend payment, or earnings reinvested for future growth in earnings and/or dividends. Earnings paid out as a dividend have a different value to investors than earnings retained in the business. Recognizing this difference and properly considering it in the quantification process is a major strength of the DCF model and is why the non-constant DCF model as I have set forth is an improvement over either the price-to-earnings ratio (P/E ratio) or dividend/price (D/P) methods. Comparing the P/E ratios and the dividend yield (D/P) are helpful as a rule of thumb, but they must be used with caution because, among other reasons, two companies with the same dividend yield can have a different COE if they have different retention rates. A DCF model is more reliable than these rules of thumb because it can account for different retention rates, among other factors.

**Q. WHY IS THERE A DIFFERENCE TO INVESTORS IN THE VALUE OF EARNINGS PAID OUT AS A DIVIDEND COMPARED TO THE VALUE OF EARNINGS RETAINED IN THE BUSINESS?**

**A.** The return on earnings retained in the business depends upon the opportunities available to that company. If a regulated utility reinvests earnings in needed "used and useful" utility assets, then those reinvested earnings have the potential to earn at whatever return is consistent with ratemaking procedures allowed and the skill of management in prudently operating the system.

When an investor receives a dividend, the investor can either reinvest it in the same or another company or use it for other things, such as paying down debt or paying living expenses. Although an investor could theoretically use the proceeds from any dividend payments to simply buy more stock in the same company, when an investor increases his investment in a company by purchasing more stock, the transaction occurs at market price. However, when the same investor sees his investment in a company increase because earnings are retained rather than paid as a dividend, the reinvestment occurs at book value. Stated within the context of the DCF terminology: earnings retained in the business earn at the future expected return on book equity "r," and dividends used to purchase new stock earn at the rate "k." When the market price exceeds book value (that is, the market-to-book ratio exceeds 1.0), retained earnings are worth more than earnings paid out as a dividend because "r" will be higher than "k." Conversely, when the market price is below book value, "k" will be higher than "r," meaning that earnings paid out as a dividend earn a higher rate than retained earnings.

**Q. IF RETAINED EARNINGS WERE MORE VALUABLE WHEN THE MARKET-TO-BOOK RATIO IS ABOVE 1.0, WHY WOULD A COMPANY WITH A MARKET-TO-BOOK RATIO ABOVE 1.0 PAY A DIVIDEND RATHER THAN RETAIN ALL OF THE EARNINGS?**

**A.** Retained earnings are more valuable than dividends only if there are sufficient opportunities to profitably reinvest those earnings. Regulated utility companies are allowed to earn the cost of capital only on assets that are used and useful in providing utility service. Investing in assets that are not needed may not produce any return at all. For unregulated companies, opportunities to reinvest funds are limited by the demands of the business. For example, how many new computer chips can Intel profitably develop at the same time?

**Q. UNDER THE NON-CONSTANT DCF MODEL, IS IT NECESSARY FOR EARNINGS AND DIVIDENDS TO GROW AT A CONSTANT RATE FOR THE MODEL TO BE ABLE TO ACCURATELY DETERMINE THE COST OF EQUITY?**

**A.** No. Because the non-constant form of the DCF model separately discounts each and every future expected cash flow, it does *not* rely on any assumptions of constant growth. The dividend yield can be different from period to period, and growth can bounce around in any imaginable pattern without harming the accuracy of the answer obtained from quantifying those expectations. When the non-constant DCF model is correctly used, the answer obtained is as accurate as the estimates of future cash flow.

# Capital Asset Pricing Model Overview

## Risk Free Rate

**Q. WHAT IS YOUR RESPONSE TO ANALYSTS WHO CLAIM THAT THE CAPM MUST BE IMPLEMENTED WITH A LONG-TERM INTEREST RATE (E.G., YIELD ON 30-YEAR TREASURY BOND) AS AN ESTIMATE OF THE RISK-FREE RATE COMPONENT OF THE CAPM?**

**A.** When looking for a security to calculate an estimate of the risk-free rate, it could be argued that it is appropriate to find one with a term or maturity that best matches the life of the asset being financed. In that sense, the 30-year Treasury bond yield can be argued to be ideal for this specific application. However, it is equally important to find a security that has a beta coefficient with the overall market as close to zero as possible, because by the very definition of the risk-free rate in the CAPM model, its movements should have no correlation to the movements of the market. And this is where the problem with the 30-year Treasury bond yield arises, as it has an established non-zero beta. The 3-month Treasury bill yield has a considerably lower beta, and therefore is superior in that respect to the 30-year Treasury bond yield. Neither one is a perfect fit on both fronts, which is why I have chosen to consider both as proxies for the risk-free rate to establish a range for my CAPM results.

**Q. HOW DO YOU RESPOND TO ANALYSTS WHO CLAIM THAT THE RISK-FREE RATE SHOULD BE BASED ON INTEREST RATE FORECASTS FROM FIRMS SUCH AS BLUE CHIP FINANCIAL?**

**A.** It is important to recognize that current long-term Treasury bond yields represent a direct observation of investor expectations and there is no need to use "expert" forecasts such as Blue Chip to determine the appropriate risk-free rate to use in a CAPM analysis or any other cost of equity calculations.

Many economists and forecasters will continue to be quoted in the press prognosticating on possible developments that are truly unpredictable. The Nobel Laureate Economist Daniel Kahneman stated the following regarding forecasting:

> It is wise to take admissions of uncertainty seriously, but declarations of high confidence mainly tell you that an individual has constructed a coherent story in his mind, not necessarily that the story is true.[1]

## Historical Beta

**Q. PLEASE EXPLAIN HOW YOU CALCULATE HISTORICAL BETAS.**

**A.** I calculate historical betas following the methodology used by Value Line, with some modifications. Specifically, Value Line adheres to the following guidelines:

1. Returns for each security are regressed against returns for the overall market in the following form:

$$\ln (p^{I}_{t} / p^{I}_{t-1}) = a_{I} + B_{I} * \ln (p^{m}_{t} / p^{m}_{t-1})$$

Where:

---

[1] DANIEL KAHNEMAN, *Thinking Fast and Slow*, p. 212 (New York: Farrar, Straus, and Giroux, 2011).

- $p^{I}_{t}$ is the price of the security I at time t
- $p^{I}_{t-1}$ is the price of the security I one week before time t
- $p^{m}_{t}$ and $p^{m}_{t-1}$ are the corresponding values of the market index
- $B_I$ is the regression estimate of Beta for the security against the market index

2. The natural log of the price ratio is used as an approximation of each return and no adjustment is made for dividends paid during the week.
3. Weekly returns are calculated on one day of the week, with a stated preference for Tuesdays to minimize the effect of holidays as much as possible.
4. Betas calculated using the regression method above are adjusted as per Blume (1971)[2] using the following formula:

$$\text{Adjusted } B_I = 0.35 + 0.67 * \text{Calculated } B_I$$

There are four differences between my historical beta calculations and Value Line's calculations:

1. The first significant difference is that whereas Value Line uses the New York Stock Exchange Composite Index as the market index, I use the S&P 500 Index.

[2] M. Blume, On the Assessment of Risk, *The Journal of Finance*, Vol. XXVI (March 1971) available at: www.stat.ucla.edu/~nchristo/Fiatlux/blume2.pdf.

2. Another important difference is that whereas Value Line calculates weekly returns on one day of the week, with a stated preference for Tuesdays, I calculate weekly returns on all days of the week.

3. Value Line only calculates betas every 3 months in their quarterly company reports, whereas I use the same consistent methodology to calculate betas every week during the most recent 3 complete months (September through November 2024).

4. Value Line always uses a 5-year period for the return regression,[3] whereas I calculate historical betas for periods of 6 months, 2 years, and 5 years, as shown in Chart 2 of my direct testimony.

In the following pages, I explain my rationale for making the four modifications above to Value Line's beta calculation methodology.

**Q. WHY DO YOU CALCULATE YOUR HISTORICAL BETAS VS. THE S&P 500 INDEX INSTEAD OF THE NEW YORK STOCK EXCHANGE (NYSE) COMPOSITE INDEX, AS VALUE LINE DOES?**

**A.** A critical factor in the calculation of a beta coefficient is the choice of index to represent the overall market. Using exactly the same beta calculation methodology with a different market index will result in different values of beta for a given company or portfolio – sometimes drastically different values. It is easy to jump to the conclusion that this points to a flaw in CAPM theory, as different values of beta would result in a different implied

[3] They offer betas calculated over different time periods on their website, including 3 years and 10 years.

cost of equity. However, another key component of the CAPM, the market risk premium, also depends on the choice of the market index, which in theory would have an offsetting effect on the cost of equity calculation. This points to the most important aspect of selecting a market index for a CAPM analysis, which is to be consistent and use the same index for the calculation of beta as for the calculation of the market risk premium. This is a fundamental concept of the CAPM and using betas based on one index with a market risk premium based on a different index yields invalid results.

As stated above, Value Line calculates its published betas based on the NYSE Composite Index. Most methodologies used to calculate the market risk premium, including those I rely on, are based on the S&P 500 Index, so using them in the CAPM together with Value Line betas exactly as published would yield invalid results.

For this reason, I calculate my historical betas versus the S&P 500 Index, making my CAPM approach entirely consistent.

As an aside related to my option-implied betas, using the S&P 500 Index consistently throughout my CAPM has the added benefit that this index has a much larger number of options traded, which makes the calculation of option-implied betas more reliable.

**Q. WHY DO YOU CALCULATE YOUR HISTORICAL BETAS USING WEEKLY RETURNS ON EVERY DAY OF THE WEEK AS OPPOSED TO USING ONLY ONE DAY OF THE WEEK, AS VALUE LINE DOES?**

**A.** Using one day of the week to calculate weekly returns for use in the regression analysis used to calculate historical betas has the unintended effect of generating different values of betas depending on the day of the week that is used. To clarify, if one were to use Value Line's precise methodology for calculating a 5-year historical beta for a given company using weekly returns calculated on Tuesdays, the resulting beta value would be different than the resulting value if one were to use the same exact methodology, but using weekly returns calculated on Wednesdays, or any other day of the week. Even though 5-year historical betas should in theory be quite stable and should not change very much from one day to the next, calculating returns on only one day of the week results in differences that can be significant and make no sense conceptually.

I only became aware of this side-effect recently, but it is easy to understand why it happens. Even though there is some correlation due to some overlap, the set of weekly returns calculated on Mondays is a completely different set of numbers than the set of weekly returns calculated on Tuesdays. As a result, there are five 5-year betas that can result from Value Line's methodology, and even though the Monday beta for a given company will change slowly from week to week, the change between the Monday beta and the Tuesday beta, calculated just one trading day apart, can be quite significant.

Since I became aware of this undesirable effect, I began calculating my historical betas based on an all-encompassing set of weekly returns calculated on every trading day in the beta calculation period. This methodology has the effect of averaging out the five possible betas that could result from using only one day of the week for the return calculations,[4] as Value Line does. In this way, a 5-year beta calculated on any two consecutive trading days would only change minimally, as it should.

Using a daily calculation of weekly returns could be criticized for the resulting overlap in a weekly return from Monday to Monday with that from Tuesday to Tuesday. However, given that the overlap is consistent and equal for the net effect of every trading day, no trading day is given undue weight in the regression. Even though the effect of each trading day appears 5 times in the weekly return data, there are also 5 times the total number of weekly returns in the overall set used in the regression, so any individual trading day has the same relative weight than in Value Line's methodology. The fact that the resulting beta value of this aggregate approach turns out to be a sort of average of the five possible values that would result from Value Line's methodology on different days of the week is the final confirmation that this is the superior approach for calculating a historical beta based on weekly returns.

Using a daily calculation of weekly returns has the added marginal benefit of providing more data pairs to be used in historical beta calculations for shorter periods, such as for 6-month historical betas, where instead of 25 return pairs, the regression is performed on 117 return pairs.

[4] The resulting beta is not a direct arithmetic or geometric average of the other five betas, but rather a regression based on the union of all five possible sets of weekly returns.

**Q. ARE THERE ADDITIONAL BENEFITS TO DOING YOUR OWN HISTORICAL BETA CALCULATIONS?**

**A.** Doing my own historical beta calculations using Value Line's established methodology allows me to see how beta values change from week to week and to use the most up-to-date beta calculations instead of relying on stale beta values that can be more than 3 months old.

**Q. HOW MANY DATA POINT PAIRS ARE NECESSARY TO ESTABLISH A STATISTICALLY SIGNIFICANT CORRELATION BETWEEN TWO VARIABLES IN A REGRESSION ANALYSIS, SUCH AS THE ONE USED TO ESTABLISH BETA COEFFICIENTS?**

**A.** Establishing a minimum number is somewhat subjective, though various authorities on statistics argue the number is between 3 and 8 data pairs. While one can broadly correctly generalize that the more data point pairs one uses, the more certain one can be about the significance of the results of any correlation analysis, this is very different from stating that one cannot achieve statistical significance with a relatively low number of data pairs. In fact, it is important to realize that one can achieve statistical significance with less than 10 data pairs, and that even hundreds of data pairs do not guarantee statistical significance. For precisely this reason, statisticians have developed a tool that helps determine statistical significance based on the number of data pairs in a regression analysis.

A "table of critical values" of Pearson's correlation, which can be readily found online[5] or in most statistics books, tells a statistician that for 25 data point pairs (implying N-2=23 "degrees of freedom"), a correlation, or beta, coefficient of 0.505 or higher will occur *by chance* with a probability of only 0.01.[6] As explained in more detail in the text regarding how to use the table of critical values,[7] any beta coefficient above this level, and certainly above the 0.544 3-month average for the recent 6-month betas for my Rothschild Gas Proxy Group, by definition are considered statistically significant. The threshold for statistical significance for 117 data point pairs (implying 115 "degrees of freedom"), is so low that it is not even included in the table of critical values. The maximum "degrees of freedom" listed is 100, with an already very low threshold of 0.254.

**<u>Historical Blended Beta</u>**

**Q. HOW DID YOU DECIDE ON THE RELATIVE WEIGHTS YOU ALLOCATE TO EACH COMPONENT OF YOUR HISTORICAL BLENDED BETAS? IS THERE ANY ACADEMIC SUPPORT FOR YOUR APPROACH?**

**A.** I am not aware of any academic study specifically focused on the optimal relative weight of historical betas to predict future betas. However, the authors of the paper I relied upon for guidance on the calculation of my option-implied betas did attempt to quantify the predictive power of 6-month option-implied ("forward-looking") betas as well as that of 6-

[5] University of Connecticut, *r Critical Value Table*, available at: https://researchbasics.education.uconn.edu/r_critical_value_table/#.

[6] In fact, many researchers use a more lenient "alpha level" of 0.05 for determinations of statistical significance.

[7] University of Connecticut, *Statistical Significance: Is there a relationship (difference) or isn't there a relationship (difference)?* available at: https://researchbasics.education.uconn.edu/statistical_significance.

month ("180-day"), 1-year, and 5-year historical betas by back-testing historical predictions with actual *expost* results, or "realized" betas, for the 30 companies in the Dow Jones Index. In addition to using each of the betas above independently, they also measured the predictive power of a "mixed" beta consisting of a simple average of the six-month option-implied beta and the 6-month historical beta.

Their conclusions for predicting 6-month future betas are as follows:

> The forward-looking beta outperforms the other methods ten times, and the same is true for the 180-day historical beta. The mixed beta is the best performer in seven cases, and the 1-year historical beta in three cases. The 5-year historical beta is always outperformed by at least one other method, and it often ranks last. The 180-day historical beta clearly dominates the two other historical methods.[8]

Their conclusions for predicting 1-year and 2-year future betas are as follows:

> Somewhat unexpectedly, the performance of the forward-looking beta compared to that of the 180-day historical beta is much better [for the one-year prediction] than [for the six-month prediction], and this conclusion carries over to [the two-year prediction]. The mixed beta also perform [sic] well. It is perhaps not surprising that the performance of the 180-day historical beta [for the one- and two-year predictions] is poorer than [for the six-month prediction], because the horizons used in the construction of realized betas are no longer equal to 180 days. What is harder to explain is why the correlation between realized beta and forward-looking beta is in many cases higher [for the one- and two-year predictions] than [for the six-month prediction]. Finally, it is also interesting that the 1-year and 5-year historical betas do not perform well [for the one-and two-year predictions]. In summary, [for the one-year prediction] either the forward-looking beta or the mixed beta is the best performer in nineteen out of thirty cases. [For the two-year prediction], this the case twenty-two times out of thirty.[9]

---

[8] Peter Christoffersen, Kris Jacobs, and Gregory Vainberg, *Forward-Looking Betas*, p. 16 (April 25, 2008) available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=891467.

[9] *Id.* at 17.

Their conclusions strongly support the use of 6-month historical betas, 6-month option-implied betas, and/or an average of the two as predictors of future betas 6 months, 1 year, or 2 years into the future. Therefore, considering a historical blended beta in conjunction with option-implied betas to calculate the cost of equity is consistent with research findings that coming historical and option-implied betas is the best predictor of future betas.

I decided on the composition of my historical blended betas primarily based on the conclusions of the authors above. Though the predictive power of longer-term historical betas seems to be quite reduced, it is not zero, so in an effort to preserve the effect of longer-term market trends in my historical blended betas, I chose to incorporate 5-year historical betas.

## Market Risk Premium

**Q. WHICH CUMULATIVE PROBABILITY DID YOU USE TO ESTIMATE THE OPTION-IMPLIED GROWTH OF THE S&P 500 IN THE CALCULATION OF YOUR MARKET RISK PREMIUM AND WHY?**

**A.** I used a cumulative probability of 50.0% in the calculation of my option-implied growth for the S&P 500, which results in a value of 6.64% as of November 30, 2024 and a value of 6.98% for the weighted average of the 3 months ending on that date. As stated above, a cumulative probability of 50% represents the median of the probability distribution, or in this case the option-implied market consensus, which is why I have chosen to use this level.

As a matter of fact, using the same probability distribution derived from the options market described above, one can also calculate the cumulative probability implied by a given cost of capital. For instance, using the same risk-free rates and betas for the Rothschild Gas Proxy Group in my CAPM analysis, Witness D'Ascendis' recommended ROE of 10.50% implies an average market risk premium of 9.1%, an average overall market return of 13.4%, average growth for the S&P 500 of 12.1%, and a cumulative probability of 69.9%.[10] In other words, to achieve the required market growth of 12.1%, reality would have to exceed 69.9% of the scenarios investors currently see as plausible for the market in aggregate, considerably more than the median market consensus at 50%. To put this into perspective, it is important to note that values on the tails of the probability function get increasingly separated, requiring an ever-increasing growth rate for every additional percentage in the cumulative probability, and making it impossible to ever arrive at 100%.

Using exactly the same methodology using the betas of the Rothschild Gas Proxy Group, my recommended 8.22% ROE implies an average market risk premium of 5.7%, an average overall market return of 10.0%, average growth for the S&P 500 of 8.7%, and a cumulative probability of 56.0%.

---

[10] Exhibit OPC (D)-3 (Calculations are shown in the Excel file).

**Q. ARE THE CUMULATIVE PROBABILITIES YOU REFER TO IN THIS CASE DIRECTLY COMPARABLE TO THE CUMULATIVE PROBABILITIES YOU HAVE USED OR REFERRED TO IN PRIOR TESTIMONIES YOU HAVE FILED?**

**A.** In late 2020, after significant efforts related to the complexities in processing extremely large volumes of option data, I was able to use option-implied volatility and option-implied skewness to come up with a log-normal function that approximates the probability distribution of the possible trajectories for the S&P 500 implied by the options market as of any given day, as explained above. All of the testimonies I have filed since then, starting in 2021, have used this complete and superior approach along with a cumulative probability of 50%, representing the median of the probability distribution, or the option-implied market consensus, to estimate expected market growth. Any references to cumulative probability in these testimonies are directly comparable.

Prior to incorporating skewness into the approximation, I used a normal function to estimate the same probability distribution referred to above. Using a normal distribution as an approximation is a simplification used commonly in economics, including in the Black-Scholes formula for a single option. However, unlike a skewed log-normal function, a normal function has the same median and mean, meaning that when applied in this case, the option-implied market consensus of this simplified approximation implies market growth of 0%. As a result, before using log-normal functions, I had to resort to finding an adequate level of cumulative probability above 50% to estimate market growth, which is admittedly somewhat subjective. To be conservative, I often used a cumulative probability of 68.3%, which is the probability found within one standard deviation of the mean of a normal distribution, which I understood would lead to a conservatively high estimate for market growth. It is important to point out that the cumulative probabilities of the simplified normal function approximation I used in cases before 2021 cannot be directly compared to the cumulative probabilities of the superior log-normal function approximation, which takes skewness into account. The considerably improved approximation based on a log-normal function eliminates all subjectivity in arriving at the implied market consensus and allows a much better measure of implied cumulative probabilities of deviations from that market consensus.

# Detailed Analysis of Current Capital Market Conditions

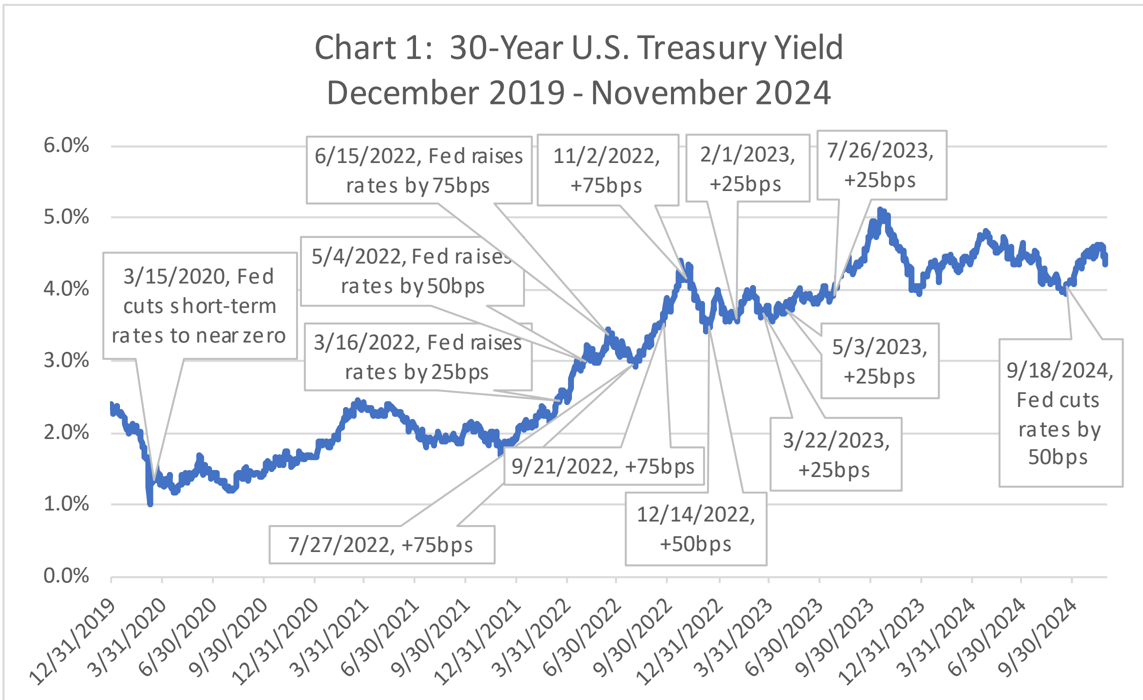
## Inflation and Interest Rates

**Q. PLEASE EXPLAIN THE IMPORTANCE OF, AND THE RELATIONSHIP BETWEEN, THE FEDERAL FUNDS RATE AND THE COST OF EQUITY.**

**A.** The Federal Funds rate is important because it can impact the cost of long-term borrowing and the cost of equity. As shown in Chart 1, the yield on the 30-year U.S. Treasury bond increased along with the Federal Funds rate, increasing from 2% at the start of 2022 to a high of over 5% October 2023. As of 11/30/2024 the yield on 30-year U.S. Treasury is 4.36%. The cost of equity increased along with the Federal Funds Rate and the yield on Treasury Bonds initially, but not one for one. However, the cost of equity for gas utility stocks has been mostly trending down since reaching highs at the end of 2022. Additionally, the market-based COE for gas utility stocks is below authorized ROEs because the market-to-book ratios of these stocks is above one (1.50 to 1.67).[1] See Exhibit OPC (D)-9 for an explanation of why a market-to-book ratio above one indicates that the cost of equity for gas utility stocks is lower than authorized ROEs.

---

1 Exhibit OPC (D)–5 at 1, 2a.



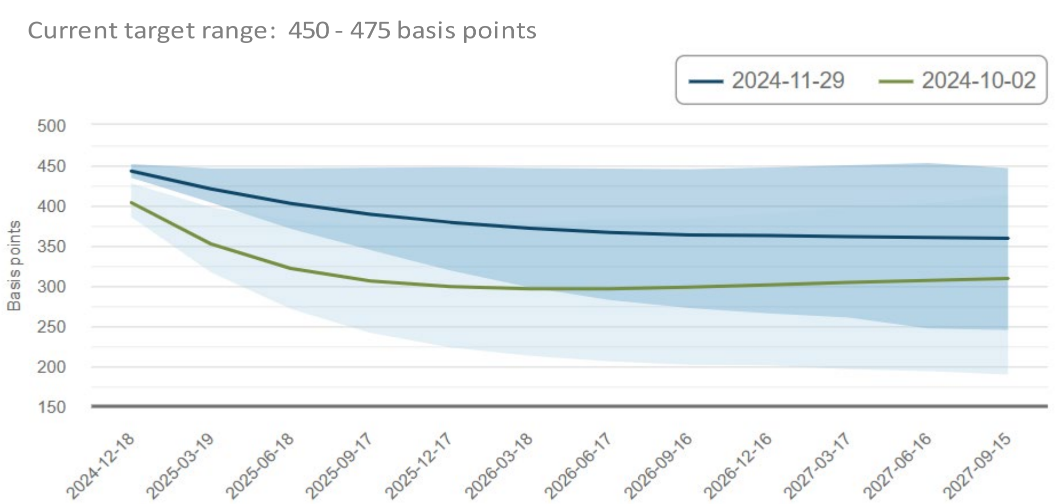

**Q. WHAT IMPACT CAN HIGHER INFLATION HAVE ON THE COST OF EQUITY?**

**A.** Higher inflation can impact the cost of equity because it can impact interest rates. Higher interest rates, all else equal, generally indicate a higher cost of equity for gas utility companies because fixed income investments become relatively more attractive when they start paying a higher rate (e.g., a bond with an interest rate of 3% is more attractive to investors, all else equal, than when they are paying a 2% rate). However, as discussed above, the cost of equity for utility companies has likely been decreasing because the cost of equity for the overall market has been declining. Additionally, the Commission can be confident that my 8.22% ROE recommendation from my direct testimony is sufficient because it is higher than my calculations that reflect interest rate changes. My calculations reflect interest rate changes because they are based on market data, including the changing market yields on government bonds.

**Q. WHAT DOES MARKET DATA INDICATE REGARDING INVESTORS' CURRENT INFLATION AND INTEREST RATE EXPECTATIONS?**

**A.** As shown in Chart 2, the Federal Reserve Bank of Atlanta estimated that as of November 30, 2024, investors expect the three-month average Federal Funds rate[2] will most likely decrease from its current range of 4.5%-4.75% to an expected value of about 3.6% in 2026 and into 2027. The same chart shows that about two months prior (October 2, 2024), investors expected the Federal Funds rate would decrease to be about 3.2% by 2026.

Chart 2: Investors' Federal Funds Rate Expectations
Three-Month Average SOFR Path as of Nov. 30, 2024




Source: Federal Reserve Bank of Atlanta (latest available date compared to oldest available date)

2 The Federal Funds rate guides overnight lending among U.S. banks, but this short-term rate impacts the interest rates on debt with longer maturities.

I use the Federal Reserve Bank of Atlanta's market-implied probabilities because it is based on investors' expectations as indicated by option prices, future prices, and swap spreads. As discussed above, market-based expectations like those provided by the Federal Reserve Bank are more appropriate to consider when calculating the cost of equity than economist/analyst projections for many reasons, primarily because market data like that used by the Federal Reserve Bank provides a direct observation of investor expectations.

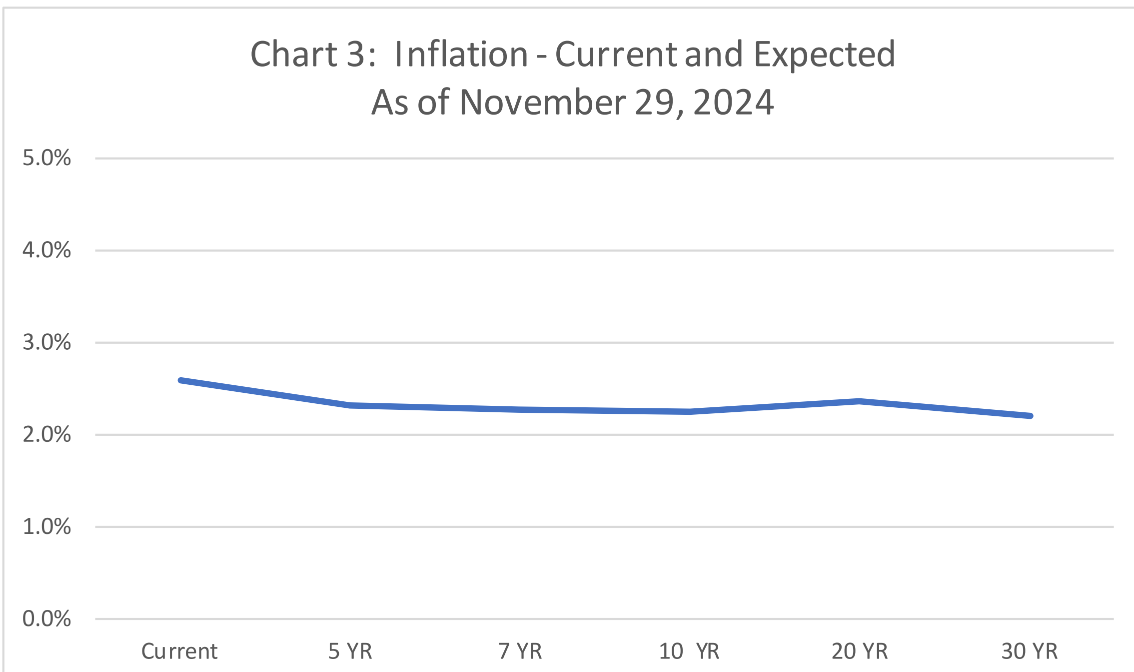
**Q. YOU STATED THAT THE FEDERAL RESERVE BANK OF ATLANTA USES MARKET DATA TO CALCULATE INVESTORS' EXPECTATIONS REGARDING THE FEDERAL FUNDS RATE. IS THERE A WAY TO MEASURE INVESTORS' INFLATION AND LONG-TERM INTEREST RATE EXPECTATIONS AS WELL?**

**A.** Yes. Regarding inflation, it is possible to measure investors' expectations directly simply by subtracting the interest rate of nominal Treasuries and TIPS (Treasury Inflation - Protected Securities) of comparable maturities. This difference is referred to as the "breakeven inflation rate" because it represents what inflation would have to be for an investor to "break even" or make the same return on both nominal Treasuries and TIPS.[3]

---

[3] For example, if the yield on a nominal 10-year Treasury is 2.5% and TIPS of the same duration are 1.5%, an investor would make the same real return on both bonds if the inflation rate is 1% over the next 10 years. (Nominal yield – real yield = breakeven inflation rate) In this case, investors' breakeven inflation rate is 1% (2.5% - 1.5% = 1%). It makes sense that investors' inflation expectation is equal to the breakeven inflation rate because if investors, on average, believed that inflation was going to be 10%, in the example above, they would buy TIPS and expect to make exceptional profits. The investor who purchases TIPS would earn 1.5% + 10% inflation = 11.5%. The investor who purchased the nominal Treasury would lose 7.5% (2.5% yield — 10% inflation rate). With such large relative

As indicated by the difference between nominal-treasuries and TIPS, Investors expect the Fed's actions will reduce the inflation rate in the coming years. As shown on Chart 3, the relative market price of inflation-protected bonds as compared to regular Treasury bonds as of November 30, 2024, indicates that investors expected the inflation rate to decline from the current 2.60% to only 2.33% over the next 5 years and to about 2.21% over the 30-year horizon.

