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PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
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WASHINGTON, D.C. 20005

ORDER

December 20, 2019

FORMAL CASE NO. 1156, 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, Order No. 20273

Before the Commission:

Willie L. Phillips, Chairman
Richard Beverly, Commissioner
Greer Gillis, Commissioner

EXECUTIVE SUMMARY

1. The District of Columbia Public Service Commission ("Commission"), in this Order, establishes a framework for alternative forms of regulation ("AFORs") in the District of Columbia. As a result of restructuring of the District's energy market, the Council of the District of Columbia granted authority to the Commission to utilize AFORs provided we find that the regulation protects consumers, ensures quality, availability and reliability of regulated services and is in the public interest of ratepayers and shareholders.

2. Historically, the Commission has been setting distribution rates through a traditional cost of service model based on a historical test year. Since the expiration of its rate freeze in 2004, the Potomac Electric Power Company ("Pepco") has filed seven electric distribution rate cases, approximately one every two years, which cost ratepayers an average of $3 million per rate case in litigation expenses for Pepco, the Commission, and the Office of the People's Counsel ("OPC"). These cases were driven in part by a need for increased investment in the electric distribution system to provide increasing reliability to District ratepayers. In July 2017, in *Formal Case No. 1139*, the Commission, recognizing the frequency and costs of traditional utility regulation as well as distributed energy resources and grid modernization in the District, indicated that it would allow Pepco to include in its next rate case a request for a fully forecasted test year and/or a multi-year rate proposal.

3. Parallel to these rate cases, the Commission, in conjunction with *Formal Case No. 1130* stakeholders, has worked to identify technologies and policies that can be implemented in the District to modernize the distribution energy delivery system for increased sustainability ("PowerPath DC" formerly called "MEDSIS"). This effort focuses on empowering customers and facilitating the deployment of distributed energy resources such as solar facilities, as well as addressing the environmental impacts of energy consumption. These efforts are linked to the District of Columbia's energy and climate action policies as articulated in the Clean Energy DC Plan and embodied in the CleanEnergy DC Omnibus Amendment Act of 2018 ("CleanEnergy DC Act"). With these efforts the District is positioned as a national leader in sustainability, resiliency, and environmental conservation, with the most aggressive renewable energy standards in the country, and has leadership dedicated to combating the effects of global climate change and realizing a clean energy future.

4. As the utility regulator, we embrace our important role in helping the District achieve a clean energy future, and we view alternative forms of regulation as a potential tool in assisting the District in achieving its clean energy and environmental goals to the benefit of District residents and ratepayers. The Commission has long recognized that other forms of regulation may facilitate achieving the District's aggressive goals regarding greenhouse gas emission reductions, transportation electrification, renewable energy development, grid modernization, and other District goals. While the Commission recognizes these potential benefits, the Commission is also concerned that the adoption of any alternative form of regulation protects consumers, ensures the quality, availability, and reliability of regulated utility services, and is in the interest of the public, including shareholders of the utility.

5. Broadly speaking, the Commission agrees with the District of Columbia Government ("DCG"), GRID2.0 Working Group/DC Consumer Utility Board ("GRID2.0/DC

CUB"), and DC Climate Action ("DCCA") that AFORs present risks and opportunities. Any change in the ratemaking process presents risks; however, the District's ambitious clean energy and climate goals require the Commission to explore new tools to achieve those objectives. Further, the Commission agrees with DCG, that "if designed well, multiyear rate plans ("MRPs") can provide benefits to customers and help achieve public policy goals." The Commission also agrees with GRID2.0/DC CUB's statement that "[a]lternative ratemaking tools need to be evaluated from the standpoint of the fundamental and transformational kinds of changes in the electricity system that were addressed in the MEDSIS proceeding and that are reflected in the MEDSIS Vision Statement and Principles." Further, the Commission agrees with GRID 2.0/DC CUB, DCG, as well as the conclusion of the *Formal Case No. 1130*, Rate Design Working Group, that properly designed Performance Incentive Mechanisms ("PIMs") represent an important tool to align utility incentives with public policy goals, such as the District's aggressive clean energy and environmental goals.

6. It is in furtherance of the District's clean energy goals and the Commission's PowerPath DC objectives, that the Commission, in this Order, establishes the framework for AFORs in the District of Columbia to explore new tools to achieve those objectives, while also preserving a high standard of energy delivery system reliability and fostering grid modernization. This Order sets forth the overarching policy concerns and framework principles for developing AFORs. Although this framework sets the Commission's starting point for an evolving evaluation process to be reviewed in the future as the public interest requires, the framework adopted in this Order will be used to evaluate Pepco's proposed MRP/PIMs proposal in this proceeding. The Commission believes, like the Hawaii Public Utilities Commission, that the framework described in this Order will provide for better alignment of a utility's financial incentives with customer needs and the District's policy goals. Based on the record and our review of other state proceedings, we establish the overarching framework principles as follows for a utility seeking AFOR treatment. A utility's AFOR application shall provide information as to how:

(1) The AFOR: (A) protects consumers; (B) ensures the quality, availability, and reliability of regulated utility services; and (C) is in the interest of the public, including shareholders of the utility;

(2) The AFOR advances the public safety, the economy of the District, the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments;

(3) The AFOR's ratemaking mechanisms advance or otherwise align with the District's public policy goals;

(4) The AFOR identifies baseline revenue and cost information, and clearly explains what process or mechanism the utility used to project revenues and expenses;

(5) The AFOR provides benefits that are measurable, quantitative, and qualitative to customers, as opposed to solely focusing on the AFORs benefits to the utility;

(6) The AFOR impacts the operational incentives of the utility with respect to maintaining a high level of customer service, while fostering productivity and cost control; maintains the financial strength, credit ratings, and financial flexibility of the utility; and helps ensure a consistently high level

of energy delivery system reliability, while promoting safe and reliable operations over time;

(7) The revenue requirements will be allocated across customer classes over time, and how rate design issues within customer classes will be handled over time, in a just and reasonable manner;

(8) The risk of over-earning a utility's authorized return will be mitigated during the duration of AFOR for the benefit of the customers, while also preserving the Commission's ability to conduct cost prudency reviews as needed;

(9) The AFOR provides an appropriate level of transparency and reporting into the utility's operational and capital plans ensuring that the plans will be maintained during the duration of the AFOR; and

(10) The AFOR avoids any unreasonable shifting of risk to utility customers.

7. Consistent with this framework and after reviewing the record, the Commission believes that a properly constructed MRP can produce just and reasonable rates and can be pursued at this time. Evaluating a MRP will entail all the same challenges as evaluating a general rate case but with the added challenge of setting rates that will be adjusted over time. We believe a rate case will provide the best foundation for meeting these challenges. Thus, we will address Pepco's overall MRP/PIM rate application in this proceeding. Pepco has provided all the requirements for a traditional rate case as well as its proposal for a MRP/PIM. As the proponent of a rate increase, Pepco has the burden of proof to demonstrate that its MRP/PIM proposal can be approved and adopted at this time.

8. The Commission's mission is to ensure that public utilities provide safe and reliable services to customers at just and reasonable rates. Pursuant to D.C. Code § 34-808.02, in supervising and regulating utility or energy companies, the Commission "shall consider the public safety, the economy of the District, the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments." This Order is a further step in the Commission fulfilling its statutory mission.

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I. INTRODUCTION

1. By this Order, the Public Service Commission of the District of Columbia ("Commission") establishes a framework for Alternative Forms of Regulation ("AFORs") in the District of Columbia. Paragraph 94 of this Order sets forth the overarching framework principles for a utility seeking AFOR treatment. Consistent with Paragraph 99 of this Order, the Commission directs the Potomac Electric Power Company ("Pepco") to file Supplemental Direct Testimony by January 21, 2020, and directs the Parties to file their Direct Testimony by February 19, 2020. In addition, consistent with Paragraph 106 of this Order, the Commission directs Pepco, the District of Columbia Government ("DCG"), and the Office of the People's Counsel of the District of Columbia ("OPC") to convene and facilitate three meetings with Parties and PowerPath DC participants. The three meetings shall occur between January 15, 2020, and March 31, 2020, to discuss what are achievable Performance Incentive Mechanisms ("PIMs") in this rate case and what information is suitable for tracking for future PIM development. Lastly, the Commission grants DC Climate Action's motion to file comments out of time.

II. BACKGROUND OF FORMAL CASE NO. 1156

2. On May 30, 2019, Pepco filed an Application for approval to increase rates for its electric distribution service in the District of Columbia ("District") ("Application")[1] under two different rate setting methodologies pursuant to Commission directives in Order No. 18846:[2] (1) a Multiyear Rate Plan ("MRP") proposal with appropriate PIMs; and (2) a traditional cost-of-service plan.

3. On June 13, 2019, the Commission issued a Public Notice and Order No. 19956, opening *Formal Case No. 1156* and directing petitions for intervention to be filed by June 19, 2019, with any oppositions to be filed by June 24, 2019.[3] On June 21, 2019, a Public Notice of Pepco's Application was published in the *D.C. Register*.[4] On June 27, 2019, by Order No. 19966, the Commission granted intervenor status to U.S. General Services Administration ("GSA"), DCG, the District of Columbia Water and Sewer Authority ("DC Water"), Washington Gas Light Company ("WGL"), the Apartment and Office Building Association of Metropolitan Washington ("AOBA"), International Brotherhood of Electrical Workers, Local Union 1900 ("IBEW"), the Laborers' International Union of North America by and through Baltimore Washington Construction and Public Employees Laborers' District Council ("BWLDC"), the Small Business

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1 *Formal Case No. 1156, 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 ("Formal Case No. 1156"),* Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service, Exhibit (B) at 50, filed May 30, 2019.

2 *See 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, rel. July 25, 2017 ("Order No. 18846").

3 *Formal Case No. 1156*, Order No. 19956, rel. June 13, 2019 ("Order No. 19956").

4 66 *D.C Reg.* 7573-7577 (June 21, 2019).

Utility Advocates ("SBUA"), and the Maryland DC Virginia Solar Energy Industries Association ("MDV-SEIA") (collectively referred to as the "Parties").[5]

4. On August 9, 2019, the Commission, in Order No. 20204, established a procedural schedule for this case including a two-day technical conference on the establishment of a framework for evaluating alternative rate regulation proposals.[6] The Commission stated that "[p]art of this technical conference will involve identifying alternative ratemaking approaches, including PIMs, that further the Commission's MEDSIS goals and the District's energy related objectives, such as transportation electrification, renewable energy development, pipeline replacement, development of new consumer solutions, grid resiliency and others laid out in the Clean Energy DC Plan" and directed "parties to identify how any PIMs they support or propose advance the MEDSIS Vision and District's goals as part of their submission and subsequent testimony."[7] Further, the Commission directed Parties and other interested persons to file comments on the Technical Conference by November 1, 2019, after which the Commission will issue a Policy Order on a framework for alternative forms of regulation in the District of Columbia.[8]

5. On September 18, 2019, the Commission issued a Public Notice that was subsequently amended on September 26, 2019, inviting all parties and interested persons to participate in the Technical Conference to be held at the Commission on October 17-18, 2019 by registering with the Commission Secretary and "to identify any additional questions or issues related to alternative form[s] of regulation of public utilities or a framework for evaluating alternative ratemaking proposals, which they believe should be discussed at the Technical Conference."[9] AARP District of Columbia ("AARP DC") was the only interested person to register to participate in the Technical Conference. No party or interested person identified any additional questions or issues related to AFORs of public utilities or a framework for evaluating alternative ratemaking proposals which they believe should be discussed at the Technical Conference.

6. Following the Technical Conference, the Commission Staff, on October 24, 2019, filed the Presentations and Other Materials Gathered By Commission Staff during the course of the Technical Conference.[10] On November 1, 2019, AARP DC, AOBA, SBUA, GSA, IBEW

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5 *Formal Case No. 1156*, Order No. 19966, rel. June 27, 2019.

6 *Formal Case No. 1156*, Order No. 20204, rel. August 9, 2019 ("Order No. 20204").

7 *See Formal Case No. 1156*, Public Notice, rel. September 18, 2019; *Formal Case No. 1156*, Amended Public Notice, ¶ 2, rel. September 26, 2019; *see also Formal Case No. 1156*, Order No. 20204, ¶32.

8 *Formal Case No. 1156*, Order No. 20204, Attachment A.

9 *Formal Case No. 1156*, Public Notice, rel. September 18, 2019; *Formal Case No. 1156*, Amended Public Notice, ¶¶ 5-6, rel. September 26, 2019.

10 *Formal Case No. 1156*, Filing of Presentations and Other Materials Gathered by Commission Staff during the course of the Technical Conference on October 17 and 18, 2019, filed October 24, 2019. These included: (1) Presentation by David Littell, The Regulatory Assistance Project (October 17, 2019) ("RAP - Littell Presentation"); (2) Presentation by Jessica Shipley, The Regulatory Assistance Project (October 18, 2019) ("RAP -

Local 1900, MDV-SEIA, BWLDC, WGL, Pepco, GRID2.0 Working Group/DC Consumer Utility Board ("GRID2.0/DC CUB"), OPC, and DCG filed comments on Alternative Ratemaking.[11] On November 4, 2019, DC Climate Action ("DCCA") filed comments on Alternative Ratemaking and a motion to file out of time.[12]

III. AUTHORITY AND BACKGROUND FOR ALTERNATIVE RATEMAKING

7. The Commission recognizes that there have been rapid changes in the energy industry and changes in the District's policy goals with regards to grid modernization, energy efficiency, clean energy and global climate change. These changes will undoubtedly impact a utility's operation in profound ways. Moreover, utility customers in the District require high level performance in energy delivery system reliability, and significant investment is required to maintain such performance, while also addressing aging infrastructure and bolstering system resiliency. In response to the District's policy goals, the Commission is examining the possibility

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Shipley Presentation"); (3) Presentation by Eric Matheson, Pennsylvania Public Utility Commission (October 18, 2019) ("PA PUC - Matheson Presentation"); (4) Presentation by Lillian Federico, Regulatory Research Associates, a group within S&P Global Market Intelligence (October 17, 2019) ("RRA – Federico Presentation"); (5) Presentation by Juan Alvarado, Maryland Public Service Commission (October 18, 2019) ("MD PSC – Alvarado Presentation"); (6) Presentation by David Parsons, Hawaii Public Utility Commission ("HI PUC - Parsons Presentation") at 10 (October 18, 2019); and (7) Minnesota PUC Docket No. E-002/CI-17-401; Order Establishing Performance-Incentive Mechanism Process (January 8, 2019) ("MN PUC 2019 Order").

11 *Formal Case No. 1156,* Comments of Potomac Electric Power Company On the Panel 1 And Panel 2 Questions For Technical Conference III, filed November 1, 2019 ("Pepco's Comments"); *Formal Case No. 1156,* Post-Technical Conference Comments of the Office of the People's Counsel for the District of Columbia, filed November 1, 2019 (OPC's Comments); *Formal Case No. 1156,* Post Workshop Comments of AARP District of Columbia, filed November 1, 2019 ("AARP DC's Comments"); *Formal Case No. 1156,* Comments of the Apartment and Office Building Association of Metropolitan Washington, filed November 1, 2019 ("AOBA's Comments"); *Formal Case No. 1156,* Comments of the Baltimore Washington Construction and Public Employees Laborers' District Council on Technical Conference III, filed November 1, 2019 ("BWLDC's Comments"); *Formal Case No. 1156,* District of Columbia Government's Comments on Technical Conference III – Framework for Evaluating Alternative Ratemaking Proposals, filed November 1, 2019 ("DCG's Comments"); *Formal Case No. 1156,* Comments of the GRID2.0 Working Group and DC Consumer Utility Board on the proceedings of the Technical Conference Framework for Evaluating Alternative Ratemaking Proposals with Respect to FC-1156 ("GRID2.0's Comments"); *Formal Case No. 1156,* Comments of the United States General Services Administration on the Framework for Evaluating Alternative Ratemaking Proposals, filed November 1, 2019 ("GSA's Comments"); *Formal Case No. 1156,* Comments of International Brotherhood of Electrical Workers, Local Union 1900 on Technical Conference III – Framework for Evaluating Alternative Ratemaking Proposals, filed November 1, 2019 ("IBEW Local 1900's Comments); *Formal Case No. 1156,* Comments of the Maryland DC Virginia Solar Energy Industries Association, filed November 1, 2019 ("MDV-SEIA's Comments"); *Formal Case No. 1156,* Comments from Small Business Utility Advocates in Rate Case 1156, filed November 1, 2019 ("SBUA's Comments"); and *Formal Case No. 1156,* Comments of Washington Gas Light Company, filed November 1, 2019 ("WGL's Comments"). For purposes of this Order, when referring to Pepco, OPC and Intervenors' comments the Commission will refer to them collectively as the Parties' Comments ("Parties' Comments"). GRID2.0 belatedly filed a second set of comments over a month after the close of the comment period. *See also Formal Case No. 1156*, Comments of the GRID2.0 Working Group, DC Consumer Utility Board, DC Chapter of Sierra Club, and General Microgrids, Regarding Alternative Rate Making and the Technical Conference, filed December 13, 2019 ("GRID2.0's Second Comments").

12 *Formal Case No. 1156,* Comments of DC Climate Action on Questions Posed for Technical Conference III and Motion to File Out of Time, filed November 4, 2019 ("DCCA's Comments").

of adopting AFORs aimed at accelerating the utilities' cost recovery for infrastructure improvement projects and aligning utility incentives with these policy goals. In the recent past, as discussed in detail in Paragraph 12, this Commission and the District have taken steps to address cost recovery issues and balance the interest of ratepayers by allowing surcharges for infrastructure improvement projects and by approving a decoupling mechanism for Pepco.

8. The Commission has the authority to regulate the activities of all public utilities operating in the District inclusive of establishing and setting distribution rates that a utility company is authorized to charge its customers.[13] Pursuant to D.C. Code § 34-911, the Commission is vested with the authority to set rates that are "just and reasonable."[14] The Commission also has authority to adopt AFORs. The District's retail electric market was restructured in 1999 with the enactment of the "Retail Electric Competition and Consumer Protection Act of 1999" ("RECCPA").[15] The RECCPA, among other things, permits the Commission to adopt alternative forms of regulating the electric company if the Commission finds that an alternative form of regulation: (1) protects consumers; (2) ensures the quality, availability, and reliability of regulated services; and (3) is in the interest of the public, including the electric company's shareholders.[16] Although there is no equivalent alternative ratemaking provision for the natural gas utility, the Commission, through its inherent/general powers, has authorized many elements of alternative ratemaking mechanisms for natural gas service.[17] These provisions afford the Commission

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[13] Retail Electric Competition and Consumer Protection Act of 1999, D.C. Law 13-107 (May 8, 2000), D.C. Code §§ 34-1501 *et seq*. (2016 Repl.); and Retail Natural Gas Supplier Licensing and Consumer Protection Act of 2004, D.C. Law 15-227 (November 1, 2004), D.C. Code §§ 34-1671.01 *et seq*. (2016 Repl.).

[14] D.C. Code § 34-911 (2001 Ed.). *See generally Office of the People's Counsel v. Public Service Comm'n of the District of Columbia*, 797 A.2d 719 (the lower boundary of the zone of reasonableness is not confiscatory in the constitutional sense and the upper bound cannot be so high as to be classified as exorbitant).

[15] Retail Electric Competition and Consumer Protection Act of 1999, D.C. Law 13-107 (May 8, 2000), D.C. Code §§ 34-1501 *et seq*. (2016 Repl.).

[16] D.C. Code § 34-1504 (d) provides:

> (1) Notwithstanding any other provision of law, the Commission may regulate the regulated services of the electric company through alternative forms of regulation.
> (2) The Commission may adopt an alternative form of regulation if the Commission finds that the alternative form of regulation: (A) Protects consumers; (B) Ensures the quality, availability, and reliability of regulated electric services; and (C) Is in the interest of the public, including shareholders of the electric company.
> (3) Alternative forms of regulation may include: (A) Price regulation, including price freezes or caps; (B) Revenue regulation; (C) Ranges of authorized return; (D) Rate of return; (E) Categories of services; and (F) Price-indexing.

[17] Although the Commission has not considered an alternative rate plan for natural gas services, the Commission has allowed some forms of alternative ratemaking such as: (1) Surcharges - WGL currently **has** a PROJECTpipes surcharge (*Formal Case No. 1115, In the Matter of Washington Gas Light Company's Request for Approval of a Revised Accelerated Pipeline Replacement Plan* ("*Formal Case No. 1115*"), Order No. 17789, ¶¶ 85-86, rel. January 29, 2015) and previously had the mechanical coupling replacement surcharge (*Formal Case No. 1027, In the Matter of the Emergency Petition of the Office of the People's Counsel for an Expedited Investigation of the Distribution System of Washington Gas Light Company*, Order No. 15627, ¶ 11, rel. December 16, 2009); (2) Non-

discretion to determine rates in any manner that is consistent with these standards. The Commission has historically chosen to determine rates based on a cost of service methodology using a historic test year or a partially forecasted test year, with a number of opportunities for out of test year expenditures.

9. In addition to statutory authority, the District of Columbia Courts have recognized and upheld the Commission's discretionary authority in setting just and reasonable rates. In *Metropolitan Bd. of Trade v. Public Service Commission of the District of Columbia*, the Court stated that the Commission has the responsibility of setting specific utility rates that are reasonable, just, and nondiscriminatory and noted that the "statutory authority was deliberately broad giving the Commission authority to formulate its own standards and to exercise its rate-making function free from judicial interference, provided the rates fall within a zone of reasonableness which assures that the Commission is safeguarding the public interest, that is, the interests of both investors and consumers."[18]

10. In the landmark case of *Duquesne Light Co. v. Barasch*, the United States Supreme Court addressed the broad authority of public utility commissions to regulate utility rates.[19] The Court rejected Duquesne's argument that the Fourteenth Amendment's Due Process Clause guarantees full rate recovery of all prudent investment or otherwise limits state public utility commissions to specific ratemaking methodologies. The Supreme Court held:

> We think that the adoption of any such rule would signal a retreat from 45 years of decisional law in this area which would be as unwarranted as it would be unsettling. *Hope* clearly held that "the Commission was not bound to the use of any single formula or combination of formulae in determining rates." ... The designation of a single theory of ratemaking as a constitutional requirement would unnecessarily foreclose alternatives which could benefit both consumers and investors. The Constitution within broad limits leaves the States free to decide what rate-setting methodology best

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volumetric rates, Straight-Fixed Variable Rate ("SFV") rate design – gas utility has a distribution charge which separates the gas company's cost of delivering gas from the amount of the gas actually consumed by a customer but the Commission still allows significant fixed cost through recovered variable per therm charges; (3) Weather Normalization – the Commission approved a weather normalization adjustment (*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, ¶¶ 184-186); (4) Pension and Other Post Employment Costs ("OPEB") – authorized pension tracker (Order No. 18712, ¶ 265); and (5) Bad debt expenses or expenses out of the control of the utility (cost of gas and tax adjustments).

18 *Metropolitan Bd. of Trade v. Public Service Comm'n of the District of Columbia*, 432 A.2d 343, 350 (1981) internal citations omitted.

19 *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 315-16 (1989). This case involved the partial construction of a nuclear plant. Although the Pennsylvania Utility Commission ("PA PUC") found that Duquesne's decisions to begin and to stop construction were prudent, it disallowed recovery of Duquesne's plant costs based on a statute that limited cost recovery to investment that was "used and useful." The Supreme Court upheld the decision of the PA PUC.

> meets their needs in balancing the interests of the utility and the public.[20]

IV. PUBLIC SERVICE COMMISSION'S CURRENT RATEMAKING APPROACH

11. The Commission uses the traditional methodology of ratemaking to determine "just and reasonable rates" for electric and gas distribution utilities and has primarily relied on a cost of service methodology using a historic test year ("HTY"). The HTY evaluates the costs incurred by the utility in a recent 12-month period and serves as a reference period for developing the utility's costs for the prospective period when rates will be effective. Consistent with our rules, the Commission has approved utilities' partially forecasted, not more than six months, rate recovery requests in conjunction with the Commission's use of the HTY approach.[21] Advantages of using an HTY approach include ensuring that rates are based on actual costs that have been verified and that utility investments are consistent with cost minimization principles.

12. It should be noted that the Commission has already employed some elements of AFORs to determine just and reasonable rates. A few recent examples of the Commission's, and District's (in the case of DC PLUG), willingness to use AFORs include its approval of the Bill Stabilization Adjustment's ("BSA") decoupling mechanisms to take into account the effect of energy efficiency programs to its customers;[22] approval of both electric and natural gas surcharges for infrastructure improvements to increase reliability and safety (DC PLUG[23] and PROJECTpipes 1[24]); and approval of post-test year reliability adjustments in electric and natural gas distribution base rate cases to mitigate regulatory lag.[25] Reliability indices (SAIDI and SAIFI) penalties can be considered as a form of Performance Based Regulation ("PBR"). These examples are case-by-case, but they demonstrate that the Commission has some flexibility in adjusting to a changing environment regarding economics and energy policy in the District, while balancing the interests of both the ratepayers and the utilities.

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[20] *Duquesne*, 488 U.S. at 315-16 (1989) (citations, footnotes omitted) (referring *to Hope Natural Gas v. Fed. Power Comm'n*, 320 U.S. 591(1941)).

[21] *See* 15 D.C.M.R. § 200.4 (February 13, 1987).

[22] *Formal Case No. 1053, ln the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service* ("*Formal Case No. 1053*"), Order No. 15556, ¶ 63, rel. September 28, 2009.

[23] *Formal Case No. 1145, In the Matter of Applications for Approval of Biennial Underground Infrastructure Improvement Projects Plans and Financing Orders*, Order No. 19167, ¶ 268, rel. November 9, 2017 (Approving the Underground Project Charge Rider, for the First Biennial Plan, which was implemented). *Formal Case No. 1116, In the Matter of Applications for Approval of Triennial Underground Infrastructure Improvement Projects Plan*, Order No. 17697, ¶ 238, rel. November 12, 2014 (Approving the Underground Project Charge Rider, which was never implemented). The DC PLUG was implemented pursuant to statute.

[24] *Formal Case No. 1115*, Order No. 17789, ¶¶ 85-86, rel. January 29, 2015.

[25] *See e.g. Formal Case No. 1139*, Order No. 18846, ¶¶ 76-81, 92-95. (Most recent approval of post-test year rate base additions.).

13. The Commission indicated that its primary goal for the Technical Conference was to establish a foundation and framework for evaluating Pepco's proposed MRP. The Commission stated that "[p]art of this technical conference will involve identifying alternative ratemaking approaches, including PIMs, that further the Commission's MEDSIS goals and the District's energy related objectives, such as [electrification, renewable development, pipeline replacement, development of new consumer solutions, and grid resiliency] laid out in the Clean Energy DC Plan," and the District's public climate commitments pursuant to the CleanEnergy Act.[26] In addition, the Commission directed the "parties to identify how any PIMs they support or propose advance the MEDSIS Vision and District's goals as part of their submission and subsequent testimony."[27] To that end, the information gained from the Technical Conference has aided our review and determinations in this Policy Order on framework for evaluating alternative forms of regulation.

V. TYPES OF ALTERNATIVE FORMS OF REGULATION ("AFORS")

14. There are several forms of alternative regulations. At the Technical Conference the participants' discussions primarily centered around MRP and PBR. Little to no discussion was proffered by the participants on other AFORs, such as, a Fully Forecasted Test Year ("FFTY"),[28] Formula Rates, and Surcharges and Riders. In addition, the Commission reviewed several other jurisdictions' alternative regulation proceedings, and because we regulate the same electric and natural gas utilities as our adjacent state, Maryland, we will look at the Maryland Public Service Commission's review of alternative rate regulation to aid our review and analysis.[29] Below is a summary of different AFORs based on the Technical Conference information, participants' comments filed after the Technical Conference, as well as our review of several jurisdictions.

A. Multi-Year Rate Plan ("MRP")

15. A MRP is a mechanism that sets base rates or revenues beyond a one-year period to account for attrition and other factors.[30] The rates begin with the issuance of a final order and ends only when a new rate is set following the processing of and decision on a subsequent rate

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26 *Formal Case No. 1156,* Order No. 20204, ¶ 32; *see also Formal Case No. 1156,* Public Notice, rel. September 18, 2019; *Formal Case No. 1156,* Amended Public Notice, ¶ 2, rel. September 26, 2019; *see* D.C. Code §§ 34-808.02 and 8-1772.21 (b)(1)(C)(i) (2019 Supp.). D.C. Code § 8-1772.21 (b)(1)(C)(i) sets forth the District's short- and long term climate commitments, including reducing greenhouse gas emissions by 50% by 2032, and carbon neutrality by 2050.

27 *Formal Case No. 1156,* Order No. 20204, ¶ 32; s*ee also Formal Case No. 1156,* Amended Public Notice, ¶ 2, rel. September 26, 2019.

28 The Pennsylvania Utility Commission's staff indicated that PA has adopted a fully forecasted test year methodology due to legislation.

29 Maryland Public Service Commission, *Administrative Docket PC51, Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company* ("*MD PC51*"), *Case No. 9618, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric of a Gas Company* ("*MD Case No. 9618*"), Order No. 89226, issued August 9, 2019 ("MD Order No. 89226").

30 Kenneth W. Costello, A Model Multiyear Rate Plan for Public Utilities, February 2019 (unpublished).

case.[31] The MRP specifies rates beyond the rate effective year of a rate case by applying a formula or index, or detailed forecasts for allowable rate changes over the duration of the plan. Some MRPs are set based upon a target return on equity with both the surplus and deficit earnings shared between the utility and ratepayers.[32] MRPs can adjust rates automatically for changing economic conditions and thereby provide a utility with greater assurance of earning its authorized revenue requirement.[33] Automatic adjustments in multi-year rate plans also reduce regulatory lag and can reduce the frequency of base rate filings by removing the need for a rate case filing if the plan is tied to the proper indices.[34] Among the concerns about a MRP is that by forecasting revenue requirements out to 3 to 5 years, it may be difficult to accurately project rate base investment and other costs for the duration of a 3 to 5-year plan.[35]

16. The MD PSC identifies several principal determinations that regulators should consider when adopting a MRP. These include: (1) the establishment of a baseline HTY, Hybrid Test Year (or bridge year), or forecasted test year to determine costs and revenues; (2) the establishment of the mechanism by which base rates will change beyond the first year of the rate effective period through formulas, indexes, or other predetermined mechanisms; and (3) the determination of the duration of the MRP.[36]

1) Potential Benefits of MRP

17. There are several advantages to MRPs. Those advantages are: (1) they reduce regulatory lag through the use of forecasts that can change over time as conditions occur; (2) they result in more predictable rates; (3) customers pay no more or no less than actual cost (this assumes the existence of a reconciliation process); (4) they limit the frequency of rate cases; (5) they allow for rate transparency because the utilities and customers know with certainty the timing and scale of rate increases; and, (6) if paired with other features, MRPs can provide performance incentives to utilities.[37]

2) Potential Disadvantages of MRP

18. In addition, there are potential disadvantages to MRPs. The disadvantages are: (1) information asymmetry; (2) complexities of the accuracy of multi-year forecasting create an opportunity for utilities to overestimate costs or underestimate revenues, which decreases the

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31 *See* MD Order No. 89226 at 12.

32 *See* HI PUC - Parsons Presentation, slide 10.

33 Hawaii Public Utility Commission, *Docket No. 2018-0088, Instituting a Proceeding to Investigate Performance-based Regulation*, Decision and Order No. 36326 at 29, issued May 23, 2019.

34 *See* DCG's Comments at 14; OPC Comments at 26-27.

35 *See e.g.*, AOBA's Comments at 2-4.

36 *See* MD Order No. 89226 at 12.

37 *See generally*, OPC Comments at 10, 24; DCG Comments at 3,7; *see also* MD Order No. 89226 at 13.

regulators' ability to discover improprieties in the estimation; and (3) issues with forecasting may not be corrected for several years and can have a lasting impact.[38]

B. Performance-Based Regulation Plan ("PBR")

19. PBR is an approach to regulation designed to try to improve utility performance as compared to traditional regulation by tying growth in revenues or rates to a metric other than costs and by providing the utility with an opportunity for greater profits by constraining costs rather than increasing sales.[39] PBRs generally include revenue adjustment mechanisms (*e.g.*, multi-year rate plans, revenue decoupling) and/or performance incentive mechanisms (*e.g.*, performance incentive mechanisms, benchmarking, earnings sharing mechanisms).[40] To counteract any tendency towards inefficiency or lack of cost control, PBRs typically include a performance-based incentive to limit any adverse effect the plan may have on ratepayers. PBRs involve alternative frameworks and regulatory mechanisms focused on a public utility's performance and desired outcomes and targets consistent with the public interest, notwithstanding the nature of the public utility's investments. PBRs can target specific areas of current utility performance that may benefit from improvement and provide incentives and penalties based on whether the public utility achieves established outcomes and targets.[41] PBRs focus on outcomes and results rather than cost recovery.[42]

20. PBRs have been used to achieve wide-ranging, overarching objectives, such as: (1) incenting cost reduction;[43] (2) incenting achievement of efficiency improvements;[44] (3) improving performance in areas that have previously been unsatisfactory;[45] (4) integrating technological advances, such as advanced metering and demand response capabilities;[46] (5) supporting new types of customer choice; and (6) encouraging a low-cost, customer-centric future. PBRs provide regulators with a means to restructure utility financial incentives to achieve specific, identified desirable or beneficial outcomes, such as meeting renewable energy targets, reducing greenhouse gas emissions, or improving reliability and resilience.

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38 *See generally*, DCG Comments at 7; OPC Comments at 11, 24; *see also* MD Order No. 89226 at 13-14.

39 *See* MD Order No. 89226 at 16.

40 Mark Newton Lowry, Tim Woolf, and Lisa Schwartz, (2016). Performance-Based Regulation in a High Distributed Energy Resources Future, Future Elec. Util. Reg. No. 3 ("Lowery et al., PBR Technical Report"), at 1, available at https://emp.lbl.gov/sites/all/lbnl-1004130_0.pdf.

41 *See* MD Order No. 89226 at 16; *see also* RAP - Littell Presentation, slides 7-8; MD Order No. 89226 at 16.

42 *See* RAP - Shipley Presentation, slide 7.

43 *See* OPC's Comments at 10; *see also* DCG's Comments at 3.

44 See DCG's Comments at 4.

45 Pepco's Comments at 12.

46 See DCG's Comments at 4.

21. Note that PBRs can vary substantially, but they each have common elements in that: (1) the goals and priorities to be accomplished under the PBR are clearly defined; (2) metrics and standards to measure utility performance are developed; (3) financial rewards and penalties are established to provide utilities with appropriate incentives; and (4) a process to monitor rates is necessary to ensure the PBR is working as designed.[47]

1) Potential Benefits of PBR

22. PBRs have some advantages in that there is a higher risk/reward potential for utilities. PBRs can: (1) provide financial incentives primarily for operational efficiency; (2) reduce regulatory lag since the return is tied directly to the utility's performance which is in the utility's control; (3) be flexible and adjusted to the needs of a jurisdiction such that they can be designed to directly support operational efficiency and reduced cost; (4) incentivize utilities to comply with state utility commission mandates and policy initiatives, if designed properly; and (5) provide administrative and procedural advantages in that the frequency of rate cases is known in advance allowing parties the opportunity to prepare prior to the start of the case.[48]

2) Potential Disadvantages of PBR

23. With the use of PBRs there is a claim that regulators lose some oversight provided through traditional ratemaking since costs, the main issue under cost of service regulation, are secondary to performance. In addition, PBRs need to include properly designed mechanisms to cap prices or revenue and establish sharing mechanisms that provide proportionate sharing of the utilities loss/gain to the benefits gained by the consumer. PBRs also lack information asymmetry and without an extensive oversight mechanism, utilities may manipulate data for favorable outcomes to ensure performance incentives.[49] Moreover, if incentive levels or targets are set at what business-as-usual operations would achieve anyway, then additional incentive costs are incurred with no additional benefit to customers. Therefore, poorly designed incentives may cause utilities to game the system to mask operational deficiencies in an effort to meet the incentivized target levels.[50]

C. A Fully Forecasted Test Year ("FFTY")

24. A FFTY is a ratemaking tool that allows utilities to submit, for review, reasonable forecasts of all sales and revenue of a hypothetical future 12-month period that will help to improve

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[47] *See* MD Order No. 89226 at 16-17.

[48] *See* MD Order No. 89226 at 17.

[49] *See* MD Order No. 89226 at 17-18.

[50] *See* Next Generation Performance Based Regulation by David Littell et. Al., Technical Report by NREL, at 20 (September 2017).

planning and cost recovery.[51] Generally, the FFTY is the first year of the rate effective period that follows a base rate case.[52]

1) Potential Benefits of FFTY

25. Some suggest that there are several potential benefits of using a FFTY regulatory method. Generally, FFTY methodology: (1) mitigates the impact of regulatory lag; (2) provides customers with more accurate pricing signals; (3) allows utilities to better manage risks and expenses; (4) provides a reasonable basis for future rates; and (5) aids customers (rate stability) and regulators alike because the distribution rates established with a FFTY reduce the frequency of rate cases and allows for proactive investment in the distribution system.[53]

2) Potential Disadvantages of FFTY

26. The main disadvantage to the FFTY method is information asymmetry intrinsic to forecasting since the utility is in control of the information it presents, thus making it difficult for regulators to accurately forecast utility operations, which could lead to misaligned incentives that favor the utility at ratepayers' expense.[54] Utilities may overestimate costs to ensure future funding and over-spend to meet the forecast subject to true-up which could lead to unnecessary rate increases.[55] FFTYs may also increase the regulatory liability of a utility due to the complexities of the required compliance filings, increasing the resources and time needed for review.[56]

D. Formula Rates

27. Formula rates allow utilities to make prospective annual adjustments to base rates outside of a general rate case. With formula rate regulation, utilities are able to make prospective rate adjustments based upon an agreed formula determined in a base rate case. Generally, the formula rate is primarily centered on a utility's allowed rate of return ("ROR"). The rate effective period of formula rates spans multiple years and rates may change annually based on projected allowed RORs that are set in the base rate case. Therefore, the formula is set to allow the utility

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51 *See* PA PUC - Matheson Presentation, slide 4.

52 *See* PA PUC - Matheson Presentation, slide 4.

53 *See* MD Order No. 89226 at 10-11.

54 *See* Ken Costello, "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives," Report No. 14-03, National Regulatory Research Institute (April 2014) at 34 and 35 ("NRRI Report").

55 *See* NRRI Report at 34-35.

56 *See* NRRI Report at 34-35.

the opportunity to earn a ROR within a specified range or "band." The band acts as a cap/limitation on the amount that rates can change year-over-year in order to minimize the risk of rate shock.[57]

1) Potential Benefits of Formula Rates

28. According to an NRRI Report, there are some advantages to formula rates methodology over traditional ratemaking, but these advantages rely on the details of design and execution. In general, formula rate methodology: (1) reduces regulatory lag and the frequency of rate cases relative to traditional rate cases; (2) is more efficient than FFTY methodology at reducing regulatory lag; and (3) provides utilities with a benefit of reduction in financial risk since the formula rate method reduces the uncertainty for future exogenous financial metrics.[58]

2) Potential Disadvantages of Formula Rates

29. Formula rate plans may be less complex than other AFORs, but there is still an issue of asymmetry of information.[59] Opponents complain that formula rate plans are not in the public interest because they do not provide utilities with strong incentives to contain costs and they shift risks to ratepayers.[60] Because of a concern that utilities may "game the system," formula based rates are usually combined with performance based metrics to control spending for efficient operations, based on just and reasonable rates.[61] A badly structured plan can produce poor incentives for a utility.[62] In addition, formula rates take a few years to develop and may differ for each utility.[63]

E. Surcharges and Riders

30. The use of surcharges allows for cost recovery for large capital projects before completion and spreads those costs over time, generally based on the utility reaching certain milestones.[64] "These are projects with significant costs that the utility can prioritize when there is

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57 *See* NRRI Report at 37-38.

58 *See* NRRI Report at 53. PA PUC - Matheson Presentation, slide 8. (PA staff mentioned that formula rates can resolve rate case expense issues).

59 *See* MD Order No. 89226 at 15.

60 DCG's Comments at 5. *See also* NRRI Report at 38 and 39. DCG cited Minnesota PUC's rejection of formula rates. DCG's comments at 29-30. AOBA indicates Pepco's proposed use of a reconciliation or true-up process would cause Pepco's MRP proposal to be more accurately described as a formula-based rate and not a MRP. AOBA's Comments at 4.

61 *See* MD Order No. 89226 at 15-16.

62 NRRI Report at 39.

63 *See* MD Order No. 89226 at 16.

64 *See* NRRI Report at 33-34, 52.

increased certainty of cost recovery."[65] Capital projects should be marked by milestones that when reached results in customer surcharges being implemented.[66] Infrastructure surcharges are more appropriate for new projects that do not create additional utility revenues.[67]

1) Potential Benefits of Surcharges and Riders

31. There are several benefits in using infrastructure surcharges and riders. The advantages are that: (1) they can be used to move the implementation of capital projects forward in a way that benefits ratepayers and utility shareholders; and (2) they increase transparency related to costs collected.[68] Surcharges can address large capital projects, spread over time, that the utility can prioritize with increased certainty of cost recovery.[69] This helps avoid large, one-time rate increases and allows for more timely cost recovery without a rate case.[70] Some additional benefits of infrastructure surcharges are: (1) the mitigation of cash flow and other utility financial problems; and (2) that they are well-suited for nonrevenue-creating investments.[71]

2) Potential Disadvantages of Surcharges and Riders

32. However, there are some shortcomings with surcharges and riders. The disadvantages are that they: (1) are prone to "duplication or conflict" with existing surcharges or other rate mechanisms which could result in double recovery; and (2) can increase fixed cost recovery possibly reducing volumetric charges, and consequently reducing the customers' control over their bills as well as the incentive for conservation.[72] According to an NRRI Report, infrastructure surcharges have the potential for imprudent utility performance and risk shifting to utility customers.[73]

VI. OVERVIEW OF PARTIES AND INTERESTED PERSONS COMMENTS

33. Because of the voluminous and detailed nature of the comments that were submitted by the Parties and interested persons on the Technical Conference, pursuant to the Commission's direction in Order No. 20204, we will not set forth a detailed summary of those comments in the body of this Order. However, detailed summaries are contained in Attachment B

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65 *See* MD Order No. 89226 at 18; and *See* NRRI Report at 53.

66 *See* NRRI Report at 53.

67 NRRI Report at 53.

68 *See* MD Order No. 89226 at 19.

69 *See* MD Order No. 89226 at 18-19.

70 *See* NRRI Report at 52.

71 NRRI Report at 53.

72 *See* MD Order No. 89226 at 19.

73 NRRI Report at 53.

to this Order for reference purposes. In this section, we merely set forth a brief description of the major positions and/or arguments of the commenters.

34. **Pepco**. Pepco proposed and supports the establishment and implementation of MRPs, PBRs, and PIMs. Pepco has already provided a detailed MRP/PIM proposal for Commission consideration.[74]

35. Concerning MRP options, the Company asserts that a public utility could elect to submit evidence similar to that required in a traditional rate proceeding to support its costs and revenues over the years requested in the MRP, using internal corporate forecasts. In the alternative, in situations where it is appropriate to use an escalation factor, Pepco submits that the utility should be permitted to present evidence supporting an escalation factor to be applied to a traditional "base case" cost and revenue determination. Lastly, Pepco maintains that a public utility should be allowed to use a hybrid approach combining forecasting in certain areas and using an escalation factor in other areas.[75]

36. As for PBRs and PIMs, Pepco maintains that a public utility should provide a description of the PIMs being proposed and a detailed rationale supporting each PIM, including the benefits to consumers. In addition, Pepco asserts that baseline data will be needed with respect to each PIM to permit analysis of future performance of a public utility; and clear metrics to determine whether a public utility meets the goals of each PIM.[76]

37. **OPC**. OPC takes no position regarding accepting or rejecting AFORs.[77] However, before the Commission acts, OPC recommends that the Commission consider: (1) whether any changes to the existing regulatory paradigm in the District are needed or appropriate; or (2) whether Pepco's application in this docket is just, reasonable, and in the public interest.[78] OPC also suggests that the Commission and stakeholders develop an alternative regulation policy collaboratively.[79]

38. OPC contends that key questions should be answered before developing a framework for AFORs. According to OPC, the Commission should ask: (1) what are the contours of utilities' roles, and what specific outcomes do we want them to achieve; (2) what are the incentives to achieve those outcomes today under the current regulatory framework, and how

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74 Pepco's Comments at 3-4.

75 Pepco's Comments at 4.

76 Pepco's Comments at 4-5.

77 OPC's Comments at 5-6.

78 OPC's Comments at 6.

79 OPC's Comments at 7.

should those incentives be changed; (3) what are the risks and trade-offs involved; and (4) how will the Commission prioritize goals that may be in tension.[80]

39. OPC contends that the Commission should not handle Pepco's MRP in this rate case, and if the Commission decides to do so, then the policy Order should be issued as a Proposed Order subject to further comments before finalization.[81] OPC also urges the Commission to use the evaluation principles for AFORs and PIMs suggested by OPC.[82]

40. OPC suggests that the Commission consider a phased two-step approach in this proceeding: Step 1 - Establishing a procedural schedule for a traditional rate case; and Step 2 - Establishing a time-limited phased proceeding to develop: (a) a Policy Statement on Goals; and (b) an Order evaluating the current regulatory framework.[83] OPC asserts that this process will establish a methodical framework for the Commission's consideration of alternative ratemaking proposals.[84]

41. **AOBA**. AOBA believes the current approach is not broken and does not need to be replaced by a MRP.[85] It also asserts that there is no evidence that a MRP will save ratepayers any costs or provide added benefits to ratepayers.[86] Contending there is no need for a MRP, AOBA states, however, if a MRP is considered by the Commission, we should use National Renewable Energy Laboratory ("NREL") and the Pennsylvania Public Utility Commission criteria.[87] Also, AOBA maintains that, if a MRP is approved, it needs to be reflected in the Company's rate of return.[88]

42. **AARP DC**. AARP DC opposes PBRs, MRPs, PIMs, and any alternative regulation which bypasses the normal thorough review of the Commission and denies consumers an

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80 OPC's Comments at 5-6, 36-37.

81 OPC's Comments at 42.

82 OPC's Comments at 43-44.

83 OPC's Comments at 41-42.

84 OPC's Comments at 41.

85 AOBA's Comments at 6.

86 AOBA's Comments at 6.

87 AOBA's Comments at 12-16. AOBA notes that the standards articulated in the NREL report are similar to the Rocky Mountain Institute Study reviewing alternative ratemaking models throughout the country. Rocky Mountain Institute, *Navigating Utility Business Model Reform A Practical Guide To Regulatory Design, at 28-72* (November 2018), available at https://www.rmi.org/wp-content/uploads/2018/10/RMI_Navigating_Utility_Business_Model_Reform_2018-1.pdf.

88 AOBA's Comments at 25.

important safeguard.[89] It, therefore, urges the Commission to reject alternative regulation, including multi-year rate plans, unless it can be clearly and conclusively demonstrated that rates will be lower than using the traditional rate case mechanisms.[90] AARP DC recommends that the Commission open a generic proceeding that includes WGL so that all stakeholders can participate in meaningful discussions of proposals and which allows the Commission to obtain a consultant to write a final report that addresses policy changes.[91] However, AARP DC indicates that, if the Commission adopts alternative regulation, the Commission should have a few meaningful metrics that focus on affordability and reliability to determine if the alternative regulatory method can provide positive benefits to consumers.[92]

43. **DCG**. The District of Columbia Government is not opposed to PBRs, MRPs, and PIMs, but DCG claims that Formula Rate Plans ("FRPs"), and MRPs that resemble FRPs, are not in the public interest.[93] DCG submits that the Commission and Stakeholders should carefully dissect MRP and PIM proposals in order to examine the incentives they provide (including negative incentives), as well as the risks they pose, and to ultimately determine whether the plan will benefit ratepayers and the District of Columbia as a whole.[94] DCG cautions against approving MRPs that "are MRPs in name only, but which function like formula rate plans" because FRPs "do not provide utilities with strong incentives to contain costs and they shift risks to ratepayers."[95]

44. The DCG observes that jurisdictions implement MRPs to achieve the following goals:

(1) Provide the utility with cost containment incentives;
(2) Encourage innovation by allowing the utility to manage business decisions with greater flexibility, rather than the regulator micro-managing the utility's investments;
(3) Reduce regulatory costs and burdens by lengthening the time between rate cases; and
(4) Provide utilities with greater regulatory guidance and assurance regarding investments in new and innovative technologies to better align utility investments with energy policy goals.[96]

45. Additionally, DCG identifies "four key design elements" to accomplish these goals:

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89 AARP DC's Comments at 1.