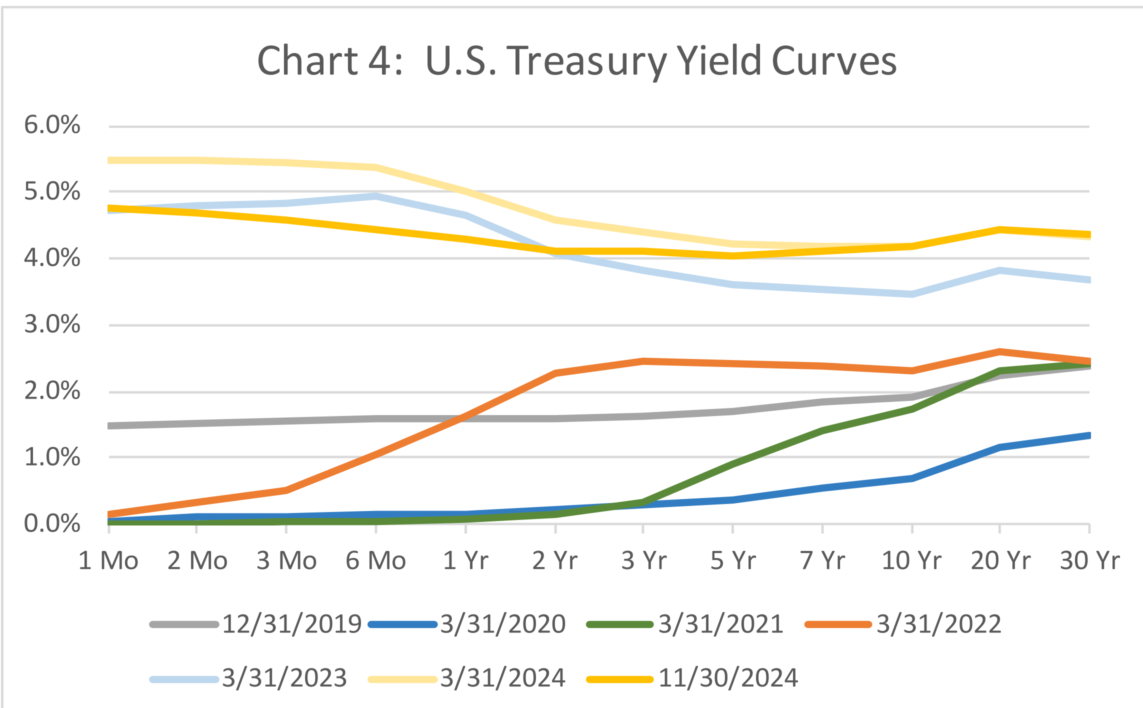



Regarding interest rates, it is possible to use the yield curve to calculate investors' expectations regarding future interest rates. An upward sloping yield curve indicates investors expect higher interest rates and a downward sloping yield curve indicates

---

returns to be made buying TIPS in this hypothetical example, investors would bid up the price of TIPS and drive down the yield until investors expect the same real return on nominal Treasuries and TIPS. And in this way, the relationship between the market yields on TIPS vs. nominal Treasury bonds is a self-balancing safe measurement of investors' expectation of inflation.

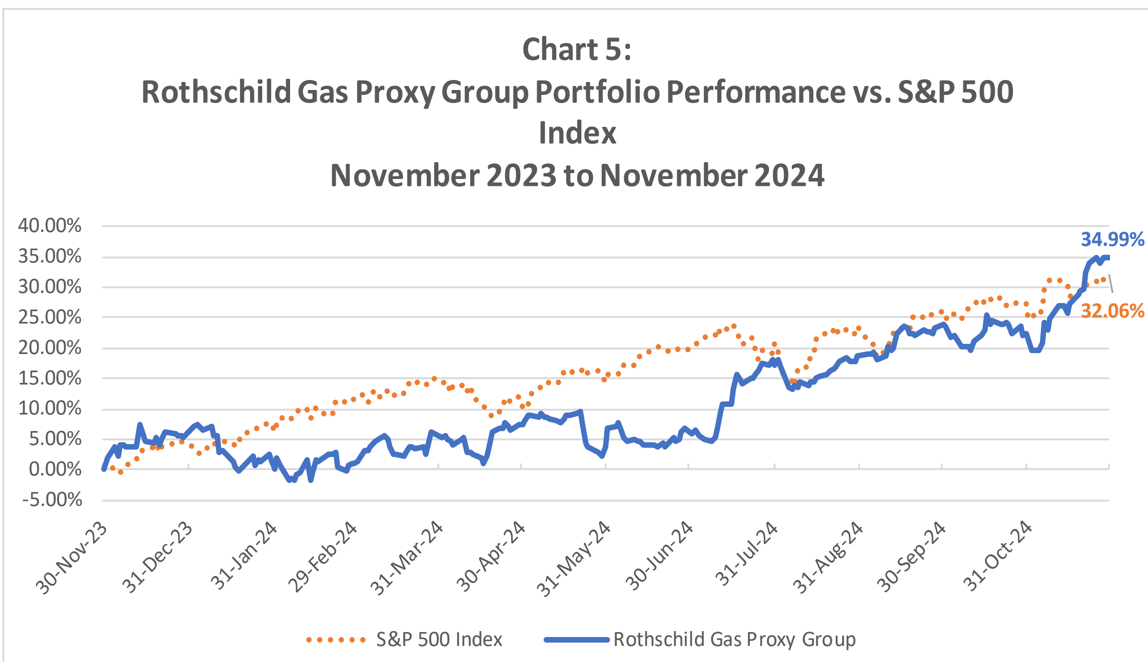
investors expect lower interest rates in the future. As shown in Chart 4, the yield curve went from being significantly upward sloping on March 31, 2021, to mostly downward sloping as of November 30, 2024. This indicates that investors expect that short-term interest rates will decline in the future along with the Federl Funds Rate. This makes sense because if investors expected short-term interest rates to remain the same there would be no reason to purchase long-term bonds and earn a lower interest rate.




**<u>The cost of equity for the overall market</u>**

**Q. WHAT, IF ANYTHING, DOES STOCK MARKET DATA INDICATE WITH REGARD TO THE COST OF EQUITY?**

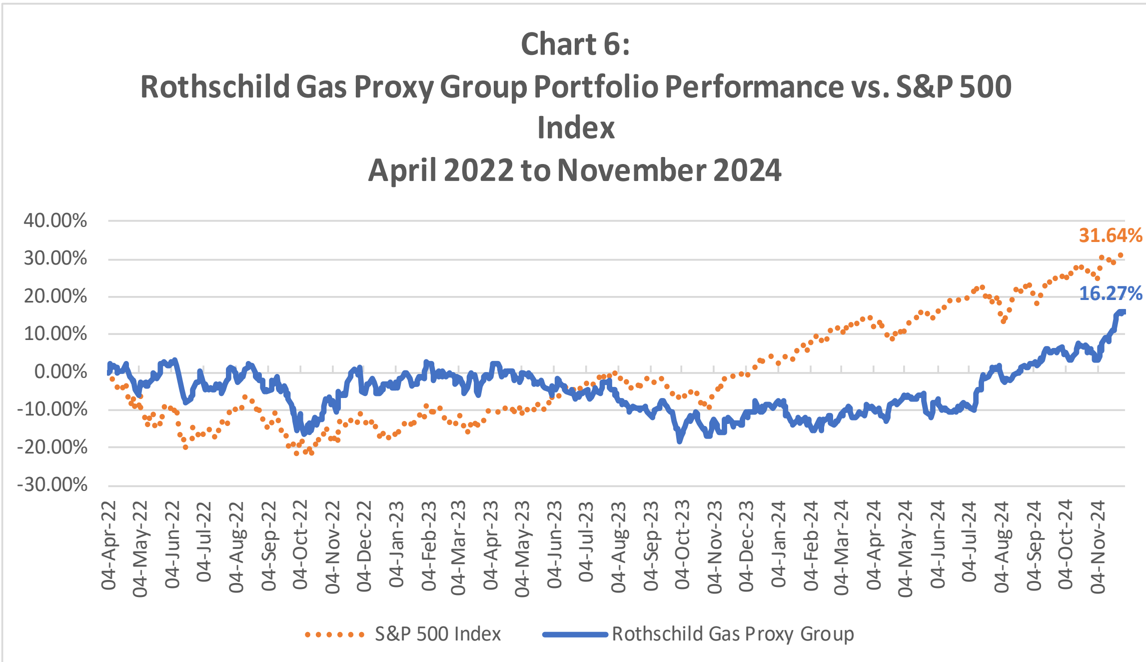
**A.** As discussed above, increasing stock prices have in recent years led to higher price-to-earnings ratios. All else equal, higher price-to-earnings ratios indicate that the cost of equity may be decreasing.[4] As show in Chart 5, stock prices for the S&P 500 have increased in recent months, up 32.06% between November 30, 2023 and November 29, 2024. On the other hand, the gas utility stocks in the Rothschild Gas Proxy Group were up 34.99% over the same time period. The recent overperformance of gas utility stocks may or may not continue, but it indicates that investors are starting to favor these stocks relative to the overall market as the FED started to reduce the Federal Funds rate and their relative cost of equity is likely decreasing as well.




As shown in Chart 6, since WGL's last rate case starting 2022, gas utility stocks have increased less than the overall market, up about 16% compared to S&P 500's increase of about nearly 32%.

---

[4] When investors pay a higher price today for the same earnings, the immediate yield or return on investment (ROI) is lower. Using our real estate investment analogy, if you spend more on an apartment, the rental income is a smaller return relative to your investment.




Regarding price of gas utility stocks, Value Line reported that "long-term capital gains potential for a number of these equities is not spectacular, resulting in unexciting total return possibilities."[5] In other words, Value Line is telling investors to expect relatively low equity returns in the future which is like saying that the cost of equity for gas utility is relatively low at current stock prices.

Value Line referred to price-to-earnings ratios because stock prices on their own cannot tell us how the cost of equity has changed. As discussed above, all else equal, price-to-earnings ratio and the cost of equity are inversely related – a higher price-to-earnings ratio indicates a lower cost of equity, and a lower price-to-earnings ratio indicates a higher cost of equity.

---

5 Value Line Gas Utility Industry Report, November 22, 2024.

**Q. DOES ADDITIONAL EVIDENCE INDICATE THAT THE COST OF EQUITY IS RELATIVELY LOW BY HISTORICAL STANDARDS?**

**A.** Yes. I discussed that increasing stock price and price-to-earning ratios show that the cost of equity for the overall market and for gas utility stocks indicates that the cost of equity has been trending down and is likely low by historical standards. Another common way to think about the cost of equity is the following:

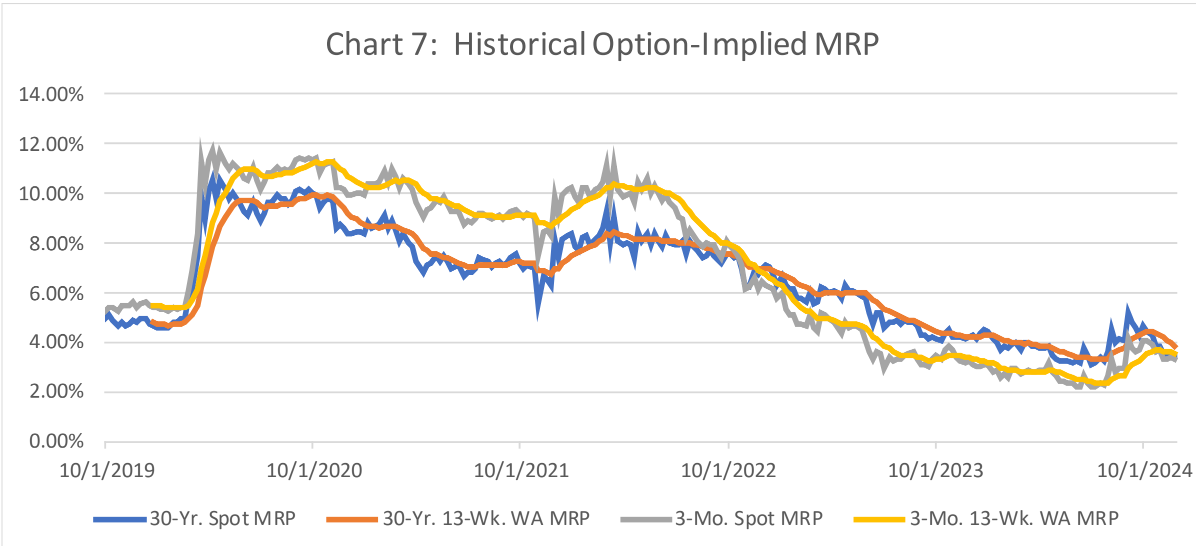
COE = risk free interest rate + market risk premium

As the equation above indicates, investors require a premium (i.e., higher return on investment) to invest in equity over debt. This makes sense because investors face more risk when they buy equity than when they buy debt. Debt holders are paid first. We often refer to this premium as the equity risk premium or market risk premium ("MRP"). Leading scholars on the topic have determined that investors generally demand an MRP of 4.0% on average. However, MRP for utilities is not always 4%; it can be higher or lower depending on current market conditions.

**Q. HOW HAS THE MRP CHANGED OVER TIME?**

**A.** As shown on Chart 7, the market risk premium mostly declined since peaking in 2020 and as the COVID-19 pandemic spread around the world in 2020. The market risk premium over the 3-month U.S. Treasury bill exceeded 10% for portions of February 2022 and declined to just over 3% by November 2023. The market risk premium over the 30-year U.S. Treasury bond was about 8% in February 2022, declining to just over 4% by January

2023 and is 3.31% as of November 26, 2024. These calculations are discussed in more detail in the portion of my testimony regarding my CAPM analysis.




**<u>Volatility Expectations</u>**

**Q. PLEASE DISCUSS CURRENT STOCK PRICE VOLATILITY EXPECTATIONS AND WHAT THEY INDICATE REGARDING THE COST OF EQUITY.**

**A.** Volatility, uncertainty, and risk are synonymous. There are two primary types of volatility: "realized volatility" and "implied volatility." The former is based on historical returns, which may or may not represent future volatility. On the other hand, implied volatility is calculated from options data, which indicates investors' future expectations for volatility. As discussed below, the "term structure" of volatility indicates investors' volatility expectations over different forward-looking time periods (i.e., 1 month, 1 year, etc.).

**Q. WHAT IS A STOCK OPTION, AND HOW DOES IT IMPLY VOLATILITY?**

**A.** A stock option is the right to buy or sell a stock at a specific price for a specified amount of time. A call option is the right to buy a stock at a specified exercise or strike price on or before a maturity date. A put option is the right to sell a stock at a specified exercise or strike price on or before a maturity date. For example, a call option to purchase 100 shares of Apple Computer stock for $230 on January 17, 2020, allows the owner the option (not the obligation) to buy Apple stock for $230 on that date. At the end of July 2019, Apple stock was trading at about $215 per share. Why would anyone pay for the right to buy a stock higher than the current price? Investors who purchased those call options thought there was a chance Apple stock would be trading higher than $230 on January 17, 2020, and those options gave those investors the right to buy Apple stock for $230 and profit by selling it at the market price on that date, if it was higher. The price of Apple's stock was $317.98 at the close of trading on January 17, 2020. Therefore, the investor who purchased this call option for $635 on July 31, 2019, earned a profit of $8,163[6] at expiry on January 17, 2020. On the other hand, the investor who purchased an Apple put option with the same expiration date and strike price on July 31, 2019, would have lost the price of the option ($2,248) and gained nothing on the expiration date because the right to sell Apple stock for $230 when the price is over $300 is worthless.

---

6 $8,163 profit from exercising call option ($31,798 from selling at $317.98 market price - $23,000 cost to purchase at $230) - $635 ($6.35 X 100) option purchase price. Note: Each call option is the right to purchase 100 shares.

Options can be used to assess future expectations for volatility because they track the type of variation in market price that investors bet will occur within the time frame during which an option can be exercised based on what type of option is purchased and what the difference is between the market price of stock and the option price, or the price that the option bets the stock will reach. As the distance between the market price and option price grows, more volatility is implied in the value of the stock over time. I used this option data to create an "implied volatility" value.

**Q. PLEASE EXPLAIN THE TERM "STRUCTURE OF VOLATILITY."**

**A.** Investors can expect volatility to increase or decrease over time. In general (i.e., in "normal" financial markets), investors expect higher volatility for longer time horizons. For example, investors generally expect that the chance stock prices will increase or decrease by 10% in 1 year to be greater than the chance of a 10% (annualized) move over the next 30 days. This makes sense because there is more uncertainty regarding economic and stock market changes the further in the future you look out.

However, during the height of a crisis, when volatility generally tends to rise in the short-term, investors often expect volatility to decrease in coming months or years. In other words, investors expect the current capital market hurricane to pass and the winds to die down. During the peak of implied volatility in mid-March 2020, shortly after the World Health Organization declared COVID-19 a pandemic, the data indicated that investors expected stock price volatility to decrease over time. This implies that investors expected the riskiness of equity investments to decrease over time. As shown in Chart 8, before the

COVID-19 outbreak, investors expected volatility to increase from less than 15% annually at the 1-month time frame to about 20% annually at the 24-month time frame. Investors' volatility expectations peaked in March 2020. At that time, investors expected stock price volatility would decrease from over 70% at the 1-month time frame to about 38% at the 24-month time frame. Chart 8 also shows that investors' volatility expectations were higher for all time frames when Russia invaded Ukraine as compared to 2021, but as of November 30, 2024 volatility expectations have dropped back to only slightly higher than 2019 levels over the full term structure of volatility.

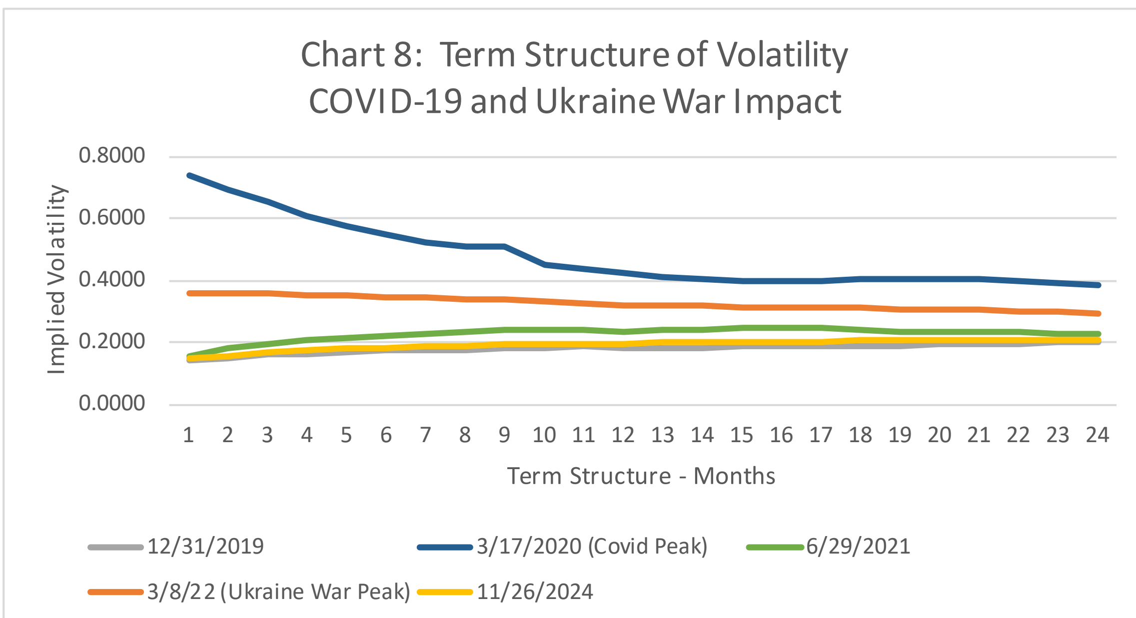
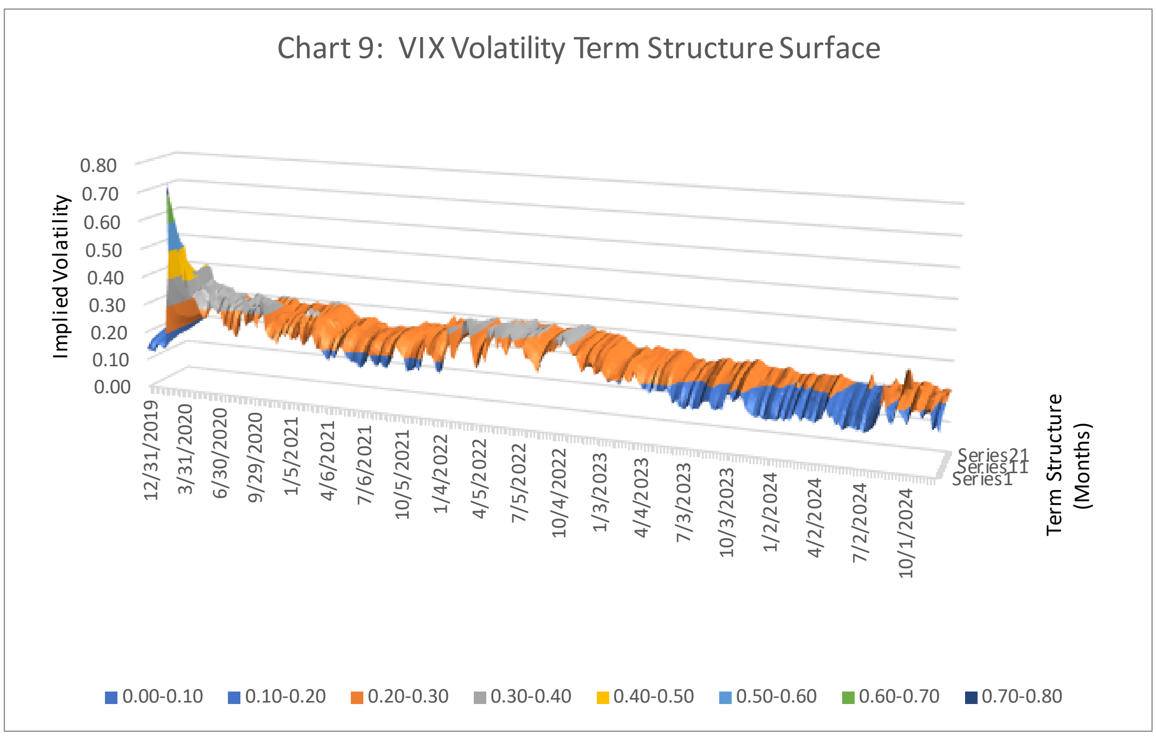



Chart 9 provides a 3-dimensional surface[7] to show how the term structure of volatility has evolved since before the COVID-19 outbreak and how it has changed during

[7] The X axis shows the implied volatility. The Y axis shows the data. The Z axis shows market expectation of future implied volatility of different time frames. Series1 = 1 month, Series11 = 11 months, and Series24 = 24 months.

and since the outbreak. As seen above in Chart 8, which shows five cross-sections of this data, during periods of low implied volatility – such as before the COVID-19 outbreak and at present – the slope of volatility expectations over time gently curves upwards, indicating lesser expectations of volatility in the short-term and greater in the long term. In Chart 9, this is represented by the surface of the line curving up and away during times of low volatility, while appearing to move downwards along the z-axis during the period of high volatility in March-April 2020 during the initial outbreak of the pandemic. Implied volatility can be seen to peak for both 1-month and 24-month time frames in mid-March 2020, with less dramatic spikes in February through October of 2022. As of the end of November 2024, the term structure of volatility has returned to near pre-COVID levels.



**Q. HOW HAVE VOLATILITY EXPECTATIONS FOR GAS UTILITY COMPANIES COMPARED TO VOLATILITY EXPECTATIONS FOR THE S&P 500?**

**A.** Chart 10 shows investors' stock price volatility expectations for the overall market (S&P 500) increased significantly as COVID-19 infections spread to the U.S. and continued to grow exponentially around the world. The solid orange line shows volatility expectations over the next 6 months, while the dashed red line shows volatility expectations over the next 30 days. On December 31, 2019, investors expected an annualized change of 13.78% over the next 30 days. In mid-March 2020, investors' volatility expectations peaked at over 80%. As of the end of November 26, 2024, investors expected an annualized change of 14.10%, even below pre-Covid levels.

The solid blue line in Chart 10 shows that investors' adjusted[8] 6-month volatility expectations for my Rothschild Gas Proxy Group, as indicated by their stock option prices, increased along with the market in mid-March 2020, but to a significantly lesser degree. Investors' 6-month adjusted volatility expectations for gas utility companies were for the most part higher than for the S&P 500 from May through August 2020, remained very comparable through March 2020, and have increased above the expectations for the market since March 2022 through the end of November 2024. However, in recent weeks, the volatility of gas utility stocks have started to fall along with the overall market.

---

[8] The implied volatility for individual stocks and small groups of stocks is almost always higher than the overall market because of the effects of diversification, even when the underlying stocks in the smaller portfolio are less risky, as is the case with gas utility companies. As a result, Chart 11 adjusts the 6-month expected volatility for the Rothschild Gas Proxy Group by the difference with the 6-month expected volatility for the S&P 500 Index on December 31, 2019 to facilitate the comparison throughout the chart.

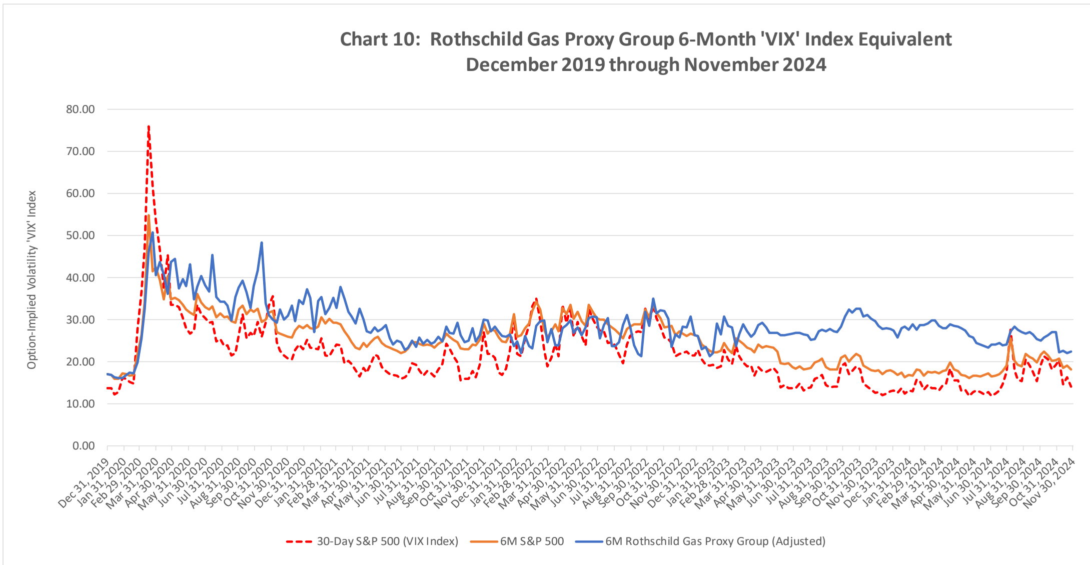



**Chart 10: Rothschild Gas Proxy Group 6-Month 'VIX' Index Equivalent**
**December 2019 through November 2024**

As discussed above, changes in implied volatility do not paint the full cost of equity picture. We must also account for implied skewness, which reflects investors' expectations about the likelihood of large drops in stock prices. For example, the perceived chance of a significant decline in gas utility stocks (e.g., down 20% in a week) may differ from that of the broader market, such as the S&P 500 Index.

**<u>Investor-Perceived Downside Risk (Option-Implied Skewness)</u>**

**Q. YOU EXPLAINED EARLIER THAT GAS UTILITY STOCKS HAVE OVERPERFORMED THE OVERALL MARKET RECENTLY. WHAT DOES STOCK OPTION DATA SHOW REGARDING INVESTORS' CONCERN THAT GAS UTILITY STOCKS WILL HAVE A LARGE DROP COMPARED TO THAT OF THE OVERALL MARKET?**

**A.** Stock option prices provide considerable information regarding investors' expectations. The most well-known measure of investors' expectations as measured by stock option prices is the VIX Index (or Volatility Index). The VIX Index is a measure of investors' volatility expectations and is referred to as the "fear index" because, all else equal, higher volatility expectations indicate higher uncertainty, risk, and scared investors.[9] However, volatility expectations are only one piece of a multi-dimensional puzzle that reveals the market-based cost of equity. After volatility expectations, the next dimension to explore (referred to as the "third moment" in statistics) is skewness. Option-Implied skewness reflects investors' expectations regarding the asymmetry of the probability distribution.

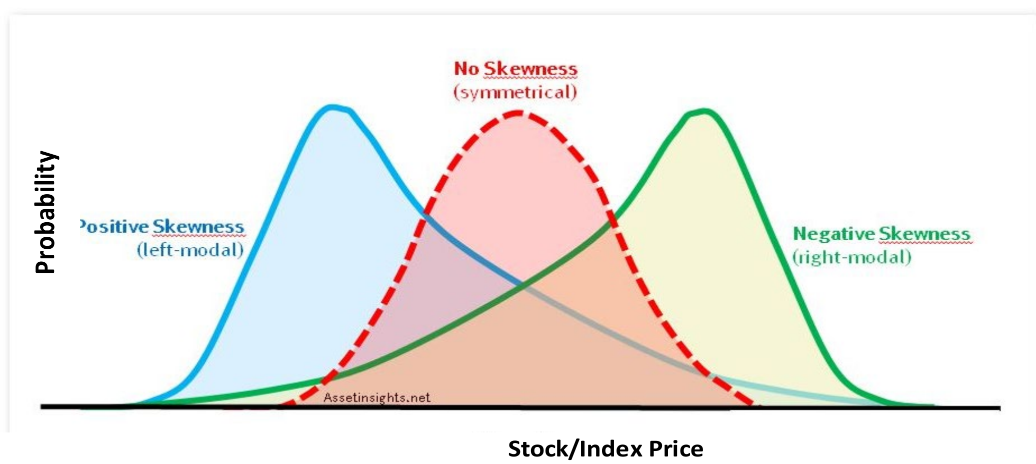
Option-implied probability distributions are almost always negatively skewed for stock market indices (e.g., S&P 500) and individual stocks, which means that investors almost always think there is a greater chance of a large decrease in stock prices than large

[9] Some investors like high volatility because it provides the opportunity to earn a lot of money quickly if the market moves in their favor. For example, an investor that shorts Microsoft, will make a lot of money if the stock drops by a large amount. However, investors who buy utility stocks generally prefer low volatility and low risk.

increases. The Chicago Board of Options Exchange ("CBOE") also publishes an index based on option-implied skewness referred to as the SKEW Index.