90 AARP DC's Comments at 4.

91 AARP DC's Comments at 4.

92 AARP DC's Comments at 4.

93 DCG's Comments at 3-4.

94 DCG's Comments at 1.

95 DCG's Comments at 3.

96 DCG's Comments at 3-4.

(1) A Rate Case Moratorium, *i.e.*, a "stay-out" provision that limits the ability for rates to be reset during the plan;
(2) A Revenue Cap, *i.e.*, revenues for each year of the plan are capped at certain predetermined levels;
(3) An Incentive to Improve Efficiency wherein utilities are incentivized to reduce costs during the plan by retaining some or all of the savings from efficiency gains, while ratepayers are protected from poor utility performance during the rate plan by being insulated from some or all of any increases in costs above the revenue cap; and
(4) An Attrition Relief Mechanism ("ARM") in which the initial year revenues may be escalated based on an index or cost forecast determined at the outset of the rate plan, or they can be frozen until the next rate case. Cost trackers may be added to the ARM for certain costs, particularly "exogenous" costs over which the utility has no control.[97]

46. **GSA**. GSA asserts that the Commission should only adopt an alternative rate proposal "if there are clear and compelling reasons to abandon traditional ratemaking, including reasonably-certain, demonstrable, and significant net benefits, including lower rates, to all customers.[98] GSA also states that the utility should carry the burden of proof to show that the proposals are clearly in the public interest and will provide greater benefits to customers that the current methodology.[99]

47. **DCCA**. DCCA is not opposed to MRPs, but expressed that there should be conditions and objectives for PIMs.[100] DCCA submits that a utility must show evidence that an alternative form of regulation is better than the current form, the evidence should be taken from actual experience elsewhere, and the District should seek the very best demonstrated practices - those showing the greatest benefits.[101] Concerning goals to be achieved, DCCA avers that the key decision factors should include the proposal's impact on greenhouse gas emissions (its climate impact), reliability, energy bills (level and predictability), resilience, safety, security, worker compensation, and financial viability of the utility.[102] DCCA also maintains that an alternative form of regulation should involve a mixture of incentives, obligations, and guarantees that remove

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97 DCG's Comments at 4.

98 GSA's Comments at 2-3.

99 GSA's Comments at 2.

100 DCCA's Comments at 2.

101 DCCA's Comments at 1.

102 DCCA's Comments at 3.

the perverse incentive on the utility to invest more than necessary, caused by rates set to meet a target ROE.[103]

48. **GRID 2.0/DC CUB**. GRID 2.0/DC CUB submits that the design and implementation of alternative ratemaking tools need to be based on the nature of the policy objectives and goals to be achieved.[104] To achieve DC's CleanEnergy Act mandates and to support DOEE's DC Clean Energy Plan, the Commission will need to evolve over time an "Integrated Grid" – one that recognizes and takes fully into account new distributed resources in utility planning and operations.[105] Alternative ratemaking tools will need to be designed and implemented in stages that can effectuate a transition from the current centralized generation/delivery utility model towards a decentralized model that includes a new Distribution System model.[106]

49. GRID 2.0/DC CUB points out that a "framework" needs to be developed by the Commission that will address the design and development of alternative ratemaking tools (such as multi-year rate plans, performance-based ratemaking in general, specific PIMs, earnings sharing mechanisms, energy-efficiency carryover mechanisms, attrition relief mechanisms, etc.) based on the policy goals and objectives that the Commission delineated within the PowerPath DC proceeding and based on the priorities that the Commission needs to establish in implementing these goals and objectives.[107] However, GRID 2.0/DC CUB warns that a "framework" based on the Commission's PowerPath DC objectives cannot be developed based on a two-day Technical Conference prompted by Pepco's multi-year ratemaking application, but will, instead, require a formal rulemaking proceeding, in which there is wide stakeholder participation and which will allow the Commission to weigh and evaluate the pros and cons relating to the different tools, as well as to balance the full array of stakeholder interests that are impacted by the new "PowerPath DC" agenda.[108]

50. GRID2.0/DC CUB's supplemental filing reiterates that the Commission should "explore and evaluate Pepco's proposal [ ] within the [ ] context of the Commission's specific policy commitments and priorities, and the Commission's overall objective to modernize the grid."[109] In addition, GRID2.0/CUB urges the Commission to reconsider the recommendations

103 DCCA's Comments at 7.

104 GRID2.0/DC CUB's Comments at 1-2.

105 GRID2.0/DC CUB's Comments at 3.

106 GRID2.0/DC CUB's Comments at 3.

107 GRID2.0/DC CUB's Comments at 3.

108 GRID2.0/DC CUB's Comments at 3-4.

109 GRID2.0's Second Comments at 39.

made by Staff in the proposed PowerPath Order and Opinion to have the Rate Design working group "PBR Learning" addressed in this case.[110]

51. **IBEW**. Local 1900 does not reject the idea of alternative ratemaking. However, IBEW asserts that any AFOR proposal should be consistent with the following three points: (1) a MRP should be limited to a three-year period; (2) the Commission should not establish PIMs that incentivize cost cutting; and (3) the Commission should start by using PIMs that do not have financial incentives and, where appropriate, introduce financial incentives incrementally.[111]

52. **BWLDC**. BWLDC does not support the Commission adopting any alternative ratemaking framework at this time.[112] In its view, implementing an alternative ratemaking framework would be a significant departure from historical ratemaking in the District. BWLDC suggests further exploration of alternative regulation to: (1) identify public policy objectives and align them with appropriate performance standards and consequences for satisfying or failing to satisfy those standards; (2) define alternative utility performance outcomes and quantify their costs and benefits to customers; (3) safeguard against excessive utility returns; (4) align rates with performance; (5) protect workers from utility and contractor practices that violate laws or otherwise impede workers' ability to work productively and safely; and 6) ensure regulators and stakeholders have the necessary information and resources to comprehensively evaluate any proposal.[113]

53. **MDV-SEIA**. MDV-SEIA is not opposed to performance-based rates, but states that utility incentives need to be aligned with "public policy objectives" and its implementation in the District "must result in a regulatory framework where utility profitability is driven by performance in meeting defined public policy objectives."[114] In addition, MDV-SEIA suggests that PBRs should "not be used as a vehicle to enhance utility earnings" but be used as a tool to "transition from traditional cost-of-service based earning to performance-based earnings" for the utility.[115]

54. MDV-SEIA recommends that the Commission's policy framework for evaluating Pepco's proposal ensure that Pepco is incentivized to facilitate renewable energy deployment in the District, while also maintaining transparent and predictable rates so that customers can predict their energy costs and accurately quantify the financial benefit from investing in a distributed solar facility, subscribing to a Community Renewable Energy Facility, or purchasing renewable energy from a competitive supplier. MDV-SEIA also recommends that the Commission adopt a policy

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110 GRID2.0's Second Comments at 40.

111 IBEW's Comments at 1-2.

112 BWLDC's Comments at 3-4.

113 BWLDC's Comments at 4.

114 MDV-SEIA's Comments at 2.

115 MDV-SEIA's Comments at 2.

framework that promotes, among other things, grid planning, development of renewable and demand response resources, and customer choice and engagement.[116]

55. **SBUA**. The Small Business Utility Advocates' concern pertains to small business or "micro enterprises," which are under resourced and not equipped to fully engage in Commission proceedings.[117] SBUA contends that the greatest need after commercial rent, is to curb rising utility costs.[118] SBUA argues that "[p]articularly for small stores with a need for multiple refrigeration units or cooling systems for food and beverage sales or other operations that require higher [energy] usage, the lack of representation in Commission proceedings have allowed runaway commercial consumer rates to disparately impact under-represented micro enterprises."[119] SBUA claims that, because the utility-related challenges that micro enterprises face are a barrier to their survival in a rapidly gentrifying city, it urges the Commission to ensure that their needs are taken into consideration.[120] SBUA recommends: (1) a study of Intervenor Compensation Programs to ensure under-represented consumers have a voice in rate cases; (2) creation of a separate rate class for micro enterprises, much like the protected class for low-income or senior residential consumers, to support start-ups and independently-owned outfits; (3) development of energy efficiency programs that incentivize micro enterprises regardless of whether or not they own their buildings; and (4) tracking, reporting, and evaluating programs for small businesses to determine their effectiveness.[121]

56. **WGL**. WGL supports MRPs as it allows the utility to reduce regulatory lag, thereby providing a reasonable opportunity for a prudent utility to earn its authorized rate of return allowed by Commission orders.[122] WGL submits that the benefits of a MRP include: (1) a reduction in the frequency and costs of rate cases; (2) a gradual change in rates since rates would change moderately on an annual basis, rather than a single large rate increase following a traditional rate case; and (3) an opportunity for customers to gain an early share of any cost efficiencies that the utility may develop.[123] WGL disputes several Parties' false notion that a MRP is a major change from the current process. WGL compares a MRP to a traditional rate case filing, and concludes that under both a MRP and a traditional rate case filing: (1) rates will be set through regulatory review before the Commission; (2) all stakeholders and customers have the opportunity

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116 MDV-SEIA's Comments at 3.

117 SBUA's Comments at 1.

118 SBUA's Comments at 1.

119 SBUA's Comments at 4.

120 SBUA's Comments at 2.

121 SBUA's Comments at 2-3.

122 WGL's Comments at 1-3.

123 WGL's Comments at 3.

to participate; and (3) the Commission makes a final decision based on a finding of just and reasonable rates.[124]

VII. LESSONS LEARNED FROM OTHER STATE COMMISSIONS[125] AND REGULATORY GOVERNMENTAL AND NON-GOVERNMENTAL INSTITUTIONS

57. There are several states that have implemented alternative regulation, as well as a few states that have recently begun to explore alternative forms of regulation.[126] In addition, there are Regulatory Associations that have issued a number of publications outlining approaches to alternative regulation.[127] The Commission is reviewing recommendations from the Parties and other Technical Conference participants, lessons learned, and outcomes and strategies

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124 WGL's Comments at 2-3.

125 Hawaii, Michigan, Minnesota, Pennsylvania, and Rhode Island legislatures imposed requirements on their Utility Commissions to adopt alternative forms of regulation. The other states noted within may have statutory authority to adopt AFORs, like the District, but the state utility commissions had discretion to act.

126 *See, e.g.*, Minnesota Public Utilities Commission, *Docket No. E,G-999/M-12-587, In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. § 216B.16, subd. 19*; Pennsylvania Public Utility Commission, *Docket No. M-2015-2518883, Alternative Ratemaking Methodologies*; Hawaii Public Utilities Commission, *Docket No. 2018-0088, MD PC51.*

127 *See, e.g.*, Performance-Based Regulation: Aligning Utility Incentives with Policy Objectives and Customer Benefits, Advanced Energy Economy, June 2018, available at https://info.aee.net/hubfs/PDF/PBR.pdf; Dan Cross-Call, Cara Goldenberg, Leia Guccione, Rachel Gold, and Michael O'Boyle, Navigating Utility Business Model Reform: A Practical Guide to Regulatory Design, Rocky Mountain Institute, November 2018, available at www.rmi.org/insight/navigating-utility-business-model-reform; Michigan Public Service Commission Department of Licensing and Regulatory Affairs, Report on the Study of Performance-Based Regulation, April 2018, available at https://www.michigan.gov/documents/mpsc/MI_PBR_Report_Final_621112_7.pdf; Janine Midgen-Ostrander, David Littel, Jessica Shipley, Camille Kadoch, and Joni Sliger, Recommendations for Ohio's Power Forward Inquiry, prepared at the request of the Ohio Public Utilities Commission, The Regulatory Assistance Project, February 2018, available at http://www.raponline.org/wp-content/uploads/2018/02/rap-recommendations-ohio-power-forward-inquiry-2018-february final2.pdf; David Littell, Camille Kadoch, Phil Baker, Ranjit Bharvirkar, Max Dupuy, Brenda Hausauer, Carl Linvill, Janine Migden-Ostrander, Jan Rosenow, Wang Xuan, Owen Zinaman, and Jeffrey Logan, Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation, Regulatory Assistance Project and National Renewable Energy Laboratory, September 2017, available at https://www.nrel.gov/docs/fylVosti/68512.pdf; Mark Newton Lowry, Matt Makos, and Jeff Deason, State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities, report prepared for the Ernest Orlando Lawrence Berkeley National Laboratory, July 2017, available at https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf; Public Utility Commission of Texas, Report and Recommendations on Alternative Ratemaking Mechanisms, January 2017 available at https://eepartnership.org/wp-content/uploads/2017/01/2017-Commission-Recommendations-on-Alternative-Ratemaking-Mechanisms-with-Christensen-Rpt-FINAL-submitted-to-legislature.pdf; Mark Newton Lowry, Tim Woolf, Performance-Based Regulation in a High Distributed Energy Resources Future, National Renewable Energy Laboratory, January 2016, available at https://emp.lbl.gov/sites/all/files/lbnl-1004130_0.pdf; Mark Newton Lowry, Matthew Makos, Gretchen Waschbusch, Alternative Regulation for Emerging Utility Challenges: 2015 Update, prepared for the Edison Electric Institute, 2015 available at http://www.puc.pa.gov/pcdocs/1418301.pdf; Paul L. Joskow, Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks, January 2006, available at https://economics.mit.edu/files/1181.

implemented in other jurisdictions that could be useful in the District of Columbia. We note that the energy market in the District has some unique distinguishing characteristics from other jurisdictions in that: (1) the District is a restructured market with open competition with no large scale generation located in the District; (2) there are only three regulated public utilities in the District, one for each industry; (3) the District shares utilities with Maryland and Virginia; and (4) the District is a member of PJM – a multi-jurisdictional Regional Transmission Organization ("RTO")/Independent System Operator ("ISO"). Understanding the District's current energy market and keeping all of the District specific characteristics in mind, the Commission must consider what forms of alternative regulation would be in the public interest and should be adopted.

A. Connecticut Public Utilities Regulatory Authority ("CT PURA")

58. The CT PURA recently approved a settlement of a multi-year rate plan. The settlement provided for: (1) the plan to be in effect for three years; (2) a new capital tracker that provides greater transparency and more frequent semi-annual adjustments for capital projects; (3) tree trimming and removal cost; (4) capital structure ROE for each of the three years; (5) earnings sharing at the end of each calendar year above the authorized ROE to be shared with customers and shareholders on a 50/50 basis; (6) Annual Full Time Employee adjustments ("FTE") with outside contractor expenses and annual compliance filings on hiring; (7) sales forecast; and (8) further adjustments to sales forecast.[128]

B. Hawaii Public Utilities Commission ("HI PUC")

59. A number of Parties refer to the HI PUC's two-phased approach to developing a comprehensive PBR framework. Hawaii's goals were to explore how alternative frameworks and regulatory mechanisms can provide: (1) greater cost control and reduce volatility; (2) efficient investment and allocation of resources regardless of classification as capital or operating expense; (3) fair distribution of risks between utilities and customers; and (4) fulfilment of state policy goals.[129]

60. The HI PUC staff noted that PBRs should include revenue adjustment mechanisms and performance incentive mechanisms. The HI PUC used Phase 1 to establish a basis from which to implement modifications to its current regulatory framework, and Phase 2 to develop the comprehensive PBR framework. In Phase 1, the HI PUC identified a three-step conceptual framework: (1) identifying priority goals and outcomes to guide PBR development; (2) characterizing and assessing the existing regulatory framework; and (3) identifying components and measures suited for change to attain identified goals and outcomes. The specific regulatory goals included enhancing customer experience (affordability, reliability, customer choice), improving utility performance (utility planning processes, investment choices, and system operations), and advancing societal outcomes (clean energy goals and other policies).[130] The HI

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[128] Connecticut PURA Docket No. 17-10-46; Application of CL&P Company D/B/A Eversource Energy to Amend its Rate Schedules; Decision (April 18, 2018).

[129] HI PUC - Parsons Presentation, slide 3.

[130] HI PUC - Parsons Presentation, slides 5-8.

PUC completed Phase 1 and has also begun the Phase 2 development of a comprehensive PBR framework through the use of working groups.[131]

C. Maine Public Utility Commission ("ME PUC")

61. Maine has successfully implemented alternative forms of regulation for nearly 20 years. However, the experience of the ME PUC with Central Maine Power ("CMP") shows that alternative forms of regulation are complex. During the term of CMP's alternative rate plan, its productivity increased well above the average productivity level of other utilities and the utility could offer flexible contracts to large customers, but at the same time it led to unintended consequences detrimental to ratepayers when the decoupling mechanism caused rates to rise when sales fell due to an economic slowdown and not due to conservation.[132] Some of the productivity level improvements were due to improved efficiencies but some were the result of deferred maintenance. Nonetheless, the ME PUC instituted customer protections such as separate revenue targets which apply to two classes (residential and commercial/industrial) with annual reconciliations for under-recovery limited to 2% revenue increases for each class, with amounts exceeding the cap deferred for recovery in subsequent years. In addition, there are limited annual reconciliations for over-recovery.[133] Service quality was tracked with PIMs during the term of the plan, and CMP generally met or exceeded the targets set.

D. Maryland Public Service Commission ("MD PSC")

62. The policy and practice of the MD PSC has generally been to rely on a purely historical data test year as the basis for ratemaking. However, over the last decade or so, the MD PSC has relied extensively on partially forecasted test years for base rate cases which are updated to actual during the course of the proceeding. In addition, the MD PSC has regularly used AFORs that incorporate the effects of future conditions into base rates (*i.e.*, BSA, Construction Work in Progress or CWIP, and surcharges). The MD PSC has also allowed price regulation (*i.e.*, price freezes, caps, or floors).

63. In August 2019, the MD PSC issued Order No. 89226 which allows utilities to pursue the implementation of a MRP based on a historic test year and allows up to three future test years to determine if it produces just and reasonable rates. MD Order No. 89226 established a working group to develop and submit a detailed Implementation Report by December 20, 2019, to include the following:

> (1) details regarding the forecasts that must be filed for subsequent years after the initial historic base year, including capital expenditures;

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131 HI PUC - Parsons Presentation, slide 11.

132 State of Maine Public Utilities Commission; Docket No. 2013-00168, Request for New Alternative Rate Plan ("ARP 2014"); Central Maine Power Company; Stipulation; July 3, 2014 ("Maine Stipulation, July 3, 2014"). *See* AARP DC's Comments at 2. AARP DC also notes that other unintended consequences could be like in Rhode Island when deferred maintenance and investments caused rates to rise in later years.

133 Maine Stipulation July 3, 2014 at 57. *See* AOBA's Comments at 20.

(2) a complete list of the proposed reporting requirements, measures, and timelines;
(3) proposals for staggering filings to prevent overburdening MD Commission Staff resources;
(4) identifying ways to make the utilities' planning process more transparent and open to the MD Commission and the ratepayers;
(5) recommendations on requirements to decrease information asymmetries between the utility and the affected parties;
(6) identifying ways to ensure that the burden of proof remains with the utilities to show that a proposed rate change is just and reasonable;
(7) proposals for an annual true-up mechanism;
(8) proposals for stay out provisions;
(9) proposed revisions to COMAR Title 20 regulations for filing MRPs;
(10) recommendations to ensure that existing COMAR metrics (such as SAIFI, SAIDI, customer call metrics, stray voltage metrics, vegetation management, etc.) are not eroded and remain intact through AFOR adoption; and
(11) advice on whether additional conditions for filing an AFOR need to be developed for utility companies on an individual basis and, if so, what approach would be most efficient.[134]

64. According to the MD PSC procedural schedule in this matter, after the submission of the Implementation Report, the working group will commence discussions on how best to integrate performance-based measures into a multi-year rate plan by identifying goals and outcomes (*e.g.*, integrating more renewable resources and energy efficiency, encouraging peak demand reductions, facilitating storage, supporting grid modernization, and any other State policy goals that may be in place or enacted) that align utility performance with State policy objectives that are not already addressed through existing regulatory measures.[135] In addition, the working group will evaluate metrics that are clearly defined, verifiable, quantifiable, subject to the utility's control, and be able to be incorporated into a multi-year rate plan. The working group shall also identify the areas where metrics are appropriate, without proposing actual metrics, by April 1, 2020, so that the MD PSC may provide additional guidance on the completeness of the list and metrics setting.[136] Also, on February 1, 2020, and thereafter, subject to the MD PSC's ruling, the utilities are allowed to file a multi-year rate plan for up to three years.[137]

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134 Maryland Order No. 89226 at 56-57.

135 Maryland Order No. 89226 at 57.

136 Maryland Order No. 89226 at 58.

137 Maryland Order No. 89226 at Appendix B-1.

E. Massachusetts Department of Public Utilities ("MA DPU")

65. Pepco and DCG both comment that the MA DPU recently approved a PBR mechanism that is a multi-year, formula rate plan with a duration of five-years.[138] The PBR mechanism is designed to work with a decoupling mechanism that: (1) adjusts the base revenue requirement based upon a revenue cap formula; (2) includes an earnings sharing mechanism with a deadband tied to the ROE; (3) includes a stay-out provision for five-years (unless extraordinary economic circumstances); and (4) requires annual filings. In addition, the MA DPU adopted metrics for review of a PBR requiring that it: (1) be designed to achieve specific, measurable results; and (2) identify, where appropriate, measurable performance indicators and targets that are not unduly subject to miscalculation or manipulation. The MA DPU found that broader performance indicators were preferred and that they should be tied to the stated goals of a program, consistent with the MA DPU's regulatory goals. The MA DPU also determined that a well-designed PBR should present a timetable for program implementation and specific milestones for program tracking and evaluation.

F. Michigan Public Service Commission ("MI PSC")

66. Pursuant to legislation, the MI PSC conducted a study to address PBR, under which a utility's authorized rate of return would depend on the utility achieving targeted policy outcomes.[139] In preparing the study, the MI PSC staff collaborated with stakeholders, the representatives of each customer class, the utilities whose rates are regulated by the Michigan PSC and other interested parties. As a result of the study's findings, the Michigan legislature authorized the Michigan PSC to use future test years as an AFOR.

G. Minnesota Public Utilities Commission ("MN PUC")

67. In 2011, the Minnesota legislature: (1) authorized MRPs for up to a three-year period, which was subsequently extended to a five-year period in 2015; (2) extended the standard rate case timeline by 90 days; (3) directed the MN PUC to consider multiyear rate plans that are designed to recover the cost of specific, clearly identified capital projects and, as appropriate, non-capital costs; (4) directed that, if the utility can identify a basis to begin recovering these capital costs within three years, the utility has satisfied the minimum standard justifying consideration of a multiyear rate plan; and (5) directed that a utility that receives MN PUC approval of its multiyear rate plan must delay filing a new rate case until after the plan expires.[140]

68. In 2013, the MN PUC, by Order, established criteria and standards for review and approval of MRPs. However, it declined to include formula rates or any method that would

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138 Massachusetts D.P.U. 17-05; Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism; Order Establishing Eversource's Revenue Requirement (November 30, 2017).

139 Public Acts of 2016, Act No. 41, Mich. Comp. Laws § 460.64 (2017).

140 Minn. Stat. § 216B.16, Subd. 19 (c) (2019).

forecast the return on equity over time. However, the criteria and standards for review included: (1) rate riders and deferred accounting; (2) an explanation of future rates when the MRP expires; and (3) deferred capital investments.[141] In 2017, the MN PUC accepted a settlement with Xcel Energy ("Xcel") that included a four-year MRP that encompassed: (1) sales forecast; (2) decoupling; (3) a settled ROE; (4) performance-based metrics; (5) capital budgeting; and (6) overearning.[142] This year, the MN PUC opened a new proceeding to evaluate performance metrics addressing customer satisfaction, customer choice, environmental stewardship, and customer outage experience that were proposed by one of its utilities in a general rate case. In this separate proceeding, the MN PUC will review the proposed metrics and explore the possibility of tying incentives or penalties to performance under those metrics.[143] As a result of the proceeding, the MN PUC adopted a PIMs process, goals and outcomes metrics focusing on promoting the public interest by ensuring environmental protection; adequate, efficient, and reasonable service; reasonable rates; and the opportunity for regulated entities to receive a fair and reasonable return on their investments.[144] The MN PUC wanted the process to be sufficiently structured but flexible so as not to hinder the development of meaningful performance measures.[145]

H. Pennsylvania Public Utility Commission ("PA PUC")

69. Pennsylvania currently has a number of alternative ratemaking options such as: (1) Traditional with incentive ROE;[146] (2) Fully Projected Future Test Year;[147] (3) Distribution System Improvement Plans;[148] (4) Decoupling Mechanisms;[149] (5) Performance Based Rates;[150]

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[141] Minnesota Public Utilities Commission; Docket No. E,G-999/M-12-587; Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans (June 17, 2013) at 5-7 ("Minn. 2013 Order").

[142] Minnesota Public Utilities Commission; Docket No. E-002/GR-15-826; Rate Application of Northern States Power; Findings of Fact, Conclusions, and Order (June 12, 2017) at 9-11, 23-25, and 32-36 ("Minn. 2017 Order").

[143] MN PUC 2019 Order.

[144] MN PUC 2019 Order at 11-13.

[145] MN PUC 2019 Order at 10-11.

[146] This form of regulation provides strong incentives to control costs between rate cases, can be combined with decoupling mechanism to address disincentives to promote energy efficiency and distributed energy resources, and can be combined with incentive ROEs during a base rate case to provide incentives to achieve important policy objectives.

[147] This form of regulation extends "test year" to 12 months from the effective date of the rate change, requires a projection of future capital spending and O&M into the "test year".

[148] DSIC mechanisms: (1) enable periodic (quarterly) increases in rates to reflect increased rate base spending; (2) establish DSIC caps (e.g. 5% of current rates); (3) establish revenue checks for over-earning and sets DSIC to zero; (4) target infrastructure for eligible facility requirements; and (5) require approval of a long-term infrastructure improvement plan (LTIIP). While DSIC can encourage targeted capital spending to address critical infrastructure issues, it can also encourage spending to gold plate the system.

[149] Decoupling mechanisms can resolve throughput issues. *See* PA PUC - Matheson Presentation, slide 8.

[150] Performance base rates can resolve gold plating issues. *See* PA PUC - Matheson Presentation, slide 8.

(6) Formula Rates;[151] (7) Multi-year Rate Plans;[152] and (8) rates based on a combination of more than one of the aforementioned mechanisms. The PA PUC may consider several principles when implementing alternative forms of regulation, which may help to guard against utilities gaming the system, such as: (1) how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs; (2) whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels; (3) how the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs; and (4) whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.[153]

I. Rhode Island Public Utility Commission ("RI PUC")

70. The RI PUC's Chief of Legal Services participated in the Commission's Technical Conference and provided unofficial comments regarding lessons learned with alternative forms of regulation in Rhode Island, including MRPs, PBRs, and PIMs.[154] The presenter indicated that the RI PUC has approved MRPs for electric and gas utilities for a number of years. The RI PUC believes that updated forecast and cost information are critical during the pendency of the MRP to ensure just and reasonable rates. In 2000, the RI PUC approved Narragansett Electric and Gas Company's ("Narragansett") MRPs for five-year terms with rate freezes with an exogeneous events reopener and an earning sharing mechanism at the end of the rate freeze period. The RI PUC required a separate service quality plan with incentives and penalties to ensure savings and efficiencies were not found at the expense of reliability, safety, and customer service. During the five-year period, the RI PUC found that the electric load growth was slow but that the utility was able to find significant cost savings resulting in benefits to ratepayers and shareholders. A five-year extension of the MRP was approved, load growth continued to be slow, earnings were below what was expected, and the utility implemented some cost saving measures reducing capital spending on asset condition categories and vegetation management. Although Narragansett continued to meet the service quality thresholds, in the next rate case there was a large increase in spending on capital vegetation management, and other reliability spending during the test year that could not be normalized. The RI PUC states that these MRP decisions have been paid for through the Company's capital investment plans.

71. For example, as a result of the negotiations among Settling Parties, a set of terms and conditions for a three-year rate plan for Narragansett (owned by National Grid) was filed. The Settlement was approved by the Rhode Island Public Utilities Commission at a meeting on August

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151 Formula rates can resolve rate case expense issues. *See* PA PUC - Matheson Presentation, slide 8.

152 MRPs can resolve rate case expenses and gold plating issues and performance incentive mechanisms are another tool in the toolbox.

153 Pennsylvania PUC Final Implementation Order, Implementation of Act 58 of 2018 Alternative Ratemaking for Utilities (April 25, 2019). *See also* Pennsylvania PUC Final Policy Statement Order, 34 Pennsylvania Bulletin, Vol. 49, No. 34 at 4819-4827 (August 24, 2019).

154 Technical Conference III Panel 2 Presentation by Cynthia G. Wilson-Frias, Chief of Legal Services for the Rhode Island Public Utility Commission, on October 18, 2019. (No slides were used).

24, 2018.[155] According to the RI PUC's Chief of Legal Services, the major components of their recent 2018 MRP are: (1) a one-year rate case with illustrative revenue increases over three years (the presenter indicated it is important to require a traditional rate filing with a historical test year, interim year, and forecasted rate year as a baseline); (2) an Earnings Sharing Mechanism; (3) protection for ratepayers related to costs that were not clearly known and measurable over the term of the plan; (4) creation of a regulatory liability to defer the amount to be returned to customers; (5) create a regulatory asset (in the event costs are higher than planned) to be recovered in the next general rate case, but in no event will the utility be allowed rates to recover more than 100% of the original cost estimate; and (6) reporting requirements to include, among other things, a program status, detail on budgets and actual spending, and explanations of variances between budgeted and actual spend. To the extent the actual costs of a program exceed the base distribution rate allowances that were allocated to the program, the overspending will be borne by the utility, unless the RI PUC allows the utility to record the difference to a regulatory asset for later recovery through a prudence review.

72. As explained by the RI PUC, to implement alternative ratemaking mechanisms to meet safety, reliability, and policy goals, a MRP or PBR is not necessary but it may be more cost effective in meeting these goals if either is used as a tool in operating a comprehensive regulatory scheme. Rhode Island law requires the forecast of annual capital investment spending and rate base additions with a reconciliation occurring the following year, with quarterly and annual reporting that explains any deviation of 10% above/below the forecast. Any recovery above the budgeted amount is discretionary.

73. The RI PUC notes that PIMs should be a potential component of an AFOR to encourage performance and that each PIM should be designed to incentivize the utility to engage in activities it otherwise would either not do or would not have a natural motivation to perform well. With respect to PIMs, the RI PUC has allowed: (1) shareholder incentives based on utility performance measures in administering the RI PUC Energy Efficiency plan; (2) sharing in risk and reward in the electric utility's managing of projects in the Forward Capacity Market; (3) performance metrics associated with service quality such as certain reliability and customer service standards; and (4) gas purchasing plan that includes performance incentives and penalties. The RI PUC notes that it is currently in the process of updating its PIMs guidelines.

J. National Renewable Energy Laboratory ("NREL")

74. Several Technical Conference participants reference the NREL Next Generation Report as a guide to the implementation of an alternative ratemaking mechanism. The participants believe that the NREL principles can be of guidance to the Commission in our review. NREL's list of guiding principles includes: (1) Clear Goal Setting; (2) Identification of Clear and Measurable Metrics; (3) Establish Transparency at Each Step of the Process; (4) Make Value to

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155 *See* Settlement filed by the parties in National Grid (Narragansett Electric and Narragansett Gas) rate cases in Rhode Island Public Utility Commission *Docket No. 4770, In Re: The Narragansett Electric Company d/b/a National Grid's Application to Change Electric and Gas Base Distribution Rates*, and *Docket No. 4780, In Re: The Narragansett Electric Company) d/b/a National Grid's Proposed Power Sector Transformation (PST) Vision and Implementation Plan,* Amended Settlement Agreement, August 16, 2018.

the Public Clear; (5) Align Benefits and Rewards; (6) Learn from Experience; (7) Compared to What; (8) Simple Designs are Good; and (9) Evaluation and Verification of the Outputs.[156]

K. Regulatory Assistance Project ("RAP")

75. Both Pepco and OPC cite to information presented by the RAP panelist. RAP "is an independent, non-partisan, non-governmental organization dedicated to accelerating the transition to a clean and reliable, and efficient energy future."[157] RAP presentation indicated that a PBR is a powerful tool in the regulator's toolbox that can align utility, ratepayer and public interest. RAP noted that for a PBR to be successful it should be clear, transparent at each step, and aligns rewards and incentives for utilities and customers. RAP indicates that PBRs can provide a regulatory framework to connect the District's and the Commission's goals, targets, and measures to utility performance or executive compensation.[158]

76. RAP also noted that there are methodologies for incentive mechanisms such as: (1) adding or subtracting incentives or penalties from return on equity; (2) lowering the rate of return (based on cost of debt or some other factor); (3) allowing payments for specific milestones instead of increased rate of return; and (4) sharing savings.[159] Likewise, RAP pronounced design principles that should also be considered, such as: (1) for every performance measure, ensure that the benefits exceed the costs (including the incentive); (2) find the balance between the amount of reward that will incentivize the utility without over-compensation; and (3) reflect importance of achievement of policy goals.[160]

L. New York State Department of Public Service ("NY DPS")[161]

77. NY DPS has a long history of using MRPs since the 1970s, when they were adopted to address the need to reduce workload for the NY DPS staff. Several parties reference the NY DPS's efforts with alternative ratemaking. One of the NY DPS's most recent cases was settled in 2017, wherein the NY DPS approved a settlement agreement between 22 parties and Consolidated Edison, Inc. ("ConEd") which, among other things, included: (1) a three-year MRP that lowered

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156 NREL, Next-Generation Performance-Based Regulation *Emphasizing Utility Performance to Unleash Power Sector Innovation* (September 2017) at 35, available at https://www.nrel.gov/docs/fy17osti/68512.pdf.

157 RAP - Littell Presentation, slide 44.

158 RAP - Shipley Presentation, slide 3.

159 RAP - Shipley Presentation, slide 26.

160 RAP - Shipley Presentation, slides 27-28.

161 The Commission has previously recognized that because the NY DPS operates in a single-state RTO/ISO, unlike the multi-state RTO/ISO that this Commission operate in, the NY DPS has the ability to promote unilateral reform impacting their transmission system. Nonetheless, the NY DPS did review materials submitted regarding the NY DPS's alternative forms of regulations and found that there are some characteristics that may be informative to this Commission. *See Formal Case No. 1130, In the Matter of the Investigation Into Modernizing the Energy Delivery System for Increased Sustainability* ("*Formal Case No. 1130*") Commission Staff's Report on Modernizing the Energy Delivery System for Increased Sustainability and Statement at 12, filed January 25, 2017.

the ROE a number of basis points; (2) a deadband; (3) earnings sharing of excess earnings (no sharing for under earnings in most revenue categories); (4) PIMs for electric reliability (all electricity reliability metrics are penalties, *i.e.*, for sanctions only), gas safety, and customer service; (5) reconciliation measures; and (6) reporting requirements.[162]

VIII. DECISION

78. The Commission has the authority to regulate the activities of all public utility companies operating in the District and is vested with the responsibility and authority to set rates that are "just and reasonable."[163] Since the restructuring of the District's energy market in 2000 and 2004, the Commission's regulatory focus has centered on ensuring that distribution rates of the electric and natural gas utilities operating in the District are just and reasonable.[164] The Commission has been setting distribution rates through a traditional cost of service model based on a historical test year.[165]

79. Since 2015, the Commission, in collaboration with *Formal Case No. 1130* stakeholders, identified technologies and policies that can be implemented in the District to modernize the distribution energy delivery system for increased sustainability and further accelerate grid modernization in the District.[166] The need for grid modernization became necessary due to improvements in technology, customer demand for greater control over their energy use, efforts to increase building energy efficiency, the expanding deployment of distributed energy resources in the District, as well as a growing need to address the environmental impacts of energy consumption.[167]

80. The goals of PowerPath DC include ensuring that our energy delivery system remains safe, reliable, and affordable while also becoming more sustainable, interactive, and secure. These goals are linked to the District of Columbia's energy and climate action policies as articulated in the Clean Energy DC Plan and embodied in the CleanEnergy DC Omnibus Amendment Act of 2018 ("CleanEnergy DC Act").[168] With these efforts the District is positioned

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162 New York Case 16-E-0060, 16-G-0196, Order Approving Electric and Gas Rate Plans, January 25, 2017.

163 D.C. Code § 34-911 (2001 Ed.). *See generally Office of the People's Counsel v. Public Service Comm'n of the District of Columbia*, 797 A.2d 719 (the lower boundary of the zone of reasonableness is not confiscatory in the constitutional sense and the upper bound cannot be so high as to be classified as exorbitant).

164 Retail Electric Competition and Consumer Protection Act of 1999, D.C. Law 13-107 (May 8, 2000), D.C. Code §§ 34-1501 *et seq*. (2016 Repl.); and Retail Natural Gas Supplier Licensing and Consumer Protection Act of 2004, D.C. Law 15-227 (November 1, 2004), D.C. Code §§ 34-1671.01 *et seq.* (2016 Repl.).

165 This could be a historical test year or partially forecasted test year such as 6+6 in this case.

166 *See generally*, *Formal Case No. 1130*. In August 2019, the Commission rebranded its grid modernization proceeding from MEDSIS to "PowerPath DC".

167 *Formal Case No. 1130*, Order No. 17912, rel. June 12, 2015; s*ee generally, Formal Case No. 1130*.

168 CleanEnergy DC Omnibus Amendment Act of 2018, D.C. Law 22-257, effective March 22, 2019 ("CleanEnergy DC Act").

as a national leader in sustainability and environmental conservation, with one of the most aggressive renewable energy standards in the country, and has leadership dedicated to combating the effects of global climate change and realizing a clean energy future.

81. Importantly for the Commission, the CleanEnergy DC Act, amends D.C. Code § 34-808.02 to read:

> In supervising and regulating utility or energy companies, the Commission shall consider the public safety, the economy of the District, the conservation of natural resources, and the preservation of environmental quality, *including effects on global climate change and the District's public climate commitments*.[169] [Emphasis added]

As the utility regulator, we embrace our important role in helping the District achieve a clean energy future, and we view alternative forms of regulation as a potential tool to helping the District achieve its clean energy and environmental goals, while preserving a high level of energy delivery system reliability and superior customer service, for the benefit of District residents and ratepayers.

82. Traditional cost of service rate cases generally reviews costs and investments through a historical approach or partially forecasted test year (which provides for six months historical data and six months of forecasted data). Under this ratemaking paradigm, Pepco has been filing rate cases approximately every two (2) years to recover the costs of their investments in the electric distribution system.[170] The expenses incurred in litigating each rate case cost ratepayers an average of $3 million per case.[171] The Commission has long recognized that other forms of regulation may facilitate achieving the District's aggressive goals regarding greenhouse gas emission reductions, transportation electrification, renewable energy development, grid modernization, and other District goals.

83. With the Commission's grid modernization efforts solidly off the ground, on July 25, 2017, in *Formal Case No. 1139*, Order No. 18846, the Commission indicated that it would allow Pepco to include in its next rate case a request for a fully forecasted test year and/or a multi-year rate proposal.[172] The Commission recognized in its decision that we are in a "period of growth

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169 D.C. Code § 34-808.02 (2019 Supp.).

170 The Commission rendered decisions in *Formal Case No. 1053* in 2008, *Formal Case No. 1076* in 2010, *Formal Case No. 1087* in 2012, *Formal Case No. 1103* in 2014, *Formal Case No. 1139* in 2017, *Formal Case No. 1150* in 2018, and is scheduled to decide *Formal Case No. 1156* in 2020. The extra year gap between *Formal Case No. 1139* and *Formal Case No. 1150* is attributable to Pepco's filing for approval of its Merger with Exelon in *Formal Case No. 1119*.

171 This figure was computed from Pepco's direct testimony on ratemaking adjustments in *Formal Case No. 1076* ($2.8 million), *Formal Case No. 1087* ($2.4 million), *Formal Case No. 1103* ($3.3million) and *Formal Case No. 1139* ($3.6 million). This figure does not include *Formal Case No. 1150* due to the fact that a settlement was filed with the Commission (which resulted in much less cost being incurred) nor does it include *Formal Case No. 1053*, since that rate case' workpapers does not appear to accurately capture the rate case costs.

172 *Formal Case No. 1139*, Order No. 18846, ⁋ 595.

and change in the District" with growing DER deployment and that "future rate design questions need to complement our development of appropriate mechanisms to help us to achieve the goals in MEDSIS."[173] The Commission directed that in Pepco's next rate filing, Pepco could elect to request a fully forecasted test year or a multi-year rate proposal, in addition to a traditional test year filing, conditioned upon the request being consistent with Commission Rules 200.1, 200.2, 200.3, and 200.5 that there must be: (1) a baseline revenue and cost evaluation which is equivalent to a historical test year; (2) an explanation on how to project revenues and expenses; and (3) additional time allowed for the first examination of the new paradigm. Further, the Commission stated that "our focus in considering any alternative mechanism will include a review of the benefits that accrue to customers as opposed to solely focusing on the utility."[174] In the same Order, the Commission noted that most multi-year rate plans feature a performance metric system that includes some PIMs that provide awards or penalties, or both, for performance in targeted areas.[175] Because this is the first time that the Commission has considered a request to adopt an alternative form of regulation, we will focus our review on what if any, risks or benefits accrue to customers as compared to the utility.

84. As detailed in Section IV, the Commission has authority to consider alternative forms of regulation under D.C. Code § 34-1504 (d) (2001), which provides:

> (1) Notwithstanding any other provision of law, the Commission may regulate the regulated services of the electric company through alternative forms of regulation.
> (2) The Commission may adopt an alternative form of regulation if the Commission finds that the alternative form of regulation: (A) Protects consumers; (B) Ensures the quality, availability, and reliability of regulated electric services; and (C) Is in the interest of the public, including shareholders of the electric company.
> (3) Alternative forms of regulation may include: (A) Price regulation, including price freezes or caps; (B) Revenue regulation; (C) Ranges of authorized return; (D) Rate of return; (E) Categories of services; and (F) Price-indexing.

A. AFORs in the District

85. Generally speaking, none of the comments received from the Parties or other commenters focused on the specific AFORs identified in D.C. Code § 34-1504 (d)(3) being implemented independently. Most comments focused on aspects of Pepco's proposed MRP and PIMs, while some comments related to price regulation or revenue regulation.[176] Some of the Parties and commenters referred to the indexing of costs under a MRP and noted that PIMs as

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173 *Formal Case No. 1139*, Order No. 18846, ⁋⁋ 593, 594, 598.

174 *Formal Case No. 1139*, Order No. 18846, ⁋ 595.

175 *Formal Case No. 1139*, Order No. 18846, ⁋ 595.

176 *See, generally* DCG Comments at 3; Pepco Comments at 29.

proposed by Pepco create effective ranges of authorized rates of return depending on whether Pepco's performance falls above or below the various PIM targets.[177]

86. While the statute permits the Commission to adopt AFORs, the Commission's review of any changes to the traditional ratemaking methodology must be deliberative, paying careful attention to the structure and framework for the evaluation of AFORs so that unintended operational or financial outcomes are mitigated and managed.[178] The District's electric and natural gas utilities combined, as of their last fully litigated rate case, collect from ratepayers $691.45 million per year to support the safe and reliable operations of energy distribution systems valued at $1.9 billion.[179] In considering and implementing changes as to how the costs of these systems are accounted for and recovered from ratepayers, the Commission must carefully consider how its actions impact the operational incentives of the utilities, ensure that it maintains the financial stability and flexibility of the utilities, and promote the utilities' continued safe and reliable operations over time. The Commission recognizes that there will not be quick or rapid changes in rate review and recovery given the importance of utility operations to the District and the scope of their operations. We believe that any changes to the traditional ratemaking methodology may require multiple rate proceedings to fully implement AFORs.

87. The principles of ratemaking balance the utility's cost recovery, rate impact, consumer interests, and public policies while taking into consideration prudent and appropriate adjustments. The Commission's traditional ratemaking methodology is based on a historic test year or partially forecasted test year and primarily looks backwards, which means that what utilities have planned for future investments is not typically a major part of the rate case review process. The Commission finds that one or more forms of AFOR may be helpful, if carefully designed, in facilitating the achievement of the District's aggressive goals regarding greenhouse gas emission reductions, transportation electrification, renewable energy development, grid modernization, and other District goals. Apart from PROJECTpipes and DC PLUG, opportunities for meaningful improvement in transparency remain regarding grid modernization and integrated distributed resources. Traditional ratemaking, without adequate regulatory mechanisms to monitor and address service quality cost control, can lead to utilities favoring capital expenditure investments which may result in sub-optimal customer benefits. For these reasons, the Commission finds that it is now appropriate in this proceeding to move forward in implementing an AFOR in the District.

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[177] *See*, *generally* DCG Comments at 10, 15; OPC Comments at 26; GSA Comments at 15.

[178] The Commission recognizes, as a number of the commenters have noted, depending on the AFORs approved by the Commission, the Commission and stakeholders will initially need additional resources for implementation. The complexity of any annual adjustment and the need for detail review of an adjustment mechanism will have the effect of diminishing the benefits of MRP/PIMs by increasing the regulatory costs and demand on resources,

[179] Add annual operating revenue and revenue adjustments for WGL and Pepco found in *Formal Case No. 1137*, Order No. 18712, ¶¶ 450 (h) and (m), rel. March 3, 2017 and *Formal Case No. 1139*, Order No. 18846, ¶¶ 450 (h) and (k). Add District of Columbia rate base for WGL and Pepco found in *Formal Case No. 1137*, Order No. 18712, ¶ 450 (g), rel. March 3, 2017, and *Formal Case No. 1139*, Order No. 18850 (Errata to Order No. 18846), ¶ 2, rel. July 31, 2017.

88. The Commission agrees with OPC's and DCG's assessment of AFORs. Specifically, we agree that AFORs hold the potential for: (1) reducing regulatory lag; (2) helping utilities better manage risks and expenses; (3) increasing the transparency of utility spending and investment decisions; (4) better aligning the utility's incentives and actions with the public interest; (5) incentivizing cost reduction or cost containment; and (6) reducing administrative burdens, including the frequency of resource-intensive rate cases.[180]

89. Broadly speaking, the Commission agrees with DCG, GRID2.0/DC CUB, and DCCA about the potential of AFORs in changing the ratemaking paradigm in the District. Specifically, the Commission agrees with DCG that "MRPs represent a fundamental change from cost of service regulation and offer the promise of increased benefits for both ratepayers and the utility. However, we recognize that MRPs also present substantial peril if not designed well."[181] Any change in the ratemaking process presents risks, but the District's ambitious clean energy and climate goals require the Commission to explore new tools to help advance the achievement of those objectives. Further, the Commission agrees with DCG, that "if designed well, MRPs can provide benefits to customers and help achieve public policy goals."[182] It is precisely the ability to achieve the District's public policy goals that present a "clear and compelling reason" to move beyond traditional ratemaking as stated by GSA.[183] The Commission also agrees with GRID2.0/DC CUB's statement that "[a]lternative ratemaking tools need to be evaluated from the standpoint of the fundamental and transformational kinds of changes in the electricity system that were addressed in the MEDSIS proceeding and that are reflected in the MEDSIS Vision Statement and Principles."[184] Likewise, the Commission concurs with DCCA that we should evaluate and select AFORs that "yield[ ] the most benefit per unit of costs" where the benefit is the "incremental good that comes from achieving" the goal and the cost is "the incremental costs of achieving those goals through performance incentives."[185] We believe that balancing the benefits and costs in this manner will provide some safeguards to prevent unintended consequences.

90. With respect to FFTYs, formula rates, and Surcharges and Riders, commenters either did not address, or summarily addressed these alternative forms of regulation. Nonetheless, the Commission briefly compares aspects of the advantages and disadvantages of these forms of alternative regulation. For instance, some of the advantages of FFTYs and formula rates are that they reduce the impact of regulatory lag and allow a utility to either reduce or better manage risk

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180 OPC Comments at 10; *see also* DCG's Comments at 7-9.

181 DCG's Comments at 1.

182 DCG's Comments at 3.

183 GSA's Comments at 2-3. ("the Commission should only adopt an alternative rate proposal 'if there are clear and compelling reasons to abandon traditional ratemaking, including reasonably-certain, demonstrable, and significant net benefits, including lower rates, to all customers.'").

184 GRID2.0/DC CUB's Comments at 2.

185 DCCA Comments at 3.

and expenses.[186] Of the two, formula rates are believed to be more efficient than FFTYs at reducing regulatory lag.[187] At present, the FFTYs would require a waiver of the Commission's rules since they presently only allow for six months of forecasted data. The Commission notes that, among other things, formula rates are complex and could require use of more resources; they shift financial risks to customers; automatic adjustments make timing for review of utility costs challenging; and it could reduce incentives for utilities to control costs.[188] However, as DCG stated "formula rate plans formulaically ensure that revenues track costs, often measured as deviations in [ ]ROE from the utility's target ROE . . . Importantly, in contrast, MRPs do not adjust revenues to equal costs during the plan."[189] In reviewing MRPs, the Commission understands DCG's concerns that "MRPs that essentially resemble FRPs [Formula Rate Plans] are not in the public interest."[190] Although DCG argues that formula rates are not in the public interest, the Commission does not foreclose exploring that option further if presented to us for review under the policy framework adopted in this Order.