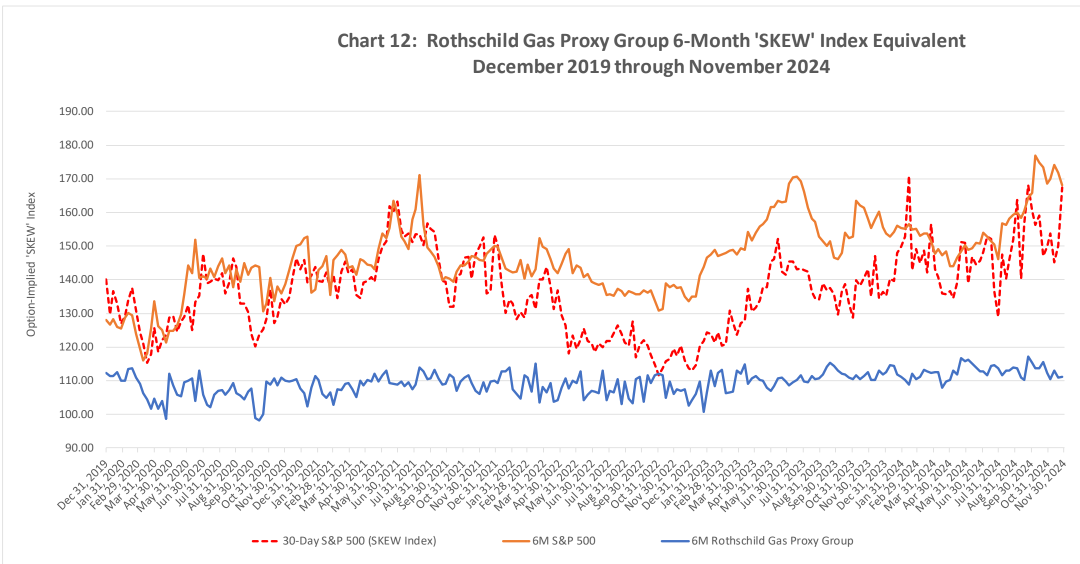
As shown in Chart 11, the probability distribution that is negatively skewed has a tail that is longer on the left. A probability distribution with positive skewness has a longer tail on the right. The right and left tails of a probability distribution with no skewness are symmetrical. If the option-implied skewness looked like the red probability distribution in Chart 11, it would mean that investors believed there was an equal chance that stock prices would move up or down by a certain amount.

Chart 11: Probability Distributions with and without Skewness




**Q. WHAT DOES THE SKEW INDEX REVEAL REGARDING THE IMPACT OF THE COVID PANDEMIC AND THE WAR IN UKRAINE ON WGL'S COST OF EQUITY?**

**A.** As shown in Chart 12, comparing the SKEW Index to an equivalent metric based on gas utility company stock options indicates that, as 2023 came to a close, investors expected the chance of gas utility stocks suffering from a large drop in investment to be much lower than the chance that the overall market will experience a large drop. This indicates the cost of equity for gas utility companies has likely remained lower relative to the overall market as interest rates have increased.



PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 7

QUESTION NO. 7-12

**Q.** **Credit Impact of Proposed Weather Normalization Mechanism.** Reference Witness D'Ascendis' Direct Testimony at 48:23-25, which states that "As discussed in Company Witness James Steffes' direct testimony, Washington Gas is pursuing a weather normalization mechanism in this proceeding." Please address the following:

a. If the Company's proposed WNA is approved, would it reduce the Company's risks related to recovery of its authorized return? Please explain and provide all supporting documentation.

b. Would the Company's credit rating be impacted by the approval of WGL's proposed WNA? Please explain and provide all supporting documentation.

**WASHINGTON GAS'S RESPONSE** 11/19/2024

**A.** a. All else being equal, a weather normalization mechanism, such as the Company's proposed WNA, will reduce some of the company-specific business risks related to the recovery of its authorized return. As stated in Mr. D'Ascendis' Direct Testimony at 48:9-18, the estimation of the Company's ROE is a comparative exercise, and if a mechanism is common throughout the companies on which one bases their analyses, the comparative risk is zero. As every single one of the proxy companies has a form of partial decoupling, the acceptance of the Company's proposed WNA would reduce the comparative risk related to the WNA to zero.

b. Mr. D'Ascendis cannot speculate to the potential credit rating of WGL upon the potential approval of WGL's proposed WNA.

SPONSOR: Dylan D'Ascendis
Consultant, Scott Madden

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 7

QUESTION NO. 7-9

**Q.** **Debt Ratings.** Reference Witness Burrows' Direct Testimony at 4: 23-24, which states "maintaining strong debt ratings is critical to ensure a reasonable cost of debt and helps maintain customer affordability." Please address the following:

a. If the Company's proposed Weather Normalization Adjustment (WNA) is approved, could it impact the Company's debt ratings? Please explain and provide all supporting documentation for the response.

b. If the Company's proposed WNA is approved, would it impact the Company's cost of equity? Please explain and provide all supporting documentation for the response.

**WASHINGTON GAS'S RESPONSE** 11/19/2024

**A.** a) It would not necessarily change the Company's credit ratings. It would help maintain the Company's current credit ratings. A WNA would provide more stable revenues and as a result provide more stable Funds from Operations (FFO). As FFO is a key measure used in ratio calculations performed by the rating agencies, more stable FFO would improve those ratios supporting our credit ratings.

b) Witness Burrows does not address the cost of equity.

SPONSOR: Janet Burrows
VP and Treasurer, AltaGas Ltd.

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 7

QUESTION NO. 7-11

**Q.** **Weather Normalization Mechanism.** Reference Witness D'Ascendis' Direct Testimony at 48:16-23, which states that "…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." Please address the following:

a. Has Witness D'Ascendis or WGL done an analysis to compare the characteristics of the various rate constructs and decoupling mechanisms used by the companies in Witness D'Ascendis' Utility Proxy Group to WGL's proposed WNA? If yes, please provide the analysis, including all supporting documentation. If not, please explain why such an analysis was not conducted.

b. What percentage of the earnings and or revenues of the companies in Witness D'Ascendis' Utility Proxy Group are impacted by such rate mechanisms?

**WASHINGTON GAS'S RESPONSE** 11/19/2024

**A.** a. No, Mr. D'Ascendis has not conduced such an analysis. As stated in Mr. D'Ascendis' Direct Testimony at 48:9-18, "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." For the purposes of estimating WGL's ROE, Mr. D'Ascendis does not believe that a further analysis into the characteristics of the various rate constructs and decoupling mechanisms is necessary.

b. Mr. D’Ascendis does not have the requested data.

SPONSOR: Dylan D’Ascendis
Consultant, Scott Madden

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

| | | |
|---|---|---|
| **In the Matter of** | **§** | |
| | **§** | |
| **The Application of Washington Gas** | **§** | **Formal Case No. 1180** |
| **Light Company for Authority to** | **§** | |
| **Increase Existing Rates and** | **§** | |
| **Charges for Gas Service** | **§** | |

**DIRECT TESTIMONY**
**AND SUPPORTING EXHIBITS OF**
**BRIAN C. ANDREWS**

**Exhibit OPC (E)**

**On behalf of the**
**Office of the People's Counsel**
**for the District of Columbia**

January 24, 2025

**TABLE OF CONTENTS**

**EXHIBIT LIST**

| | |
|---|---|
| Exhibit OPC (E)-1 | Qualifications of Brian C. Andrews |
| Exhibit OPC (E)-2 | Select Pages from WGL 2015 Depreciation Study |
| Exhibit OPC (E)-3 | WGL Response to OPC Data Request No. 2-33 |
| Exhibit OPC (E)-4 | WGL Response to OPC Data Request No. 2-23 |
| Exhibit OPC (E)-5 | WGL Response to OPC Data Request No. 2-24 |
| Exhibit OPC (E)-6 | WGL Response to OPC Data Request No. 2-12, Attachment 1, pages 57-62 |
| Exhibit OPC (E)-7 | Andrews Actuarial Life Analysis Results Account 376.20 |
| Exhibit OPC (E)-8 | WGL Response to OPC Data Request No. 2-27 |
| Exhibit OPC (E)-9 | Summary of OPC’s Proposed Depreciation Rates |
| Exhibit OPC (E)-10 | Comparison of WGL and OPC’s Proposed Depreciation Rates |
| Exhibit OPC (E)-11 | WGL Response to OPC Data Request No. 2-28 |
| Exhibit OPC (E)-12 | WGL Response to OPC Data Request No. 2-29 |
| Exhibit OPC (E)-13 | WGL Response to OPC Data Request No. 2-12, Attachment 1, pages 120-125 |
| Exhibit OPC (E)-14 | Andrews Actuarial Life Analysis Results Account 380.20 |
| Exhibit OPC (E)-15 | WGL Response to OPC Data Request No. 2-32 |

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q. WHAT IS YOUR OCCUPATION?**

A. I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.**

A. This information is included in Exhibit OPC (E)-1.

**Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A. I am appearing in this proceeding on behalf of the Office of the People's Counsel for the District of Columbia ("OPC").

**Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA ("COMMISSION") REGARDING DEPRECIATION ISSUES?**

A. Yes, I filed depreciation related testimony in Formal Case No. ("FC") 1162 and FC 1176. I have also filed depreciation related testimony before the public service commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kentucky, Louisiana, Michigan, Missouri, Montana, New Mexico, Oklahoma, and South Carolina.

**Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?**

A. Yes. I am a member and Past President of the Society of Depreciation Professionals ("SDP").

**Q. DO YOU HOLD ANY CERTIFICATIONS AS A DEPRECIATION EXPERT?**

A. Yes. SDP has awarded me the designation of Certified Depreciation Professional ("CDP"). This certification is based upon my education, experience, and successful completion of the CDP Exam.

**Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?**

A. Yes.

## II. SCOPE AND SUMMARY OF TESTIMONY

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

A. The purpose of my testimony is to present OPC's proposed depreciation rates. I will provide my assessment of Washington Gas Light Company's ("WGL" or "Company") depreciation rates and propose adjustments to the average service life assumptions for WGL's two largest accounts, Plastic Mains in Account 376.20 and Plastic Services in Account 380.20.

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.**

A. My conclusions and recommendations are as follows:

- WGL has hired Dr. Ronald White, of Foster Associates, to conduct its 2024 depreciation study, which the Company filed in this proceeding as Exhibit WG (G)-2.

- WGL has requested the Commission's approval of the depreciation rates presented in the Company's 2024 depreciation study; WGL's study would increase depreciation expense by $6.53 million, or 24.6%. This is based on an overall proposed depreciation rate of 2.75%.

- WGL's proposed depreciation rates are excessive due to WGL's proposed average service lives for its two largest accounts – Account 376.20 and Account 380.20.

- The average service life utilized for Account 376.20, Plastic Mains, should be 67 years rather than the 55 years proposed by WGL. A 67-year life is a better statistical fit to the data and results in a more reasonable depreciation rate for these assets.

- The average service life utilized for Account 380.20, Plastic Services, should be 65 years rather than the 55 years proposed by WGL; 65 years is a statistically better fit to the data than 55 years and will result in more reasonable depreciation rates for the assets in this account.

- These two adjustments, when combined with Dr. White's reserve reallocation procedure, would reduce WGL's annualized depreciation accrual by $6.13 million, and the composite depreciation rate would be 2.24%, rather than the 2.75% proposed by WGL.

- I recommend the Commission approve OPC's proposed depreciation rates presented in Exhibit OPC (E)-9.

## III. <u>BOOK DEPRECIATION CONCEPTS</u>

**Q. PLEASE EXPLAIN THE PURPOSE OF BOOK DEPRECIATION ACCOUNTING.**

A. Book depreciation is the recognition in a utility's income statement of the consumption or use of assets to provide utility service. Book depreciation is recorded as an expense and is included in the ratemaking formula to calculate the utility's overall revenue requirement.

The basic underlying principle of utility depreciation accounting is intergenerational equity, where the customers/ratepayers who benefit from the service of assets pay all the costs for those assets during the benefit period, which is over the life of those assets.[1] The concept of intergenerational equity can be achieved through depreciation by allocating costs to customers in a systematic and rational manner that is consistent with the period of time in which customers receive the service value.[2]

Book depreciation provides for the recovery of the original cost of the utility's assets that are currently providing service. Book depreciation expense is not intended to provide for replacement of the current assets, but provides for capital recovery or return of the current investment. Generally, this capital recovery occurs over the average service life of the investment or assets. As a result, it is critical that appropriate average service lives be used to develop the depreciation rates so no generation of ratepayers is disadvantaged.

In addition to capital recovery, depreciation rates also contain a provision for net salvage. Net salvage is the scrap or reuse value less the removal cost of the asset being depreciated. Accordingly, a utility will also recover the net salvage costs over the useful life of the asset.

---

[1] Edison Electric Institute, Introduction to Depreciation for Public Utilities and Other Industries at viii (April 2013).

[2] *Id.* at 22.

**Q. PLEASE FURTHER EXPLAIN NET SALVAGE.**

A. As noted, net salvage is the value received from the sale or reuse of retired property (salvage value) less the cost of retiring such property (cost of removal). Net salvage can be either positive or negative. If the salvage value exceeds the cost of removal, the net salvage is positive. If the cost of removal is greater than the salvage value received as a result of retirement, the resulting net salvage is negative.

**Q. ARE THERE ANY DEFINITIONS OF DEPRECIATION ACCOUNTING THAT ARE UTILIZED FOR RATEMAKING PURPOSES?**

A. Yes. One of the most quoted definitions of depreciation accounting is the one contained in the Code of Federal Regulations:

> Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources.

18 C.F.R. § 201.12(B). Effectively, depreciation accounting provides for the recovery of the original cost of an asset, adjusted for net salvage, over its expected useful life.

**Q. HOW DO DEPRECIATION RATES AFFECT A UTILITY'S REVENUE REQUIREMENT?**

A. Depreciation expense is typically one of the largest single line items in a utility's overall revenue requirement that is ultimately recovered through tariff rates. When a utility updates its depreciation rates, it is effectively updating the amount of capital that is returned to it each year for investments that have been made to provide utility service. The depreciation rates are calculated in a depreciation study. The resulting depreciation rates are then applied to test year plant balances to determine the depreciation expense component of the utility revenue requirement.

**Q. HOW ARE DEPRECIATION RATES DETERMINED?**

A. Depreciation rates are determined in a depreciation study using a depreciation system. There are three components, each with a number of variations, used to determine a depreciation system, which is then used to estimate depreciation rates. The three basic components are: (1) methods, (2) procedures, and (3) techniques. The choice of a depreciation system can significantly affect the resulting depreciation rates and, in turn, the revenue requirement.

**Q. PLEASE FURTHER DESCRIBE THE METHODS THAT ARE USED IN A DEPRECIATION SYSTEM.**

A. There are generally three types of methods of spreading depreciation expense over the life of property. These methods are Straight Line, Accelerated, and Deferred. The Straight Line Method is the method most widely used by utility companies for accounting and ratemaking purposes as it is easy to apply and does not create intergenerational inequities because it spreads an equal portion of the plant cost across each accounting period. The accelerated methods result in higher depreciation rates earlier in an asset's life and lower depreciation rates later. The deferred methods provide increasing rates over an asset's life.

**Q. PLEASE DESCRIBE THE GROUPING PROCEDURES THAT ARE USED IN A DEPRECIATION SYSTEM.**

A. There are four main grouping procedures used in a depreciation system. They are: the individual procedure, the Broad Group (more commonly known as the Average Life Group ("ALG"), the Vintage Group ("VG"), and the Equal Life Group ("ELG").

The individual procedure assigns a specific depreciation rate to each individual asset. That is, each asset has its own depreciation rate based on its unique characteristics and is not grouped with other similar assets.

In the ALG Procedure, all units within a particular account or category are assumed to be part of a single group that exhibits the same life and retirement characteristics. This is the most commonly utilized procedure.

The VG and the ELG Procedures assemble sub-groups based on when assets were installed (VG Procedure) or their expected lives (ELG Procedure). These procedures assume that sub-groups within a particular account or category may exhibit unique life characteristics. As an example of the VG Procedure, it may determine that all poles installed in 1985 have a 50-year life, while all poles installed in year 1995 have a 45-year life. The ELG Procedure may assume that all poles that will attain a life of 50 years should have one depreciation rate while poles that only attain life spans of 40 years would have a different depreciation rate. The overall group depreciation rate would be a composite of the sub-group depreciation rates.

**Q. PLEASE FURTHER DESCRIBE THE TECHNIQUES THAT ARE USED IN A DEPRECIATION SYSTEM.**

A. There are two techniques used to calculate depreciation rates: Whole Life and Remaining Life. The Whole Life Technique spreads the original cost plus net salvage of the account over the average life of the account. This technique requires that separate amortizations be made to correct for over and under accumulations due to changes in an account's average service life.

The Remaining Life Technique spreads the unrecovered cost plus net salvage over the remaining life of the account. The Remaining Life Technique is the most commonly used technique and it has a self-correcting nature that spreads any over- or under-accumulations over the remaining life.

**Q. IN YOUR EXPERIENCE, WHAT DEPRECIATION SYSTEM IS MOST COMMONLY UTILIZED TO DETERMINE UTILITY DEPRECIATION RATES FOR RATEMAKING PURPOSES?**

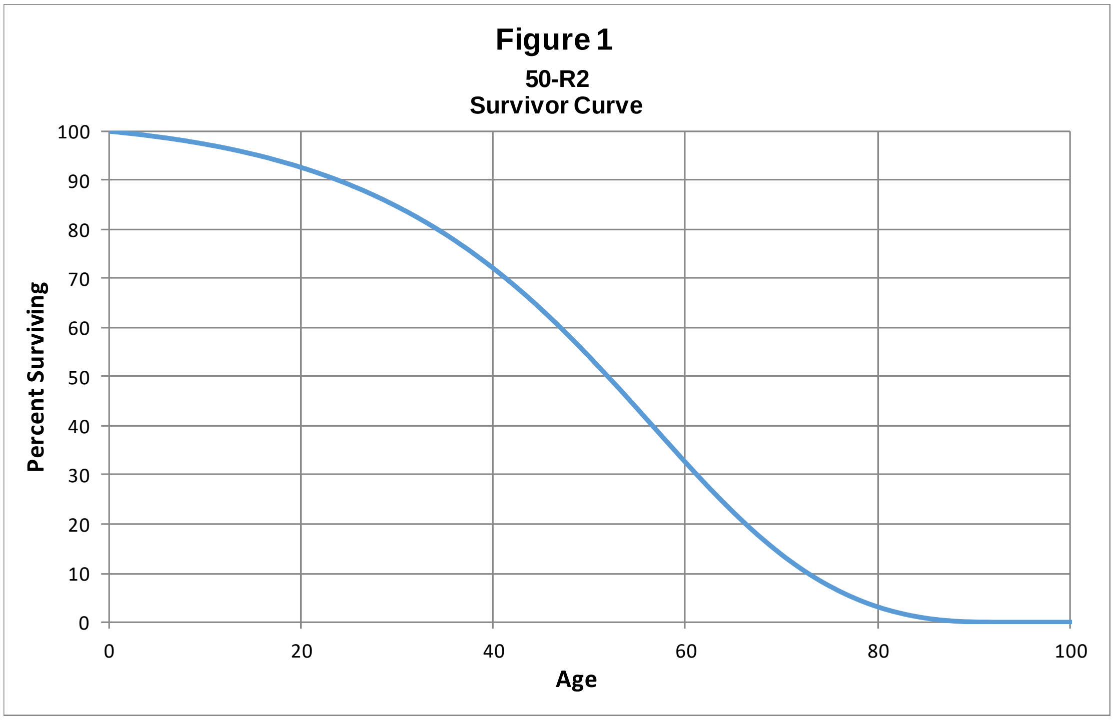
A. The most common depreciation system is one that consists of the Straight Line Method, the ALG Procedure, and the Remaining Life Technique. This system is commonly used because it offers simplicity, efficiency, and adaptability for depreciation needs. This combination ensures accurate depreciation rates for diverse asset types while accommodating changes in useful life and net salvage estimates.

**Q. WHAT ARE SURVIVOR CURVES AND HOW ARE THEY USED IN DEVELOPING DEPRECIATION RATES?**

A. The selection of the survivor curve is one of the most important decisions in conducting a depreciation study. A survivor curve is a graphical representation of the amount of property existing at each age interval throughout the life of a group of property. From the survivor curve, parameters required to calculate depreciation rates can be determined, such as the average service life of the group of property and the composite remaining life. For assets with an assumed lifespan or retirement date, the survivor curve is used to estimate the interim retirements that will occur between the study date and the estimated year of final retirement. These parameters directly affect the depreciation rate calculations. Therefore, informed judgment should be used in their selection.

In this proceeding, as well as the majority of utility regulatory rate case proceedings throughout the U.S. and Canada, the Iowa Curves are the general survivor curves utilized to describe the mortality characteristics of a group of property. There are four types of Iowa Curves: (1) right-moded, (2) left-moded, (3) symmetrical-moded, and (4) origin-moded. Each type describes where the greatest frequency of retirements occur relative to the average service life.

A survivor curve consists of an average service life and Iowa Curve type combination. For example, when describing property with a 50-year average service life that has mortality characteristics of the R2 Iowa Curve, the survivor curve would simply be notated as “50-R2.” I present the 50-R2 survivor curve in Figure 1.




**Q. PLEASE DESCRIBE THE ACTUARIAL LIFE ANALYSIS THAT IS PERFORMED TO EVALUATE HISTORICAL ASSET RETIREMENT EXPERIENCE.**

A. Actuarial life analysis (retirement rate method) is described by the National Association of Regulatory Utility Commissioners' ("NARUC") Public Utility Depreciation Practices Manual ("NARUC Manual") as follows:

> Actuarial analysis is the process of using statistics and probability to describe the retirement history of property. The process may be used as a basis for estimating the probable future life characteristics of a group of property.
>
> Actuarial analysis requires information in greater detail than do other life analysis models (e.g., turnover, simulation) and, as a result, may be impractical to implement for certain accounts (see Chapter VII). However, for accounts for which application of actuarial analysis is practical; **it is a powerful analytical tool and, therefore, is generally considered the preferred approach**.

> Actuarial analysis objectively measures how the company has retired its investment. The analyst must then judge whether this historical view depicts the future life of the property in service. The analyst takes into consideration various factors, such as changes in technology, services provided, or, capital budgets.

NARUC, Public Utility Depreciation Practices 111 (1996) ("NARUC Manual") (emphasis added).

As explained by NARUC, when the required data exists (i.e., a database that contains the year of installation and the year of retirement for each vintage of property), actuarial life analysis is the preferred method of determining the life and, thus, retirement characteristics of a group of property. In this type of analysis, there are two major steps. The first step is to use available aged data from the company's continuing plant records to create an observed life table. The observed life table provides the percent surviving for each age interval of property. The observed life tables can be created from multiple combinations of placements and experience of the aged property data. It is important to select a combination of data that will best reflect future lives of the property. The second step is to match the actual survivor data from the observed life table to a standard set of mortality, or survivor curves. Typically, the observed life table data is matched to Iowa Curves. The fitting process is both a mathematical fitting process, which would minimize the Sum of Squared Differences ("SSD") between the actual data and the Iowa Curves, and a visual fitting process. Though the mathematical fitting process provides a curve that is theoretically possible, the visual matching process allows the trained depreciation professional to use informed judgment in the determination of the best-fitting survivor curve.

**Q. PLEASE PROVIDE FURTHER EXPLANATION OF THE SSD STATISTICAL MEASUREMENT.**

A. The Actuarial Life Analysis section of the NARUC Manual describes SSD as follows:

> Generally, the goodness of fit criterion is the least sum of squared deviations. The difference between the observed and projected data is calculated for each data point in the observed data. This difference is squared, and the resulting amounts are summed to provide a single statistic that represents the quality of the fit between the observed and projected curves.
>
> The difference between the observed and projected data points is squared for two reasons: (1) the importance of large differences is increased, and (2) the result is a positive number, hence the squared differences can be summed to generate a measure of the total absolute difference between the two curves. The curves with the least sum of squared deviations are considered the best fits.
>
> NARUC Manual at 124-125.

## IV. ASSESSMENT OF WGL DEPRECIATION STUDY

**Q. HAS WGL PROPOSED NEW DEPRECIATION RATES IN THIS PROCEEDING?**

A. Yes. WGL retained Dr. Ronald White, of Foster Associates, to conduct a depreciation study on WGL's property as of December 31, 2023. As stated previously, this depreciation study has been filed as Exhibit WG (G)-2.

**Q. WHAT DEPRECIATION SYSTEM DID WGL UTILIZE IN THE CALCULATION OF DEPRECIATION RATES PRESENTED IN EXHIBIT WG (G)-2?**

A. WGL used a depreciation system consisting of the Straight Line Method, the VG Procedure and the Remaining Life Technique to calculate its proposed depreciation rates.

**Q. DO WGL'S PROPOSED NEW DEPRECIATION RATES INCREASE DEPRECIATION EXPENSE?**

A. Yes. WGL is proposing an overall depreciation rate of 2.75%. This represents a 24% increase over the currently approved rate of 2.21%. This change to the depreciation rate translates to an annualized depreciation expense increase of $6,533,828. I show the increase by functional group in Table 1 below.

**TABLE 1**

**Impact of WGL's Proposed Depreciation Rates and Expense**
**($ Millions)**

| | Depreciation Expense ($ Millions) | | | | Depreciation Rates | | |
|---|---|---|---|---|---|---|---|
| | | | Difference | | | | |
| **Depreciable Group** | **Present** | **Proposed** | **Amount** | **Percent** | **Present** | **Proposed** | **Difference** |
| Storage | $ 0.32 | $ 0.23 | $ (0.09) | -28.72% | 2.67% | 1.90% | -0.77% |
| Transmission | $ 1.01 | $ 1.42 | $ 0.42 | 41.40% | 1.57% | 2.22% | 0.65% |
| Distribution | $ 21.22 | $ 27.43 | $ 6.21 | 29.29% | 2.01% | 2.60% | 0.59% |
| General | $ 4.01 | $ 4.00 | $ (0.01) | -0.13% | 5.57% | 5.56% | -0.01% |
| **Total** | **$ 26.55** | **$ 33.09** | **$ 6.53** | **24.61%** | **2.21%** | **2.75%** | **0.54%** |

Source: Exhibit WG (G)-2, Statements A and B

**Q. WHAT ARE THE MAJOR DRIVERS TO THIS PROPOSED CHANGE IN DEPRECIATION RATES AND EXPENSE?**

A. A major driver of the increase to the depreciation rates and expense is the growth of investment held in utility property over the last ten years. In addition, Dr. White notes that the 2024 increase is also due to the retention in FC 1162 settlement of the 2015 depreciation study rates, and use of the present value method of accruing net salvage.[3]

For Transmission Plant, WGL's proposed depreciation rates in this case were calculated to ensure recovery of $64,093,623 of plant in service over a composite remaining life of 49.86 years. In WGL's 2015 depreciation study, the depreciation rates were calculated to ensure recovery of $29,814,267 over a composite remaining life of 41.79 years.[4] WGL has more than doubled its investment in transmission infrastructure since the 2015 depreciation study, necessitating an increase to the depreciation rates and expense. Also impacting the transmission depreciation rates is the change to net salvage rates approved in Maryland and Virginia for property that is allocated to the District. Overall, the future net salvage rate for transmission plant has changed from -9.5% in the 2015 depreciation study[5] to -19.5% in the current study.

For Distribution Plant, the increase can largely be attributed to the plastic mains and services accounts. Dr. White proposes a $2.5 million depreciation expense increase

---

[3] Exhibit WG (G) (White) at 2.

[4] *See* Exhibit OPC (E)-2, which provides the support for the figures cited from the WGL's 2015 depreciation study.

[5] *Id.*

for Account 376.20 – Plastic Mains and a $2.0 million depreciation expense increase for Account 380.20 – Plastic Services. These two accounts represent 70% of the total depreciation expense increase. Both accounts are proposed to have an increase to the net salvage rate to -75%, with Account 376.20 currently at -50% and Account 380.20 currently at -60%. The change to the net salvage rate, along with the increased investment balances, are the driving factors for the increase. In the 2015 depreciation study, the plant in service for these two accounts totaled approximately $394.0 million, and the remaining life over which that investment was recovered was approximately 40.5 years. Account 376.20 – Plastic Mains now contains $454.1 million, up from $193.6 million in the 2015 depreciation study.[6] Account 380.20 – Plastic Services now contains $357.6 million, up from $200.4 million in the 2015 depreciation study.[7] These significant increases to the plant balances, as well as the change to the net salvage rate, are driving up the depreciation rates for these accounts.

**Q. WHAT IS YOUR ASSESSMENT OF WGL'S DEPRECIATION STUDY?**

A. WGL's depreciation study was conducted using a depreciation system consisting of the Straight Line Method, the VG Procedure and the Remaining Life Technique to calculate its proposed depreciation rates. The manner in which Dr. White has conducted his depreciation study is consistent with his past depreciation studies conducted for WGL, as well as those he calculates for other companies across the country. However, I

[6] *See* Exhibit OPC (E)-2, which provides the support for the figures cited from the WGL's 2015 depreciation study; Exhibit WG (G)-2 (White), Statement B at 20 (specifying plant in service amounts as of December 31, 2023).

[7] *Id.*

believe WGL has overstated its depreciation rates for two accounts – Account 376.20 (Plastic Mains) and Account 380.20 (Plastic Services). The proposed depreciation rates for these two accounts are excessive and inappropriately burden WGL's present day customers with an unsupported level of depreciation expense.

**Q. CAN YOU EXPLAIN THE ACTUARIAL LIFE ANALYSIS THAT DR. WHITE CONDUCTED IN THE WGL DEPRECIATION STUDY?**

A. Yes. Exhibit OPC (E)-3 contains WGL's Response to OPC Data Request No. 2-33, wherein Dr. White has provided more detail on his actuarial life analysis. I summarize that information, as well as the information presented in WGL's depreciation study[8] here. Dr. White used a technique whereby first-, second-, and third-degree polynomial functions were fitted to a set of observed retirement ratios. The observed retirement ratios were derived from WGL's continuing property record data. These three functions are called "polynomial hazard functions," which provide the conditional probability of retirement during an age interval, assuming that the property survived to the beginning of that age interval. Those resulting hazard functions were then transformed into survivorship functions (a curve that shows the percent surviving as a function of age, see Figure 1 of this testimony), which were then numerically integrated to obtain an estimate of the projection life. I would note that the estimate of the life derived from this integration procedure does not appear to be utilized in any manner by Dr. White.

Because the Iowa Curves are most commonly used to describe the life characteristics of property in a depreciation study, each of the three polynomial

[8] Exhibit WG (G)-2 (White) at 8-10.

survivorship functions were fitted to the Iowa Curves using a weighted-least squares procedure. This step resulted in a best-fitting average service life and Iowa curve combination for each of the three polynomial functions. For each set of data analyzed, Dr. White determined what he believed to be the best-fitting survivor curve for each of the three polynomial functions. In order to reach his final recommendation for each account, Dr. White also "blended . . . informed judgment and expectations about the future"[9] with his statistical analysis to form his opinion of the appropriate survivor curve for each account.

I would note that Dr. White's usage of this hazard function methodology is not, to my knowledge, used by other depreciation consulting firms that conduct depreciation studies for public utility companies. This method is unnecessarily complex and is no more accurate than a simple mathematical fitting analysis, which I will describe later in this testimony.