91. Likewise, with respect to advantages and disadvantages of Surcharges and Riders, surcharges will allow the utility to implement capital projects in a manner that benefits ratepayers and utility shareholders and increases transparency related to cost. No commenter is actively advocating for the adoptions of surcharges, although Pennsylvania utilizes a type of surcharge, the DISC, to reduce regulatory lag to promote utility infrastructure investment. The Commission has previously considered capital expenditure reliability related surcharges for Pepco in *Formal Case No. 1087*. Pepco requested approval "in principle" of a Reliability Investment Recovery Mechanism ("RIM"), which was a surcharge, adjusted annually, to allow Pepco to "recover future reliability improvement and construction costs on an accelerated basis."[191] Pepco proposed the RIM "in order to reduce the frequency of rate case filings and the chronic under-earning that is produced by regulatory lag inherent in traditional ratemaking."[192] In that case, the Commission ultimately rejected Pepco's proposed RIM surcharge.[193] The RIM proposal appears to function much like the Pennsylvania PUC's DISC, where utilities can recover quarterly investments, subject to their long-term infrastructure plans. More recently, this Commission has approved relatively narrow project specific surcharges to address large on-going construction projects like

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186 *See MD PC51,* Comments of the Staff of the Public Service Commission of Maryland Regarding Alternative Forms of Ratemaking and the Implementation Thereof, at 14, filed March 29, 2019 ("MD PSC Staff Report").

187 *See MD PC51*, MD PSC Staff Report at 27.

188 *See MD PC51*, MD PSC Staff Report at 27.

189 DCG's Comments at 5.

190 DCG's Comments at 7.

191 *Formal Case No. 1087, 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* ("*Formal Case No. 1087*"), Order No. 16930, ¶ 424, rel. September 27, 2012 ("Order No. 16930").

192 *Formal Case No. 1087*, Order No. 16930, ¶ 424.

193 *Formal Case No. 1087*, Order No. 16930, ¶ 476.

WGL's PROJECTpipes and Pepco's DC PLUG infrastructure projects. Again, the Commission is not foreclosed from considering these options in the future.

92. Regarding a multi-year rate plan as an AFOR, the Commission finds that pursuing the implementation of a MRP based on a historic test year is appropriate and can be accomplished reasonably quickly given that the Commission has a plethora of information to transition to this AFOR. The Commission recognizes the concerns expressed by OPC, DCG, AOBA, GSA, and AARP DC, DCCA, Grid 2.0/DC CUB about implementing AFORs and being allotted sufficient time to review any proposed AFORs. In moving forward, the Commission notes, that *in Formal Case No. 1139*, we recognized that both Parties and the Commission would need additional time to review any proposed AFORs in the District. Since the Commission made this pronouncement, Pepco hosted a series of workshops with stakeholders to address AFORs.[194] In addition, the Commission is issuing a modified schedule, Attachment A, which provides the Parties with sufficient time for further development of PIMs, which can be done before the conclusion of this proceeding. We believe that establishing these additional meetings for the parties and PowerPath DC stakeholders will facilitate identifying those PIMs which could be achievable in this proceeding. Further, the record shows several benefits for MRPs such as shortening the cost recovery period, providing more predictable revenues for utilities and more predicable rates for consumers, spreading changes in rates over multiple years, and decreasing administrative burdens on regulators by staggering filings over several years. MRPs also allow adjustments to reflect changes in the business environment, rather than changes in the utility's actual revenue and costs.[195] A key element of a MRP, the year over year escalation of rate base, will require significant detail into utility planning that is not available to interested parties today. The Commission is of the opinion that multi-year rate plans based on a historic test year would combine the stability of traditional ratemaking while permitting adjustments that better reflect the changing energy market. The Commission also finds that it can draw on the experiences of many states. For example, Pennsylvania, like the District, determined a need for investments in the state's infrastructure and established a distribution system improvement charge that is being implemented and has been compatible with using a fully forecasted test year mechanism since 2012. Pennsylvania's model may be instructive as this Commission is implementing grid modernization, PROJECTpipes, and DC PLUG, but now seeks to incorporate forecasting, which will provide more transparency into the utility planning process and allow the Commission an opportunity to question the customer benefits of projects in advance of capital commitments. Accordingly, the Commission, after reviewing the record, believes that a properly constructed multi-year plan can produce just and reasonable rates.

93. The Commission determines that a utility submitting a MRP will need to demonstrate that its requested rate increase is based on a historic test year, and that the plan: (1) allows up to three future test years; (2) has a stay-out provision and the specific criteria of any off-ramp; (3) has a tracker to track the accuracy of the utility's forecasts; (4) does not shift risks to

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194 AFOR/Performance-Based Regulation Workshops were held on September 19, 2018, October 30, 2018, January 29, 2019, and April 9, 2019.

195 Parties also generally recognize there are potential benefits of MRPs and 17 states have adopted MRP for gas or electric utilities. *See* RRA – Federico Presentation, slide 11.

customers and reflect shareholder risk reductions in a lower ROE; (5) has an annual adjustment process; and (6) contains adequate reporting requirements.[196]

B. AFOR Framework

94. As stated in Order No. 20204, the purpose of this Order is to set forth a framework for evaluating AFOR proposals and to establish a foundation for assessing Pepco's MRP/PIMs proposal in this proceeding. As recommended by OPC, AOBA, DCG, GRID2.0/DC CUB, AFOR implementation requires the Commission to first set clear goals and principles for the AFOR framework that advance or otherwise align with the District's public policy goals and helps facilitate modernization of the energy delivery system. Based on the above discussion, the filed comments, presentations, and our review of other state proceedings, the Commission establishes the overarching framework principles as follows for a utility seeking AFOR treatment. As articulated by the Hawaii Public Utility Commission, "the purpose of this regulatory framework is to provide better alignment of utility financial incentives with customer needs and state policy goals."[197] The Commission hereby adopts the below overarching framework principles for a utility seeking AFOR treatment. The utility's AFOR application shall provide information as to how:

(1) The AFOR: (A) protects consumers; (B) ensures the quality, availability, and reliability of regulated utility services; and (C) is in the interest of the public, including shareholders of the utility;
(2) The AFOR advances the public safety, the economy of the District, the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments;
(3) The AFOR's ratemaking mechanisms advance or otherwise align with the District's public policy goals;
(4) The AFOR identifies baseline revenue and cost information, and clearly explains what process or mechanism the utility used to project revenues and expenses;
(5) The AFOR provides benefits that are measurable, quantitative, and qualitative to customers, as opposed to solely focusing on the AFORs benefits to the utility;
(6) The AFOR impacts the operational incentives of the utility with respect to maintaining a high level of customer service, while fostering productivity and cost control; maintains the financial strength, credit ratings, and financial flexibility of the utility; and helps ensure a consistently high level of energy delivery system reliability, while promoting safe and reliable operations over time;
(7) The revenue requirements will be allocated across customer classes over time, and how rate design issues within customer classes will be handled over time, in a just and reasonable manner;

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196 This does not restrict utility from including modified or additional proposals it wishes in rate applications.

197 *See Docket No. 2018-0088, Instituting a Proceeding to Investigate Performance-based Regulation,* Hawaii PUC Decision and Order No. 36326 at 2, issued May 23, 2019.

(8) The risk of over-earning a utility's authorized return will be mitigated during the duration of AFOR for the benefit of the customers, while also preserving the Commission's ability to conduct cost prudency reviews as needed;

(9) The AFOR provides an appropriate level of transparency and reporting into the utility's operational and capital plans ensuring that the plans will be maintained during the duration of the AFOR; and

(10) The AFOR avoids any unreasonable shifting of risk to utility customers.

95. This framework sets the Commission's starting point for an evolving evaluation process for AFOR proposals to be reviewed in the future by the Commission as the public interest requires.[198] The framework adopted in this Order will be used to evaluate Pepco's proposed MRP/PIMs proposal in this proceeding.

96. Based on the information the utility files, as the proponent of an AFOR, and any filings by intervenors, the Commission will determine on a case-by-case basis whether the principles of the framework have been met in the proposed AFOR under the specific facts and circumstances of the case. With the exception of those principles that are statutorily required, the remaining principles should be considered when presenting a well-designed/properly constructed AFOR.[199]

C. Pepco's AFOR Proposal

97. As explained in Section II, Pepco's AFOR Proposal in its Application consists of a MRP with PIMs. Pepco's MRP: (1) provides for three years of rates through 2022; (2) contains an annual adjustment/true-up mechanism; and (3) maintains an identical ROE to its traditional rate proposal. A PIM is a mechanism designed to provide an incentive for specific action by a utility. PIMs can often take the form of specific measurable metrics for a utility to track and report. In financial PIMs, if a utility exceeds a certain target, its ROE increases by a given amount, and if the utility underperforms, and it does not meet a certain target, its ROE decreases by a given amount. Pepco proposes four financial PIMs with incentives and penalties on specific utility performance: SAIDI, SAIFI, Customer Service Level, and DER Interconnection Review Timeframe. Pepco also proposes a fifth metric reporting PIM (collecting and reporting CEMI-4 performance) but without an incentive or penalty attached.

1) Pepco's MRP Proposal

98. The Commission, after reviewing the record, believes that a properly constructed MRP can produce just and reasonable rates and can be pursued at this time. The Commission

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[198] The Commission recognizes the evolution of other proceedings before the Commission (*e.g.*, PowerPath DC) and other District Government efforts (*e.g.*, clean energy and environmental goals) to advance its goals may require modifications to the framework. We will also continue to look to our neighboring jurisdictions including, Maryland, where Pepco also operates and regulatory alignment offers the potential for synergies regarding MRPs, as well as several other states that have established frameworks for MRPs.

[199] AFOR Principle (1) tracks the language of D.C. Code § 34-1504 (d) (2001), and AFOR Principle (2) tracks the language of D.C. Code § 34-808.02 (2019 Supp.) and must be addressed.

recognizes that we have the responsibility of balancing the interest of utilities, ratepayers and District policy goals to ensure just and reasonable rates. As the MD PSC recognized, there is no one size fits all solution to MRP/PIMs because each jurisdiction and its utilities are unique, face different challenges and have different objectives. In the District, the policy performance objectives for our utilities are clearly laid out in the District Government's Clean Energy DC Plan, the Commission's PowerPath DC Vision, and the performance objectives that are delineated in the Commission's quality of service regulations. DCG, DCCA, GRID2.0/DC CUB, and MDV-SEIA all indicate that PIMs should be crafted to promote the District policy goals. Evaluating a MRP will entail all the same challenges as evaluating a general rate case under our rules but with the added challenge of setting rates that will be adjusted over time. We believe a rate case will provide the best foundation for meeting these challenges. Thus, we will address Pepco's overall rate application in this proceeding. Pepco has provided all the requirements for a traditional rate case as well as its proposal for a MRP. As the proponent of a rate increase, Pepco will have the burden of proof to demonstrate that its MRP proposal can be approved and adopted at this time.

99. To assist in the Commission's determination regarding Pepco's MRP proposal, Pepco and the Parties shall develop and submit a detailed implementation recommendation in their supplemental and direct testimony. The testimony should address the following:

(1) Details regarding the forecasts that must be filed for subsequent years after the initial historic base year, including capital expenditures;
(2) A complete list of the proposed reporting requirements, measures, and timelines;
(3) Identify ways to make the utilities' planning process more transparent and open to the Commission and ratepayers;[200]
(4) Recommendations on requirements to decrease information asymmetries between the utility and the affected parties;[201]
(5) Proposals for an annual reconciliation and cost true-up mechanism (either downward adjustment, upward adjustment or both ways);
(6) Pros and Cons of stair-step vs. index (I-X)[202] approach;
(7) Proposals for Earning Sharing Mechanism;
(8) The role of Capital Trackers;
(9) Proposals for stay out provision;
(10) Proposed revisions to Title 15 of the DCMR for filing MRPs;
(11) Recommendations to ensure that existing Title 15 metrics (such as SAIFI, SAIDI, customer call metrics, etc.) are not eroded and remain intact through MRP adoption; and

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[200] In the technical conference, DCCA and DCG have mentioned that other states' distribution planning examples should be looked into such as California, New Hampshire, Michigan and Minnesota.

[201] DCG has indicated that information asymmetries are a key concern for MRP.

[202] I is referring to index for inflation and X is the productivity factor.

(12) The seventeen ratemaking adjustments in Pepco's direct testimony and any other adjustments to revenue requirements proposed by Pepco's MRP.[203]

100. It is clear from the comments, that MRPs also raise a number of critical issues that Parties should address in their filed testimony. Specifically, how does the reduced regulatory lag created by a MRP impact the risks borne by utility shareholders and, consequently, the required return on equity necessary to attract capital? Additionally, how will revenue requirements be allocated across customer classes over time, and how will rate design issues within customer classes be handled over time? Also, given information asymmetries between utilities, the Commission, and stakeholders, what is the appropriate way to adjust the revenue requirement over the course of a MRP? The Commission notes that DCG, while generally favoring the escalation of revenue based on "an external cost index to provide the allowed revenue for each year of the plan,"[204] identifies a number of mitigation strategies to address information asymmetry under a utility cost forecast approach. Alternatively, revenue increases could be based on a predetermined amount each year, rather than being tied to an index, resulting in a stair-step approach. Pepco, by contrast, proposes a detailed annual reconciliation mechanism that would account for various changes in its costs, which AOBA and DCG assert causes the MRP to operate like a formula rate. Further, how should the Commission assess the need for and application of any true-up or earning sharing mechanisms that are proposed? To the extent it deems necessary, Pepco is to file supplemental testimony addressing these and any other matters raised in this Order by January 21, 2020. Parties' testimony shall be filed by February 19, 2020.

2) District Specific PIMs

101. The Commission agrees with DCG and GRID 2.0/DC CUB's most recent filing that properly designed PIMs represent an important tool to align utility incentives with public policy goals, such as the District's aggressive clean energy and environmental goals.[205] As further discussed below in Paragraph 106, GRID2.0/DC CUB will be able to address their concerns afresh in the PIMs discussion meetings. This conclusion is further supported by the work of the *Formal Case No. 1130*, Rate Design Working Group, which stated that "while PIMs are a key component to PBR, they must be properly designed to support both a financially healthy utility and drive

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203 A MRP must be established on a base-line equivalent to a historical test year. The 12-month per book baseline must be adjusted to reflect known and measurable changes, normalization of volatile costs, and adjustments to reflect Commission practice regarding cost allowances and disallowances. Pepco has proposed a historical, per book baseline for its rate base, revenues, and expenses using the 12-months ended December 31, 2018. The Company has also proposed 17 ratemaking adjustments. The Parties should consider the baseline put forth by the Company and the appropriateness of the 17 proposed ratemaking adjustments. The Parties should include their position on Pepco's baseline, proposed adjustments and recommend other adjustments, if appropriate, when their testimony is filed.

204 *See* DCG's Comments at 14.

205 *See* GRID2.0/DC CUB's Comments at 3; DCG's Comments at 3-4; *See also* GRID2.0's Second Comments. We believe that our establishment of the three stakeholder meetings discussed in Paragraph 106 below, will facilitate how the Commission should regulate a "utility's performance in meeting the District's energy goals as set forth in the Clean Energy Plan and recent clean energy legislation." *See* GRID2.0's Second Comments at 2.

outcomes consistent with the MEDSIS Vision and the District's energy policies."[206] It is clear from the comments, and a review of the various states that have adopted AFORs, that the development of PIMs is more of an art than a science, but there are some clear guideposts for developing appropriate PIMs.

102. As OPC stated, there may be broad categories of PIMs inclusive of financial PIMs, which can be either symmetric or asymmetric (penalty only), and can take different forms (*e.g.*, dollar payments, basis points added to or subtracted from return on equity, or split-the-savings ,arrangements).[207] As a general matter, the Commission agrees with AOBA and BWLDC that a utility should not be rewarded for essential elements of its provision of utility service, such as service quality or customer service measures, absent some compelling justification because these costs of safe and reliable service are the basis for a utility's base rates. Such PIMs could also be structured with only a downside such that failure to provide a targeted service automatically penalizes a utility.

103. It is clear from the comments and experience in other states that stakeholders recognize the complexity of developing suitable and meaningful PIMs. After reviewing RAP's and Hawaii PUC's presentations, as well as Minnesota PUC's, Rhode Island PUC's, OPC's, DCG's and other Parties' comments and suggestions concerning PIMs, the Commission proposes the following broad general guidelines that Pepco and the Parties should further develop as they propose or address PIMs in subsequently filed testimony:

(1) PIMs should advance or otherwise align with the District's public policy goals and the PowerPath DC objectives (such as grid modernization, energy efficiency, clean energy, and climate goals);
(2) PIMs should be clearly defined;
(3) PIMs should be able to be quantified by the utility using reasonably available data;
(4) PIMs should be sufficiently objective and free from external influences;
(5) PIM should be easily interpreted and easily verified;
(6) PIM should not duplicate a target or objective that is already addressed by any existing standards, metrics or requirements;
(7) PIMs should focus on outcome rather than input (costs);
(8) PIMs should have historical performance data;
(9) PIMs should be considered only when the utility lacks an incentive (or has disincentive) to align its performance with the public interest, there is evidence of under-performance, and evidence that improved performance will deliver incremental benefits;
(10) PIMs should be designed to maximize total quantifiable, verifiable net benefits; and
(11) PIMs should offer the utility no more financial benefit than is necessary to align its performance with the public interest (the utility should not be paid

[206] *Formal Case No. 1130,* Final Report v1.0 of the DCPSC MEDSIS Stakeholder Working Groups at 132, filed May 31, 2019 ("Final WG Report").

[207] OPC's Comments at 32.

for performance above the value perceived by customers for that improvement).

104. The Commission will consider Pepco and the Parties' testimony and finalize this list in our final order if Pepco's MRP/PIM is adopted. As submitted in its Application, Pepco has only proposed four financial PIMs and one data reporting PIM. Additionally, Pepco has indicated that it is open to further PIMs that may be developed for inclusion in either this case or future cases.[208] DCG has identified a number of "gaps" which it recommends be addressed through metrics or actionable PIMs.[209] The Commission also observes that there is a need for historical performance data, as stated in guideline (8) above, which suggests that due to limitations in Pepco's current data collection practices, PIMs may be limited in this case. Further, the Commission notes that, as recognized by RAP and DCG, tracking specific data can be useful to understand utility performance, while creating a track record for future PIM development.

105. In setting the procedural schedule for this proceeding, the Commission, in Order No. 20204, explicitly recognized that PIMs under consideration would not be limited to those proposed by Pepco and would be developed during the course of this case.[210] The Commission put Parties on notice of the CleanEnergy DC Act's directive that PIMs for utility proposed energy efficiency and demand response programs would be developed by a working group, in *Formal Case No. 1160*, and filed with the Commission for consideration in January 2020.[211] Further, the Commission recognizes that our sister jurisdiction, Maryland, is concurrently developing PIMs that could be applied to our shared utility, Pepco. Finally, in setting up the procedural schedule, the Commission built in an extended amount of time, including additional rounds of testimony, in which to consider the various elements of Pepco's Application such as PIMs.

106. Therefore, to facilitate the Parties' and other stakeholders' engagement to develop and propose actionable PIMs, the Commission recommends that the Parties and other stakeholders, including PowerPath DC participants, meet and discuss what are achievable PIMs in this rate case, how PIMs can be utilized to advance the District's clean energy goals, and what information is suitable for tracking for future PIM development. Pepco, DCG, and OPC should work to facilitate the three meetings to occur between January 15, 2020 and March 31, 2020. The Commission notes that the timing of this discussion aligns with the filing and consideration of energy efficiency and

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208 Pepco's Application, Pepco (B) at 43 (McGowan). ("The Company will continue to participate in these initiatives throughout the year and would consider including additional PIMs into this filing, or the Company's next MRP filing, once PIMs and target metrics can be properly developed in alignment with the Commission's approvals.").

209 DCG Comments at 23-24.

210 *See Formal Case No. 1156*, Order No. 20204, ¶ 33.

211 *Formal Case No. 1156*, Order No. 20204, ¶ 33. The Commission set the first meeting of the Energy Efficiency and Demand Response Working Group for November 1, 2020, which provides for a filing date of the Group's recommendation on January 30, 2020. *See Formal Case No. 1160, In the Matter of the Development of Metrics for Electric Company and Gas Company Energy Efficiency and Demand Response Programs Pursuant to Section 201 (b) of the Clean Energy DC Omnibus Amendment Act of 2018* ("*Formal Case No. 1160*"), Public Notice, rel. October 3, 2019.

demand response PIMs proposed in *Formal Case No. 1160*.[212] After completion of the meetings, the Parties should include in their Rebuttal testimony those PIMs which they believe are trackable and achievable in this case. In their testimony, the proponent of any PIMs should review the general guidelines for PIMs identified in Paragraph 103. In addition, the Parties and other stakeholders should file a report, no later than 10 calendar days after the conclusion of the last meeting, that provides and gives detail on any consensus PIMs that the participants could agree on that should be developed in the future. The report should also note comments on any non-consensus PIMs that participants believe could be developed in the future.

D. Conclusion

107. As stated in D.C. Code § 34-1504 (d)(2), to approve AFORs, the Commission must ensure that the selected AFOR plan: (A) Protects consumers; (B) Ensures the quality, availability, and reliability of regulated electric services; and (C) Is in the interest of the public, including shareholders of the electric company. Further, as we stated in *Formal Case No. 1139*, Order No. 18846, "our focus in considering any alternative mechanism will include a review of the benefits that accrue to customers as opposed to solely focusing on the utility."[213] Moreover, as Pepco indicated, the burden of proof under AFOR should remain on the utility.

108. The Commission, at Paragraph 94, has set forth its overarching policy goals and framework for assessing AFORs in the District. This regulatory framework will assist the Commission in evaluating AFORs and will help us to determine if the utility's financial incentives and customers' needs align with the Commission's PowerPath DC objectives and the District's policy goals. Moreover, at Paragraph 99, the Commission has determined the essential elements that a proponent of an MRP should present for evaluation of an MRP which should include establishing a historical baseline test year, for determining costs and revenues. The MRP should also include a duration of a minimum of three (3) years. We believe that any MRP that is adopted should be accompanied by PIMs. Consistent with Paragraph 103, the Commission has set forth the guidelines for PIMs in the District.

109. As discussed at Paragraph 99, the Commission has directed Pepco and the Parties to submit a detailed implementation recommendation their supplemental and direct testimony. Similarly, as outlined in Paragraph 106, Pepco and the other Parties after discussions should include in their rebuttal testimony those PIMs which they believe are trackable and achievable in this case.

110. The Commission sets forth, in Attachment A, a modified schedule to accommodate the Supplemental testimony and the additional PIM process/working and settlement conferences that we have directed in this Order.

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212 *See Formal Case No. 1160*, Public Notice, rel. October 3, 2019. The Commission set the first meeting of the Energy Efficiency and Demand Response Working Group for November 1, 2020, which provides for a filing date of the Group's recommendation on January 30, 2020.

213 *Formal Case No. 1139*, Order No. 18846, ⁋ 594.

111. Lastly, the Commission sought comments from the Parties and stakeholders on what rules or regulations would need to be developed and implemented if the Commission were to approve AFORs. After reviewing the comments from the Technical Conference, the Commission believes that the question was premature and that the Parties should have the opportunity to propose AFOR rules as part of their filed testimony.

THEREFORE, IT IS ORDERED THAT:

112. DC Climate Action's Motion to File Out of Time is **GRANTED**;

113. The Commission's overarching policy concerns and goals for establishing the framework for Alternative Forms of Regulations in the District of Columbia, for the purposes of this case, are set forth in Paragraph 94;

114. The Potomac Electric Power Company, to the extent it deems it necessary, **MAY FILE** Supplemental Direct Testimony consistent with Paragraphs 89 through 106 of this Order by January 21, 2020;

115. The Office of the People's Counsel and Intervenors **SHALL FILE** their Direct Testimony, and include, among other things, testimony consistent with Paragraph 99 of this Order by February 19, 2020;

116. The Potomac Electric Power Company, the District Government, and the Office of the People's Counsel **SHALL CONVENE AND FACILITATE** three meetings inviting all Parties, stakeholders, and the PowerPath DC participants to continue the discussions on what are achievable Performance Incentive Mechanisms in this rate case as it relates to the policies and goals that the Commission set forth in Paragraph 103 of this Order; the three meetings **SHALL** occur between January 15, 2020, and March 31, 2020; and

117. The Parties and other stakeholders shall file a report, no later than 10 calendar days after the conclusion of the last PIMs' meeting, that provides and gives detail on any consensus PIMs that the participants agreed on for development in the future.

A TRUE COPY: **BY DIRECTION OF THE COMMISSION:**

CHIEF CLERK: **BRINDA WESTBROOK-SEDGWICK**
COMMISSION SECRETARY

ATTACHMENT A: REVISED PROCEDURAL SCHEDULE

Action	**Date**
Pepco Application Filed	May 30, 2019
Public Notice Issued	June 13, 2019
Petitions to Intervene	June 19, 2019
Discovery Begins	June 28, 2019
Technical Conference I – CCOSS Model	July 16, 2019
Technical Conference II – Construction	July 25, 2019
Pepco **Supplemental Direct / Updates to Actuals** for the Test-Year with Variance Explanations by Account	September 16, 2019
Technical Conference III – Framework for Evaluating Alternative Ratemaking Proposals	September 25-26, 2019
Comments from all Stakeholders on Technical Conference III	October 15, 2019
Technical Conference IV – MRP Annual Reconciliation and BSA Frameworks	October 24, 2019
Policy Order on Alternative Ratemaking Framework	December 20, 2019
Three Discussion of possible PIMs development in the District	Between January 15, 2020 and March 31, 2020
Pepco **Supplemental Direct addressing Policy Order No. 20273**	January 21, 2020
OPC/Intervenors file **Direct Testimony**, Exhibits and Workpapers	February 19, 2020
Settlement & Stipulation Conference	By March 6, 2020
Report on Settlement & Stipulation Conference	By March 11, 2020
All Parties file **Rebuttal Testimony**, Exhibits and Workpapers	April 8, 2020
All Parties file **Surrebuttal Testimony**, Exhibits and Workpapers	May 20, 2020
Community Hearings (Date & Locations)	TBD
Discovery Ends	May 22, 2020
Settlement & Stipulation Conference	May 27, 2020
Joint Prehearing Statement and Report on Settlement & Stipulation Conference	May 29, 2020
Prehearing Status Conference	June 3, 2020
Order and Report on Status Conference	June 17, 2020
Hearings	Week of June 29, 2020
Post-Hearing Brief	August 26, 2020
Post-Hearing Reply Brief	September 10, 2020

ATTACHMENT B: PARTIES AND INTERESTED PERSONS COMMENTS

A. Pepco

1. Pepco provides comments on the questions discussed in Panels 1 and 2 of Technical Conference III.[214] With regard to the issues presented to Panel 1, Pepco recommends that the Commission primarily consider the existing laws regarding its selection of an appropriate type of alternative regulation mechanism, citing to DC Code Section 34-1504(d) as the standard for consideration of an alternative regulation mechanism because it must (1) protect customers, (2) ensure the quality, availability and reliability of regulated electric services, and (3) in the public interest, including the interests of shareholders of the utility.[215] Pepco recommends that the Commission consider several factors in evaluating a specific alternative regulation proposal: (1) are the resulting rates just and reasonable, (2) does the proposal support the District's energy and other policy goals, (3) does the proposal support the Commission's policy goals, (4) does the proposal provide adequate customer protections, (5) does the proposal provide for a financially healthy utility, and (6) does the proposal lower administrative and regulatory costs and burdens.[216]

2. Pepco contends that public utilities should be permitted to choose among three MRP options: (1) the utility could elect to submit evidence similar to that required in a traditional rate proceeding to support its costs and revenues over the years requested in the MRP, using internal corporate forecasts. (2) In the alternative, in situations where Pepco states that it is appropriate to use an escalation factor, the utility should be permitted to present evidence supporting an escalation factor to be applied to a traditional "base case" cost and revenue determination. In this alternative proposal, Pepco states that the utility provide evidence that supports the escalation factor used. (3) Lastly, Pepco maintains that the utility should be allowed to use a hybrid approach combining forecasting in certain areas and using an escalation factor in other areas.[217]

3. With regard to PIMs, Pepco asserts that public utilities should propose a description of the PIMs being proposed; a detailed rationale supporting each PIM, including the benefits to consumers; baseline data with respect to each PIM to permit analysis of future performance of the utility; and clear metrics to determine whether the utility meets the goals of each PIM. Pepco adds that the utility should be required to submit evidence supporting its proposals for revenue adjustments in the event that the utility exceeds or falls below the targets for the respective PIMs.[218]

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214 Pepco's Comments at 1.

215 Pepco's Comments at 3; Pepco cites DC Code §34-l504 (d)(1): "Notwithstanding any other provision of law, the Commission may regulate the regulated services of the electric company through alternative forms of regulation."

216 Pepco's Comments at 3-4.

217 Pepco's Comments at 4.

218 Pepco's Comments at 4.

4. With regard to the benefits of any alternative forms of regulation, including performance-based ratemaking ("PBR") or MRP/PIM, relative to its costs/risks, Pepco cites the presentation from The Regulatory Assistance Project ("RAP"), wherein the presenter states that "PBR is a powerful tool in the regulator's tool box."[219] The benefits of MRPs, according to Pepco, are the reduction and frequency of rate cases, lowering costs to customers and reducing the administrative burden on the Commission and stakeholders. It also provides incentives to the utility to be more efficient.[220] As a result, the Commission, the utility and intervenors will expend fewer resources on rate case proceedings under a MRP. Pepco points out that many presenters assert that PBR and MRPs/PIMs are not new, that many states have adopted and are benefitting from PBR and MRPs. Pepco cites two states that are beginning to adopt PBR and MRPs as examples, Hawaii and Maryland. Pepco also cites the Commission's willingness to consider alternative ratemaking in *Formal Case No. 1139*, the Commission stated that it was "not averse to allowing Pepco to include in its next rate case a request for a fully forecasted test year or a multi-year rate proposal, in addition to a traditional test year filing...."[221] Pepco states that because the benefits of various alternative rate methodologies may differ, its comments focus on MRPs in its discussion.[222]

5. Pepco explains that PBR uses specific performance metrics, targets or incentives to influence utility performance in ways that support jurisdictional priorities. Citing the RAP presentation, Pepco maintains that MRPs and PIMs improve the alignment of utility performance with the goals of the District and Commission to facilitate investment that support the District's policies.[223] This, according to Pepco, produces a fair distribution of risk between utilities and customers, citing the Hawaii Commission's presentation.[224] Pepco also mentions favorably the District Government's presentation asserting that MRPs increase innovation by allowing the utility to manage business decisions with greater flexibility.[225] Pepco argues favorably about the many benefits of MRPs. MRPs provide the Commission and stakeholders with a long-term view of future capital investments and operation and maintenance ("O&M") costs, as the utility is required to submit information regarding its financial plans during the full MRP period.[226] Pepco contrasts MRPs with a traditional rate case that relies on historical costs, stating that the Commission and stakeholders are able to review the utility's financial plan in advance of the money being spent. Among other benefits to customers, MRPs provide increased transparency, leading to increased

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219 Pepco's Comments at 5; *citing* RAP Panel I Presentation, slide 47.

220 Pepco's Comments at 5; *citing* Synapse Panel I Presentation, slide 2.

221 Pepco's Comments at 5; *citing Formal Case No. 1139,* Order No. 18846, ¶ 594.

222 Pepco's Comments at 5.

223 Pepco's Comments at 6, *citing* RAP Panel 1 Presentation, slide 7

224 Pepco's Comments at 6, *citing* Hawaii Commission Panel 2 Presentation, slide 3.

225 Pepco's Comments at 6.

226 Pepco's Comments at 6, *citing* EEI's presentation.

utility accountability and provides incentives for the utility to manage resources and administrative costs.[227]

6. Pepco asserts that MRPs provide rate predictability to customers, which is not available under the traditional ratemaking process. To assist them in their decision-making and planning processes, a reconciliation mechanism that provides customers with greater bill certainty. Pepco adds that adjustments resulting from the reconciliation process, which may increase or decrease bill changes, are subject to Commission review and approval. Such reconciliation adjustments, according to Pepco, would be more akin to a "fine tuning" of, rather than significant modifications to, the amount of bill changes and would serve to protect customers.[228] Pepco offers that a MRP proposal may improve the overall financial health of the utility. It reasons that borrowing costs and rates may be lowered and access to capital may improve to allow the utility to earn its approved return and also eliminates "regulatory lag."[229] Pepco contrasts traditional ratemaking methodologies under which the utility recovers the costs investments well after they are incurred-in many cases 12 to 24 months later- while under a MRP those costs can be recovered more timely. The result, according to Pepco, is a MRP that will reduce the number of rate cases a utility will be required to file to recover the costs of the investments essential to meet the District's goals.[230] With regard to PIMs, Pepco cites Order No. 18846[231] and asserts that PIMs can improve specific areas of utility performance, providing targeted benefits to customers, but to realize the benefits of PIMs, they need to be structured properly using clearly defined and measurable performance criteria. Metrics,[232] according to Pepco, must be defined as well as outputs[233] and outcomes.[234]

7. With regard to how can the Commission assure ratepayers, under alternative ratemaking including MRPs, that they are paying only for prudent and efficient costs, and that the burden of proof remains with the public utility to show that a proposed rate change is just and reasonable, Pepco states in response that the Commission's level of oversight should remain the same regardless of the ratemaking plan adopted. It adds that the burden of proof, with regard to

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227 Pepco's Comments at 6.

228 Pepco's Comments at 6-7.

229 Pepco's Comments at 7, *citing* RRA Panel I Presentation, slide 18.

230 Pepco's Comments at 7.

231 The Commission noted in *Formal Case No. 1139*, Order No. 18846, ¶ 595, "[m]ost multi-year rate plans feature a performance metric system that includes some performance incentive mechanisms ("PIM"). These PIMs provide awards or penalties, or both, for performance in targeted areas."

232 Pepco's Comments at 7, *citing* RAP Panel I Presentation, slide 15.

233 Pepco's Comments at 7, *citing* RAP Panel I Presentation, slide 16. According to the RAP presenter, "[o]utputs are specific results of utility actions, often measured as a measurable performance criteria or metrics."

234 Pepco's Comments at 7, *citing* RAP Panel I Presentation, slide 16. According to the RAP presenter, "[o]utcomes are how utility services affect [customers] and society and are the desired results from a specific guiding goal, directional incentive and/or operational incentive."

justifying its rate proposal and the costs it seeks to recover through rates were prudently incurred, would remain on the utility. Pepco asserts that, in the case of a MRP, the Commission's oversight ability is enhanced with a longer-term view of future capital and O&M investments before the utility makes the investments, increasing transparency. Pepco adds that the Commission retains jurisdiction to fully evaluate a utility's rate filing and to provide any necessary guidance regarding ratemaking initiatives.[235] Pepco asserts that the Commission's oversight ability is enhanced through the utility providing ongoing reporting as part of the MRP, and through its annual reconciliation filings. These filings, according to Pepco, will permit the Commission and interested parties to carefully review the utility's annual expenditures and costs and to allow them to review actual results versus projections. A reconciliation mechanism in place will provide additional insurance that the utility's rates remain just and reasonable and customer rates reflect the utility's investments. Pepco adds that reconciliations also will benefit customers "if a utility earns a return higher than that authorized."[236] Moreover, Pepco states that any MRP proposal should also include a provision that would permit a party, or the Commission on its own motion, to propose to re-open and review the MRP if there is an issue that cannot be resolved in any other manner under the proposal *(e.g.,* new legislation adopted that materially decreases the utility's costs).[237]

8. In response to the issue of the key decision factors (metrics or criteria) to be used to evaluate and select an alternative form of regulation which will balance the public utility's cost recovery (including whether a decoupling mechanism should be applied), earning sharing mechanism, incentives for the public utility to improve its targeted performance, rate impact, consumer interest, grid modernization, clean energy and environmental policies/goals, affordability and reliability goals to meet public interest, Pepco reiterates its response to Question 1, in which the Company recommends that the Commission primarily consider the existing laws, specifically, the Commission should use DC Code §34-1504(d) as the standard for consideration of an alternative regulation mechanism. Pepco adds that once the Commission selects an alternative regulation mechanism, the Commission should consider the six factors previously discussed in response to Question 1 in its evaluation of a specific alternative regulation proposal.[238] Pepco discusses how multiple states have implemented both alternative ratemaking, in the form of multiyear rate plans and decoupling, but addressing different goals and concerns. According to Pepco, revenue decoupling is designed to assist utilities, states, and consumers in meeting environmental and market outcomes by de-linking utility revenue from the level of commodity sales made. In contrast, Pepco asserts that alternative ratemaking attempts to encourage utility efficiency and cost savings, while also addressing concerns with regulatory lag and use of resources for frequent rate cases. Pepco asserts that there is no reason why a utility cannot have both a MRP and decoupling in place simultaneously, even in taking into account the interests of

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[235] Pepco's Comments at 8.

[236] Pepco's Comments at 8-9, *citing* Maryland Commission Panel 2 Presentation, slide 23.

[237] Pepco's Comments at 9.

[238] Pepco's Comments at 9.

meeting the District's climate initiatives. Pepco notes from the participants' statements that several states allow both alternative ratemaking mechanisms and decoupling.[239]

9. In response to the question of what specific performance outcomes and targets by the public utility should be measured and reported, inclusive of those aligned with the District's clean energy goals, Pepco cites the CleanEnergy DC Act, passed in January 2019.[240] The objectives of the CleanEnergy DC Act, according to Pepco, are to expand the District's renewable portfolio standard ("RPS") to 100% renewable electricity by 2032 and to reduce greenhouse gas ("GHG") emissions some 50% by 2032. Pepco avers that the CleanEnergy DC Act increased access to energy efficiency programs for low- and moderate-income residents, expanded solar energy in the District and expanded transportation GHG emissions reductions. Pepco also believes that there is a general consensus among the stakeholders that participated in the technical conference regarding the importance of the District's energy goals.[241] Pepco asserts that the Commission built upon this progress with the issuance of its proposed order in PowerPath DC, in which it proposed the integration of more non-wire alternatives through Pepco's improved distribution system planning process; greater data access by customers and third parties; increased distributed energy resource deployment - including the need for demonstration projects; consolidated and enhanced customer education materials; development of energy efficiency programs for master metered apartments; and alternative technological advancements.[242] According to Pepco, the proceedings currently underway at the Commission will identify the specific performance outcomes and outputs to achieve the District's and Commission's policy goals. Pepco states that outcomes and outputs from these and other Commission workstreams will help identify PIMs supporting District and Commission goals that could be incorporated into a MRP in the future.

10. Regarding additional key goals for the electric utilities for which performance metrics should be developed, Pepco reiterates that PIMs can be used to drive policy and incentivize utilities to perform at or above the target levels, in support of the District's and Commission's policies and goals. The effectiveness of PIMs, according to Pepco, is dependent on measurability, and should measure activities for which the utility is reasonably able to impact the outcome or output. For activities outside of the utility's ability to impact, Pepco recommends that the Commission use tracking mechanisms rather than PIMs in order to gather data.[243] When considered in the future, Pepco states that PIMs may reflect reliability metrics, service level metrics, interconnection metrics, supplier diversity and local business engagement metrics, energy efficiency metrics, and metrics based on the utility's efforts to reduce the greenhouse gas emissions

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[239] Pepco's Comments at 10.

[240] Pepco's Comments at 10; *citing* DC Law 22-257, effective March 22, 2019.

[241] Pepco's Comments at 10; Pepco states that the CleanEnergy DC Act expressly requires that the Commission in its supervision and regulation of utilities consider "the preservation of environmental quality, including effects on global climate change and the District's public climate commitments." D.C. Code §34-808.02.

[242] Pepco's Comments at 10.

[243] Pepco's Comments at 12.

produced by its operations.[244] Pepco comments that it and the Commission currently measure reliability, service level and abandonment rates, and certain aspects of interconnection of distributed energy resources. Pepco adds that the metrics were developed through Electric Quality of Service Standards ("EQSS") *(e.g.,* service level and abandonment rates), merger commitments *(e.g.,* SAIDI and SAIFI), and separate rulemakings and Commission orders *(e.g.,* small generator interconnection standards). Citing the discussion from RAP, Pepco states that customer service and reliability metrics help ensure that utility performance continues to be strong in light of cost management incentives in MRPs.[245] Pepco also cites the Minnesota Public Utilities Commission's implementation of several reliability and customer service PIMs.[246]

11. Pepco asserts that PIMs should be structured to reflect how a particular utility operates, as every company and jurisdiction is slightly different and what works for one may not be appropriate in another without modification. Pepco adds that the metrics selected for the PIM should permit the utility to communicate clearly to the Commission given the utilities existing operational standards. Pepco also recommends that PIMs should be measured based on appropriate trackable standards that are within the utility's ability to impact and should also incorporate a reasonable deadband. Finally, Pepco states that the metrics used to measure PIMs must be able to be verified on a cost effectiveness basis.[247]

12. With regard to whether rate design (revenue requirement allocation to various customer classes) should stay the same for all the rate years within a MRP, Pepco comments that any discrete change to rate design can be made in the context of either a traditional test period rate case or a MRP. Pepco explains that in a MRP, rate design and class cost of service should remain the same throughout the term of the MRP, and that the rate design should be determined prior to the beginning of the MRP. Pepco recommends that the Commission consider the same factors that it currently considers when evaluating rate design proposals. The Company states that class cost of service should be based on the traditional test period or historical data and that the jurisdictional allocation, which represents costs allocated between multiple jurisdictions based on work activity, should be able to change from year to year based on the forecasted allocation. Pepco reiterates that alternative regulation does not reduce the need for a decoupling mechanism, and several utilities have both mechanisms.[248]

13. Pepco references a number of mechanisms and/or incentives that the Commission could consider ensuring effective review of forecast methodology and data inputs. As examples,

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244 Pepco's Comments at 12.

245 Pepco's Comments at 12-13, *citing* RAP Panel I Presentation, slide 32 and discussion.

246 Pepco's Comments at 12-13, *citing In the Matter of a Commission Investigation to Identify Performance Metrics and Potentially Incentives for Xcel Energy's Electric Utility Operation,* Docket No. E-002/Cl-17-40 I, Order Establishing Performance Metrics, rel. September 18, 2019. Pepco also cites the presenter from the Maryland Public Service Commission who stated, "[s]uperior performance by a utility results in increased profits, while inferior performance may lead to decreased profits." Maryland Commission Panel 2 Presentation, slide 13.

247 Pepco's Comments at 13.

248 Pepco's Comments at 14.

Pepco states that the Commission could require that the utility provide information regarding its budget and financial forecasting process, including narrative explanations of the process and specific data underlying the financial forecasts. Such a proposal, according to Pepco, should include a year's historical data to allow the Commission and parties a foundation from which to view the forecasted costs. Pepco adds that in order to include appropriate context for the costs, the proposal should provide a list of initiatives and the financial planning assumptions.[249] With regard to forecasting methodology, Pepco states that the Commission and parties should have the opportunity to review it with respect to an alternative ratemaking proceeding, such as a MRP proceeding, providing transparency into the financial planning and financial forecasting. Citing the District Government's presenter, Pepco states that earnings sharing mechanisms generally contain deadbands, within which no earnings are shared, thereby creating a strong incentive for the utility to operate efficiently.[250]

14. Pepco states that utility proposals should contain an annual reconciliation mechanism that helps streamline the regulatory process and improve administrative efficiencies. Pepco reasons that annual reconciliations balance the need for customer protections and transparency with the administrative burden and cost of repeated filings. Pepco cautions that in order to achieve the appropriate balance, the annual reconciliation should not become a mini rate case examining all costs every year. Pepco believes that the time to challenge the MRP or other alternative rate proposal is when the proposal is being litigated in the first instance. Pepco recommends that the parties be given a period of discovery commensurate with the streamlined process and then afforded the opportunity to provide comments to which the utility should be able to reply. The Commission could then issue an order.[251]

15. Pepco argues against the recoverability of a cost determined to be imprudent by the Commission, regardless of whether a traditional or an alternative form of regulation is used. Pepco points out that an important aspect of a MRP is an annual reconciliation mechanism that inures to the benefit of both the customer and the utility. Such a mechanism, according to Pepco, can ensure the appropriate sharing of risk and that the use of a deadband creates an incentive for the utility to control costs, because if results fall within the deadband, there is no adjustment to rates, and no sharing is required. Pepco suggests that annual reconciliation filings can be designed to provide adequate information and reporting and an explanation of material variances between actual utility costs and forecasts.[252]

16. Pepco maintains that alternative regulation should be designed to recover the revenue requirement, including the cost of specific investments, planned capital programs and O&M costs. Pepco maintains that a meaningful alternative regulation proposal provides flexibility to the utility to deploy capital and make system investments as system needs change over time. The Company suggests that a utility's internal financial planning forecast can be used as the basis

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249 Pepco's Comments at 14-15.

250 Pepco's Comments at 15.

251 Pepco's Comments at 16.

252 Pepco's Comments at 16-17.

for setting its rates, such as through a MRP. It adds that annual reporting provides an opportunity for the utility to apprise parties and the Commission of the status of key projects.[253]

17. Pepco points out that the Commission already engages in extensive public outreach regarding utility proposals and provides opportunities for public comment. For this reason, Pepco asserts that the Commission would not need to adopt additional notification procedures regarding an alternative ratemaking proposal. It adds, however, that any notices provided should clearly state that the utility has made such a proposal.[254] Pepco also recommends that the Commission ensure that there are transparent, informal processes outside of any formal rate case proceeding, such as workshops or technical conferences, which afford interested parties the opportunity to be informed of the alternative ratemaking proposal and to have the opportunity to offer feedback to the utility. The Company suggests that workshops or technical conferences allow parties to gain a better understanding of performance-based regulation, alternative ratemaking, performance incentive mechanisms and similar elements of alternative ratemaking.[255] Lastly, Pepco suggests that ongoing community engagement by the utility provides an opportunity to inform customers and community leaders.[256]

18. With regard to Capital Structure and Rate of Return, Pepco recommends that the capital structure (percent of equity and debt) and authorized ROE should be established at the beginning of the MRP and remain constant over the term of the MRP. Pepco reasons that by setting the ROE for the entirety of the term allows the utility to plan and alleviates the administrative burden and cost to re-litigate and seek an authorized ROE each year. Pepco also suggests that the cost of debt be established at the beginning of the MRP, but if an annual reconciliation filing is included, the cost of debt should be adjusted annually to reflect the most current cost of financing with any adjustment flowing through the annual reconciliation filing.[257]

19. With regard to considerations in establishing a ROE, Pepco describes utility companies as capital-intensive, needing to finance large and long-lived projects with the help of externally generated funds from investors. Because the ratio of revenues generated by a utility is low relative to the level of capital investments it makes, Pepco states that a utility does not generate adequate cash flow generally to fund its capital construction program. To resolve this issue, Pepco asserts that in order to meet the obligation to provide safe and reliable service and meet the changing and growing needs of customers and stakeholders, utilities require access to investor-supplied capital. Pepco adds that to attract external funds, a utility must provide a competitive return to investors given the risk of the business and the industry in which the utility operates. To do so, a utility must compete with other utilities and other firms in the capital markets. To Pepco, a reasonable return should be competitive with those available on investments of comparable risk.

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[253] Pepco's Comments at 17.

[254] Pepco's Comments at 18.

[255] Pepco's Comments at 18.

[256] Pepco's Comments at 18.

[257] Pepco's Comments at 18-19.

Pepco asserts that with the many choices investors have, they will favor investing in companies that offer competitive and reasonable investment returns over companies that offer less competitive or bottom-of-the range investment returns. Pepco notes the comment during Technical Conference III that, a competitive return "[r]ecognizes the level of risk facing the company as compared to alternative investment options" and is viewed in comparison to industry averages.[258]

20. In response to the issues presented to Panel 2, Pepco summarizes that performance based and alternative regulation has been widely applied throughout the country and internationally. Pepco states that 17 states have MRPs,[259]16 states have PIMs,[260] and several more states have many years of experience with both PIMs and MRPs. Pepco cites as examples, New York, which it states has used MRPs since the 1970s, when they were adopted to address the need to reduce workload for the New York Commission's staff, and the California Public Utility Commission ("California PUC") which, Pepco asserts, has one of the longest history of PBR (although its plans are not always called PBR) in North America for retail energy utility services. Pepco asserts that PBR was initially implemented in California to contain costs and better align utilities' strategies with public policy goals (largely conservation efforts at the time).[261] Pepco also cites Massachusetts as having established PIMs more than a decade ago.[262]

21. Pepco explains that alternative forms of regulation have evolved over time, citing the California PUC's initial approval of two-year MRPs for Southern California Edison in 1980. It states that the standard plan increased to three years in 1984, and increased to four- and five-year rate plans, though less common, that have been approved by the California PUC. Pepco adds that different forms of attrition relief mechanisms ("ARMs") and energy cost trackers to be incorporated into such rate plans to account for additional revenue requirements between rate cases have been permitted by the California PUC.[263] Pepco also asserts that utilities in California have experimented with different rate designs and demand-side management PIMs. Pepco states that such PIMs have been effective in furthering demand-side management goals, but the California

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[258] Pepco's Comments at 19; *citing* RRA Panel 2 Presentation, slide 18.

[259] Pepco's Comments at 21; Pepco states that this includes states that have a multiyear rate plan for either natural gas or electric utilities. Grid Modernization Laboratory Consortium, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," sponsored by the U.S. Department of Energy, July 2017.