**Q. IS WGL PROPOSING TO INCORPORATE THE DISTRICT'S CLIMATE POLICIES INTO ITS DEPRECIATION ANALYSIS?**

A. No. WGL witness James Steffes testifies that "the Company has not modified the expected lives for distribution assets or depreciation rates for ratemaking purposes. In this case, the Company's depreciation rates recognize the useful life of the assets consistent with industry practice and accounting principles . . ."[10]

---

[9] Exhibit WG (G) (White) at 9:1-2.
[10] Exhibit WG (2A) (Steffes) at 6:12-19.

**Q. ARE YOU PROPOSING TO MAKE ANY ADJUSTMENTS TO THE LIFE PARAMETERS FOR ANY ACCOUNTS?**

A. Yes. I am proposing a change to the survivor curves for Account 376.20 – Plastic Mains and Account 380.20 – Plastic Services. As I will demonstrate, WGL is proposing survivor curves for these two accounts that are not supported by its own data and that are too short, resulting in excessive depreciation rates.

## V. <u>ACCOUNT 376.20 – PLASTIC MAINS</u>

**Q. WHAT PROPERTY IS HELD IN ACCOUNT 376.20?**

A. Account 376.20 largely consists of the plastic pipeline used to deliver natural gas to WGL's customers. Per OPC Data Request No. 2-23, attached hereto as Exhibit OPC (E)-4, WGL installs Polyethylene ("PE") pipe meeting ASTM D2513-12, which, according to WGL, is the "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings."[11] The Company delivers natural gas from the transmission system to the services that connect the WGL distribution system to its customers. As of December 31, 2023, WGL had $454.1 million of property within this account, largely consisting of PE pipe ranging in diameter from 3/4" to 16".[12] The majority of the pipe is between 2" and 4".[13] Exhibit OPC (E)-5 provides WGL's Response to OPC Data Request No. 2-24, which provides the contents of Account 376.20.

---

[11] Exhibit OPC (E)-4 at 1.
[12] Exhibit OPC (E)-5 at 2.
[13] *Id.*

**Q. WHAT SURVIVOR CURVE HAS DR. WHITE PROPOSED TO DETERMINE THE DEPRECIATION RATE FOR ACCOUNT 376.20?**

A. Dr. White has proposed to use a survivor curve that consists of a 55-year average service life and the R4 Iowa Curve type, or, in other words, a 55-R4 survivor curve. The 55-R4 is the same survivor curve that is currently approved for this account.

**Q. DO THE RESULTS OF DR. WHITE'S ACTUARIAL ANALYSIS SUPPORT HIS PROPOSED SURVIVOR CURVE FOR THIS ACCOUNT?**

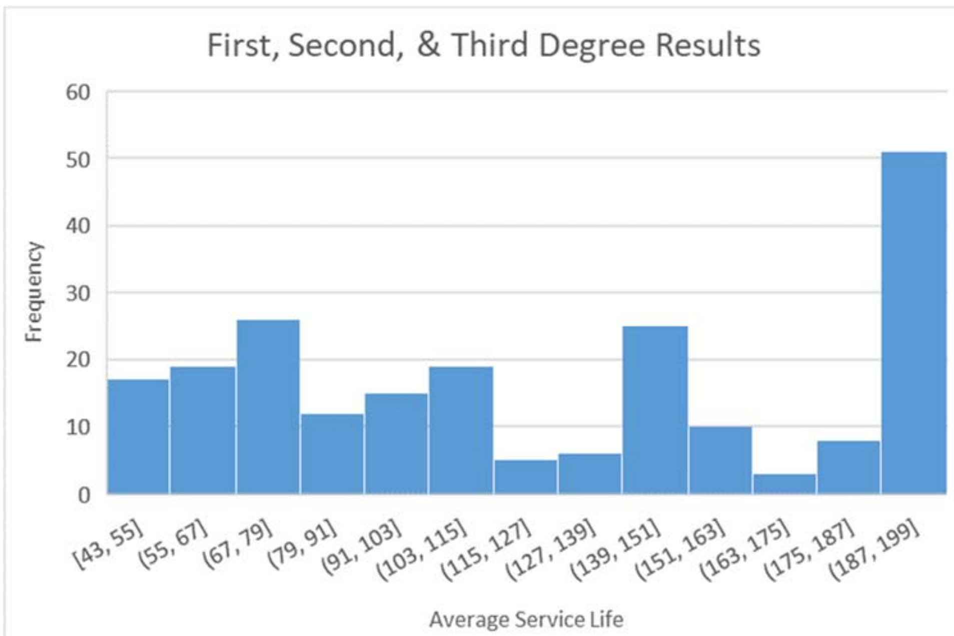
A. No. Dr. White has conducted an actuarial life analysis on 72 life tables that he constructed from WGL's property data for this account. The entire set of data consists of retirement history from property that was installed between 1958 and 2023 and experienced retirements between 1986 and 2023. Dr. White constructed 72 subsets of this data and performed his analysis on each. Dr. White conducted his "hazard function" version of actuarial analysis that attempts to fit a first-, second-, and third-order polynomial function to the data in the life tables. For each life table, Dr. White has presented what he views as the best-fitting survivor curves for this first-, second-, and third-degree hazard functions. I have included the relevant pages from Dr. White's workpapers as OPC Exhibit (E)-6.[14] These workpapers present 216 unique survivor curves, representing the first-, second-, and third-order polynomials for each of the 72 subsets of data. The average service life for all of the 72 first-degree hazard function survivor curves is 157 years. For the second-degree hazard functions, the average service life of the 72 data sets is 136 years. For the third-degree hazard functions, the

[14] Exhibit OPC (E)-6 at 1-6.

average of the data sets is 78 years. When all 216 results are averaged, I calculate the average service life to be 124 years. I present the results of Dr. White's actuarial analysis in a histogram below in Figure 2. Each bar represents a "bin" in which the results belong based on an average service life; the height of the bar identifies how many of the 216 results fell into the "bin."

**Figure 2**

WGL's Actuarial Life Analysis Results – Account 376.20




To clarify the meaning of the figure above, the first bar on the left indicates there were 17 results that were between 43 years and 55 years for the average service life. Similarly, the bar on the far right, indicates there were 51 results that showed the average service life of this account should be between 187 and 199 years. This histogram clearly demonstrates that the actuarial life analysis conducted by Dr. White supports an average service life for this account that is substantially greater than the 55 years he has recommended. Of the 216 unique results that Dr. White presents, 198 (or 92%) are greater than 55 years.

**Q. HAVE YOU CONDUCTED YOUR OWN ACTUARIAL LIFE ANALYSIS ON ACCOUNT 376.20?**

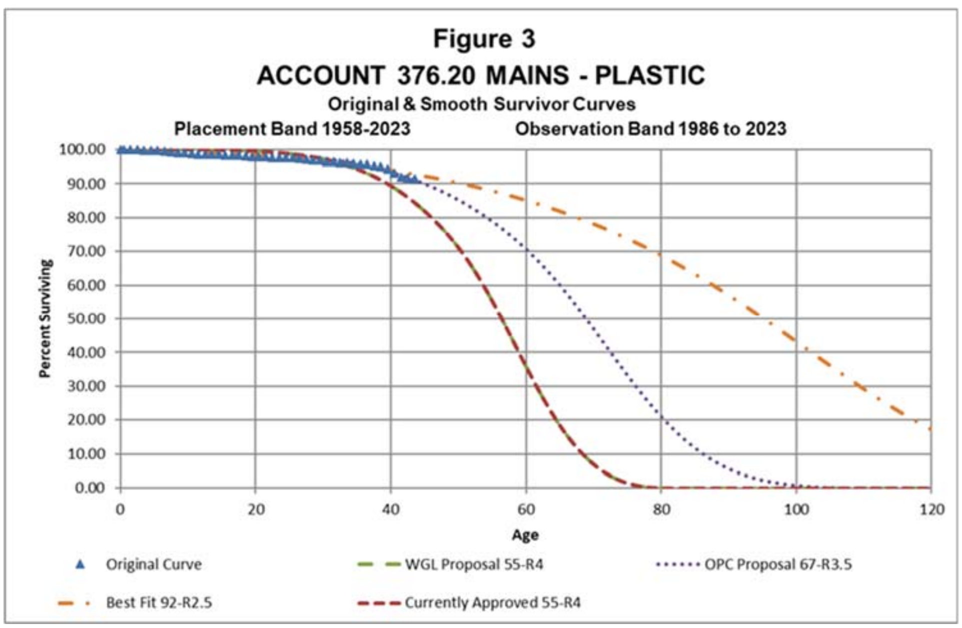
A. Yes. I have conducted an actuarial life analysis on a single life table – that is, the life table consisting of the complete dataset which covers the retirement experience from 1986 through 2023. The actuarial analysis I have conducted provides the best-fitting average service life for each of the Iowa Curve types. This fitting analysis directly determines the average service life for each Iowa Curve type that best matches the retirement date included in the original life table containing the full set of data. The life table that I have used is the same one that Dr. White includes in Schedule E; see Exhibit OPC (E)-6. The best-fitting curves are those that minimize the SSD between WGL's data and the Iowa Curves. I present the results of this analysis in Exhibit OPC (E)-7. My actuarial life analysis shows that the best-fitting survivor curve for Account 376.20 is the 92-R2.5 survivor curve.

**Q. HOW DO YOUR RESULTS COMPARE TO DR. WHITE'S?**

A. Dr. White's first-, second-, and third-degree results derived from his analysis on the same dataset I have analyzed are 149.9 years, 105 years, and 71.5 years, respectively. My analysis shows the best-fit is 91.6 years.

**Q. WHAT SURVIVOR CURVE DO YOU RECOMMEND FOR ACCOUNT 376.20?**

A. I recommend the 67-R3.5 survivor curve be utilized for Account 376.20. This survivor curve is a better-fit to the data and well within the range of reasonableness for plastic mains. Dr. White's recommended 55-R4 survivor curve results in an SSD of 217. My recommended 67-R3.5 survivor curve results in an SSD of 25. Again, a lower SSD indicates a better-fit to the actual data. Below in Figure 3, I present WGL's retirement data, Dr. White's proposed 55-R4 curve, and my recommended 67-R3.5 curve. As can be seen, my recommendation fits the actual data better, which will result in a more accurate and reasonable depreciation rate for this account.




**Q. DO YOU HAVE OTHER SUPPORT FOR YOUR 67-YEAR AVERAGE SERVICE LIFE RECOMMENDATION?**

A. Yes. According to WGL's Response to OPC Data Request No. 2-27, attached hereto as Exhibit OPC (E)-8, WGL has not implemented any Operations &

Maintenance ("O&M") programs that will affect the property in this account.[15] In fact, WGL's PROJECT*pipes* program is a capital program that is largely replacing other pipe materials with plastic. (Some older plastic may also be replaced). Further, it is my general understanding that plastic pipe should last longer than steel pipe, as corrosion is not an issue for plastic as it is with steel. In this case, Dr. White is assuming the steel distribution mains will have a life of 80 years. Increasing the life of the plastic mains from 55 years to 67 years is completely reasonable and appears to be a conservatively low estimate.

**Q. IF YOUR RECOMMENDATION OF A 67-YEAR AVERAGE SERVICE LIFE IS A LOW ESTIMATE, WHY ARE YOU NOT RECOMMENDING A HIGHER AVERAGE SERVICE LIFE?**

A. As seen on page 1 of Exhibit OPC (E)-7, the best-fitting average service life for 28 of the 32 curves is greater than the 55-year average service life proposed by Dr. White. The majority are also significantly greater than my 67-year average service life recommendation. As stated above, my understanding is that plastic pipe should last longer than steel pipe, meaning that, technically, the average service life for plastic pipe should be greater than the 80-year service life for steel. Although the analysis indicates that the 92-R2.5 curve is the overall best-fit to the data, increasing the service life by almost 40 years from the current 55-year estimate is not appropriate or reasonable. In fact, even increasing the average service life to the expected steel average service life

---

15 Exhibit OPC (E)-8.

of 80 years is still an increase of 25 years within one rate case. Instead, a moderate, gradual increase to 67 years is more reasonable.

**Q. HOW DOES YOUR PROPOSED SURVIVOR CURVE IMPACT THE DEPRECIATION RATE AND 2023 ANNUALIZED DEPRECIATION EXPENSE FOR THIS ACCOUNT?**

A. In Exhibit OPC (E)-9, I provide OPC's recommended depreciation rates for all accounts. In Exhibit OPC (E)-10, I provide a comparison of OPC's recommended depreciation rates and WGL's. I summarize the impacts on Account 376.20 in Table 2 below.

**TABLE 2**

**Account 376.20 Depreciation Comparison**

| | | Proposed | | |
|---|---|---|---|---|
| | **Present** | **WGL** | **OPC** | **Difference** |
| Depreciation Rate | 2.10% | 2.66% | 1.96% | -0.70% |
| 2023 Depreciation Expense | $9,536,229 | $12,079,224 | $8,900,481 | ($3,178,743) |

Source: Exhibit WG (G)-2, Statement A and B and Exhibit OPC (E)-9

## VI. ACCOUNT 380.20 – PLASTIC SERVICES

**Q. WHAT PROPERTY IS HELD IN ACCOUNT 380.20?**

A. Account 380.20 contains the investment in plastic pipeline that connects the distribution system to the customer meters. Similar to the distribution mains, WGL installs PE pipe meeting ASTM D2513-12. WGL includes both medium- and high-density PE pipe in account 380.20.[16] As of December 31, 2023, Account 380.20 contained $357.9 million of property, consisting of plastic pipe ranging in diameter from ½" to 12".[17]

**Q. WHAT SURVIVOR CURVE HAS DR. WHITE PROPOSED TO DETERMINE THE DEPRECIATION RATE FOR ACCOUNT 380.20?**

A. Dr. White has proposed to use a survivor curve that consists of a 55-year average service life and the L2 Iowa Curve type, or in other words, a 55-L2 survivor curve. The 55-L2 is also the survivor curve that is currently approved for this account.

**Q. DO THE RESULTS OF DR. WHITE'S ACTUARIAL ANALYSIS SUPPORT HIS PROPOSED SURVIVOR CURVE FOR THIS ACCOUNT?**

A. No. Dr. White also conducted an actuarial life analysis on 72 life tables that he constructed from WGL's property data for this account. The entire set of data consists of retirement history from property that was installed between 1953 and 2023 and experienced retirements between 1986 and 2023. Dr. White constructed 72 subsets of this data and performed his analysis on each. Dr. White conducted his "hazard function" version of actuarial analysis that attempts to fit a first-, second-, and third-order polynomial function to the data in the life tables. For each life table, Dr. White has presented what he determined to be the best-fitting survivor curves for this first-, second-, and third-degree hazard functions. I have included the relevant pages from Dr. White's workpapers as OPC Exhibit (E)-13.[18] These workpapers present 216 unique survivor curves, representing the first-, second-, and third-order polynomials

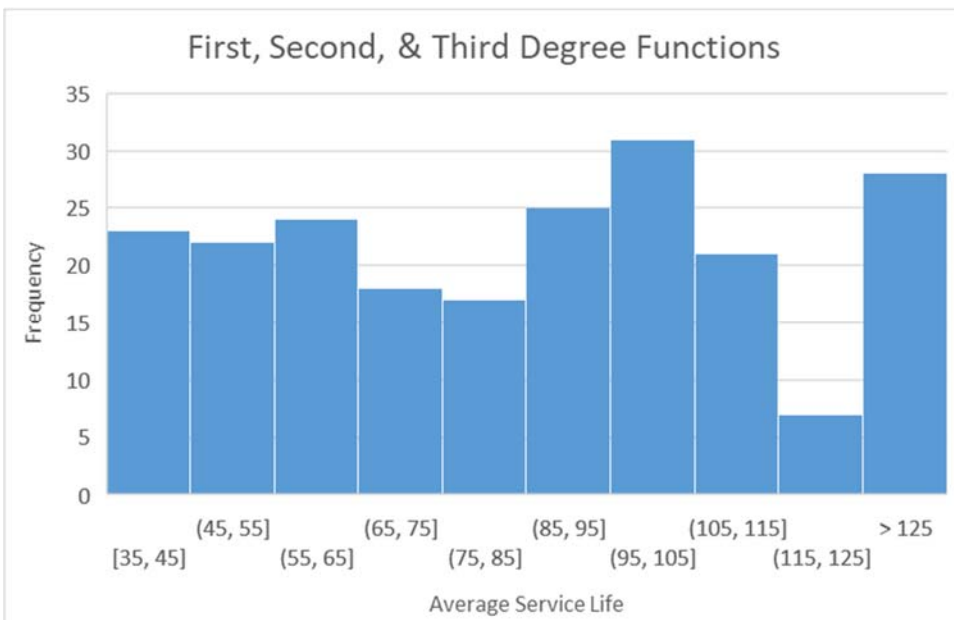
---

16 Exhibit OPC (E)-11.
17 Exhibit OPC (E)-12.
18 Exhibit OPC (E)-13 at 1-6.

for each of the 72 subsets of data. The average service life of all the 72 first-degree hazard function survivor curves is 106 years. For the second-degree hazard function, the average life of the 72 data sets is 76 years. For the third-degree hazard functions, the average life of the results is 80 years. When all 216 results are averaged, I calculate the average life to be 88 years. I present the results of Dr. White's actuarial analysis in a histogram in Figure 4. Each bar represents a "bin" in which the results belong based on an average service life; the height of the bar identifies how many of the 216 results fell into the "bin".

**Figure 4**

WGL's Actuarial Life Analysis Results – Account 380.20




To clarify the meaning of the figure above, the first bar on the left indicates there were 23 results that were between 35 years and 45 years for the average service life. Similarly, the bar on the far right indicates there were 28 results that showed the average service life of this account should be greater than 125 years. This histogram clearly demonstrates that the actuarial life analysis conducted by Dr. White supports an average service life for this account that is substantially greater than the 55 years he has recommended. Of the 216 unique results that Dr. White presents, 171 (or 79%) are greater than 55 years.

**Q. HAVE YOU CONDUCTED YOUR OWN ACTUARIAL LIFE ANALYSIS ON ACCOUNT 380.20?**

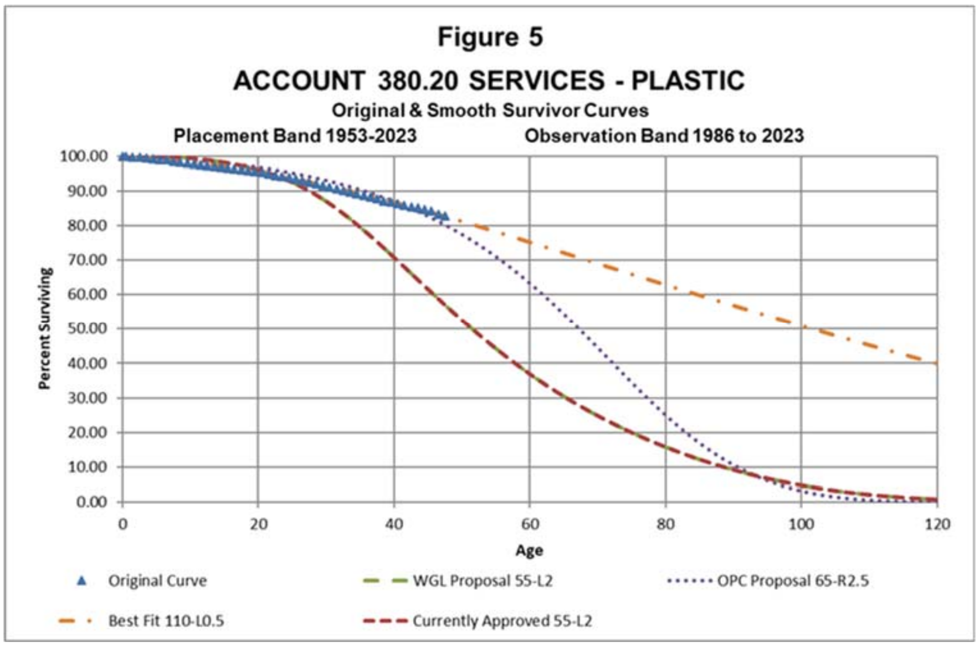
A. Yes. I have conducted an actuarial life analysis on a single life table (i.e., the life table consisting of the complete dataset, which covers the retirement experience from 1986 through 2023). The actuarial analysis I have conducted provides the best-fitting average service life for each of the Iowa Curve types. The best-fitting curves are those that minimize the SSD between WGL's data and the Iowa Curves. I present the results of this analysis in Exhibit OPC (E)-14. My actuarial life analysis shows that the survivor curve that is the best-fit for Account 380.20 is the 110-L0.5 survivor curve.

**Q. HOW DO YOUR RESULTS COMPARE TO DR. WHITE'S?**

A. Dr. White's first-, second-, and third-degree results derived from his analysis on the same dataset I have analyzed are 105.1 years, 99.8 years, and 154.5 years, respectively. My analysis shows the best-fit is 109.9 years.

**Q. WHAT SURVIVOR CURVE DO YOU RECOMMEND FOR ACCOUNT 380.20?**

A. I recommend the 65-R2.5 survivor curve be utilized for Account 380.20. This survivor curve is a better-fit to the data and well within the range of reasonableness for plastic services. Dr. White's recommended 55-L2 survivor curve results in an SSD of 4,813. My recommended 65-R2.5 survivor curve results in an SSD of 73. Again, a lower SSD indicates a better-fit to the actual data. Below in Figure 5, I present WGL's retirement data, Dr. White's proposed 55-L2 curve, and my recommended 65-R2.5 curve. As can be seen, my recommendation fits the actual data better, which will result in a more accurate and reasonable depreciation rate for this account.




**Q. DO YOU HAVE OTHER SUPPORT FOR YOUR 65-YEAR AVERAGE SERVICE LIFE RECOMMENDATION?**

A. Yes, and the support is based on reasons similar to those referenced earlier in relation to Account 376.20. According to WGL's Response to OPC Data Request No. 2-32, attached hereto as Exhibit OPC (E)-15, WGL has not implemented any O&M programs that will affect the property in this account.[19] Again, WGL's PROJECT*pipes* program is a capital program that is replacing other pipe materials with plastic. Again, it is my

19 Exhibit OPC (E)-15.

general understanding that plastic pipe should last longer than steel pipe, as corrosion is not an issue for plastic as it is with steel. The pipe being installed for services is the same material as distribution mains. Accordingly, I am recommending the life for distribution services be extremely close to the life for distribution mains. This is supported by both the material being installed and the historical data in this account.

**Q. THE BEST-FITTING CURVE FOR ACCOUNT 380.20 IS THE 110-L0.5, WHICH HAS A SIGNIFICANTLY LONGER AVERAGE SERVICE LIFE THAN YOUR RECOMMENDATION. PLEASE ELABORATE ON WHY YOU DID NOT RECOMMEND THE OVERALL BEST-FITTING CURVE.**

A. As seen on page 1 of Exhibit OPC (E)- 14, the best-fitting average service life for 26 of the 32 curves is greater than the 55-year average service life proposed by Dr. White. The majority are also significantly greater than my 65-year average service life recommendation. As plastic pipe is expected to last longer than steel pipe, the average service life should technically be greater for the plastic pipe. My recommendation of a 65-year service life is greater than both the current and WGL’s proposed average service lives for the Steel Services in Account 380.10. Additionally, although the analysis indicates that the 110-L0.5 curve is the overall-best fit to the data, doubling the service life is not appropriate or reasonable. A gradual increase to 65 years is reasonable, and thus, my recommendation is appropriate.

**Q. HOW DOES YOUR PROPOSED SURVIVOR CURVE IMPACT THE DEPRECIATION RATE AND 2023 ANNUALIZED DEPRECIATION EXPENSE FOR THIS ACCOUNT?**

A. In Exhibit OPC (E)-9, I provide OPC's recommended depreciation rates for all accounts. In Exhibit OPC (E)-10, I provide a comparison of OPC's recommended depreciation rates and WGL's. I summarize the impacts on Account 380.20 in Table 3.

**TABLE 3**

**Account 380.20 Depreciation Comparison**

| | | **Proposed** | | |
|---|---|---|---|---|
| | **Present** | **WGL** | **OPC** | **Difference** |
| Depreciation Rate | 2.15% | 2.71% | 2.09% | -0.62% |
| 2023 Depreciation Expense | $7,688,723 | $9,691,367 | $7,474,154 | ($2,217,213) |

Source: Exhibit WG (G)-2, Statement A and B and Exhibit OPC (E)-9

## VII. RESERVE REALLOCATION

**Q. DO THE ADJUSTMENTS YOU HAVE PROPOSED FOR ACCOUNTS 376.20 AND 380.20 IMPACT THE DEPRECIATION RATES FOR OTHER ACCOUNTS?**

A. Yes. By changing the survivor curves for these two accounts, the theoretical reserve is also changed. The theoretical reserve is a value calculated for each account that indicates how much depreciation expense would have been recovered if the current life and net salvage parameters had always been used to calculate depreciation rates and the property behaved exactly as depicted by the survivor curve. The theoretical reserve, or computed reserve (as Dr. White refers to it), is used to create the allocators used to conduct a reserve reallocation. Distribution Accounts 375.00 through 387.00 and General Plant Accounts 390.00 and 397.20 were included in a reserve reallocation procedure. When the theoretical reserve for any individual account is altered, the amount of reserves allocated to each account within the group is also altered.

**Q. WHAT IS A RESERVE REALLOCATION?**

A. A reserve reallocation is a procedure by which the actual book reserves for a group of accounts is reallocated to the individual accounts within the group. The reallocation is conducted by creating allocators based on the theoretical reserve calculations. Accounts 376.20 and 380.20 were included in a reserve group that contained all distribution accounts assigned to the District and Accounts 390.00 and 397.20. The reserves that are allocated to each account is used to determine the amount of remaining and unrecovered investment that will be returned to the company over the remaining life of the accounts through depreciation expense.

**Q. ARE YOU CONDUCTING THE SAME RESERVE ALLOCATION PROCEDURE AS DR. WHITE?**

A. Yes. I have conducted the exact same reserve allocation procedure that is discussed on pages 10 and 11 of Dr. White's Direct Testimony and on pages 13-14 of Exhibit WG (G)- 2.

## VIII. OPC'S PROPOSED DEPRECIATION RATES

**Q. HAVE YOU CALCULATED DEPRECIATION RATES FOR WGL'S PROPERTY ACCOUNTS CONSISTENT WITH THE PROPOSALS YOU ARE RECOMMENDING?**

A. Yes. OPC's proposed depreciation rates are presented in Exhibit OPC (E)-9. The depreciation rates were calculated by updating Dr. White's workpapers with the updated life parameters that I have calculated for Accounts 376.20 and 380.20.

**Q. HOW DO OPC'S PROPOSED DEPRECIATION RATES COMPARE TO THOSE PROPOSED BY WGL?**

A. I have included an exhibit that compares OPC's and WGL's respective proposals in Exhibit OPC (E)-10. The summary by functional group is presented in Table 4.

**Q. HOW WOULD OPC'S PROPOSED DEPRECIATION RATES AFFECT THE 2023 ANNUALIZED DEPRECIATION EXPENSE?**

A. I provide a summary of the impact on 2023 annualized depreciation accruals below in Table 4. The details are included in Exhibit OPC (E)-10. I would note that the figures shown in Table 4 do not reflect any of the OPC's adjustments to plant balances. The depreciation expense adjustment is relative to the level of plant investment that is used in WGL's depreciation study.

**TABLE 4**

**Impact of OPC's Proposed Depreciation Rates and Expense**

| | Depreciation Expense ($ Millions) | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Difference | | Depreciation Rates | | |
| Depreciable Group | WGL | OPC | Amount | Percent | WGL | OPC | Difference |
| Storage | $ 0.23 | $ 0.23 | $ - | 0.00% | 1.90% | 1.90% | 0.00% |
| Transmission | $ 1.42 | $ 1.42 | $ - | 0.00% | 2.22% | 2.22% | 0.00% |
| Distribution | $ 27.43 | $ 21.44 | $ (6.00) | -21.86% | 2.60% | 2.03% | -0.57% |
| General | $ 4.00 | $ 3.86 | $ (0.14) | -3.46% | 5.56% | 5.37% | -0.19% |
| **Total** | **$ 33.09** | **$ 26.95** | **$ (6.13)** | **-18.54%** | **2.75%** | **2.24%** | **-0.51%** |

Source: Exhibit OPC (E)-10

**Q. HOW WOULD OPC'S PROPOSED DEPRECIATION RATES IMPACT THE REVENUE REQUIREMENT IN THIS PROCEEDING?**

A. The revenue requirement impact of this adjustment is discussed in the Direct Testimony of Bion Ostrander, filed as Exhibit OPC (B)[20].

## IX. CONCLUSION

**Q. MR. ANDREWS, PLEASE SUMMARIZE YOUR TESTIMONY.**

A. WGL's depreciation analysis is flawed and does not accurately represent the life of WGL's assets. My specific recommendations are as follows:

- WGL's proposed depreciation rates are excessive because WGL's proposed average service life for its two largest accounts, Account 376.20 and Account 380.20, are based on proposed survivor curves that are not supported by the Company's own data and are too short.

- The average service life utilized for Account 376.20, Plastic Mains, should be 67 years rather than the 55 years proposed by WGL. A 67-year life is a better statistical fit to the data and results in a more reasonable depreciation rate for these assets.

20 Exhibit OPC (B) at 23:17-33.

- For Account 376.20, Plastic Mains, I am recommending an adjustment that will yield a 1.96% depreciation rate, resulting in a $3,178,743 reduction in 2023 depreciation expense.

- The average service life utilized for Account 380.20, Plastic Services, should be 65 years rather than the 55 years proposed by WGL. 65 years is a statistically better-fit to the data than 55 years and will result in more reasonable depreciation rates for the assets in this account.

- For Account 380.20, Plastic Services, I am recommending an adjustment that will yield a 2.09% depreciation rate, resulting in a $2,217,213 reduction in 2023 depreciation expense.

- The two adjustments recommended herein, when combined with Dr. White's reserve reallocation procedure, would reduce WGL's annualized depreciation accrual by $6.13 million and the composite depreciation rate would be 2.24%, rather than the 2.75% proposed by WGL.

- I recommend the Commission approve OPC's proposed depreciation rates presented in Exhibit OPC (E)-9.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF THE DISTRICT OF COLUMBIA**

| | | |
|---|---|---|
| **In the Matter of** | **§** | |
| | **§** | |
| **The Application of Washington Gas** | **§** | **Formal Case No. 1180** |
| **Light Company for Authority to** | **§** | |
| **Increase Existing Rates and** | **§** | |
| **Charges for Gas Service** | **§** | |

**AFFIDAVIT**

I declare under penalty of perjury that the foregoing testimony was prepared by me or under my direction and is true and correct to the best of my knowledge, information, and belief.

Brian C. Andrews

Date: January 24, 2025

# Qualifications of Brian C. Andrews

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q. PLEASE STATE YOUR OCCUPATION.**

A. I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

**Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.**

A. I received a Bachelor of Science Degree in Electrical Engineering from the Washington University in St. Louis/University of Missouri - St. Louis Joint Engineering Program. I have also received a Master of Science Degree in Applied Economics from Georgia Southern University.

I have attended training seminars on multiple topics including class cost of service, depreciation, power risk analysis, production cost modeling, cost-estimation for transmission projects, transmission line routing, MISO load serving entity fundamentals and more.

I am a member and a former President of the Society of Depreciation Professionals. I have been awarded the designation of Certified Depreciation Professional ("CDP") by the Society of Depreciation Professionals. I am also a certified Engineer Intern in the State of Missouri.