[260] Pepco's Comments at 21; *citing* O'Neill Management Consulting, LLC, "Recommendations for Strengthening the Massachusetts Department of Public Utilities' Service Quality Standards," Prepared for the Massachusetts Office of the Attorney General, December 2012.

[261] Pepco's Comments at 22; Pepco suggests for additional detail, *see also* Grid Modernization Laboratory Consortium, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," sponsored by the U.S. Department of Energy, July 2017.

[262] Pepco's Comments at 22.

[263] Pepco's Comments at 22; Pepco states that revenue decoupling has also been implemented to mitigate the incentive for utilities to boost retail sales and further power conservation policy goals.

PUC has not explored earnings sharing mechanisms and service quality PIMs as much as other jurisdictions.[264]

22. Pepco comments that there are no industry-wide surveys of best practices for the reconciliation process, generally, but recommends that the reconciliation process should have the following characteristics: (a) Limited in scope and focused on resolution of reconciliation-related issues; it should not be used to re-litigate issues that the Commission resolved in the base rate case *(e.g.,* rate design); (b) Time limited in order to mitigate impacts of regulatory lag and allow timely reconciliation, which can provide customer and utility benefits; and (c) Standardized such that filing expectations are clear and sufficient to allow an efficient regulatory process.[265] With respect as to whether an alternative form of regulation always requires a proposal for base year (historical test year), a bridge year and one or more forecasted test years, Pepco recommends that when forecasting continuing expenses, historical data should be provided to allow for the benchmarking of forecasts.

23. Pepco cites *Formal Case No. 1139*, Order No. 18846, to indicate the importance of a reconciliation mechanism for any alternative regulation proposal.[266] Pepco lists what it believes the reconciliation process should be: (a) Limited in scope and focused on resolution of reconciliation-related issues rather than re-litigating issues that were decided in the general rate case such as rate design; (b) Time limited to mitigate impacts of regulatory lag and allow timely reconciliation so that benefits are timely incorporated into rates; and (c) Standardized such that filing expectations are clear and sufficient to allow for an orderly and efficient regulatory process.[267]

24. Pepco comments that many jurisdictions appear to have successfully implemented MRPs and PIMs. Pepco cites the continued use of alternative ratemaking mechanisms by states over many years along with a continued increase in the number of states moving toward the use of alternative ratemaking to show that alternative ratemaking is meeting the objectives of the states and leads to just and reasonable rates. As examples, Pepco cites several evolving public policy goals, such as reducing GHG and increasing the penetration of electric vehicles, that have been addressed through the adoption of PIMs. Pepco distinguishes PIMs from "tracking only" metrics through the use of a financial impact (either penalty or reward). Pepco asserts that New York has the most PIMs related to evolving public policy goals in place through its Earning Adjustment Mechanisms or ("EAMs"), and that the state of Hawaii is also developing new PIMs and has identified a number of areas on which to focus its efforts.[268]

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264 Pepco's Comments at 22.

265 Pepco's Comments at 23.

266 Pepco's Comments at 24; Pepco states that the Commission directed it "to provide a mechanism which allows parties to reconcile any forecasted components to subsequent actuals for the same test year." *Formal Case No. 1139*, Order No. 18846, ¶ 594.

267 Pepco's Comments at 24-25.

268 Pepco's Comments at 25.

25. Pepco cites the experience of the New York Public Service Commission, which issued the NY Reforming the Energy Vision ("REV") Track Two Order in May 2016, creating a new regulatory model that incentivizes utilities to achieve objectives such as attracting distributed energy resources ("DERs") and reducing GHG. Pepco states that as part of the NY REV proceeding, EAMs were established—a form of performance incentive under which utilities can earn a return for achieving NY REV objectives. Pepco cites five "opportunity areas" the New York Commission identified for utilities to develop EAMs and allowed a maximum of 100-basis point reward across the EAMs. Pepco states that EAMs are evaluated by the New York Commission for their effectiveness in areas such as: system efficiency and peak reduction; energy efficiency; distributed generation interconnection; customer engagement; and GHG reduction. Pepco adds that Consolidated Edison's EAM proposal initially included six EAMs that could provide the utility with a reward but not a penalty and two reporting only EAMs.[269]

26. Pepco cites the Hawaii Public Utilities Commission for having identified three areas in which to develop two to six new PIMs: interconnection experience, customer engagement, and DER asset effectiveness.[270] The development of the individual metrics within the three areas is ongoing through a stakeholder process. In addition to the new PIMs, the Hawaii Public Utilities Commission proposed developing new shared saving mechanisms and reporting-only metrics (some with goals).

27. Lastly, Pepco cites Rhode Island, wherein an initial settlement that was negotiated by National Grid and parties included seven public-policy-oriented PIMs; but an amended settlement maintained only one of the seven. Pepco describes the PIM approved by the Rhode Island Public Utilities Commission ("RI PUC") in the amended settlement as having an annual MW capacity savings which the RI PUC implemented as a peak reduction program. Pepco states that the RI PUC decided to track additional metrics (which had been PIMs in the original settlement) without financial consequences. Pepco states that the RI PUC left open the potential for National Grid to become eligible for a performance incentive for additional metrics, such as: installed energy storage capacity; avoided CO2 from consumer electric vehicles; light duty government and commercial fleet electrification; awarded low-income and multi-unit EV service equipment ("EVSE") sites; interconnection (time to ATl).[271] Pepco adds that the RI PUC is actively engaged in a review of principles to guide the development of PIMs.[272]

28. Pepco explains that MRP reconciliations based on earnings are relatively common. As of 2015, according to Pepco, 14 states had electric MRPs and of those, 10 had reconciliations,

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[269] Pepco's Comments at 26; Pepco states since this time, the "Distributed Generation Interconnection" has been removed due to improved performance and statistically unreliable survey data from developers, which underlies a portion of the EAM.

[270] Pepco's Comments at 26-27; *citing* Public Utilities Commission of the State of Hawaii, Decision and Order No. 36326, Docket No. 2018-0088, (May 23, 2019).

[271] Pepco's Comments at 27; Pepco states that National Grid also has a non-wires alternative program called "System Reliability Procurement."

[272] Pepco's Comments at 27; *citing* http://www.ripuc.org/eventsactions/docket/4943page.html.

which are typically referred to as earning sharing mechanisms ("ESMs").[273] Pepco describes ESMs as mostly asymmetric, reconciling only over-earnings, and can vary significantly in structure. It states that some include a deadband in which no sharing takes place, and if earnings fall outside of the deadband established for the ESM, sharing may include several "bands" with varying percentages of sharing between customers and the utility depending on how far outside of the deadband the actual earnings fall (e.g., 50/50, 75/25, 90/10). Pepco explains that the ESM for Consolidated Edison as having a 50 basis point deadband. The first sharing band is 50 basis points wide and shares overearnings 50% to customers. The second sharing band is 50 basis points wide and shares overearnings 75% with customers. The final sharing band, is any overearnings beyond the first two bands, is shared 90% with customers.[274]

29. Commenting on Hawaii's experience, Pepco states that, historically Hawaiian electric companies have had a one-sided ESM in which only over-earnings were shared with customers, but the Commission staff in Hawaii recently proposed, and the Hawaii Commission prioritized in its order, the development of an ESM with "upside" and "downside" sharing outside a deadband. According to Pepco, the design of an appropriate deadband and sharing bands is now being discussed through a stakeholder process. Pepco states that the Hawaii Commission retained the use of revenue decoupling to true up revenues to an annual revenue target as part of the MRP. According to Pepco, its understanding is that the Staff of the MD PSC is also currently considering a reconciliation process that incorporates an "upside" and "downside" true up mechanism in Case No. 9618.[275]

30. Pepco comments that MRP revenue requirements/price caps are set in the rate case and are not updated during the term of the plan. Pepco adds that although updated forecasts for revenue requirements are typically not required, MRPs often include one or more mechanisms to allow for "course correction" if initial forecasts differ significantly from actual results.[276] Pepco includes possible mechanisms: (a) Earning sharing mechanisms that allow the MRP to correct based on the earnings actually achieved as compared to the regulated allowed earnings; (b) Reconciliations that adjust for specific types of costs *(e.g.,* property tax or pension) or capital expenditures (or plant in service), although reconciliations for specific investments are generally related to larger projects, such as a new generating facility; (c) Accommodations, such as deferred accounting to address extraordinary events, that appropriately allow the utility to absorb (or refund) unanticipated large expenditures in areas that are outside of the utility's control, such as major storm costs or changes in tax laws; and (d) Off-ramps and reopeners that allow the Commission on its own motion or the parties to request the Commission to review the approved

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[273] Pepco's Comments at 28; *citing* Edison Electric Institute, Alternative Regulation for Emerging Utility Challenges: 2015 Update, prepared by Pacific Economics Group, November 11, 2015 (EEI 2015 Update).

[274] Pepco's Comments at 28; *citing* State of New York Public Service Commission, Joint Proposal, Docket No. I 6-E-0060, September 19, 2016.

[275] Pepco's Comments at 28-29; *citing In the Matter of the Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or a Gas Company,* MD PSC Case No. 9618.

[276] Pepco's Comments at 29-30.

MRP if it is not performing as expected and the problem cannot be resolved through any other mechanism available under the MRP.[277]

31. Pepco comments that credit rating agencies view the impact of alternative forms of regulation as dependent on their scope and implementation. Pepco suggests that, all else being equal, the regulatory approaches that provide faster and more assured forms of cost recovery are generally considered to be credit positive. Pepco cautions that the specific details of any alternative regulatory mechanisms have to be carefully assessed because they may include a range of aspects, some of which will be viewed as being credit positive while others will be viewed as having credit negative outcomes.[278]

32. Pepco states that its presenter was not aware of any studies (systematic or otherwise) that have addressed non-cost- related performance in the United States. From a conceptual standpoint, Pepco states that MRPs, depending on their features, could create incentives for a utility to control its costs in a way that could result in service degradation. In order to address this potential issue, Pepco states that MRPs are frequently paired with PIMs that are designed to incentivize the utility to maintain or even improve upon pre-determined service levels.[279]

33. Pepco does not believe that the use of alternative forms of regulation, such as MRPs and PIMs, should fundamentally change the role of the Commission and parties, because these forms of alternative regulation are adjuncts to, rather than a wholesale departure from, cost-of-service regulation. Pepco explains further that, in response to Question 3 of Panel 1, in the case of a MRP, the Commission's oversight ability is enhanced because the Commission receives a longer-term view of future capital and O&M investments before the utility makes the investments, increasing transparency as well as the utility's ongoing reporting requirements as part of the MRP. Pepco adds that one of the benefits often identified for implementing MRPs is to ease the demands on regulatory commission staffs by eliminating the utility's need for back-to-back, annual base rate case filings.[280]

34. Pepco does not suggest at this stage any specific rules or regulations that the Commission should implement, but that it will ultimately depend on the form of alternative regulation that the Commission seeks to implement. Pepco states that the suggestions would differ depending on whether the Commission elected to implement a formula rate, for example, or if it chose to use a MRP. Pepco explains further that even within a specific alternative form of regulation, there could be significant differences depending on the elements the Commission determined it wished to incorporate. As an example, Pepco states that the regulations for a MRP based on a utility's projections of future O&M and/or capital expenditures could differ significantly from one in which some or all costs were increased from a base year based on a particular index or a combination of outside measures or factors. Pepco adds that it is not clear at

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[277] Pepco's Comments at 30.

[278] Pepco's Comments at 31.

[279] Pepco's Comments at 31-32.

[280] Pepco's Comments at 32.

this point whether the Commission wishes to permit only one form of alternative regulation or whether it will consider more than one option.[281]

B. OPC

35. At the outset, OPC submits that without responses to questions such as: what goals do the regulated utilities have a role in pursuing; what are the contours of their roles, and what specific outcomes do we want them to achieve; what are their incentives to achieve those outcomes today, under the current regulatory framework, and how (if at all) should those incentives be changed; what are the risks and tradeoffs involved; and how will the Commission prioritize goals that may be in tension; it is premature for OPC to offer any specific rules or regulations, or to choose the appropriate alternative ratemaking methodology that should be used in the District.[282]

36. OPC states that it takes no position at this time as to: (1) whether *any* changes to the existing regulatory paradigm in the District are needed or appropriate; or (2) whether Pepco's application in this docket is just, reasonable, and in the public interest.[283] OPC believes that successful implementation of alternative regulation in the District requires a methodical approach that builds on the previous work that has already been done and allows the Commission and stakeholders to develop alternative regulation policy collaboratively.[284] OPC recommends, however, that if the Commission were to decline this approach, and instead decide to issue an Order on frameworks for evaluating alternative ratemaking proposals now, then the Order should incorporate the general criteria set forth in its Comments.[285]

37. OPC states that properly designed alternative regulation plans have the potential to produce benefits, including: reducing regulatory lag; helping utilities better manage risks and expenses; increasing the transparency of utility spending and investment decisions; better aligning the utility's incentives and actions with the public interest; incentivizing cost reduction or cost containment; and reducing administrative burdens, including the frequency of resource-intensive rate cases.[286]

38. OPC comments that the technical conference presentations and discussion revealed broad consensus that poorly designed alternative regulation plans risk producing negative outcomes. Such negative outcomes include: increasing the complexity of regulatory processes; reducing transparency and regulatory insight; exacerbating the deleterious effects of information asymmetries; shifting financial risks from the utility to ratepayers; diminishing cost-reduction and cost-containment incentives; paying the utility for doing what it should be doing anyway;

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281 Pepco's Comments at 33.

282 OPC's Comments at 5-6.

283 OPC's Comments at 6.

284 OPC's Comments at 7.

285 OPC's Comments at 7.

286 OPC's Comments at 10.

penalizing the utility for outcomes outside its control; failing to incentivize desired outcomes or inadvertently producing counterproductive ones.[287]

39. OPC maintains that while alternative regulation has been used at different times in different places for decades, the evidence regarding its effectiveness and impact on consumers and regulators remains sparse and anecdotal.[288] As a starting point, OPC states that any evaluation of proposed ratemaking plans in the District must start with the requirements of D.C. Code § 34-1101: "the charge made by any public utility for a facility or service furnished, rendered, or to be furnished or rendered, shall be reasonable, just, and nondiscriminatory."[289] OPC asserts further that alternative ratemaking proposals must meet the requirements of D.C. Code § 34-1504 (d)(2), which authorizes the Commission to adopt an alternative form of regulation if the Commission finds that it: protects consumers; ensures the quality, availability, and reliability of regulated electric services; and is in the interest of the public, including shareholders of the electric company.[290]

40. OPC contends that an alternative ratemaking proposal should not be found "to be in the public interest," unless it "benefit[s] the public rather than merely leave it unharmed." OPC recommends that the Commission not accept or adopt any alternative regulation proposal unless it first determines, based on a comprehensive review, that the new framework (including new components and retained features of the previous framework) does not harm customers and that it produces tangible benefits. This, according to OPC, means that the proposal should advance the Commission's goals and objectives—including those set forth in the MEDSIS Vision Statement—more fully and cost-effectively than the status quo, should provide incremental net benefits to consumers, and must avoid shifting financial risks to consumers.[291] OPC adds that the plan's incremental benefits to consumers should exceed its incremental costs, and any claimed benefits should be specific, verifiable, and quantified.[292]

41. OPC recommends that alternative regulation plans must not invert the burden of proof or exacerbate or exploit information asymmetries. To OPC, the utility must retain the burden

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287 OPC's Comments at 11; *citing* RAP October 17 Presentation, slides 23-27; *see also* Melissa Whited et al., *Utility Performance Incentive Mechanisms: A Handbook for Regulators,* Synapse Energy Economics, Inc., at 2, 14, 31, 56, 65-69 (March 9, 2015) ("Synapse Performance Incentive Handbook"), available at https://www.synapseenergy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

288 OPC's Comments at 12.

289 OPC's Comments at 17-18.

290 OPC's Comments at 18-19; OPC asserts that the authorization provided under D.C. Code § 34-1504 (d)(1) is limited to "regulat[ing] the regulated services of the electric company through alternative forms of regulation." In its amended notice convening the technical conference, however, the Commission stated that in "reviewing alternative forms of regulation, any policy decisions should be broad and flexible enough to be applicable to all public utilities." *Citing* Amended Notice at 2.

291 OPC's Comments at 20-21.

292 OPC's Comments at 21.

to demonstrate that its rates satisfy the applicable standards. As a consequence, OPC contends that alternative rate plans should neither exacerbate nor exploit information asymmetries that make it difficult to assess the utility's justifications. According to OPC, this means that if the proposed ratemaking mechanism proposes to base rates on forecasts, then the proposal should be supported with data and testimony sufficient to demonstrate that the forecasts are reasonably accurate and that the utility has a demonstrated pattern of forecasting accuracy.[293] The support should include, at minimum: several years of historic data, quantitative and qualitative analyses of trends, and clear explanations of why any costs or billing determinants are forecasted to deviate from observed trends. OPC adds that proposals also should include mechanisms to track the accuracy of the utility's forecasts and to terminate reliance on them if forecasting errors exceed acceptable bounds.[294]

42. OPC recommends that an alternative rate plan should not shift risk to customers and should reflect any shareholder risk reductions in lower ROE. OPC asserts that management and shareholders should remain responsible for their poor decisions, not customers. At the same time, OPC states that if an alternative regulation plan shortens the lag between a utility's incurrence of costs and the recognition of those costs in rates, or otherwise reduce the utility's risk, then the Commission should assess the extent to which those changes reduce the return on equity necessary to attract capital to the company.[295]

43. OPC recommends that an alternative regulation plan should include proposed processes and protocols that are clear, concise, not overly burdensome, with sufficient time and resources available to accomplish each essential task. To OPC, alternative regulation plans have clear protocols that are sufficient to accomplish essential regulatory tasks. As an example, OPC contends that customers and the Commission would have a true opportunity to assess whether the Company's actual costs were prudent. For capital projects, OPC offers as examples as to whether: (a) it was prudent to pursue the project and, if so; (b) whether the utility prudently managed the project and its costs. OPC adds that if the time to assess prudence under a proposed alternative rate plan will occur during a mid-plan update or reconciliation rather than a base rate case, then the protocols and timelines must be suited to that task. OPC recommends that the utility be required to provide relevant data proactively, at the outset of the reconciliation or update, regarding project budgets, alternatives, actual costs, variances, and project status. Thereafter, the utility should be required to respond to reasonable information requests promptly and fully. If stakeholders believe the utility is not fulfilling its duties in this regard, OPC contends that the plan should include a mechanism to bring disputes to the Commission for expedited resolution. OPC concludes that any approval of such a plan should make clear that, if a pattern of delay or

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293 OPC's Comments at 21. OPC cautions that if the proposal is based on forecasts, the Commission will face similar forecast accuracy concerns and issues as it has in the past, but in an amplified fashion as the forecasts will set rates for the entire duration of the plan term. *See Formal Case No. 1139*, Order No. 18846, ¶¶ 578-581, 594 ("reminding Pepco of the concerns raised in *Formal Case No. 1087* where Pepco's test year included six months of forecasted test year data and the ability of Pepco to demonstrate and the parties to discover, how budgeted data was used to derive the forecasted amounts in the test year").

294 OPC's Comments at 21.

295 OPC's Comments at 22.

nondisclosure emerges, the Commission may terminate the alternative regulation plan or eliminate mid-plan rate adjustments.[296]

44. OPC recommends that alternative regulation plan applications should include an assessment of the extent to which the proposed plan will impose quantitatively greater or qualitatively different demands on Commission staff, OPC, and intervenors. OPC cites the MD PSC's survey of other states that showed that "a change in the regulatory paradigm will result in the need for additional resources," but "the type and amount of additional resources will depend on the nature and number of [alternative regulation] mechanisms the Commission adopts."[297] In the District, OPC states that the Commission's decision on any alternative ratemaking proposal include an independent assessment of the need for additional resources and a plan for ensuring (at least as to the Commission and OPC) that such resources will be in place before the plan becomes effective.[298]

45. OPC recommends that new alternative rate plans be reasonably time-limited and include adequate reporting protocols during the term of the plan. OPC reasons that to limit the potential for unintended consequences and adverse outcomes, new alternative rate plans should be reasonably time-limited and should include adequate reporting protocols during the term of the plan. It recommends that upon the introduction of a new plan or a new component added to an existing plan, the intended outcomes be specified as clearly and precisely as possible. OPC adds that the plan should specify at the outset how, when, and what processes will be used to determine whether the plan is accomplishing its objectives.[299]

46. OPC professes that it takes no position as to the merits of any methodology or specific proposal now before the Commission, but offers its general comments with regard to certain issues raised during the conference with respect to MRPs and performance-based rates.[300] OPC lists the commonly cited reasons for adopting MRPs, such as: (i) reducing rate-case expense and other regulatory burdens; and (ii) establishing or enhancing the utility's incentive to contain or reduce operating and/or capital costs between base rate cases. OPC cautions, however, that various MRP design choices will affect the extent to which either of these goals is realized and how the MRP will interact with other goals the regulator wishes to pursue.[301] OPC suggests the following examples:

> (a) Plan term. The efficacy of a MRP is affected by the number of years over which the plan will be in place; (b) Basis for initial revenue requirement and

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296 OPC's Comments at 22-23.

297 OPC's Comments at 23; *citing* MD PSC Staff Report at 58. Additional required resources might include larger consulting budgets, increased staff training budgets, new software, and/or additional time for review during base rate cases.

298 OPC's Comments at 23.

299 OPC's Comments at 23.

300 OPC's Comments at 24.

301 OPC's Comments at 24.

> escalation. The basic idea of a MRP is to set rates in advance for the duration of the plan and put a moratorium on rate cases for the specified term; (c) Rate Freeze. The most powerful cost-containment incentives may be produced by the simplest mechanism: setting rates on the basis of historic costs, without any "Attrition Relief Mechanism;"(d) Indexing. Reduced but still significant cost containment can be achieved by basing rates on historic costs and including an ARM to escalate allowed revenues using one or more objective indices; (e) Forecasts. Another potential approach is to base MRP rates on revenues necessary to recover the utility's forecasted costs; (f) Cost reconciliations (if used). Some MRPs include annual cost reconciliations; (g) Decoupling or revenue reconciliation. Some MRPs operate in concert with revenue reconciliation mechanisms such as a decoupling mechanism; and (h) Earnings Sharing Mechanisms (if used). Some MRPs provide for utilities to share over- or under-earnings with ratepayers.[302]

47. With regard to PIMs, OPC states that MRPs often are paired with performance PIMs in an attempt to ensure that cost containment does not come at the expense of service quality, reliability, sustainability or other performance-related goals the regulator wants the utility to achieve.[303] OPC states that the Commission already uses certain PIMs in connection with its reliability targets and offers that PIMs of different descriptions could be developed and attached to virtually any outcome a regulator wished to incentivize a utility to achieve or avoid.[304] OPC points out that conference participants identified at least three broad categories of PIMs, with differing levels of usefulness: Metric/reporting only PIMs; Scorecard/ranking PIMs; and Financial PIMs, which can be either symmetric or asymmetric (e.g., penalty-only), and can take different forms (e.g., dollar payments, basis points added to or subtracted from return on equity, or split-the-savings arrangements). To OPC, non-financial PIMs may be particularly appropriate for behaviors as to which there is insufficient baseline data or a speculative connection between the metric and the desired outcome.[305]

48. OPC cautions that the inherent flexibility of PIMs presents a danger. Specifically, OPC asserts that it is too easy to develop and apply PIMs without due regard for whether they are actually needed, whether they are calibrated to achieve their intended ends without overcharging ratepayers, whether they target outcomes within the utility's control or influence, how they interact with incentives created by other PIMs or other aspects of the regulatory scheme, and the range of ways (both intended and unintended) in which a utility might respond.[306]

49. OPC professes that it is not prepared to comment on specific PIM targets or designs or whether PIMs are appropriate for the District. OPC recommends, however, that a

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302 OPC's Comments at 24-30.