As a Principal at BAI, and as an Associate, Senior Consultant, Consultant, Associate Consultant and Assistant Engineer before that, I have been involved with several regulated and competitive electric service issues. These have included book depreciation, fuel and purchased power cost, transmission planning, transmission line routing, resource planning including renewable portfolio standards compliance, electric price forecasting, class cost of service, power procurement, and rate design. This has involved use of power flow, production cost, cost of service, and various other analyses and models to address these issues, utilizing, but not limited to, various programs such as Strategist, RealTime, PSS/E, MatLab, R Studio, ArcGIS, Excel, and the United States Department of Energy/Bonneville Power Administration's Corona and Field Effects ("CAFÉ") Program. In addition, I have received extensive training on the PLEXOS Integrated Energy Model and the EnCompass Power Planning Software. I have provided testimony on many of these issues before the Public Service Commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, New Mexico, Oklahoma, South Carolina, Texas, and Washington DC.

BAI was formed in April 1995. BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Exhibit WG (H)–2

# 2015 Depreciation Rate Study

Washington Gas™
A WGL Company

– District of Columbia

foster associates

**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: 3.32 Percent

| | 12/31/14 | 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 |
| **STORAGE AND PROCESSING PLANT** | | | | | | | | |
| **Allocated Property** | | | | | | | | |
| 361.00 Structures and Improvements | | | | | | | | |
| Maryland (Rockville) | $792,097 | $21,783 | $7,050 | $28,833 | $18,931 | $6,020 | $24,951 | ($3,882) |
| Virginia (Ravensworth) | 733,454 | 19,290 | 3,741 | 23,031 | 18,116 | 3,667 | 21,783 | (1,248) |
| **Total Account 361.00** | $1,525,551 | $41,073 | $10,791 | $51,864 | $37,047 | $9,687 | $46,734 | ($5,130) |
| 362.00 Gas Holders | | | | | | | | |
| Maryland (Rockville) | $4,690,563 | $78,332 | $26,267 | $104,599 | $79,271 | $26,736 | $106,007 | $1,408 |
| Virginia (Ravensworth) | 3,464,888 | 60,636 | 11,434 | 72,070 | 62,021 | 11,781 | 73,802 | 1,732 |
| **Total Account 362.00** | $8,155,451 | $138,968 | $37,701 | $176,669 | $141,292 | $38,517 | $179,809 | $3,140 |
| 363.50 Other Equipment | | | | | | | | |
| Maryland (Rockville) | $517,723 | $14,962 | | $14,962 | $27,802 | $569 | $28,371 | $13,409 |
| Virginia (Ravensworth) | 165,263 | (942) | 10,081 | 9,139 | 3,256 | 2,545 | 5,801 | (3,338) |
| **Total Account 363.50** | $682,986 | $14,020 | $10,081 | $24,101 | $31,058 | $3,114 | $34,172 | $10,071 |
| **Total Allocated Property** | $10,363,988 | $194,061 | $58,573 | $252,634 | $209,397 | $51,318 | $260,715 | $8,081 |
| **Total Storage and Processing Plant** | $10,363,988 | $194,061 | $58,573 | $252,634 | $209,397 | $51,318 | $260,715 | $8,081 |
| **TRANSMISSION PLANT** | | | | | | | | |
| **Assigned Property** | | | | | | | | |
| 365.20 Rights of Way | | | | | | | | |
| 366.00 Meas. and Reg. Station Structures | | | | | | | | |
| 367.10 Mains - Steel | 2,062,079 | 21,033 | 3,093 | 24,126 | 10,723 | 3,918 | 14,641 | (9,485) |
| 369.00 Measuring and Regulating Equipment | 2,446,498 | 46,728 | 5,138 | 51,866 | 31,560 | 4,893 | 36,453 | (15,413) |
| **Total Assigned Property** | $4,508,577 | $67,761 | $8,231 | $75,992 | $42,283 | $8,811 | $51,094 | ($24,898) |
| **Allocated Property** | | | | | | | | |
| 365.20 Rights of Way | | | | | | | | |
| District | $534 | $9 | | $9 | $2 | | $2 | ($7) |
| Maryland | 912,211 | 15,325 | | 15,325 | 14,595 | | 14,595 | (730) |
| Virginia | 455,454 | 5,875 | | 5,875 | 5,238 | | 5,238 | (637) |
| **Total Account 365.20** | $1,368,199 | $21,209 | | $21,209 | $19,835 | | $19,835 | ($1,374) |
| 366.00 Meas. and Reg. Station Structures | | | | | | | | |
| Maryland | $450,974 | $8,929 | | $8,929 | $1,488 | $5,592 | $7,080 | ($1,849) |
| Virginia | 619,365 | 12,635 | 1,239 | 13,874 | 8,238 | 124 | 8,362 | (5,512) |
| **Total Account 366.00** | $1,070,339 | $21,564 | $1,239 | $22,803 | $9,726 | $5,716 | $15,442 | ($7,361) |

**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: 3.32 Percent

| Account Description | 12/31/14 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 | $1,244,633 | $12,197 | $1,867 | $14,064 | $16,180 | $2,365 | $18,545 | $4,481 |
| Maryland | 8,088,580 | 126,182 | | 126,182 | 118,093 | (2,427) | 115,666 | (10,516) |
| Virginia | 5,584,195 | 85,997 | 13,960 | 99,957 | 82,646 | 5,584 | 88,230 | (11,727) |
| **Total Account 367.10** | $14,917,408 | $224,376 | $15,827 | $240,203 | $216,919 | $5,522 | $222,441 | ($17,762) |
| 369.00 Measuring and Regulating Equipment | | | | | | | | |
| District | $84,438 | $1,410 | $177 | $1,587 | ($152) | $169 | $17 | ($1,570) |
| Maryland | 5,490,804 | 105,423 | 15,923 | 121,346 | 15,923 | 131,779 | 147,702 | 26,356 |
| Virginia | 2,374,502 | 38,229 | 11,398 | 49,627 | 13,060 | | 13,060 | (36,567) |
| **Total Account 369.00** | $7,949,744 | $145,062 | $27,498 | $172,560 | $28,831 | $131,948 | $160,779 | ($11,781) |
| **Total Allocated Property** | $25,305,690 | $412,211 | $44,564 | $456,775 | $275,311 | $143,186 | $418,497 | ($38,278) |
| **Total Transmission Plant** | $29,814,267 | $479,972 | $52,795 | $532,767 | $317,594 | $151,997 | $469,591 | ($63,176) |
| **DISTRIBUTION PLANT** | | | | | | | | |
| **Assigned Property** | | | | | | | | |
| 375.00 Structures and Improvements | | | | | | | | |
| 376.10 Mains - Steel | 71,096,875 | 910,040 | 263,058 | 1,173,098 | 710,969 | 369,704 | 1,080,673 | (92,425) |
| 376.20 Mains - Plastic | 193,633,686 | 3,117,502 | 890,715 | 4,008,217 | 3,059,412 | 1,103,712 | 4,163,124 | 154,907 |
| 376.30 Mains - Cast Iron | 5,968,483 | 28,052 | 69,234 | 97,286 | (74,009) | 68,041 | (5,968) | (103,254) |
| 376.40 Mains - Copper | | | | | | | | |
| 377.00 Compressor Station Equipment | | | | | | | | |
| 378.00 Measuring and Regulating Equipment | 8,448,406 | 100,536 | 9,293 | 109,829 | 93,777 | 9,293 | 103,070 | (6,759) |
| 380.10 Services - Steel | 19,018,346 | 317,606 | 290,981 | 608,587 | 247,238 | 173,067 | 420,305 | (188,282) |
| 380.20 Services - Plastic | 200,436,513 | 3,046,635 | 1,763,841 | 4,810,476 | 2,986,504 | 1,463,187 | 4,449,691 | (360,785) |
| 380.30 Services - Copper | 3,268,329 | 34,971 | 45,757 | 80,728 | (39,547) | 47,718 | 8,171 | (72,557) |
| 381.10 Meters - Tin Case | 6,378 | 41 | (1) | 40 | (302) | | (302) | (342) |
| 381.20 Meters - Hard Case | 19,330,065 | 765,471 | (1,933) | 763,538 | 641,758 | | 641,758 | (121,780) |
| 381.30 Meters - Electronic Devices | 1,090,096 | 48,945 | | 48,945 | 31,722 | | 31,722 | (17,223) |
| 381.50 Meters - Electronic Demand Recorders | 852,990 | 21,922 | | 21,922 | 4,436 | | 4,436 | (17,486) |
| 382.00 Meter Installations | 35,491,868 | 383,312 | 42,590 | 425,902 | 617,559 | 99,377 | 716,936 | 291,034 |
| 383.00 House Regulators | 3,324,275 | 77,456 | 34,240 | 111,696 | 62,829 | 50,529 | 113,358 | 1,662 |
| 384.00 House Regulator Installations | 2,624,230 | 30,966 | 262 | 31,228 | 49,336 | | 49,336 | 18,108 |
| 385.00 Industrial Meas. and Reg. Station Equip. | | | | | | | | |
| 387.00 Other Equipment | 102,163 | 1,962 | 2,513 | 4,475 | 337 | 2,544 | 2,881 | (1,594) |
| **Total Assigned Property** | $564,692,703 | $8,885,417 | $3,410,550 | $12,295,967 | $8,392,019 | $3,387,172 | $11,779,191 | ($516,776) |

**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: 3.32 Percent

| | 12/31/14 | 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 | 205,747 | 7,571 | (165) | 7,406 | 7,921 | (206) | 7,715 | 309 |
| Virginia | 48,720 | 3,357 | 541 | 3,898 | 2,538 | 268 | 2,806 | (1,092) |
| **Total Account 378.00** | $254,467 | $10,928 | $376 | $11,304 | $10,459 | $62 | $10,521 | ($783) |
| **Total Allocated Property** | $254,467 | $10,928 | $376 | $11,304 | $10,459 | $62 | $10,521 | ($783) |
| **Total Distribution Plant** | $564,947,170 | $8,896,345 | $3,410,926 | $12,307,271 | $8,402,478 | $3,387,234 | $11,789,712 | ($517,559) |
| **GENERAL PLANT** | | | | | | | | |
| **Allocated Property (Depreciable)** | | | | | | | | |
| 390.00 Structures and Improvements | | | | | | | | |
| District | $221,233 | $5,287 | $3,827 | $9,114 | $4,956 | $465 | $5,421 | ($3,693) |
| Maryland | 1,773,613 | 44,518 | 1,774 | 46,292 | 41,503 | 2,306 | 43,809 | (2,483) |
| Virginia | 12,022,761 | 226,028 | 24,046 | 250,074 | 236,848 | 24,046 | 260,894 | 10,820 |
| **Total Account 390.00** | $14,017,607 | $275,833 | $29,647 | $305,480 | $283,307 | $26,817 | $310,124 | $4,644 |
| **Total Allocated Property (Depreciable)** | $14,017,607 | $275,833 | $29,647 | $305,480 | $283,307 | $26,817 | $310,124 | $4,644 |

**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: 3.32 Percent

| Account Description | 12/31/14 Plant | Current | | | SFAS 143 | | | Difference |
|---|---|---|---|---|---|---|---|---|
| | | Investment | Net Salvage | Total | Investment | Net Salvage | Total | |
| A | B | C | D | E=C+D | F | G | H=F+G | I=H-E |
| **Assigned Property (Amortizable)** | | | | | | | | |
| 303.05 Software - 5 year | $9,259,297 | $1,638,058 | | $1,638,058 | $1,638,058 | | $1,638,058 | |
| 303.10 Software - 10 year | 6,639,647 | 663,965 | | 663,965 | 663,965 | | 663,965 | |
| 391.11 Office Furniture and Equipment | 2,076,672 | 102,316 | | 102,316 | 102,316 | | 102,316 | |
| 391.21 Computer Equipment | 3,260,870 | 416,803 | | 416,803 | 416,803 | | 416,803 | |
| 393.00 Stores Equipment | 89,491 | 4,469 | | 4,469 | 4,469 | | 4,469 | |
| 394.00 Tools, Shop & Garage Equipment | 2,158,488 | 103,252 | | 103,252 | 103,252 | | 103,252 | |
| 395.00 Laboratory Equipment | 57,909 | 2,717 | | 2,717 | 2,717 | | 2,717 | |
| 397.10 Communication Equipment - Telephones | 6,279,877 | 417,730 | | 417,730 | 417,730 | | 417,730 | |
| 397.20 ENSCAN Equipment* | 18,394,488 | 706,348 | | 706,348 | 793,436 | | 793,436 | 87,088 |
| 397.30 TRACE - AMR Devices | | | | | | | | |
| 398.00 Miscellaneous Equipment | 369,182 | 24,318 | | 24,318 | 24,318 | | 24,318 | |
| **Total Assigned Property (Amortizable)** | $48,585,921 | $4,079,976 | | $4,079,976 | $4,167,064 | | $4,167,064 | $87,088 |
| **Total General Plant** | $62,603,528 | $4,355,809 | $29,647 | $4,385,456 | $4,450,371 | $26,817 | $4,477,188 | $91,732 |
| **TOTAL JURISDICTION** | $667,728,953 | $13,926,187 | $3,551,941 | $17,478,128 | $13,379,840 | $3,617,366 | $16,997,206 | ($480,922) |

*Currently Depreciable.

**WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA**

Statement E

Parameter Summary - SFAS 143
Vintage Group Procedure
Accretion Rate: 3.32 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 | 46.73 | 25.93 | -33.3 | -31.0 | 45.00 | R3 | 46.05 | 31.91 | -31.0 | -31.0 |
| Virginia (Ravensworth) | 45.00 | R4 | 45.66 | 29.28 | -19.4 | -20.0 | 45.00 | R4 | 45.97 | 28.58 | -20.0 | -20.0 |
| **Total Account 361.00** | | | | | | | | | 46.01 | 30.31 | -25.7 | -25.5 |
| 362.00 Gas Holders | | | | | | | | | | | | |
| Maryland (Rockville) | 45.00 | R3 | 48.23 | 24.46 | -32.8 | -31.0 | 45.00 | R3 | 48.61 | 23.71 | -31.0 | -31.0 |
| Virginia (Ravensworth) | 45.00 | R4 | 45.86 | 23.18 | -19.0 | -20.0 | 45.00 | R4 | 46.32 | 23.08 | -20.0 | -20.0 |
| **Total Account 362.00** | | | | | | | | | 47.61 | 23.43 | -26.3 | -26.3 |
| 363.50 Other Equipment | | | | | | | | | | | | |
| Maryland (Rockville) | 15.00 | O3 | 16.78 | 14.49 | | | 15.00 | O3 | 15.78 | 14.61 | | |
| Virginia (Ravensworth) | 25.00 | L0 | 26.73 | 19.75 | -33.1 | 5.0 | 35.00 | L0 | 35.73 | 30.92 | | |
| **Total Account 363.50** | | | | | | | | | 18.25 | 16.63 | | 3.8 |
| **Total Allocated Property** | | | | | | | | | 42.85 | 23.32 | -24.5 | -23.1 |
| **Total Storage and Processing Plant** | | | | | | | | | 42.85 | 23.32 | -24.5 | -23.1 |
| **TRANSMISSION PLANT** | | | | | | | | | | | | |
| **Assigned Property** | | | | | | | | | | | | |
| 365.20 Rights of Way | | | | | | | | | | | | |
| 366.00 Meas. and Reg. Station Structures | | | | | | | | | | | | |
| 367.10 Mains - Steel | 80.00 | R3 | 80.00 | 40.51 | -14.9 | -15.0 | 60.00 | R3 | 61.21 | 39.90 | -15.0 | -10.9 |
| 369.00 Measuring and Regulating Equipment | 50.00 | S3 | 50.14 | 38.61 | -22.5 | -15.0 | 50.00 | S3 | 50.14 | 39.30 | -15.0 | -9.9 |
| **Total Assigned Property** | | | | | | | | | 54.66 | 39.55 | -15.0 | -10.4 |
| **Allocated Property** | | | | | | | | | | | | |
| 365.20 Rights of Way | | | | | | | | | | | | |
| District | 60.00 | R3 | 70.08 | 9.40 | | | 60.00 | R3 | 73.48 | 7.71 | | 0.0 |
| Maryland | 60.00 | R3 | 60.26 | 47.31 | | | 60.00 | R3 | 60.39 | 42.77 | | -0.2 |
| Virginia | 60.00 | R3 | 81.26 | 33.81 | | | 60.00 | R3 | 77.71 | 34.78 | | -0.1 |
| **Total Account 365.20** | | | | | | | | | 65.23 | 40.53 | | 0.0 |

**WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA**
Parameter Summary - SFAS 143
Vintage Group Procedure
Accretion Rate: 3.32 Percent

Statement E

| | | 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 |
| 366.00 | Meas. and Reg. Station Structures | | | | | | | | | | | | |
| | Maryland | 43.00 | S4 | 43.01 | 30.43 | | | 43.00 | S4 | 43.01 | 28.20 | | -0.1 |
| | Virginia | 45.00 | R3 | 45.10 | 36.92 | -9.8 | -10.0 | 50.00 | R3 | 50.06 | 41.61 | -10.0 | -10.1 |
| | **Total Account 366.00** | | | | | | | | | 46.83 | 35.46 | -5.8 | -5.9 |
| 367.10 | Mains - Steel | | | | | | | | | | | | |
| | District | 80.00 | R3 | 80.00 | 40.51 | -14.9 | -15.0 | 60.00 | R3 | 61.21 | 39.90 | -15.0 | -11.0 |
| | Maryland | 60.00 | R3 | 60.17 | 43.73 | -0.2 | | 60.00 | R3 | 59.98 | 44.15 | | -0.1 |
| | Virginia | 60.00 | R3 | 60.44 | 43.33 | -15.7 | -15.0 | 60.00 | R4 | 60.04 | 45.70 | -15.0 | -17.1 |
| | **Total Account 367.10** | | | | | | | | | 60.10 | 44.38 | -6.9 | -7.3 |
| 369.00 | Measuring and Regulating Equipment | | | | | | | | | | | | |
| | District | 50.00 | S3 | 50.14 | 38.61 | -22.5 | -15.0 | 50.00 | S3 | 50.14 | 39.30 | -15.0 | -10.0 |
| | Maryland | 45.00 | R2 | 45.31 | 36.57 | -13.5 | -11.0 | 45.00 | R2 | 45.32 | 36.51 | -11.0 | -14.8 |
| | Virginia | 55.00 | L0.5 | 55.43 | 46.49 | -29.8 | -30.0 | 60.00 | L0.5 | 60.39 | 50.89 | -30.0 | -28.5 |
| | **Total Account 369.00** | | | | | | | | | 49.02 | 40.03 | -16.7 | -23.6 |
| | **Total Allocated Property** | | | | | | | | | 55.72 | 42.20 | -9.5 | -12.0 |
| | **Total Transmission Plant** | | | | | | | | | 55.55 | 41.79 | -9.5 | -11.6 |
| **DISTRIBUTION PLANT** | | | | | | | | | | | | | |
| **Assigned Property** | | | | | | | | | | | | | |
| 375.00 | Structures and Improvements | | | | | | | | | | | | |
| 376.10 | Mains - Steel | 80.00 | R3 | 80.00 | 44.16 | -50.1 | -50.0 | 70.00 | R2.5 | 70.72 | 41.30 | -50.0 | -32.3 |
| 376.20 | Mains - Plastic | 60.00 | R3 | 59.93 | 48.20 | -50.0 | -50.0 | 55.00 | R4 | 54.84 | 41.69 | -50.0 | -30.6 |
| 376.30 | Mains - Cast Iron | 70.00 | R2.5 | 83.56 | 16.44 | -50.4 | -50.0 | 70.00 | R2.5 | 83.43 | 15.19 | -50.0 | -49.0 |
| 376.40 | Mains - Copper | | | | | | | | | | | | |
| 377.00 | Compressor Station Equipment | | | | | | | | | | | | |
| 378.00 | Measuring and Regulating Equipment | 80.00 | L1.5 | 80.39 | 61.46 | -21.1 | -20.0 | 80.00 | L1.5 | 80.46 | 61.49 | -20.0 | -8.5 |
| 380.10 | Services - Steel | 50.00 | SC | 54.43 | 33.63 | -60.6 | -60.0 | 50.00 | SC | 54.49 | 32.85 | -60.0 | -44.1 |
| 380.20 | Services - Plastic | 55.00 | L2 | 55.00 | 40.18 | -60.1 | -60.0 | 55.00 | L2 | 54.95 | 39.03 | -60.0 | -38.5 |
| 380.30 | Services - Copper | 55.00 | R3 | 56.71 | 15.48 | -60.4 | -60.0 | 55.00 | R3 | 57.48 | 12.72 | -60.0 | -55.6 |

**WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA** Statement E

Parameter Summary - SFAS 143
Vintage Group Procedure
Accretion Rate: 3.32 Percent

| | | Current Parameters | | | | | | SFAS 143 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Account Description | 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' |
| | A | B | C | D | E | F | G | H | I | J | K | L | M |
| 381.10 | Meters - Tin Case | 30.00 | L3 | 33.47 | 5.32 | 0.3 | | 30.00 | L3 | 35.04 | 3.83 | | 0.0 |
| 381.20 | Meters - Hard Case | 23.00 | S0.5 | 22.94 | 14.13 | 0.1 | | 24.00 | S1 | 23.90 | 14.63 | | 0.0 |
| 381.30 | Meters - Electronic Devices | 18.00 | L3 | 18.52 | 8.70 | 0.1 | | 18.00 | L3 | 19.10 | 8.09 | | 0.0 |
| 381.50 | Meters - Electronic Demand Recorders | 22.00 | R3 | 22.00 | 11.44 | | | 15.00 | L1.5 | 20.92 | 5.60 | | 0.0 |
| 382.00 | Meter Installations | 63.00 | R0.5 | 63.00 | 52.74 | -15.0 | -15.0 | 45.00 | S4 | 45.34 | 28.70 | -15.0 | -12.4 |
| 383.00 | House Regulators | 40.00 | R4 | 40.09 | 27.53 | -52.8 | -50.0 | 40.00 | R4 | 40.14 | 27.32 | -75.0 | -59.5 |
| 384.00 | House Regulator Installations | 54.00 | O1 | 54.00 | 41.68 | -0.3 | | 40.00 | SC | 43.74 | 28.19 | | -0.1 |
| 385.00 | Industrial Meas. and Reg. Station Equip. | | | | | | | | | | | | |
| 387.00 | Other Equipment | 40.00 | R1 | 43.46 | 20.60 | -159.6 | -100.0 | 40.00 | R1 | 44.53 | 17.99 | -100.0 | -91.0 |
| | **Total Assigned Property** | | | | | | | | | 53.27 | 36.77 | -49.3 | -20.6 |
| **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 | 56.04 | 38.39 | -6.0 | -1.0 | 55.00 | L1.5 | 56.30 | 36.52 | -1.0 | -1.0 |
| | Virginia | 30.00 | L0 | 33.72 | 21.45 | -13.1 | -15.0 | 35.00 | L0 | 38.18 | 26.16 | -10.0 | -10.0 |
| | **Total Account 378.00** | | | | | | | | | 51.61 | 33.84 | -2.7 | -3.0 |
| | **Total Allocated Property** | | | | | | | | | 51.61 | 33.84 | -2.7 | -3.0 |
| | **Total Distribution Plant** | | | | | | | | | 53.27 | 36.77 | -2.7 | -29.4 |

**WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA**

Statement E

Parameter Summary - SFAS 143
Vintage Group Procedure
Accretion Rate: 3.32 Percent

| | Current Parameters | | | | | | SFAS 143 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | P-Life/ | Curve | VG | Rem. | Avg. | Fut. | P-Life/ | Curve | VG | Rem. | Fut. Net Sal. | |
| Account Description | AYFR | Shape | ASL | Life | Sal. | Sal. | AYFR | Shape | ASL | Life | Sf | Sf |
| A | B | C | D | E | F | G | H | I | J | K | L | M |
| **GENERAL PLANT** | | | | | | | | | | | | |
| **Allocated Property (Depreciable)** | | | | | | | | | | | | |
| 390.00 Structures and Improvements | | | | | | | | | | | | |
| District | 40.00 | S4 | 38.60 | 25.32 | -60.0 | -10.0 | 40.00 | S4 | 36.58 | 26.17 | -10.0 | -16.2 |
| Maryland | 37.00 | R1 | 37.60 | 27.46 | -3.0 | | 37.00 | R1 | 37.56 | 27.47 | | 0.4 |
| Virginia | 50.00 | R4 | 49.96 | 35.61 | -10.4 | -10.0 | 50.00 | R2 | 49.97 | 47.58 | -10.0 | -10.0 |
| **Total Account 390.00** | | | | | | | | | 47.70 | 43.91 | -8.7 | -7.7 |
| **Total Allocated Property (Depreciable)** | | | | | | | | | 47.70 | 43.91 | -8.7 | -7.7 |
| **Assigned Property (Amortizable)** | | | | | | | | | | | | |
| 303.05 Software - 5 year | 5.00 | SQ | 5.00 | 3.00 | | | 5.00 | SQ | 5.00 | 2.86 | | |
| 303.10 Software - 10 year | 10.00 | SQ | 10.00 | 7.24 | | | 10.00 | SQ | 10.00 | 3.36 | | |
| 391.11 Office Furniture and Equipment | 20.00 | SQ | 20.00 | 7.42 | | | 20.00 | SQ | 20.00 | 12.17 | | |
| 391.21 Computer Equipment | 7.00 | SQ | 7.00 | 3.30 | | | 7.00 | SQ | 7.00 | 3.32 | | |
| 393.00 Stores Equipment | 20.00 | SQ | 20.00 | 9.49 | | | 20.00 | SQ | 20.00 | 8.59 | | |
| 394.00 Tools, Shop & Garage Equipment | 20.00 | SQ | 20.00 | 8.01 | | | 20.00 | SQ | 20.00 | 9.71 | | |
| 395.00 Laboratory Equipment | 20.00 | SQ | 20.00 | 7.98 | | | 20.00 | SQ | 20.00 | 6.58 | | |
| 397.10 Communication Equipment - Telephones | 15.00 | SQ | 15.00 | 6.22 | | | 15.00 | SQ | 15.00 | 9.72 | | |
| 397.20 ENSCAN Equipment* | 23.00 | L1 | 24.04 | 15.87 | | | 18.00 | SQ | 18.00 | 8.36 | | 0.0 |
| 397.30 TRACE - AMR Devices | | | | | | | | | | | | |
| 398.00 Miscellaneous Equipment | 15.00 | SQ | 15.00 | 6.31 | | | 15.00 | SQ | 15.00 | 10.94 | | |
| **Total Assigned Property (Amortizable)** | | | | | | | | | 10.41 | 5.21 | | |
| **Total General Plant** | | | | | | | | | 12.62 | 7.51 | -2.0 | |
| **TOTAL JURISDICTION** | | | | | | | | | 40.85 | 27.85 | -6.3 | -22.7 |

*Currently Depreciable.

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 2

QUESTION NO. 2-33

**Q.** Please provide a detailed narrative explaining what is represented by the "polynomial hazard function" as used in the Depreciation Study. Additionally, please explain the procedure used to determine the Actual, 1st, 2nd, and 3rd, data points and curves presented in Schedule E. Lastly, please provide the formulas used for the polynomial hazard functions shown on page 48 of the Depreciation Study, Exhibit WG (G)-2.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** The answer to the same question asked in Case No. 1162 is repeated below.

The fundamental probability distribution of interest in estimating the service life of industrial property is called a *hazard function*. This function, which is also used in reliability theory, is a parametric equation that describes the conditional probability of retirement (called a *hazard rate*) during an age interval given survival to the beginning of the interval. So, for example, the probability that plant that has been in service, say for 5 years, will be retired during the 6th year is a conditional probability of retirement. In other words, the probability is conditioned upon having achieved an age of 5 years.

The objective of a statistical analysis of plant retirements is to identify the form of an equation that best describes the conditional probabilities of retirement, where the form of the equation is dictated by the underlying forces of retirement. Any number of equations can be considered as candidates for selection. The so–called Iowa curves are a family of probability distributions often used in conducting depreciation studies.

Each Iowa curve has a unique hazard function derived from the ratio of its retirement frequency distribution to its survivor distribution. Iowa density functions, however, cannot be integrated to obtain a functional form of survivor curves. It is for this reason that polynomials of the form $y = a + bx + cx^2 + dx^3$ are used to estimate the conditional probabilities of a hazard function. The variable *y* is the hazard rate and *x* is the age interval of the rate.[1] A polynomial can then be transformed into a survivorship function and numerically integrated to obtain an estimate of the projection life of a plant category. The observed proportions surviving are 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 only purpose of fitting to Iowa curves is to obtain service–life descriptors more familiar to users of Iowa curves than curves described by the coefficients of a polynomial.

The problem, therefore, is to estimate the coefficients (*i.e.*, *a*, *b, c* and *d*) of the polynomial from an estimate of hazard rates derived from a sampling of historical retirements recorded for a plant category. Different estimators of the hazard rate can be used depending upon the desired statistical properties (*e.g.*, unbiased, minimum variance, etc.) of the estimator. The ratio of retirements to exposures is most often used for depreciation studies. Although some correlation can be found in the conditional proportion retired, the covariance between the hazard rates in two age–intervals is asymptotically zero. This property has permitted the development of various methods of weighting that reflect serial independence of the disturbance term.

Estimators of hazard rates used in the depreciation study are the ratio of retirements during and age–interval to exposures at the beginning of the interval. Coefficients of the polynomial are estimated using OLS linear regression, weighted by exposures.[2] The formulas for each degree of polynomial are as follows:

$$1^{\text{st}} \text{ degree: } \lambda(x) = \text{-}1.41\text{E}-02 + 3.52\text{E}-03X$$

$$2^{\text{nd}} \text{ degree: } \lambda(x) = 1.09\text{E}-02 - 1.81\text{E}-03X + 1.85\text{E-}04X^2$$

$$3^{\text{rd}} \text{ degree: } \lambda(x) = 3.44\text{E}-03 + 8.071\text{E}-04X - 1.13\text{E-}05X^2 + 3.83\text{E-}06X^3$$

[1]The reason polynomials are limited to a third–degree term (*i.e.*, a polynomial having an $x^3$ term) is that some low modal Iowa curves exhibit two inflection points in a plot of the hazard function.

[2]A procedure developed by Chebyshev (*i.e.*, orthogonal polynomials) was used to estimate the coefficients of the polynomials without rewriting the normal equations for each successive power of the polynomial. The coefficients of a second-degree equation, for example, can be derived from a first-degree equation without rewriting the equations used in a normal least squares regression.

SPONSOR: Ronald E. White, Ph.D.
President
Foster Associates Consultants, LLC

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS‘S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE’S COUNSEL

OPC DATA REQUEST NO. 2

QUESTION NO. 2-23

**Q.** Please provide a detailed description of the property that is contained within Account 376.20-Mains-Plastic. Please identify the plastic technology/material used for this property.

**WASHINGTON GAS’S RESPONSE** 10/04/2024

**A.** Washington Gas installs polyethylene pipe meeting ASTM D2513-12, “Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings”. The attached table lists installed pipe sizes, pipe type (service or main) and corresponding material designation codes: PE2708 (“medium density”) and PE4710 (“high density”). The listings are the typical types used. There may be special circumstances where high density pipe is used in a size where medium density would normally be used and there are certain instances where certain pipe sizes are no longer used. These sizes have very small dollar amounts associated with them.

SPONSOR: Jacob Waller,
Manager Codes and Standards

| **Nominal Pipe Diameter** | **Size** | **Type** | **Pipe Designation Code** |
|---|---|---|---|
| Sleeves 6" and under | Iron Pipe Size (IPS) | Service-380 | PE2708 |
| 1/2 | Copper Tubing Size (CTS) | Service-380 | PE2708 |
| 3/4 | Iron Pipe Size (IPS) | Service-380 | PE2708 |
| 1 | Copper Tubing Size (CTS) | Service-380 | PE2708 |
| 1 | No-Longer Used | Main 376 | No-Longer Used |
| 1-1/2 | No-Longer Used | Service-380 | No-Longer Used |
| 1-1/2 | No-Longer Used | Main 376 | No-Longer Used |
| 1-1/4 | Copper Tubing Size (CTS) | Service-380 | PE2708 |
| 1-1/4 | Iron Pipe Size (IPS) | Service-380 | PE2708 |
| 2 | Iron Pipe Size (IPS) | Service- 380 or Main 376 | PE2708 |
| 2-1/2 | No-Longer Used | Service-380 | No-Longer Used |
| 3 | Iron Pipe Size (IPS) | Main (Typ.) Limited Services exist at these sizes | PE2708 |
| 4 | Iron Pipe Size (IPS) | Main (Typ.) Limited Services exist at these sizes | PE2708 |
| 6 | Iron Pipe Size (IPS) | Main (Typ.) Limited Services exist at these sizes | PE2708 |
| 8 | Iron Pipe Size (IPS) | Main (Typ.) Limited Services exist at these sizes | PE2708 |
| 10 | Iron Pipe Size (IPS) | Main-376 | PE4710 |
| 12 | Iron Pipe Size (IPS) | Main-376 | PE4710 |
| 12 | Iron Pipe Size (IPS) | Service-380 | PE4710 |
| 16 | Iron Pipe Size (IPS) | Main-376 | PE4710 |

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 2

QUESTION NO. 2-24

**Q.** Please identify the retirement units WGL utilizes for accounting purposes for Account 376.20. Additionally, please provide a spreadsheet that segregates the plant balance as of December 31, 2023 into those same retirement units.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** Please see the Excel spreadsheet provided with this response.

SPONSOR: Donald Preston
Manager of Fixed Asset Accounting

**Formal Case No. 1180**
**OPC Data Request No.2-24**
**Attachment 1**
**Page 1 of 1**

**District of Columbia**
**Account 376200**
**December 31, 2023**

| utility_account | retirement_unit | Total | |
|---|---|---|---|
| 376200 - Distr - Mains - Plastic | 376201-Main Pipe, Pl 3/4" | 3,193,012 | |
| | 376202-Main Pipe, Pl 1 " | 36,435 | |
| | 376203-Main Pipe, Pl 1-1/4" | 2,496,604 | |
| | 376204-Main Pipe, Pl 1-1/2" | 38,831 | |
| | 376205-Main Pipe, Pl 2 " | 154,066,551 | |
| | 376206-Main Pipe, Pl 3 " | 6,764,468 | |
| | 376207-Main Pipe, Pl 4 " | 90,188,346 | |
| | 376208-Main Pipe, Pl 6 " | 63,098,783 | |
| | 376209-Main Pipe, Pl 8 " | 24,270,162 | |
| | 376210-Main Pipe, Pl 10 " | 7,410,321 | |
| | 376211-Main Pipe, Pl 12 " | 27,088,924 | |
| | 376212-Main Pipe, Pl 16 " | 3,628,018 | |
| | Non-unitized | 71,803,885 | 1/ |
| **376200 - Distr - Mains - Plastic Total** | | **454,084,341** | |

1/ Non-Unitized Services are assets that were put into service and are depreciating.
at the time

## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

**Distribution Plant**

**Account: 376.20 Mains - Plastic**

T-Cut: None
Placement Band: 1958-2023
Hazard Function: Proportion Retired
Weighting: Exposures

**Rolling Band Life Analysis**

| Observation Band | Censoring | First Degree | | | Second Degree | | | Third Degree | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 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 | 99.2 | 197.7 | SQ* | 0.16 | 70.2 | S2 | 0.98 | 194.1 | SQ * | 0.52 |
| 1987-1991 | 98.5 | 197.0 | SQ* | 0.46 | 117.5 | S2 | 0.39 | 196.9 | SQ * | 0.43 |
| 1988-1992 | 96.3 | 192.6 | S6* | 0.79 | 194.3 | SQ * | 0.94 | 56.6 | S3 | 0.93 |
| 1989-1993 | 97.4 | 193.7 | S6* | 0.43 | 194.9 | SQ * | 0.51 | 71.7 | S3 | 0.48 |
| 1990-1994 | 97.5 | 194.9 | SQ* | 0.40 | 195.2 | SQ * | 0.46 | 63.9 | S3 | 0.58 |
| 1991-1995 | 97.5 | 194.5 | S6* | 0.43 | 195.3 | SQ * | 0.54 | 66.9 | R4 | 0.52 |
| 1992-1996 | 95.6 | 187.4 | R4* | 1.03 | 189.7 | R5 * | 0.50 | 49.6 | R4 | 2.80 |
| 1993-1997 | 95.8 | 189.6 | R5* | 0.62 | 190.2 | R5 * | 0.49 | 46.8 | R4 | 4.32 |
| 1994-1998 | 89.7 | 189.1 | R5* | 3.07 | 189.0 | R5 * | 3.06 | 42.6 | R4 | 6.75 |
| 1995-1999 | 93.1 | 190.0 | R5* | 1.35 | 190.5 | R5 * | 1.53 | 44.2 | R4 * | 7.31 |
| 1996-2000 | 91.7 | 127.0 | SC | 2.90 | 183.4 | R4 * | 0.51 | 44.4 | R4 * | 6.48 |
| 1997-2001 | 93.0 | 118.2 | SC | 3.09 | 185.9 | R4 * | 0.83 | 46.4 | R4 * | 6.02 |
| 1998-2002 | 94.4 | 123.1 | S-.5 | 2.93 | 187.7 | R4 * | 0.71 | 49.4 | R4 * | 4.96 |
| 1999-2003 | 95.0 | 129.4 | R0.5 | 2.58 | 189.1 | R5 * | 0.62 | 52.6 | R4 * | 3.62 |
| 2000-2004 | 95.4 | 132.6 | R0.5 | 2.54 | 189.5 | R5 * | 0.59 | 54.4 | R4 * | 3.39 |
| 2001-2005 | 98.3 | 180.3 | R3 | 0.72 | 195.7 | SQ * | 0.15 | 68.7 | R4 * | 1.09 |
| 2002-2006 | 81.8 | 193.2 | SQ | 7.78 | 197.1 | SQ * | 8.04 | 77.5 | R4 * | 7.25 |
| 2003-2007 | 88.5 | 176.9 | R3 | 4.50 | 193.9 | S6 * | 4.63 | 72.7 | S3 * | 3.36 |
| 2004-2008 | 20.3 | 170.8 | R2.5 | 31.85 | 96.1 | S2 | 30.60 | 57.6 | R4 * | 25.96 |
| 2005-2009 | 39.9 | 134.1 | R0.5 | 16.14 | 183.6 | R4 * | 17.95 | 64.6 | R3 | 15.38 |
| 2006-2010 | 13.9 | 140.3 | R0.5 | 31.72 | 180.5 | R3 * | 32.63 | 62.5 | R3 | 29.62 |
| 2007-2011 | 0.0 | 140.5 | R0.5 | 39.54 | 182.4 | R4 * | 40.77 | 65.3 | R3 | 38.00 |
| 2008-2012 | 0.0 | 105.7 | L1 | 40.94 | 63.0 | S1.5 | 36.60 | 47.4 | R4 * | 26.32 |
| 2009-2013 | 0.0 | 114.1 | S-.5 | 42.30 | 67.9 | S1.5 | 38.72 | 49.3 | R4 * | 29.09 |
| 2010-2014 | 0.0 | 103.0 | L1.5* | 43.03 | 63.8 | S2 * | 37.39 | 53.5 | R4 * | 31.97 |
| 2011-2015 | 48.9 | 106.4 | L1.5* | 18.81 | 66.8 | S2 * | 14.05 | 56.9 | S3 * | 11.00 |
| 2012-2016 | 84.0 | 113.6 | L1.5* | 2.73 | 70.1 | S2 * | 3.95 | 61.6 | S3 * | 6.56 |
| 2013-2017 | 73.5 | 141.8 | R1* | 9.82 | 95.8 | S1.5 * | 8.36 | 189.8 | R5 * | 10.43 |
| 2014-2018 | 92.6 | 140.3 | R1* | 0.78 | 98.1 | S1.5 * | 1.94 | 190.0 | R5 * | 1.08 |
| 2015-2019 | 94.5 | 159.0 | R1.5 | 0.56 | 118.8 | S1.5 | 1.24 | 188.5 | R5 * | 0.41 |
| 2016-2020 | 91.9 | 141.7 | R1* | 1.06 | 85.9 | S2 | 3.78 | 71.5 | S3 | 6.02 |
| 2017-2021 | 92.9 | 151.6 | R1 | 0.94 | 88.8 | S2 | 3.72 | 79.4 | R3 | 4.64 |
| 2018-2022 | 92.4 | 155.0 | R1.5 | 0.89 | 98.3 | S1.5 | 2.64 | 77.7 | R3 | 4.54 |
| 2019-2023 | 92.7 | 158.5 | R1.5 | 1.02 | 102.7 | S1.5 | 2.35 | 80.3 | R3 | 4.13 |

## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

**Distribution Plant**

**Account: 376.20 Mains - Plastic**

T-Cut: None
Placement Band: 1958-2023
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 | 87.6 | 149.9 | R1 | 1.39 | 105.0 | S1 | 1.17 | 71.5 | R3 | 5.41 |
| 1988-2023 | 87.5 | 150.0 | R1 | 1.39 | 105.0 | S1 | 1.17 | 71.5 | R3 | 5.42 |
| 1990-2023 | 87.5 | 150.0 | R1 | 1.39 | 105.0 | S1 | 1.16 | 71.4 | R3 | 5.45 |
| 1992-2023 | 87.6 | 149.9 | R1 | 1.37 | 105.2 | S1 | 1.16 | 71.3 | R3 | 5.48 |
| 1994-2023 | 87.6 | 149.6 | R1 | 1.36 | 105.2 | S1 | 1.16 | 71.4 | R3 | 5.48 |
| 1996-2023 | 87.6 | 149.2 | R1 | 1.34 | 105.7 | S1 | 1.14 | 71.3 | R3 | 5.51 |
| 1998-2023 | 87.7 | 146.7 | R1 | 1.26 | 106.3 | S1 | 1.15 | 71.9 | R3 | 5.28 |
| 2000-2023 | 87.7 | 146.0 | R1 | 1.23 | 107.5 | S1 | 1.11 | 71.7 | R3 | 5.33 |
| 2002-2023 | 88.0 | 145.3 | R1 | 1.24 | 99.3 | S1.5 | 1.61 | 75.5 | R3 | 4.27 |
| 2004-2023 | 88.0 | 144.7 | R1 | 1.20 | 99.4 | S1.5 | 1.61 | 75.5 | R3 | 4.26 |
| 2006-2023 | 87.9 | 144.5 | R1 | 1.20 | 98.9 | S1.5 | 1.64 | 75.4 | R3 | 4.27 |
| 2008-2023 | 87.7 | 143.6 | R1 | 1.15 | 99.9 | S1.5 | 1.56 | 74.9 | R3 | 4.33 |
| 2010-2023 | 89.4 | 145.5 | R1 | 1.12 | 91.4 | S1.5 | 2.76 | 83.5 | S2 | 3.45 |
| 2012-2023 | 92.2 | 145.4 | R1 | 1.15 | 90.8 | S1.5 | 3.93 | 83.8 | S2 | 4.53 |
| 2014-2023 | 93.5 | 152.5 | R1.5 | 1.02 | 101.4 | S1.5 | 2.90 | 106.6 | S1.5 | 2.78 |
| 2016-2023 | 93.7 | 160.7 | R1.5 | 0.83 | 104.0 | S1.5 | 2.42 | 84.9 | R3 | 3.65 |
| 2018-2023 | 92.9 | 156.9 | R1.5 | 0.96 | 103.0 | S1.5 | 2.44 | 83.5 | R3 | 3.73 |
| 2020-2023 | 92.4 | 159.4 | R1.5 | 1.34 | 97.9 | S2 | 2.58 | 80.6 | S3 | 4.07 |
| 2022-2023 | 95.2 | 174.3 | R2.5 | 0.75 | 190.0 | R5 * | 0.76 | 83.8 | R4 * | 2.71 |

**Schedule D**
**Page 1 of 1**

## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

**Distribution Plant**

**Account: 376.20 Mains - Plastic**

T-Cut: None
Placement Band: 1958-2023
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 | 99.8 | 198.2 | SQ* | 0.07 | 198.5 | SQ* | 0.03 | 66.4 | S3 * | 0.11 |
| 1986-1989 | 99.6 | 198.1 | SQ* | 0.05 | 108.0 | S2 | 0.23 | 197.9 | SQ * | 0.11 |
| 1986-1991 | 98.6 | 197.2 | SQ* | 0.44 | 118.0 | S2 | 0.37 | 197.0 | SQ * | 0.40 |
| 1986-1993 | 97.9 | 194.6 | S6* | 0.28 | 195.4 | SQ* | 0.31 | 69.5 | S3 | 0.50 |
| 1986-1995 | 98.2 | 195.9 | SQ* | 0.21 | 196.0 | SQ* | 0.24 | 75.7 | S3 | 0.30 |
| 1986-1997 | 96.4 | 191.2 | SQ* | 0.35 | 192.4 | SQ* | 0.19 | 48.6 | R4 | 3.69 |
| 1986-1999 | 94.3 | 192.2 | SQ* | 1.33 | 192.8 | S6* | 1.52 | 46.9 | R4 | 5.65 |
| 1986-2001 | 93.8 | 139.0 | R0.5 | 2.00 | 188.9 | R5* | 0.58 | 49.3 | R4 * | 4.39 |
| 1986-2003 | 95.3 | 159.8 | R1 | 1.63 | 190.8 | R5* | 0.32 | 52.7 | R4 * | 4.30 |
| 1986-2005 | 96.4 | 173.5 | R2 | 1.42 | 192.1 | SQ* | 0.23 | 58.3 | R4 * | 3.14 |
| 1986-2007 | 88.8 | 186.5 | R4* | 3.01 | 192.9 | SQ* | 3.85 | 58.9 | R4 | 2.20 |
| 1986-2009 | 47.4 | 141.4 | R0.5 | 12.41 | 188.1 | R5* | 14.59 | 58.3 | R4 * | 9.49 |
| 1986-2011 | 44.3 | 151.4 | R1 | 15.36 | 188.7 | R5* | 17.16 | 60.4 | R4 | 11.53 |
| 1986-2013 | 4.9 | 137.0 | R0.5 | 41.52 | 81.9 | S1.5 | 39.23 | 51.0 | R4 * | 28.17 |
| 1986-2015 | 37.0 | 131.7 | R0.5 | 22.16 | 80.0 | S1.5 | 19.34 | 54.8 | R4 * | 11.18 |
| 1986-2017 | 49.4 | 142.4 | R1 | 16.90 | 91.9 | S1 | 14.93 | 59.9 | R4 | 8.21 |
| 1986-2019 | 60.3 | 144.5 | R1 | 12.55 | 100.2 | S1 | 11.09 | 65.1 | R3 | 6.45 |
| 1986-2021 | 61.0 | 144.4 | R1 | 13.03 | 92.0 | S1.5 | 10.62 | 66.2 | R3 | 6.56 |
| 1986-2023 | 87.6 | 149.9 | R1 | 1.39 | 105.0 | S1 | 1.17 | 71.5 | R3 | 5.41 |

**Schedule E**
**Page 1 of 1**

## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

**Distribution Plant**

**Account: 376.20 Mains - Plastic**

**T-Cut: None**

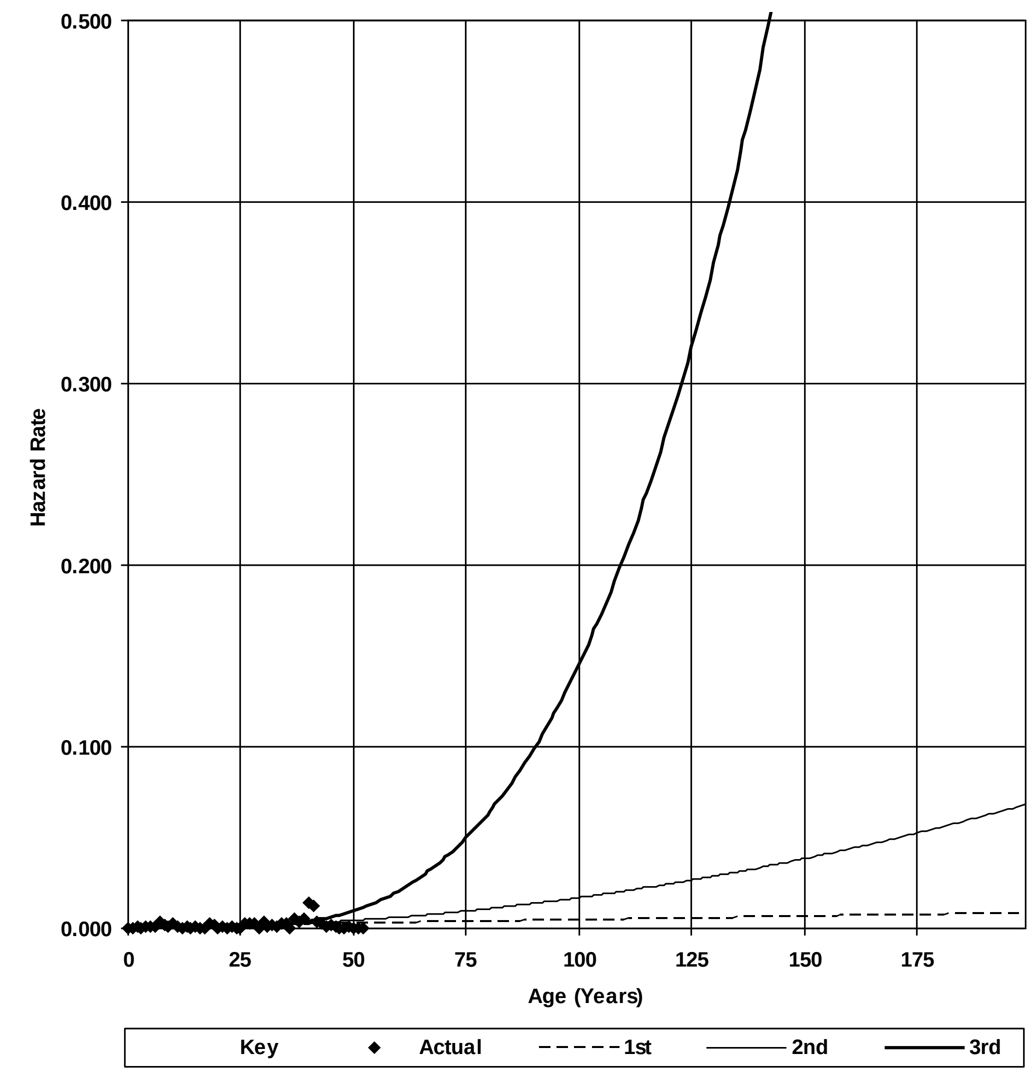
**Placement Band: 1968-2023 Observation Band: 1986-2023**

**Hazard Function: Proportion Retired**

**Weighting: Exposures**

### Polynomial Hazard Functions

**1st: 150.0-R1 2nd: 105.2-S1 3rd: 71.4-R3**



Schedule E
Page 1 of 1

# WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

## Distribution Plant

## Account: 376.20 Mains - Plastic

T-Cut: None

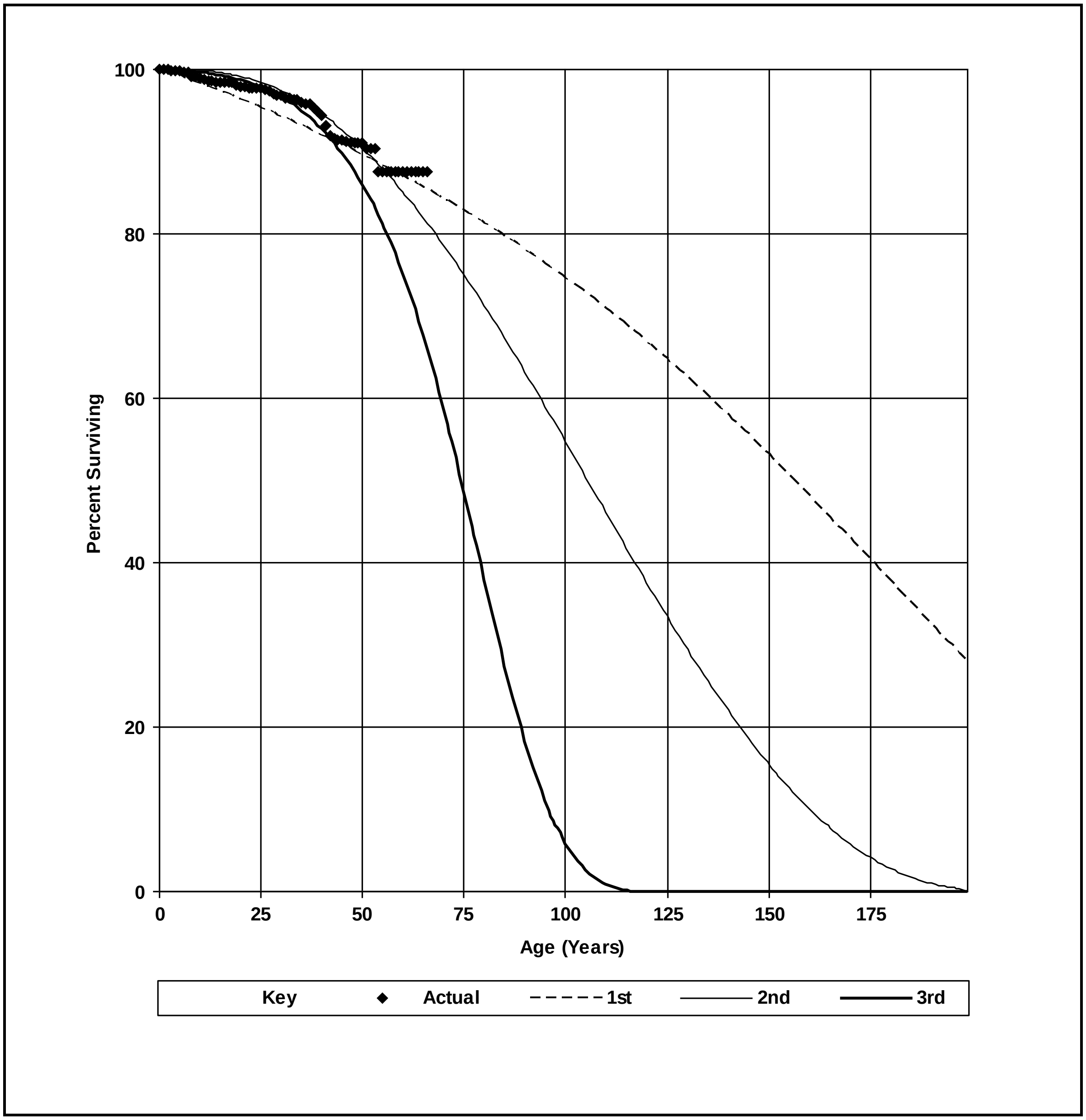
Placement Band: 1958-2023 Observation Band: 1986-2023

Hazard Function: Proportion Retired

Weighting: Exposures

### Survivorship Functions

1st: 149.9-R1 2nd: 105.0-S1 3rd: 71.5-R3



Schedule E
Page 1 of 1

## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

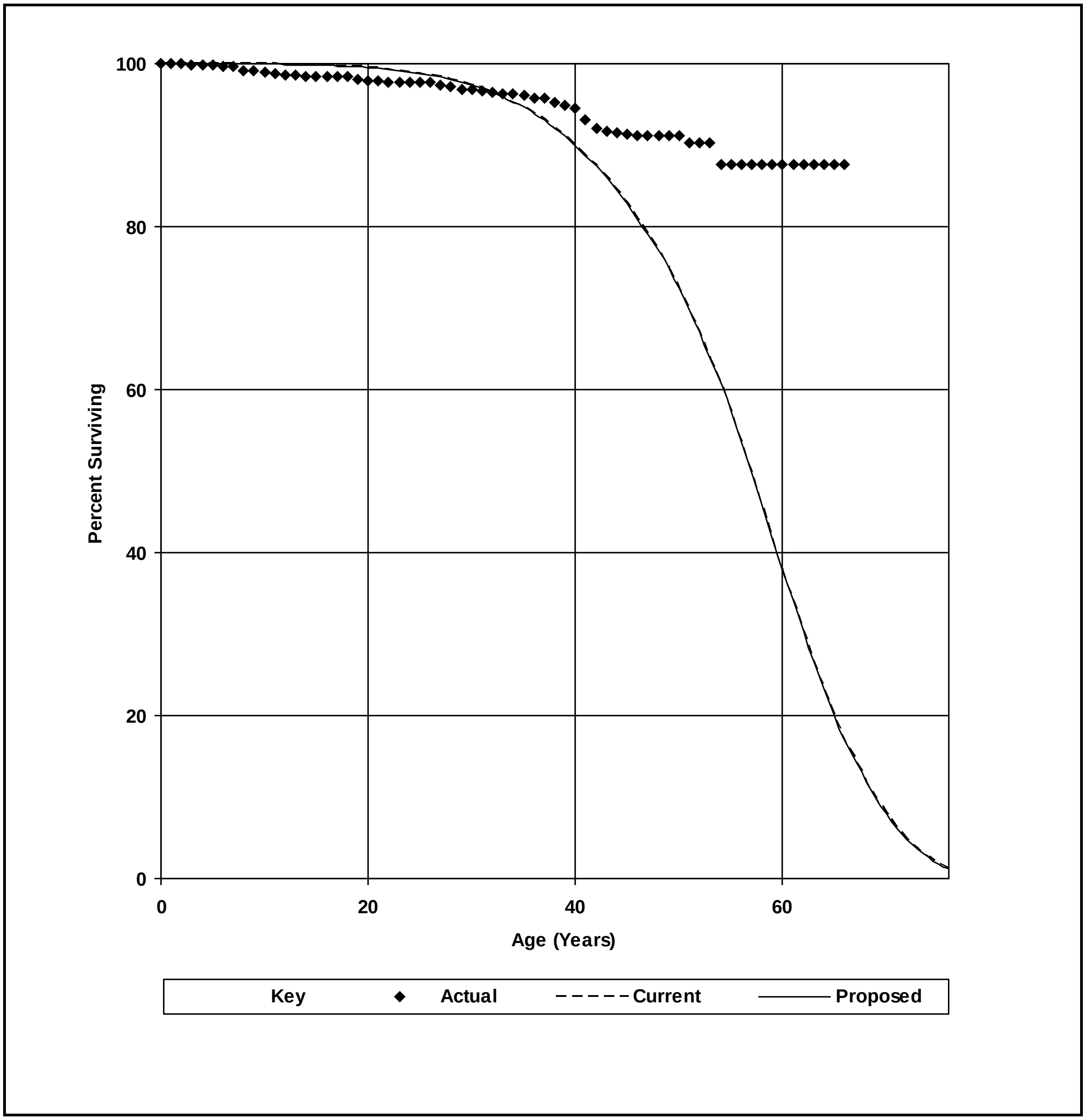
**Distribution Plant**

**Account: 376.20 Mains - Plastic**

T-Cut: None
Placement Band: 1958-2023
Observation Band: 1986-2023

**Projection Life Curves**

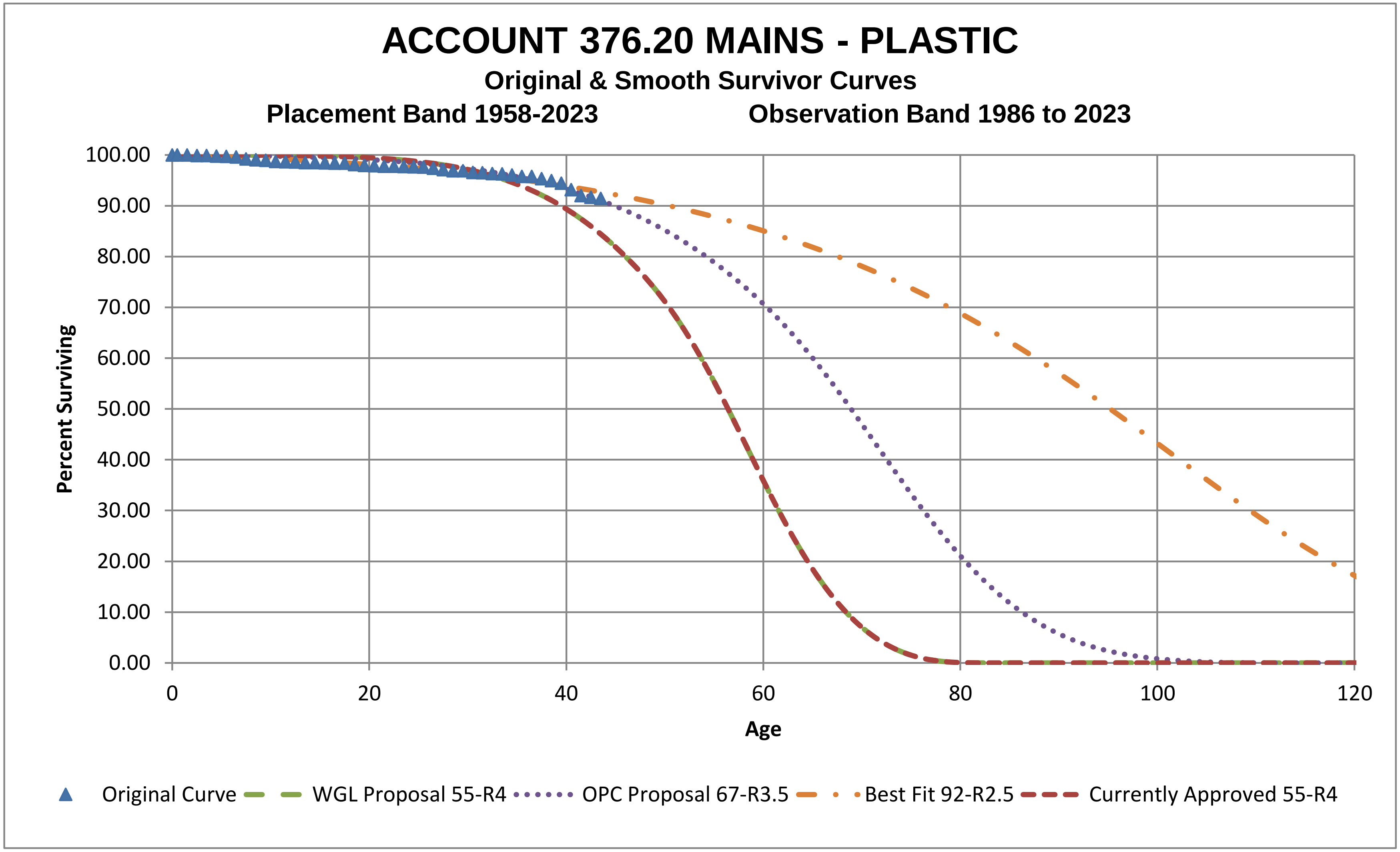
Current: 55.0-R4 Proposed: 55.0-R4



## Account 376.2 Fitting Analysis Results

| Iowa Curve | Average Service Life | SSD |
|---|---|---|
| R2.5 | 91.6 | 11.7 |
| L1 | 136.5 | 12.9 |
| L1.5 | 113.1 | 14.6 |
| S0.5 | 122.2 | 15.3 |
| R3 | 75.1 | 16.4 |
| S0 | 151.4 | 16.6 |
| R2 | 114.2 | 17.0 |
| L0.5 | 185.5 | 18.0 |
| L0 | 242.3 | 20.6 |
| S1 | 98.6 | 23.0 |
| L2 | 91.4 | 23.6 |
| R3.5 | 67.0 | 25.3 |
| R1.5 | 159.2 | 26.2 |
| S1.5 | 86.0 | 27.2 |
| L2.5 | 81.2 | 29.9 |
| R1 | 213.2 | 30.4 |
| R0.5 | 292.8 | 33.8 |
| O2 | 422.9 | 35.2 |
| O1 | 377.8 | 35.2 |
| O3 | 616.4 | 35.4 |
| O4 | 853.3 | 35.5 |
| S2 | 75.3 | 48.9 |
| L3 | 71.1 | 50.2 |
| S2.5 | 69.0 | 57.6 |
| R4 | 60.8 | 58.3 |
| S3 | 63.5 | 88.6 |
| L4 | 59.9 | 96.9 |
| R5 | 52.1 | 154.8 |
| S4 | 55.1 | 155.2 |
| L5 | 53.1 | 166.5 |
| S5 | 50.4 | 229.4 |
| S6 | 47.6 | 309.6 |

| | |
|---|---|
| WGL Proposal 55-R4 | 217 |
| Currently Approved 55-R4 | 217 |
| OPC Proposal 67-R3.5 | 25 |


ACCOUNT 376.20 MAINS - PLASTIC
Original & Smooth Survivor Curves
Placement Band 1958-2023
Observation Band 1986 to 2023
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
WGL Proposal 55-R4
OPC Proposal 67-R3.5
Best Fit 92-R2.5
Currently Approved 55-R4

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 2

QUESTION NO. 2-27

**Q.** Please provide a detailed narrative of the O&M programs that affect the property in Account 376.20. Please explain if these programs have been newly implemented in the last 10-years.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** The Company does not have any specific O&M programs related to the property in Account 376.2. Please refer to OPC Data Request No. 2-26 for the Company's response on the replacement program for property in Account 376.2.

SPONSOR: Donald Preston
Manager of Fixed Asset Accounting

**Washington Gas Light Company**
**OPC Recommended Depreciation Rates**
**Calculated By The Remaining Life Method**
**Based On Depreciable Plant In Service At December 31, 2023**

| Account | | Original Cost As Of December 31, 2023 | Recommended Annual Accrual Amount | Recommended Annual Accrual % |
|---|---|---|---|---|
| (1) | | (2) | (3) | (4) |
| **STORAGE AND PROCESSING PLANT** | | | | |
| **Allocated Property** | | | | |
| 361.00 | Structures and Improvements | | | |
| | Maryland (Rockville) | $ 1,311,110 | $ 32,778 | 2.50% |
| | Virginia (Ravensworth) | 1,183,946 | 29,954 | 2.53% |
| | **Total Account 361.00** | $ 2,495,056 | $ 62,732 | 2.51% |
| 362.00 | Gas Holders | | | |
| | Maryland (Rockville) | $ 4,460,885 | $ 61,560 | 1.38% |
| | Virginia (Ravensworth) | 3,676,243 | 66,172 | 1.80% |
| | **Total Account 362.00** | $ 8,137,128 | $ 127,732 | 1.57% |
| 363.50 | Other Equipment | | | |
| | Maryland (Rockville) | $ 818,973 | $ 18,754 | 2.29% |
| | Virginia (Ravensworth) | 604,207 | 20,060 | 3.32% |
| | **Total Account 363.50** | $ 1,423,180 | $ 38,814 | 2.73% |
| **Total Allocated Property** | | $ 12,055,364 | $ 229,278 | 1.90% |
| **Total Storage and Processing Plant** | | **$ 12,055,364** | **$ 229,278** | **1.90%** |
| **TRANSMISSION PLANT** | | | | |
| **Assigned Property** | | | | |
| 365.20 | Rights of Way | $ - | $ - | 0.00% |
| 366.00 | Meas. and Reg. Station Structures | 0 | 0 | 0.00% |
| 367.10 | Mains - Steel | 4,258,093 | 52,374 | 1.23% |
| 369.00 | Measuring and Regulating Equipment | 7,874,665 | 113,395 | 1.44% |
| **Total Assigned Property** | | $ 12,132,758 | $ 165,769 | 1.37% |
| **Allocated Property** | | | | |
| 365.20 | Rights of Way | | | |
| | District | $ 470 | $ (21) | -4.47% |
| | Maryland | 803,227 | 11,245 | 1.40% |
| | Virginia | 401,040 | 2,928 | 0.73% |
| | **Total Account 365.20** | $ 1,204,737 | $ 14,152 | 1.17% |
| 366.00 | Meas. and Reg. Station Structures | | | |
| | Maryland | $ 499,988 | $ 15,700 | 3.14% |
| | Virginia | 3,153,657 | 71,588 | 2.27% |
| | **Total Account 366.00** | $ 3,653,645 | $ 87,288 | 2.39% |

**Washington Gas Light Company**
**OPC Recommended Depreciation Rates**
**Calculated By The Remaining Life Method**
**Based On Depreciable Plant In Service At December 31, 2023**

| Account | | Original Cost As Of December 31, 2023 | Recommended Annual Accrual Amount | Recommended Annual Accrual % |
|---|---|---|---|---|
| (1) | | (2) | (3) | (4) |
| 367.10 | Mains - Steel | | | |
| | District | $ 1,833,775 | $ 33,008 | 1.80% |
| | Maryland | 11,899,374 | 185,631 | 1.56% |
| | Virginia | 15,473,955 | 270,794 | 1.75% |
| | **Total Account 367.10** | $ 29,207,104 | $ 489,433 | 1.68% |
| 369.00 | Measuring and Regulating Equipment | | | |
| | District | $ 599,848 | $ (4,798) | -0.80% |
| | Maryland | 13,331,810 | 905,230 | 6.79% |
| | Virginia | 3,963,721 | (232,670) | -5.87% |
| | **Total Account 369.00** | $ 17,895,379 | $ 667,762 | 3.73% |
| **Total Allocated Property** | | $ 51,960,865 | $ 1,258,635 | 2.42% |
| **Total Transmission Plant** | | **$ 64,093,623** | **$ 1,424,404** | **2.22%** |
| **DISTRIBUTION PLANT** | | | | |
| **Assigned Property** | | | | |
| 375.00 | Structures and Improvements | $ - | $ - | 0.00% |
| 376.10 | Mains - Steel | 96,886,105 | 1,637,375 | 1.69% |
| 376.20 | Mains - Plastic | 454,106,167 | 8,900,481 | 1.96% |
| 376.30 | Mains - Cast Iron | 6,002,962 | 58,229 | 0.97% |
| 378.00 | Measuring and Regulating Equipment | 11,225,235 | 232,363 | 2.07% |
| 380.10 | Services - Steel | 53,992,928 | 1,214,841 | 2.25% |
| 380.20 | Services - Plastic | 357,615,007 | 7,474,154 | 2.09% |
| 380.30 | Services - Copper | 3,030,970 | 18,185 | 0.60% |
| 381.20 | Meters - Hard Case | 23,438,610 | 785,193 | 3.35% |
| 381.30 | Meters - Electronic Devices | 2,491,253 | 114,847 | 4.61% |
| 381.50 | Meters - Electronic Demand Recorders | 852,990 | (21,837) | -2.56% |
| 382.00 | Meter Installations | 35,599,234 | 758,264 | 2.13% |
| 383.00 | House Regulators | 4,735,146 | 187,512 | 3.96% |
| 384.00 | House Regulator Installations | 3,728,682 | 65,624 | 1.76% |
| 386.20 | Gas Lights | 107,165 | 3,536 | 3.30% |
| **Total Assigned Property** | | $ 1,053,812,454 | $ 21,428,767 | 2.03% |
| **Allocated Property** | | | | |
| 375.00 | Structures and Improvements | | | |
| | District | $ - | $ - | 0.00% |
| | Maryland | 0 | 0 | 0.00% |
| | Virginia | 0 | 0 | 0.00% |
| | **Total Account 375.00** | $ - | $ - | 0.00% |
| 377.00 | Compressor Station Equipment | | | |
| | District | $ - | $ - | 0.00% |
| | Maryland | 0 | 0 | 0.00% |
| | Virginia | 0 | 0 | 0.00% |
| | **Total Account 377.00** | $ - | $ - | 0.00% |

**Washington Gas Light Company**
**OPC Recommended Depreciation Rates**
**Calculated By The Remaining Life Method**
**Based On Depreciable Plant In Service At December 31, 2023**

| | | Original Cost As Of December 31, 2023 | Recommended Annual Accrual Amount | Recommended Annual Accrual % |
|---|---|---|---|---|
| | Account (1) | (2) | (3) | (4) |
| 378.00 | Measuring and Regulating Equipment | | | |
| | District | $ - | $ - | 0.00% |
| | Maryland | 170,682 | 6,349 | 3.72% |
| | Virginia | 28,078 | 1,034 | 3.68% |
| | **Total Account 378.00** | $ 198,760 | $ 7,383 | 3.71% |
| | **Total Allocated Property** | $ 198,760 | $ 7,383 | 3.71% |
| | **Total Distribution Plant** | **$ 1,054,011,214** | **$ 21,436,150** | **2.03%** |
| **GENERAL PLANT** | | | | |
| **Allocated Property (Depreciable)** | | | | |
| 390.00 | Structures and Improvements | | | |
| | District | $ 607,056 | $ 12,748 | 2.10% |
| | Maryland | 5,474,473 | 114,965 | 2.10% |
| | Virginia | 20,131,767 | 424,781 | 2.11% |
| | **Total Account 390.00** | $ 26,213,296 | $ 552,494 | 2.11% |
| | **Total Allocated Property (Depreciable)** | $ 26,213,296 | $ 552,494 | 2.11% |
| **Assigned Property (Amortizable)** | | | | |
| 303.05 | Software - 5 year | $ 3,181,844 | $ 636,369 | 20.00% |
| 303.06 | Software (DC POR) - 10 year | 762,920 | 76,292 | 10.00% |
| 303.10 | Software - 10 year | 14,210,276 | 1,421,028 | 10.00% |
| 391.10 | Office Furniture and Equipment (DC POR) | 7,234 | 362 | 5.00% |
| 391.11 | Office Furniture and Equipment | 3,831,631 | 191,582 | 5.00% |
| 391.21 | Computer Equipment | 1,902,016 | 271,798 | 14.29% |
| 393.00 | Stores Equipment | 31,298 | 1,565 | 5.00% |
| 394.00 | Tools, Shop & Garage Equipment | 2,286,711 | 114,336 | 5.00% |
| 395.00 | Laboratory Equipment | 18,011 | 901 | 5.00% |
| 397.10 | Communication Equipment - Telephones | 7,532,335 | 0 | 0.00% |
| 397.20 | ENSCAN Equipment | 11,521,899 | 568,030 | 4.93% |
| 398.00 | Miscellaneous Equipment | 414,859 | 27,671 | 6.67% |
| | **Total Assigned Property (Amortizable)** | $ 45,701,034 | $ 3,309,934 | 7.24% |
| | **Total General Plant** | **$ 71,914,330** | **$ 3,862,428** | **5.37%** |
| | **TOTAL JURISDICTION** | **$ 1,202,074,531** | **$ 26,952,260** | **2.24%** |

**Comparison Of WGL And OPC Depreciation Models**
**Related To Gas Plant As Of December 31, 2023**

| | Account | Original Cost As Of December 31, 2023 | WGL Model Total Annual Accrual Amount[1] | WGL Model Total Annual Accrual Rate[2] | OPC Model Total Annual Accrual Amount[3] | OPC Model Total Annual Accrual Rate[3] | Delta Total Annual Accrual Amount | Delta Total Annual Accrual Rate |
|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) = (5)-(3) | (8) = (6)-(4) |
| **STORAGE AND PROCESSING PLANT** | | | | | | | | |
| **Allocated Property** | | | | | | | | |
| 361.00 | Structures and Improvements | | | | | | | |
| | Maryland (Rockville) | $ 1,311,110 | $ 32,778 | 2.50% | $ 32,778 | 2.50% | $ - | 0.00% |
| | Virginia (Ravensworth) | 1,183,946 | 29,954 | 2.53% | 29,954 | 2.53% | 0 | 0.00% |
| | **Total Account 361.00** | $ 2,495,056 | $ 62,732 | 2.51% | $ 62,732 | 2.51% | $ - | 0.00% |
| 362.00 | Gas Holders | | | | | | | |
| | Maryland (Rockville) | $ 4,460,885 | $ 61,560 | 1.38% | $ 61,560 | 1.38% | $ - | 0.00% |
| | Virginia (Ravensworth) | 3,676,243 | 66,172 | 1.80% | 66,172 | 1.80% | 0 | 0.00% |
| | **Total Account 362.00** | $ 8,137,128 | $ 127,732 | 1.57% | $ 127,732 | 1.57% | $ - | 0.00% |
| 363.50 | Other Equipment | | | | | | | |
| | Maryland (Rockville) | $ 818,973 | $ 18,754 | 2.29% | $ 18,754 | 2.29% | $ - | 0.00% |
| | Virginia (Ravensworth) | 604,207 | 20,060 | 3.32% | 20,060 | 3.32% | 0 | 0.00% |
| | **Total Account 363.50** | $ 1,423,180 | $ 38,814 | 2.73% | $ 38,814 | 2.73% | $ - | 0.00% |
| **Total Allocated Property** | | $ 12,055,364 | $ 229,278 | 1.90% | $ 229,278 | 1.90% | $ - | 0.00% |
| **Total Storage and Processing Plant** | | **$ 12,055,364** | **$ 229,278** | **1.90%** | **$ 229,278** | **1.90%** | **$ -** | **0.00%** |
| **TRANSMISSION PLANT** | | | | | | | | |
| **Assigned Property** | | | | | | | | |
| 365.20 | Rights of Way | $ - | $ - | 0.00% | $ - | 0.00% | $ - | 0.00% |
| 366.00 | Meas. and Reg. Station Structures | 0 | 0 | 0.00% | 0 | 0.00% | 0 | 0.00% |
| 367.10 | Mains - Steel | 4,258,093 | 52,374 | 1.23% | 52,374 | 1.23% | 0 | 0.00% |
| 369.00 | Measuring and Regulating Equipment | 7,874,665 | 113,395 | 1.44% | 113,395 | 1.44% | 0 | 0.00% |
| **Total Assigned Property** | | $ 12,132,758 | $ 165,769 | 1.37% | $ 165,769 | 1.37% | $ - | 0.00% |
| **Allocated Property** | | | | | | | | |
| 365.20 | Rights of Way | | | | | | | |
| | District | $ 470 | $ (21) | -4.47% | $ (21) | -4.47% | $ - | 0.00% |
| | Maryland | 803,227 | 11,245 | 1.40% | 11,245 | 1.40% | 0 | 0.00% |
| | Virginia | 401,040 | 2,928 | 0.73% | 2,928 | 0.73% | 0 | 0.00% |
| | **Total Account 365.20** | $ 1,204,737 | $ 14,152 | 1.17% | $ 14,152 | 1.17% | $ - | 0.00% |
| 366.00 | Meas. and Reg. Station Structures | | | | | | | |
| | Maryland | $ 499,988 | $ 15,700 | 3.14% | $ 15,700 | 3.14% | $ - | 0.00% |
| | Virginia | 3,153,657 | 71,588 | 2.27% | 71,588 | 2.27% | 0 | 0.00% |
| | **Total Account 366.00** | $ 3,653,645 | $ 87,288 | 2.39% | $ 87,288 | 2.39% | $ - | 0.00% |
| 367.10 | Mains - Steel | | | | | | | |
| | District | $ 1,833,775 | $ 33,008 | 1.80% | $ 33,008 | 1.80% | $ - | 0.00% |
| | Maryland | 11,899,374 | 185,631 | 1.56% | 185,631 | 1.56% | 0 | 0.00% |
| | Virginia | 15,473,955 | 270,794 | 1.75% | 270,794 | 1.75% | 0 | 0.00% |
| | **Total Account 367.10** | $ 29,207,104 | $ 489,433 | 1.68% | $ 489,433 | 1.68% | $ - | 0.00% |
| 369.00 | Measuring and Regulating Equipment | | | | | | | |
| | District | $ 599,848 | $ (4,798) | -0.80% | $ (4,798) | -0.80% | $ - | 0.00% |
| | Maryland | 13,331,810 | 905,230 | 6.79% | 905,230 | 6.79% | 0 | 0.00% |
| | Virginia | 3,963,721 | (232,670) | -5.87% | (232,670) | -5.87% | 0 | 0.00% |
| | **Total Account 369.00** | $ 17,895,379 | $ 667,762 | 3.73% | $ 667,762 | 3.73% | $ - | 0.00% |
| **Total Allocated Property** | | $ 51,960,865 | $ 1,258,635 | 2.42% | $ 1,258,635 | 2.42% | $ - | 0.00% |
| **Total Transmission Plant** | | **$ 64,093,623** | **$ 1,424,404** | **2.22%** | **$ 1,424,404** | **2.22%** | **$ -** | **0.00%** |
| **DISTRIBUTION PLANT** | | | | | | | | |
| **Assigned Property** | | | | | | | | |
| 375.00 | Structures and Improvements | $ - | $ - | 0.00% | $ - | 0.00% | $ - | 0.00% |
| 376.10 | Mains - Steel | 96,886,105 | 1,782,704 | 1.84% | 1,637,375 | 1.69% | (145,329) | -0.15% |
| 376.20 | Mains - Plastic | 454,106,167 | 12,079,224 | 2.66% | 8,900,481 | 1.96% | (3,178,743) | -0.70% |
| 376.30 | Mains - Cast Iron | 6,002,962 | 164,481 | 2.74% | 58,229 | 0.97% | (106,252) | -1.77% |
| 378.00 | Measuring and Regulating Equipment | 11,225,235 | 251,446 | 2.24% | 232,363 | 2.07% | (19,083) | -0.17% |
| 380.10 | Services - Steel | 53,992,928 | 1,252,636 | 2.32% | 1,214,841 | 2.25% | (37,795) | -0.07% |
| 380.20 | Services - Plastic | 357,615,007 | 9,691,367 | 2.71% | 7,474,154 | 2.09% | (2,217,213) | -0.62% |
| 380.30 | Services - Copper | 3,030,970 | 82,745 | 2.73% | 18,185 | 0.60% | (64,560) | -2.13% |
| 381.20 | Meters - Hard Case | 23,438,610 | 890,667 | 3.80% | 785,193 | 3.35% | (105,474) | -0.45% |
| 381.30 | Meters - Electronic Devices | 2,491,253 | 124,314 | 4.99% | 114,847 | 4.61% | (9,467) | -0.38% |
| 381.50 | Meters - Electronic Demand Recorders | 852,990 | 18,595 | 2.18% | (21,837) | -2.56% | (40,432) | -4.74% |
| 382.00 | Meter Installations | 35,599,234 | 800,983 | 2.25% | 758,264 | 2.13% | (42,719) | -0.12% |
| 383.00 | House Regulators | 4,735,146 | 211,187 | 4.46% | 187,512 | 3.96% | (23,675) | -0.50% |
| 384.00 | House Regulator Installations | 3,728,682 | 69,726 | 1.87% | 65,624 | 1.76% | (4,102) | -0.11% |
| 386.20 | Gas Lights | 107,165 | 4,994 | 4.66% | 3,536 | 3.30% | (1,458) | -1.36% |
| **Total Assigned Property** | | $ 1,053,812,454 | $ 27,425,069 | 2.60% | $ 21,428,767 | 2.03% | $ (5,996,302) | -0.57% |

**Comparison Of WGL And OPC Depreciation Models**
**Related To Gas Plant As Of December 31, 2023**

| Account | | Original Cost As Of December 31, 2023 | WGL Model Total Annual Accrual Amount[1] | WGL Model Total Annual Accrual Rate[2] | OPC Model Total Annual Accrual Amount[3] | OPC Model Total Annual Accrual Rate[3] | Delta Total Annual Accrual Amount | Delta Total Annual Accrual Rate |
|---|---|---|---|---|---|---|---|---|
| (1) | | (2) | (3) | (4) | (5) | (6) | (7) = (5)-(3) | (8) = (6)-(4) |
| **Allocated Property** | | | | | | | | |
| 375.00 | Structures and Improvements | | | | | | | |
| | District | $ - | $ - | 0.00% | $ - | 0.00% | $ - | 0.00% |
| | Maryland | 0 | 0 | 0.00% | 0 | 0.00% | 0 | 0.00% |
| | Virginia | 0 | 0 | 0.00% | 0 | 0.00% | 0 | 0.00% |
| | **Total Account 375.00** | $ - | $ - | | $ - | 0.00% | $ - | |
| 377.00 | Compressor Station Equipment | | | | | | | |
| | District | $ - | $ - | 0.00% | $ - | 0.00% | $ - | 0.00% |
| | Maryland | 0 | 0 | 0.00% | 0 | 0.00% | 0 | 0.00% |
| | Virginia | 0 | 0 | 0.00% | 0 | 0.00% | 0 | 0.00% |
| | **Total Account 377.00** | $ - | $ - | 0.00% | $ - | 0.00% | $ - | 0.00% |
| 378.00 | Measuring and Regulating Equipment | | | | | | | |
| | District | $ - | $ - | 0.00% | $ - | 0.00% | $ - | 0.00% |
| | Maryland | 170,682 | 6,349 | 3.72% | 6,349 | 3.72% | 0 | 0.00% |
| | Virginia | 28,078 | 1,034 | 3.68% | 1,034 | 3.68% | 0 | 0.00% |
| | **Total Account 378.00** | $ 198,760 | $ 7,383 | 3.71% | $ 7,383 | 3.71% | $ - | 0.00% |
| **Total Allocated Property** | | $ 198,760 | $ 7,383 | 3.71% | $ 7,383 | 3.71% | $ - | 0.00% |
| **Total Distribution Plant** | | **$ 1,054,011,214** | **$ 27,432,452** | **2.60%** | **$ 21,436,150** | **2.03%** | **$ (5,996,302)** | **-0.57%** |
| **GENERAL PLANT** | | | | | | | | |
| **Allocated Property (Depreciable)** | | | | | | | | |
| 390.00 | Structures and Improvements | | | | | | | |
| | District | $ 607,056 | $ 13,355 | 2.20% | $ 12,748 | 2.10% | $ (607) | -0.10% |
| | Maryland | 5,474,473 | 121,533 | 2.22% | 114,965 | 2.10% | (6,568) | -0.12% |
| | Virginia | 20,131,767 | 440,886 | 2.19% | 424,781 | 2.11% | (16,105) | -0.08% |
| | **Total Account 390.00** | $ 26,213,296 | $ 575,774 | 2.20% | $ 552,494 | 2.11% | $ (23,280) | -0.09% |
| **Total Allocated Property (Depreciable)** | | $ 26,213,296 | $ 575,774 | 2.20% | $ 552,494 | 2.11% | $ (23,280) | -0.09% |
| **Assigned Property (Amortizable)** | | | | | | | | |
| 303.05 | Software - 5 year | $ 3,181,844 | $ 636,369 | 20.00% | $ 636,369 | 20.00% | $ - | 0.00% |
| 303.06 | Software (DC POR) - 10 year | 762,920 | 76,292 | 10.00% | 76,292 | 10.00% | 0 | 0.00% |
| 303.10 | Software - 10 year | 14,210,276 | 1,421,028 | 10.00% | 1,421,028 | 10.00% | 0 | 0.00% |
| 391.10 | Office Furniture and Equipment (DC POR) | 7,234 | 362 | 5.00% | 362 | 5.00% | 0 | 0.00% |
| 391.11 | Office Furniture and Equipment | 3,831,631 | 191,582 | 5.00% | 191,582 | 5.00% | 0 | 0.00% |
| 391.21 | Computer Equipment | 1,902,016 | 271,798 | 14.29% | 271,798 | 14.29% | 0 | 0.00% |
| 393.00 | Stores Equipment | 31,298 | 1,565 | 5.00% | 1,565 | 5.00% | 0 | 0.00% |
| 394.00 | Tools, Shop & Garage Equipment | 2,286,711 | 114,336 | 5.00% | 114,336 | 5.00% | 0 | 0.00% |
| 395.00 | Laboratory Equipment | 18,011 | 901 | 5.00% | 901 | 5.00% | 0 | 0.00% |
| 397.10 | Communication Equipment - Telephones | 7,532,335 | 0 | 0.00% | 0 | 0.00% | 0 | 0.00% |
| 397.20 | ENSCAN Equipment | 11,521,899 | 683,249 | 5.93% | 568,030 | 4.93% | (115,219) | -1.00% |
| 398.00 | Miscellaneous Equipment | 414,859 | 27,671 | 6.67% | 27,671 | 6.67% | 0 | 0.00% |
| **Total Assigned Property (Amortizable)** | | $ 45,701,034 | $ 3,425,153 | 7.49% | $ 3,309,934 | 7.24% | $ (115,219) | -0.25% |
| **Total General Plant** | | **$ 71,914,330** | **$ 4,000,927** | **5.56%** | **$ 3,862,428** | **5.37%** | **$ (138,499)** | **-0.19%** |
| **TOTAL JURISDICTION** | | **$ 1,202,074,531** | **$ 33,087,061** | **2.75%** | **$ 26,952,260** | **2.24%** | **$ (6,134,801)** | **-0.51%** |

**Note:**
(1) Source: Exhibit WG (G)-2, page 19-22 (Statement B)
(2) Source: Exhibit WG (G)-2, page 17-18 (Statement A)
(3) Source: Exhibit OPC (E)-9

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 2

QUESTION NO. 2-28

**Q.** Please provide a detailed description of the property that is contained within Account 380.20-Services-Plastic. Please identify the plastic technology/material used for this property.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** Washington Gas installs polyethylene pipe meeting ASTM D2513-12, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings". The table provided in response to OPC Data Request 2-28 lists installed pipe sizes, pipe type (service or main) and corresponding material designation codes: PE2708 ("medium density") and PE4710 ("high density"). The listings are the typical types used. There may be special circumstances where high density pipe is used in a size where medium density would normally be used, and there are certain instances where certain pipe sizes are no longer used. These sizes have very small dollar amounts associated with them.

SPONSOR: Jacob Waller
Manager Codes and Standards

Formal Case 1180
OPC Data Request No. 2-28
Attachment 1
Page 1 of 1

| **Nominal Pipe Diameter** | **Size** | **Type** | **Pipe Designation Code** |
|---|---|---|---|
| Sleeves 6" and under | Iron Pipe Size (IPS) | Service-380 | PE2708 |
| 1/2 | Copper Tubing Size (CTS) | Service-380 | PE2708 |
| 3/4 | Iron Pipe Size (IPS) | Service-380 | PE2708 |
| 1 | Copper Tubing Size (CTS) | Service-380 | PE2708 |
| 1 | No-Longer Used | Main 376 | No-Longer Used |
| 1-1/2 | No-Longer Used | Service-380 | No-Longer Used |
| 1-1/2 | No-Longer Used | Main 376 | No-Longer Used |
| 1-1/4 | Copper Tubing Size (CTS) | Service-380 | PE2708 |
| 1-1/4 | Iron Pipe Size (IPS) | Service-380 | PE2708 |
| 2 | Iron Pipe Size (IPS) | Service- 380 or Main 376 | PE2708 |
| 2-1/2 | No-Longer Used | Service-380 | No-Longer Used |
| 3 | Iron Pipe Size (IPS) | Main (Typ.) Limited Services exist at these sizes | PE2708 |
| 4 | Iron Pipe Size (IPS) | Main (Typ.) Limited Services exist at these sizes | PE2708 |
| 6 | Iron Pipe Size (IPS) | Main (Typ.) Limited Services exist at these sizes | PE2708 |
| 8 | Iron Pipe Size (IPS) | Main (Typ.) Limited Services exist at these sizes | PE2708 |
| 10 | Iron Pipe Size (IPS) | Main-376 | PE4710 |
| 12 | Iron Pipe Size (IPS) | Main-376 | PE4710 |
| 12 | Iron Pipe Size (IPS) | Service-380 | PE4710 |
| 16 | Iron Pipe Size (IPS) | Main-376 | PE4710 |

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 2

QUESTION NO. 2-29

**Q.** Please identify the retirement units WGL utilizes for accounting purposes for Account 380.20. Additionally, please provide a spreadsheet that segregates the plant balance as of December 31, 2023 into those same retirement units.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** Please see the Excel spreadsheet provided with this response.

SPONSOR: Donald Preston
Manager of Fixed Asset Accounting

**Formal Case No. 1180**
**OPC Data Request No.2-29**
**Attachment 1**
**Page 1 of 1**

**District of Columbia**
**Account 380200**
**December 31, 2023**

| utility_account | retirement_unit | Total | |
|---|---|---|---|
| 380200 - Distr - Services - Plastic | 380201-Service Pipe Plastic 3/4" | 57,181,544 | |
| | 380202-Service Pipe Plastic 1 " | 38,042,091 | |
| | 380203-Service Pipe Plastic 1-1/4" | 71,281,170 | |
| | 380204-Service Pipe Plastic 1-1/2" | 895,954 | |
| | 380205-Service Pipe Plastic 2 " | 51,766,868 | |
| | 380206-Service Pipe Plastic 3 " | 5,541,245 | |
| | 380207-Service Pipe Plastic 4 " | 8,613,996 | |
| | 380208-Service Pipe Plastic 6 " | 1,191,431 | |
| | 380209-Service Pipe Plastic 8 " | 425,124 | |
| | 380211-Service Pipe Plastic 12 " | 28,008 | |
| | 380220-Service Pipe Plastic 2-1/2" | 94,287 | |
| | 380221-Service Pipe Plastic 1/2" | 35,903,898 | |
| | 380225-Service Sleeves -6" & Under | 5,974 | |
| | Non-unitized | 86,894,361 | 1/ |
| **380200 - Distr - Services - Plastic Total** | | **357,865,950** | |

1/ Non-Unitized Services are assets that were put into service and are depreciating.
at the time

Schedule D
Page 1 of 1

## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

**Distribution Plant**

**Account: 380.20 Services - Plastic**

T-Cut: None
Placement Band: 1953-2023
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 | 71.7 | 153.2 | R0.5 | 3.64 | 44.2 | R2 | 7.02 | 176.1 | R2.5 * | 3.40 |
| 1987-1991 | 51.1 | 97.7 | L0.5 | 16.57 | 49.5 | S1 | 12.90 | 110.2 | O3 * | 13.73 |
| 1988-1992 | 53.4 | 110.6 | S-.5 | 12.86 | 51.7 | S1.5 | 8.76 | 44.9 | R2.5 | 7.16 |
| 1989-1993 | 7.5 | 95.8 | L1 | 31.05 | 78.9 | S0.5 | 30.62 | 37.5 | R3 * | 17.84 |
| 1990-1994 | 7.7 | 94.7 | L0.5 | 32.12 | 107.9 | L0 | 32.28 | 36.1 | R4 * | 15.11 |
| 1991-1995 | 28.8 | 110.6 | S-.5 | 35.32 | 73.6 | S0.5 | 34.33 | 37.5 | R4 * | 22.07 |
| 1992-1996 | 0.0 | 134.9 | R0.5 | 16.37 | 59.9 | R2 | 13.56 | 38.4 | R4 | 10.99 |
| 1993-1997 | 0.0 | 163.7 | R1* | 14.18 | 83.9 | R1.5 | 13.48 | 39.8 | R3 | 11.25 |
| 1994-1998 | 0.0 | 142.6 | SC | 47.10 | 65.1 | R1.5 | 45.12 | 37.7 | R3 | 31.83 |
| 1995-1999 | 0.0 | 110.6 | S-.5 | 18.82 | 53.9 | R2 | 15.19 | 37.1 | R4 * | 12.58 |
| 1996-2000 | 0.0 | 89.4 | L0.5 | 17.65 | 52.4 | S1.5 | 14.43 | 37.7 | R4 * | 11.64 |
| 1997-2001 | 0.0 | 78.1 | L1 | 12.16 | 49.4 | S1.5 | 9.62 | 38.5 | R4 * | 12.25 |
| 1998-2002 | 0.0 | 74.9 | L1 | 13.12 | 49.4 | S1.5 | 9.90 | 39.6 | R4 * | 8.68 |
| 1999-2003 | 0.0 | 72.4 | L1* | 11.47 | 52.0 | S1.5 | 9.84 | 43.4 | R3 * | 8.72 |
| 2000-2004 | 56.4 | 71.2 | L1* | 4.36 | 51.2 | S1.5 | 3.71 | 43.8 | R3 * | 3.18 |
| 2001-2005 | 74.5 | 80.1 | L1* | 2.30 | 56.0 | S1.5 | 1.65 | 49.5 | R3 | 1.37 |
| 2002-2006 | 71.2 | 89.1 | L1 | 2.91 | 61.8 | S1.5 | 2.45 | 52.4 | R3 | 2.16 |
| 2003-2007 | 74.4 | 84.3 | L1 | 2.52 | 61.5 | S1.5 | 2.03 | 50.0 | R3 * | 1.56 |
| 2004-2008 | 74.9 | 83.6 | L1 | 2.18 | 59.6 | S1.5 | 1.56 | 48.4 | R3 * | 0.85 |
| 2005-2009 | 65.2 | 86.2 | L0.5 | 3.58 | 61.4 | S1 | 3.10 | 47.3 | R3 * | 2.11 |
| 2006-2010 | 67.7 | 85.8 | L0.5 | 2.62 | 60.4 | R1.5 | 2.09 | 48.6 | R2.5 | 1.40 |
| 2007-2011 | 65.6 | 83.5 | L0.5 | 2.24 | 64.2 | S0.5 | 1.89 | 51.2 | R2.5 | 1.48 |
| 2008-2012 | 70.4 | 94.4 | L0 | 2.00 | 69.0 | S0.5 | 1.65 | 56.5 | R2 | 1.49 |
| 2009-2013 | 67.6 | 102.6 | L0.5 | 2.56 | 77.0 | S0.5 | 2.31 | 62.3 | R2 | 2.17 |
| 2010-2014 | 70.1 | 97.6 | L1 | 2.38 | 75.3 | S0.5 | 2.09 | 69.5 | R2 | 2.04 |
| 2011-2015 | 64.9 | 93.2 | L1 | 3.08 | 76.5 | S1 | 2.84 | 64.4 | R2.5 | 2.64 |
| 2012-2016 | 62.6 | 101.5 | L1 | 3.68 | 73.9 | S1 | 3.29 | 59.5 | R3 | 2.75 |
| 2013-2017 | 59.3 | 99.1 | L1 | 3.95 | 71.9 | S1.5 | 3.52 | 61.3 | R3 | 3.10 |
| 2014-2018 | 69.8 | 101.5 | L1 | 2.49 | 74.0 | S1.5 | 2.06 | 65.9 | R2.5 | 1.84 |
| 2015-2019 | 70.1 | 99.6 | L1 | 2.06 | 72.9 | S1.5 | 1.62 | 64.6 | R2.5 | 1.34 |
| 2016-2020 | 78.2 | 110.8 | S-.5 | 1.10 | 80.2 | S1 | 0.70 | 71.7 | R2.5 | 0.58 |
| 2017-2021 | 81.7 | 113.2 | L1 | 0.65 | 85.7 | S1 | 0.31 | 158.0 | R0.5 * | 0.42 |
| 2018-2022 | 84.4 | 117.3 | S0 | 0.61 | 89.4 | S1 | 0.24 | 87.8 | S1.5 | 0.25 |
| 2019-2023 | 84.5 | 123.1 | S0 | 0.33 | 101.3 | S1 | 0.23 | 84.6 | R2.5 | 0.25 |

## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

**Distribution Plant**

**Account: 380.20 Services - Plastic**

T-Cut: None

Placement Band: 1953-2023

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 | 78.2 | 105.1 | L0.5 | 0.26 | 99.8 | L1 | 0.30 | 154.5 | R0.5 * | 0.23 |
| 1988-2023 | 78.3 | 104.6 | L0.5 | 0.27 | 101.0 | L1 | 0.29 | 155.1 | R0.5 * | 0.22 |
| 1990-2023 | 78.3 | 104.3 | L0.5 | 0.27 | 103.0 | L1 | 0.28 | 152.4 | SC * | 0.22 |
| 1992-2023 | 78.4 | 104.3 | L0.5 | 0.28 | 101.4 | L1 | 0.30 | 156.2 | R0.5 * | 0.22 |
| 1994-2023 | 78.3 | 104.4 | L0.5 | 0.27 | 102.7 | L1 | 0.29 | 154.0 | SC * | 0.22 |
| 1996-2023 | 78.4 | 104.1 | L0.5 | 0.29 | 103.2 | L1 | 0.29 | 155.8 | R0.5 * | 0.23 |
| 1998-2023 | 78.5 | 103.4 | L1 | 0.31 | 106.2 | L0.5 | 0.29 | 157.4 | R0.5 * | 0.23 |
| 2000-2023 | 78.7 | 103.9 | L1 | 0.30 | 104.9 | L0.5 | 0.29 | 156.9 | R0.5 * | 0.23 |
| 2002-2023 | 78.9 | 105.2 | L1 | 0.27 | 100.1 | L1 | 0.31 | 152.7 | SC * | 0.23 |
| 2004-2023 | 79.2 | 106.5 | L1 | 0.27 | 96.0 | S0 | 0.32 | 147.4 | SC * | 0.25 |
| 2006-2023 | 79.1 | 107.4 | L0.5 | 0.26 | 97.4 | S0 | 0.29 | 117.9 | SC * | 0.27 |
| 2008-2023 | 79.5 | 108.6 | S-.5 | 0.27 | 95.9 | S0 | 0.28 | 109.8 | L0.5 * | 0.27 |
| 2010-2023 | 80.6 | 111.6 | S-.5 | 0.32 | 91.7 | S0.5 | 0.29 | 133.4 | SC * | 0.24 |
| 2012-2023 | 81.4 | 113.5 | L1 | 0.39 | 90.6 | S1 | 0.30 | 104.8 | L1 * | 0.27 |
| 2014-2023 | 81.6 | 113.2 | L1 | 0.42 | 89.9 | S1 | 0.32 | 124.2 | SC * | 0.27 |
| 2016-2023 | 82.7 | 120.9 | S-.5 | 0.50 | 91.6 | S1 | 0.25 | 82.9 | R2 | 0.30 |
| 2018-2023 | 84.5 | 122.7 | S0 | 0.37 | 99.3 | S1 | 0.22 | 89.2 | R2 | 0.23 |
| 2020-2023 | 86.9 | 139.3 | R1 | 0.45 | 111.7 | S1 | 0.37 | 78.9 | R3 | 0.27 |
| 2022-2023 | 85.6 | 136.0 | R1 | 0.66 | 114.9 | S0.5 | 0.70 | 76.3 | R3 * | 0.65 |

**Schedule D**
**Page 1 of 1**

## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

**Distribution Plant**

**Account: 380.20 Services - Plastic**

T-Cut: None
Placement Band: 1953-2023
Hazard Function: Proportion Retired
Weighting: Exposures

**Progressing Band Life Analysis**

| Observation Band | Censoring | First Degree Average Life | First Degree Disper-sion | First Degree Conf. Index | Second Degree Average Life | Second Degree Disper-sion | Second Degree Conf. Index | Third Degree Average Life | Third Degree Disper-sion | Third Degree Conf. Index |
|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K |
| 1986-1987 | 93.1 | 174.6 | R2* | 1.60 | 155.5 | R1 | 1.68 | 35.1 | R3 | 11.10 |
| 1986-1989 | 90.5 | 181.2 | R3* | 3.83 | 39.6 | R2 | 13.31 | 177.3 | R2.5 * | 4.58 |
| 1986-1991 | 50.7 | 117.7 | SC | 16.97 | 50.3 | S1 | 13.24 | 42.8 | R2.5 | 11.71 |
| 1986-1993 | 57.2 | 136.8 | SC | 14.31 | 55.6 | R2 | 10.69 | 40.3 | R3 | 6.52 |
| 1986-1995 | 23.4 | 131.1 | SC | 36.38 | 62.0 | S1 | 33.78 | 39.7 | R3 | 25.26 |
| 1986-1997 | 0.0 | 149.9 | R0.5 | 15.85 | 77.7 | R1.5 | 14.74 | 42.2 | R3 | 8.38 |
| 1986-1999 | 0.0 | 112.6 | SC | 20.47 | 56.1 | R2 | 16.69 | 38.3 | R3 | 8.41 |
| 1986-2001 | 0.0 | 90.9 | L0.5 | 18.81 | 51.0 | S1.5 | 14.40 | 38.8 | R3 | 8.46 |
| 1986-2003 | 0.0 | 85.3 | L0.5 | 18.65 | 52.6 | S1.5 | 15.17 | 41.8 | R3 | 10.01 |
| 1986-2005 | 0.0 | 87.9 | L1 | 17.15 | 55.6 | S1.5 | 14.91 | 45.2 | R3 | 12.28 |
| 1986-2007 | 0.0 | 87.5 | L1 | 16.94 | 58.0 | S1 | 15.32 | 47.5 | R3 | 13.47 |
| 1986-2009 | 0.0 | 84.0 | L1 | 16.89 | 58.6 | S1 | 15.57 | 47.9 | R3 | 13.90 |
| 1986-2011 | 0.0 | 85.8 | L0.5 | 11.93 | 62.2 | S1 | 11.25 | 52.6 | R2.5 | 10.71 |
| 1986-2013 | 67.3 | 91.2 | L0.5 | 2.16 | 70.1 | S0.5 | 1.71 | 63.1 | R2 | 1.59 |
| 1986-2015 | 61.9 | 89.9 | L1 | 3.02 | 69.7 | S0.5 | 2.47 | 61.6 | R2 | 2.24 |
| 1986-2017 | 57.2 | 93.5 | L0.5 | 3.60 | 72.2 | S0.5 | 3.05 | 63.3 | R2 | 2.79 |
| 1986-2019 | 67.3 | 94.1 | L0.5 | 1.96 | 74.2 | S0.5 | 1.37 | 67.3 | R2 | 1.20 |
| 1986-2021 | 76.2 | 100.2 | L0.5 | 0.47 | 85.9 | S0 | 0.25 | 129.7 | SC * | 0.31 |
| 1986-2023 | 78.2 | 105.1 | L0.5 | 0.26 | 99.8 | L1 | 0.30 | 154.5 | R0.5 * | 0.23 |

## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

**Distribution Plant**

**Account: 380.20 Services - Plastic**

**T-Cut: None**

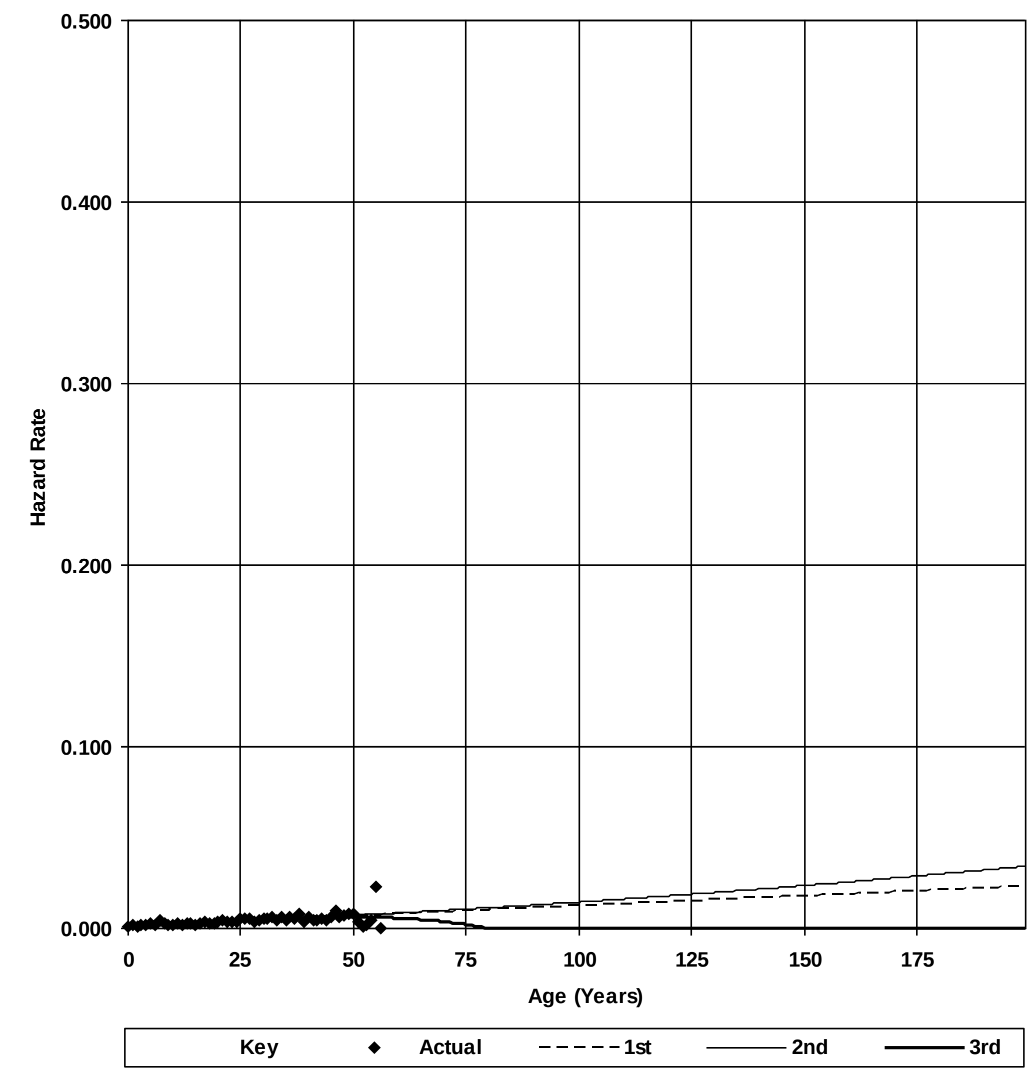
**Placement Band: 1953-2023 Observation Band: 1986-2023**

**Hazard Function: Proportion Retired**

**Weighting: Exposures**

### Polynomial Hazard Functions

**1st: 105.1-L0.5 2nd: 99.8-L1 3rd: 154.5-R0.5**



**Schedule E**
**Page 1 of 1**

## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

**Distribution Plant**

**Account: 380.20 Services - Plastic**

**T-Cut: None**

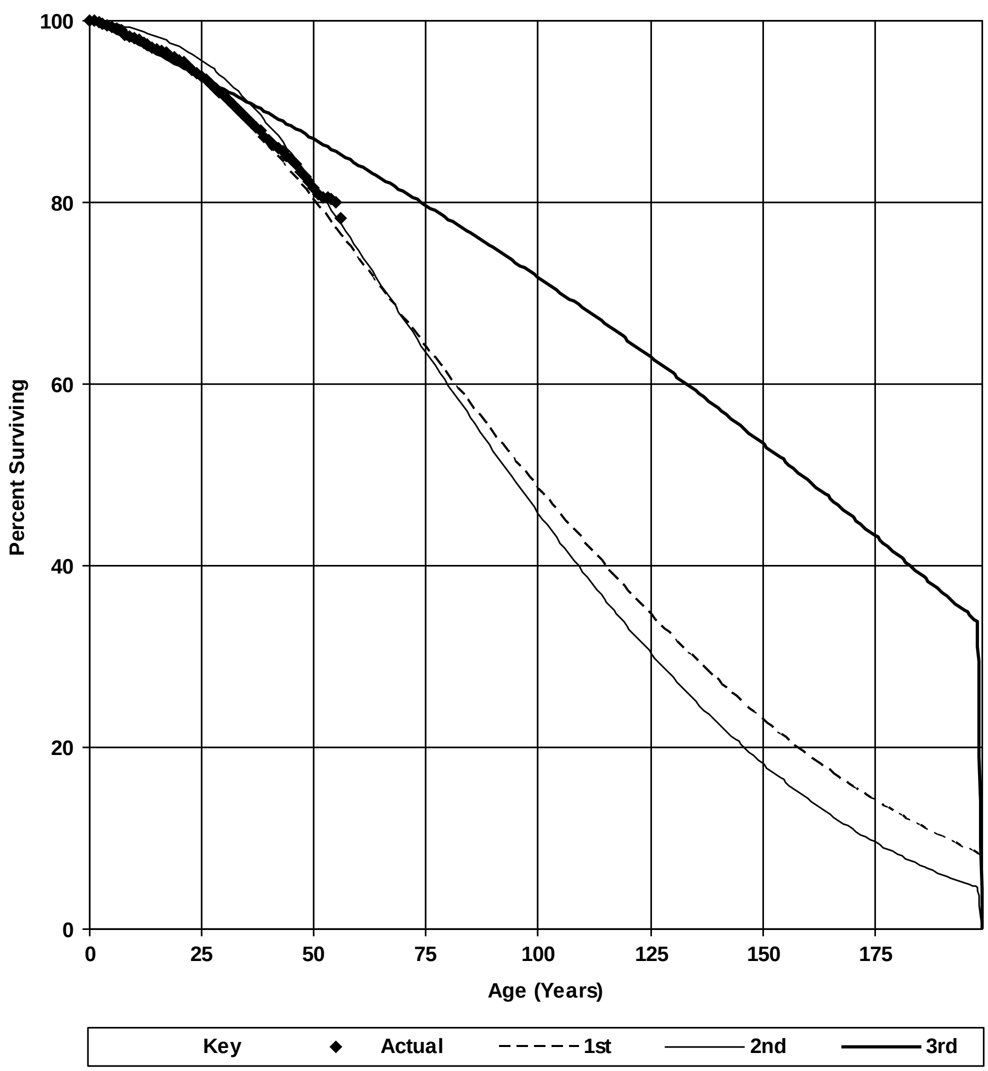
**Placement Band: 1953-2023 Observation Band: 1986-2023**

**Hazard Function: Proportion Retired**

**Weighting: Exposures**

**Survivorship Functions**

**1st: 105.1-L0.5 2nd: 99.8-L1 3rd: 154.5-R0.5**



## WASHINGTON GAS LIGHT - DISTRICT OF COLUMBIA

**Distribution Plant**

**Account: 380.20 Services - Plastic**

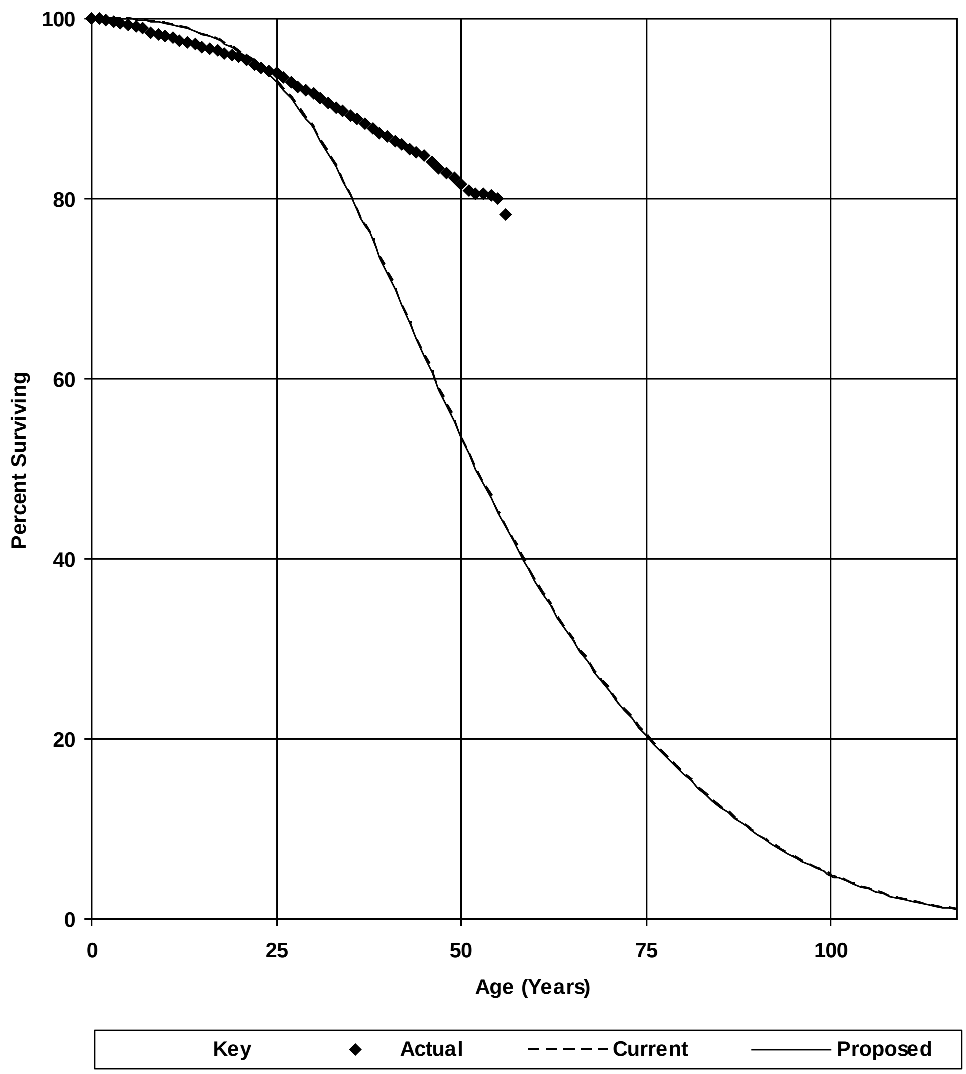
**T-Cut: None**

**Placement Band: 1953-2023**

**Observation Band: 1986-2023**

**Projection Life Curves**

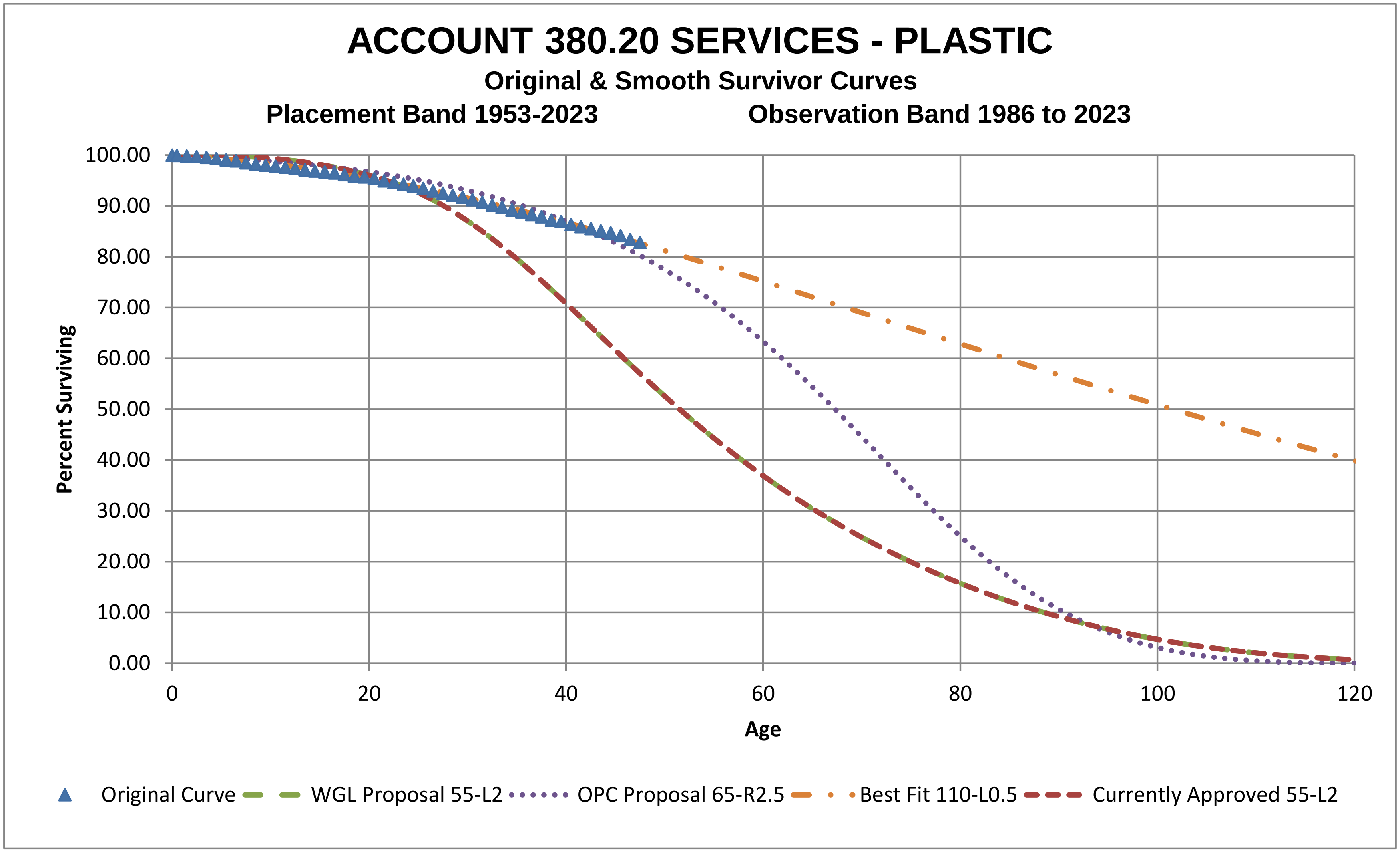
**Current: 55.0-L2** **Proposed: 55.0-L2**



## Account 380.2 Fitting Analysis Results

| Iowa Curve | Average Service Life | SSD |
|---|---|---|
| L0.5 | 109.9 | 2.2 |
| L0 | 132.9 | 5.7 |
| R1.5 | 84.4 | 6.6 |
| S0 | 94.2 | 9.2 |
| R2 | 72.2 | 15.1 |
| R1 | 101.9 | 27.9 |
| S0.5 | 82.4 | 39.5 |
| L1 | 93.4 | 44.9 |
| R0.5 | 129.0 | 53.8 |
| O2 | 179.8 | 68.2 |
| O1 | 160.5 | 68.4 |
| O3 | 260.0 | 71.7 |
| R2.5 | 65.0 | 73.1 |
| O4 | 358.7 | 73.5 |
| L1.5 | 82.0 | 95.9 |
| S1 | 73.8 | 142.4 |
| S1.5 | 67.9 | 234.5 |
| R3 | 59.9 | 234.6 |
| L2 | 73.4 | 259.5 |
| L2.5 | 67.5 | 355.0 |
| R3.5 | 56.9 | 399.1 |
| S2 | 63.4 | 432.7 |
| S2.5 | 60.3 | 568.8 |
| L3 | 62.8 | 590.6 |
| R4 | 54.6 | 677.2 |
| S3 | 57.7 | 824.6 |
| L4 | 55.9 | 944.7 |
| S4 | 53.6 | 1,410.5 |
| R5 | 51.5 | 1,498.9 |
| L5 | 52.6 | 1,545.7 |
| S5 | 51.2 | 1,991.8 |
| S6 | 49.8 | 2,510.4 |

| | |
|---|---|
| WGL Proposal 55-L2 | 4,813 |
| Currently Approved 55-L2 | 4,813 |
| OPC Proposal 65-R2.5 | 73 |


ACCOUNT 380.20 SERVICES - PLASTIC
Original & Smooth Survivor Curves
Placement Band 1953-2023
Observation Band 1986 to 2023
Percent Surviving
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
20
40
60
80
100
120
Age
Original Curve
WGL Proposal 55-L2
OPC Proposal 65-R2.5
Best Fit 110-L0.5
Currently Approved 55-L2

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

WASHINGTON GAS LIGHT COMPANY

FORMAL CASE NO. 1180

WASHINGTON GAS'S RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY TO
THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 2

QUESTION NO. 2-32

**Q.** Please provide a detailed narrative of the O&M programs that affect the property in Account 380.20. Please explain if these programs have been newly implemented in the last 10-years.

**WASHINGTON GAS'S RESPONSE** 10/04/2024

**A.** The Company does not have any specific O&M programs related to the property in Account 380.2. Please refer to OPC Data Request 2-31 for the Company's response on the replacement program for property in Account 380.2.

SPONSOR: Donald Preston
Manager of Fixed Asset Accounting

## CERTIFICATE OF SERVICE

**Formal Case No. 1180, In the Matter of the Application of Washington Gas Light Company for the Authority to Increase Existing Rates and Charges for Gas Service**

I certify that on January 24, 2025, a copy of the *Office of People's Counsel for the District of Columbia's Public Direct Testimony of OPC Witnesses, Exhibits OPC (A) – (E)* was served on the following parties of record by hand delivery, first class mail, postage prepaid or electronic mail:

Brinda Westbrook-Sedgwick
Commission Secretary
Christopher Lipscombe
General Counsel
Public Service Commission of the District of Columbia
1325 G Street, NW, Suite 800
Washington, DC 20005
bwestbrook@psc.dc.gov
CLipscombe@psc.dc.gov

Brian Caldwell
Assistant Attorney General
Office of the Attorney General
for the District of Columbia
400 6th Street, N.W., 10th floor
Washington, DC 20001
Brian.caldwell@dc.gov

Alec Bowman
Associate Attorney
Office of the Attorney General for the District of Columbia
Public Advocacy Division Housing and Environmental Justice Section
400 6th Street, N.W., 10th Floor
Washington, D.C. 20001
Alec.Bowman@dc.gov

Cathy Thurston-Seignious
Supervisor, Administrative and Associate General Counsel
John Dodge
Associate General Counsel
Washington Gas Light Company
1000 Maine St. SW, Suite 700
Washington, DC 20024
Cthurstoneignious@washgas.com
Jdodge@washgas.com

Frann G. Francis
Apartment and Office Building Assoc.
1025 Connecticut Ave. NW, Suite 1005
Washington, DC 20036
ffrancis@aoba-metro.org

Lariza Sepulveda
Economist
Assistant General Counsel
Public Utility Rates and Regulations
Energy Division, U.S. GSA
1800 F Street, NW, Room 5122
Washington, DC 20405
Lariza.Sepulveda@gsa.gov

Dennis Goins
Potomac Management Group
On behalf of the United States General Services Administration
P.O. Box 3022
Alexandria, Virginia 22310
dgoinspmg@verizon.net

Timothy Oberleiton
Susan Miller
Earthjustice on behalf of Sierra Club
1001 G St. NW, Ste. 1000
Washington, D.C. 20001
Toberleiton@earthjustice.org
smiller@earthjustice.org

*/s/ Ade Adeniyi*
Ade Adeniyi
Assistant People's Counsel