303 OPC's Comments at 31.

304 OPC's Comments at 32.

305 OPC's Comments at 32.

306 OPC's Comments at 33.

comprehensive review of all rate components is needed to determine whether a PIM would benefit customers and is otherwise appropriate. It recommends that the Commission develop guiding principles for PIM development and evaluation. OPC believes that once the guiding principles are set, the PIM design process should identify key goals, determine how to prioritize them, refine and translate them into specific outcomes the regulator wishes the utility to achieve, and develop PIMs that are well-tailored to achieve those outcomes cost-effectively.[307]

50. OPC recommends that the Commission establish principles for evaluating any proposed PIM. The guiding principles should require that a PIM have: clearly articulated principles and goals; clear, verifiable, and reliable metrics that are appropriately tailored to the utility; targets that are neither too easy nor too difficult for the utility to achieve; and that there are mechanisms and resources sufficient to ensure that reported performance can be verified independently. OPC offers that rates that include proposed PIMs should be: (1) just and reasonable, (2) protect customers, (3) ensure the quality, availability, and reliability of regulated energy services, and (4) are in the public interest.[308]

51. OPC offers two examples as guides, one from Minnesota and the other from Rhode Island. In Minnesota, OPC states that the Commission adopted guiding principles that PIMs must be: tied to the policy goal; clearly defined; able to be quantified using reasonably available data; sufficiently objective and free from external influences; easily interpreted; easily verified; and should complement and inform evaluation of utility performance.[309] In Rhode Island, OPC states stakeholder comments were requested on proposed principles that PIMs: should be considered only when the utility lacks an incentive (or has a disincentive) to align its performance with the public interest, there is evidence of under-performance, and evidence that improved performance will deliver incremental benefits; should be designed to enable a comparison of the cost of achieving the target outcome with the quantifiable benefits; should be designed to maximize total quantifiable, verifiable net benefits; should offer the utility no more financial benefit than is necessary to align its performance with the public interest; and should offer the same incentive for the same benefits. Specifically, no action should receive a greater reward than another action that produces the same benefit.[310] OPC recommends that if the Commission adopts PIMs, it should

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[307] OPC's Comments at 33; OPC states that virtually all conference participants agreed that there is no single "best practice" for PIMs, that PIMs must be tailored to reflect utility- or jurisdiction-specific issues and policy goals, and must reflect conscious decisions about the relative priorities of the goals. *See, e.g.*, RAP October 17 Presentation, slides 10, 22, 38; RAP October 18 Presentation, slide 3; Maryland PSC Staff Presentation, slide 21; Hawaii PUC Presentation, slides 5-10; Pepco October 18 Presentation, slide 4; *Formal Case No. 1156*, Pepco, "Framework for Evaluating Alternative Ratemaking Proposals," slide 8, presented Oct. 17, 2019.

[308] OPC's Comments at 34.

[309] OPC's Comments at 34-35; *citing* MN PUC 2019 Order

[310] OPC's Comments at 35; *citing* RI PUC Commissioner Abigail Anthony in a March 5, 2019 memorandum, founded on principles previously used by the RI PUC. The RI PUC received stakeholder comments on memorandum, and is currently reviewing the comments. *See* Notice of Open Meeting (R.I. Pub. Serv. Comm'n, Mar. 11, 2019), available at http://www.ripuc.org/eventsactions/docket/Open%20Meeting%20Notice%203-18-19.pdf; Minutes of Open Meeting Held On March 18, 2019 (R.I. Pub. Serv. Comm'n, Mar. 18, 2019), available at http://www.ripuc.org/eventsactions/minutes/Minutes%20March%2018,%202019%20Workshop.pdf; *Guidance Document Regarding Principles to Guide the Development and Review of Performance Incentive Mechanisms –*

start with only a few to reduce complexity and the risk of unforeseen interactions and to give stakeholders an opportunity to become more familiar with their operation.[311]

52. OPC avers that it is premature at this time to submit proposed rules and regulations that the Commission should adopt with respect to alternative ratemaking. Rather, OPC encourages the Commission to adopt a methodical process for determining whether alternative regulation is necessary and appropriate and, if so, developing a plan that will produce consumer benefits and more cost-effectively achieve the District's policy goals.[312] OPC warns that if poorly designed alternative regulation leads to unreasonable electricity or natural gas rates, District residents will face hard choices, adding that the Commission can change course later, that will not remedy the harm that has occurred in the meantime.[313]

53. OPC states that the Commission should heed lessons from other states about developing alternative regulation frameworks, such as assessing the utility's incentives under the existing regulatory paradigm; identify additional incentives the regulator wishes to create or existing incentives it wishes to change; define the outputs and outcomes the regulator wants the utility to achieve; consider the availability and suitability of data regarding the utility's baseline performance level; design appropriate metrics and, potentially, financial incentives; consider how the proposed plan interacts with any retained elements of the previous regulatory structure; and assess the proposed plan's potential for unintended incentives and consequences. OPC avers that in states that have considered alternative regulation frameworks, these steps often have taken three or more years of focused effort.[314]

54. OPC cites Hawaii for lessons learned in the development of an alternative regulation framework. OPC views the process used by the Hawaii PUC to be a reasonable model in developing an alternative regulation framework because it provided a formal, systematic, and iterative process for the Hawaii PUC and stakeholders to collaboratively work together and develop solutions.[315] According to OPC, the Hawaii PUC undertook a comprehensive and

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Docket No. 4943, Status Update and Expected Process (R.I. Pub. Serv. Comm'n, July 29, 2019), available at http://www.ripuc.org/eventsactions/docket/4943_StatusProcessNotice_7-29-19.pdf.

311 OPC's Comments at 36.

312 OPC's Comments at 36.

313 OPC's Comments at 36-37.

314 OPC's Comments at 37; *citing* MD PSC Staff Report at 50. ("[W]hile the implementation periods for [alternative forms of regulation (AFORs)] vary substantially from state to state, all processes were lengthy to ensure that the needs of all stakeholders are met and balanced. Some AFORs were implemented in as little as three years, but other experiences, such as the one playing out in Pennsylvania, show that the process might take as long as six or seven years despite enabling statutory authority.").

315 OPC's Comments at 38.

methodical process "to ensure that the existing suite of regulatory mechanisms do not work at cross purposes, and to examine whether additional refinements or modifications are necessary."[316]

55. OPC states that the Hawaii PUC is utilizing a bifurcated proceeding in developing an alternative ratemaking framework. In Phase I, three technical conferences were facilitated by the Rocky Mountain Institute, wherein the Hawaii PUC staff circulated a concept paper to provide parties with a discrete proposal upon which to provide feedback and to facilitate focused discussion.[317] According to OPC, after each conference, parties submitted briefs informed by the conference discussion and commenting on the staff's paper. Following the third conference and briefing, OPC states that commission staff submitted a more comprehensive proposal for consideration and comment. Thereafter, OPC states that parties submitted statements of position on staff's proposal, exchanged information requests as to others' statements, and then filed reply statements.[318] In Phase 2, OPC states that the focus, through monthly working group meetings and workshops, is on designing updated regulatory mechanisms to achieve the priority outcomes established in the Hawaii PUC's May 2019 order. OPC states that in June 2020, parties will file comprehensive PBR proposals and a decision is expected by the end of 2020 after formal briefing and hearing on the proposals.[319]

56. OPC recommends that the Commission consider the two alternative courses of action outlined below. The first, OPC's preferred approach, proposes a detour away from the current procedural schedule, which OPC thinks is essential because, as Commissioner Beverly noted recently, a rate case proceeding is not well-designed "to develop the core regulatory principles, goals, and outcomes necessary to determine what (if any) form of alternative regulation would not only ensure the quality, availability, and reliability of regulated services, protect consumers, and serve the public interest, but also align financial incentives for a public utility with the District's clean energy goals."[320]

57. In the alternative, OPC offers that if the Commission is inclined to move ahead and adopt a Policy Order without the benefit of the further deliberations outlined below, then OPC

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316 OPC's Comments at 38; *citing* Hawaii PUC Order No. 35411, at 30.

317 OPC's Comments at 38-39. OPC states that they first focused on: (1) reviewing PBR efforts in other jurisdictions, including tools and processes used; (2) building a shared understanding of the potential for PBR in Hawaii and a planned approach for the PBR proceeding; and (3) discussing potential regulatory goals and outcomes for PBR in Hawaii. The second focused on: (1) deepening collective understanding of existing regulatory mechanisms; (2) exploring how existing structures are or are not supporting achievement of particular regulatory outcomes; and (3) strengthening parties' and stakeholders' capacity to collaborate in this work. The third sought to: (1) identify refinements to existing mechanisms that support prioritized outcomes; (2) consider new regulatory approaches to support prioritized outcomes not well met by existing regulations; and (3) explore common approaches and principles for metric design. App. A.

318 OPC's Comments at 39-40.

319 OPC's Comments at 40.

320 OPC's Comments at 40-41; citing *Formal Case No. 1156*, Order No. 19956, Commissioner Beverly's dissent at 3 ("A better course of action may be to move the discussion of alternative regulation into a separate case that is informal in nature and open to all interested stakeholders, rather than just parties in the rate case.").

urges that: (1) the Order is issued as a proposed order, and be subject to further comment before finalization; (2) that it adopts, at a minimum, each of the principles presented in Section II.D, of its Comments, as criteria to be used in evaluating an alternative ratemaking proposal; and (3) that it set forth PIM guiding principles as discussed in II.E.2.[321]

58. OPC recommends Phased Additional Deliberations: Step 1 would either sever or hold in abeyance consideration of Pepco's proposed alternative ratemaking proposal, and establish a procedural schedule that allows for review of the portion of Pepco's rate case that is based on existing ratemaking methodology (*i.e.*, the 6 + 6 test year); Step 2 would establish a time-limited phased proceeding that is aimed at developing the following deliverables OPC refers to as Phase 1: Policy Statement on Goals—wherein, based on information from this technical conference, the MEDSIS proceeding, and various workshops, the Commission should establish a process for developing a "Policy Statement on Goals for Regulation;"[322] and Phase 2: Order Evaluating the Current Regulatory Framework—wherein, following issuance of the Policy Statement, the Commission and stakeholders should evaluate the current regulatory framework's ability to achieve the goals and outcomes articulated therein.[323]

59. In the alternative, if the Commission were inclined to proceed without the additional deliberations outlined above, then OPC urges that the Order: (1) be issued as a proposed Order and be subject to further comment before finalization;[324] (2) adopt, at a minimum, each of the factors presented in Sections II.D as criteria to be used in evaluating alternative ratemaking proposals; and (3) establish PIM guiding principles as discussed in Section II.E.2. OPC offers that applying these standards requires a thorough and wide-ranging review of how a given proposal is likely to affect consumers and the Commission's ability to fulfill its mission.[325]

60. In OPC's summation, no alternative proposal should be adopted unless it: meets the requirements of D.C. Code § 34-1101, *i.e.*, that all rates must be "just, reasonable, and nondiscriminatory;" meets the three-pronged requirements of D.C. Code § 34-1504 (d)(2); benefits the public rather than merely leave it unharmed; leaves intact the utility's burden of proof; does not exacerbate or exploit information asymmetries; does not shift risk to customers; reflects any reduction in shareholder risk through a lowered ROE; includes proposed processes and protocols that are clear, concise, and not overly burdensome, while leaving stakeholders with sufficient time and resources available to accomplish all essential reviews; includes an assessment of the extent to which the proposed plan will impose quantitatively greater or qualitatively different demands

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321 OPC's Comments at 41.

322 OPC's Comments at 41-42.

323 OPC's Comments at 42.

324 OPC's Comments at 42-43; OPC states that this can be accomplished by having Staff issue the Order as a proposed Commission opinion. *See, e.g. Formal Case No. 1130*, Order No. 19984.

325 OPC's Comments at 43.

on Commission staff, OPC, and intervenors; and is reasonably time-limited and should include adequate reporting protocols during the term of the plan.[326]

C. AARP DC

61. According to AARP DC, consumers "cannot afford higher rates for speculative projects or undertakings not needed for reliability."[327] In general, AARP DC acknowledges that the concept of alternative regulatory mechanisms have been around since the 1980s, but opposes the use of multi-year rate plans and the use of alternative regulation because it bypasses the safeguards in the Commission's normal review process.[328] AARP DC asserts that the Commission should not commence alternative regulations unless a utility can make a clear showing that rates will be lower than using traditional rate case mechanisms.[329] Alternatively, AARP DC suggests that if the Commission proceeds with alternative ratemaking, we consider allowing "a small pilot program with a few meaningful metrics that focus on affordability and reliability in order to see if such an alternative can provide positive benefits to customers."[330]

62. More specifically, AARP DC states that: (1) performance based ratemaking is not a benefit to consumers because utilities have been allowed to propose easy-to-meet targets or metrics, and then be awarded with extra revenues for possibly doing nothing more than what they are obligated to already do;[331] (2) the certainty of rate increases over multiple years is not a benefit to customers because they are based on speculative forecast that may be incentivizing the utility for doing its regular job (i.e.; providing good customer service or replacing aging equipment);[332] (3) the asymmetry of information makes metrics verification difficult since the utility is essentially the only source for the data;[333] (4) the special interest groups performance metrics should not replace the goal of affordable and reliable service because such measures could cause rates to rise;[334] (5) that under the current policies, customers already have the ability to sign up for renewable energy alternatives with marketers offering such programs;[335] and (6) too much risk is

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326 OPC's Comments at 43-44.

327 AARP DC's Comments at 1.

328 AARP DC's Comments at 1.

329 AARP DC's Comments at 1.

330 AARP DC's Comments at 1.

331 AARP DC's Comments at 2.

332 AARP DC's Comments at 2.

333 AARP DC's Comments at 3. AARP DC notes that establishment of verification metrics is time consuming, costly and more complicated, potentially requiring the Commission to need additional staff resources.

334 AARP DC's Comments at 3. AARP DC is concerned about having an analysis done of who pays and who benefits with this policy change, and notes that a new regulatory paradigm is not needed to meet DC's renewable energy goals of 2032 or 2050.

335 AARP DC's Comments at 3.

transferred to customers because the utility benefits under alternative regulation with quicker implementation of rate increases than allowed under traditional ratemaking and the receipt of incentives for meeting its goals under PBRs.[336] AARP DC argues that with the implementation of an alternative rate regulation the utility has lowered risk, therefore the ROE should be reduced.[337]

63. In Sum, AARP DC urges the Commission to reject alternative regulations including multi-year rate plans.[338] AARP DC recommends that the Commission open a generic proceeding that includes WGL so that all stakeholders can participate in meaningful discussions of proposals, and allows the Commission to obtain a consultant to write a final report that addresses policy changes.[339] However, AARP DC indicates that if the Commission adopts alternative regulation, the Commission should have a few focused metrics that address affordable rates and reliable service.[340]

D. AOBA

64. AOBA states that it does not want the Commission to gamble with ratepayer money by approving a course of action that is questionable whether it will provide identifiable benefits to ratepayers or yield unintended increase in cost to ratepayers.[341] AOBA notes that alternative forms of regulation should not be pursued without substantive consideration of the Commission's goals and objectives and the development of sound approaches to obtain those goals.[342] AOBA asserts that "alternative forms of regulation do not necessarily reduce regulatory workload or the regulatory expense that ratepayers must bear."[343] AOBA's comments note that there were some general themes developed from the Technical Conference, such as:

> (1) Proper evaluation of MRPs and other alternative forms of regulation must start with the identification of regulatory policy objectives.
> (2) MRPs and alternative regulation must be performance focused, and ratepayer interests are not well served if a MRP is viewed simply as a cost recovery mechanism.
> (3) The costs and benefits of MRPs, PBRs, and PIMs are highly sensitive to the parameters of each specific mechanism considered and cannot be generically determined.

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336 AARP DC's Comments at 3.

337 AARP DC's Comments at 3.

338 AARP DC's Comments at 4.

339 AARP DC's Comments at 4.

340 AARP DC's Comments at 4.

341 AOBA's Comments at 25.

342 AOBA's Comments at 2-11.

343 AOBA's Comments at 2.

> (4) The tracking of capital expenditures is essential to ensure that capital expended produces expected ratepayer benefits, and one year of project detail for projected capital expenditures is not sufficient to justify approval of rates for the second and third years of a multi-year rate plan.
> (5) Existing regulatory issues, such as grid modernization, expansion of DER, and negative class rates of return must be addressed within the structure of any MRP for it to have on-going viability.
> (6) A MRP or other forms of alternative regulation must not exempt utility management from accountability for their actions, and the focus of a MRP should be on encouraging utilities to demonstrate that they can manage their costs and operations within reasonably forecasted cost levels while maintaining or improving customer benefits.
> (7) PIMs and PBRs should not be employed with the implementation of MRPs initially. And, then only after metrics are established and tracked if the utility can explicitly demonstrate that the costs of achieving the performance levels required to obtain performance incentives are not included in the forecasted capital and O&M expenditures on which MRP rates are based.[344]

65. In addition, AOBA briefly highlights a wide range of issues with alternative forms of regulation as noted by conference participants, such as the reconciliation/true-up process being equivalent to formula based rates, decoupling mechanisms, the allowance of a partially forecasted test year, the complexity of alternative forms of regulation, affordability and the potential for unintended consequences detrimental to ratepayers.[345] AOBA also noted OPC's participant's emphasis on the need for the Commission to have clearly articulated goals as a prerequisite to establishing the framework for evaluating alternative forms of regulation.[346] Furthermore, AOBA supports BWDLC's position that no performance-based regulation or performance incentive mechanism should provide any incremental benefits to the utility for what ratepayers expect the utility to perform as a normal part of its franchise obligation.[347]

66. AOBA believes that the Commission should consider the following in establishing the framework for alternative forms of regulation:

> (1) The current approach to rate regulation in the District of Columbia may not be perfect. It is not a broken process and it does not need to be replaced with Multi-Year Rate Plans.

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344 AOBA's Comments at 2-4.

345 AOBA's Comments at 4-5.

346 AOBA's Comments at 5.

347 AOBA's Comments at 9.

> (2) There is no evidence that Multi-Year Rate Plans will save ratepayers any costs or provide ratepayers any added benefits. The costs and time requirements for establishing, monitoring and adjusting rates under multi-year rate plans will be greater than the time and costs for litigating traditional rate cases.
> (3) The primary beneficiaries of MRPs are investors in the utility holding companies that now own the District's energy distribution utilities.
> (4) MRPs must not sacrifice transparency in the ratemaking process and ratepayer protection from unjustified rate increases.
> (5) MRPs and other forms of alternative ratemaking must be addressed on a utility-by-utility basis.
> (6) The Commission should not experiment with ratepayer funds in its pursuit of alternative ratemaking methodologies. Improvements can be made to the current rate case process without drastically altering the current regulatory paradigm.[348]

67. Additionally, AOBA asserts that there are specific issues that need to be addressed separately for the District's electric and gas utilities. For the electric utility, AOBA asserts that there will be a need to consider massive subsidization of affluent residential customers, the appropriateness of continuation of Pepco's BSA with or without approval of a MRP, and the impact of legislated building energy performance standards on customer's use of electricity and Pepco's expected revenue recoveries.[349] With respect to the gas utility, AOBA contends that there will be a need to consider gas system safety, rapidly escalating leak response costs, the impact of rising leak rates and increasing unaccounted for gas percentages on the District's efforts to meet its greenhouse gas reduction goals, and the ability of WGL and its ultimate parent company to raise the capital necessary to fund its requirements for accelerated pipe replacement across three jurisdictions.[350]

68. AOBA states that to ensure successful implementation of an alternative ratemaking mechanism, the Commission should also consider the regulatory standards developed in the NREL report, *Next-Generation Performance-Based Regulation Emphasizing Utility Performance to Unleash Power Sector Innovation*.[351] AOBA believes that the NREL principles, set forth in Section VII *infra*, are "applicable to any alternative form of utility regulation, whether multi-year rate plan, performance incentive mechanism or a combination of various proposals intended to align environmental and energy public policy goals and objectives with grid modernization that

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348 AOBA's Comments at 5-6.

349 AOBA's Comments at 6-7.

350 AOBA's Comments at 7.

351 NREL, Next-Generation Performance-Based Regulation *Emphasizing Utility Performance to Unleash Power Sector Innovation* (September 2017) at 35, available at *https://www.nrel.gov/docs/fy17osti/68512.pdf* ("NREL Publication").

serve as an alternative to the rate-base rate of return regulatory model.[352] AOBA suggests adding the following five additional principles to the NREL principles:

> (1) The need for policies to advance private sector investment;
> (2) Financial risk sharing;
> (3) Cost-benefit analysis;
> (4) Transparency in access to information and stakeholder participation; and
> (5) Ratepayer protections that ensure that customers pay for only what is needed at the best price whether the utility or a third party provides the goods and or services.[353]

69. AOBA also states that if the Commission decides to implement some form of alternative regulation, the Commission should not only consider adopting NREL principles but also the Pennsylvania Public Utility Commission's ("PA PUC") principles, which could help to eliminate utilities gaming the system.[354] The PA PUC principles, as set forth in Section VII *infra*, require the Commission to consider whether the proposal is a just and reasonable distribution ratemaking mechanism.[355]

70. In addition, AOBA states that any alternative form of regulation approved by the Commission should be consistent with the NREL best practices and the Pennsylvania PUC Final Policy Statement.[356] AOBA also avers that with respect to utilities gaming the system, the Commission should look to the NREL reports' position "that best practices require that regulators design clear and well-defined incentives and metrics in alternative ratemaking plans to minimize the risk of gaming."[357]

71. Likewise, AOBA is concerned with the escalating costs for the delivery of electricity and natural gas service in the District of Columbia and does not believe that alternative forms of regulation should be allowed to shift utility financial and operating risks to ratepayers.[358]

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[352] AOBA's Comments at 13.

[353] AOBA's Comments at 12-13. AOBA notes that the standards articulated in the NREL report are similar to the Rocky Mountain Institute Study reviewing alternative ratemaking models throughout the country. Rocky Mountain Institute, *Navigating Utility Business Model Reform, A Practical Guide to Regulatory Design, at 28-72* (November 2018), available at https://www.rmi.org/wp-content/uploads/2018/10/RMI_Navigating_Utility_Business_Model_Reform_2018-1.pdf.

[354] AOBA's Comments at 12-16.

[355] AOBA's Comments at 14-16. *See also* Pennsylvania PUC Final Policy Statement Order, 34 Pennsylvania Bulletin, Vol. 49 No. 34 at 4819-4827 (August 24, 2019), available at http://www.puc.state.pa.us/pcdocs/1633016.pdf ("PA PUC Policy Order").

[356] AOBA's Comments at 16, 24.

[357] AOBA's Comments at 16-17.

[358] AOBA's Comments at 24.

AOBA argues that any form of alternative regulation must be consistent with the public interest and focus on utility performance and accountability.[359] AOBA states that the process must be open and transparent and provide meaningful opportunities for examination of utility costs, utility performance, utility forecast updates, and rate adjustments.[360] According to AOBA, "the Commission must ensure that: (1) utility customers pay only for services that are actually needed to ensure safe and reliable service; (2) utility costs are demonstrated to be economically justified through the development and presentation of cost-benefit analysis; and (3) only utility costs that are prudently incurred will be recoverable through rates."[361]

72. Lastly, AOBA acknowledges that financially healthy utilities are essential to ensuring the delivery of reliable energy services; however, "the utility's cost of capital and return on investment must remain consistent with the standards established through the Hope and Bluefield decisions."[362] Moreover, AOBA argues that "[t]o the extent that an alternative form of regulation, including a MRP, provides a utility greater certainty in its recovery of costs and/or predictability of future revenues, the impacts of changes in utility risk must be reflected in utility authorized rates of return."[363]

E. BWLDC

73. BWLDC states a general concern with utilities increasingly relying on construction contractors rather than in-house personnel to perform construction and operations task.[364] BWLDC asserts that the Commission has a role of oversight in setting policy for responsible contracting to the extent it affects service costs and quality.[365] In addition, BWLDC suggests that if there is no oversight, workers can be exploited, cost can increase due to worker turnover and service errors, and lead to public safety and worker safety risks.[366]

74. BWLDC's does not support the Commission adopting an alternative rate design and states that because it is difficult and a significant departure from historical ratemaking, that before making any changes, the Commission should consider:

> (1) identifying public policy objectives and align them with appropriate performance standards and consequences for satisfying or failing to satisfy those standards; (2) define alternative utility performance outcomes and quantify their costs and benefits to

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359 AOBA's Comments at 24.

360 AOBA's Comments at 24.

361 AOBA's Comments at 24.

362 AOBA's Comments at 24-25.

363 AOBA's Comments at 25.

364 BWLDC's Comments at 2-3.

365 BWLDC's Comments at 3.

366 BWLDC's Comments at 3-4.

> customers; (3) safeguard against excessive utility returns; (4) align rates with performance; (5) protect workers from utility and contractor practices that violate the laws or otherwise impede workers' ability to work productively and safely; and (6) ensure regulators and stakeholders have the necessary information and resources to comprehensively evaluate any proposal.[367]

75. According to BWLDC there should be general principles to inform the Commission on how to move forward with any alternative rate design framework. BWLDC believes that whatever Policy Order the Commission ultimately adopts for alternative regulation should include overarching principles such as: (1) rates must reflect prudence performance; (2) prudent performance deserves normal returns, not excess returns; (3) any rate plan must cause the utility and its contractors to treat workers properly; (4) rate plans should show responsiveness and accountability to the public interest; and (5) to make rate plans work for consumers, regulators need resources.[368]

76. In addition, BWLDC further asserts that any alternative framework the Commission considers must be consistent with and promote the broader public policy objectives of the District inclusive of the environmental goals as well as amplify the social and economic justice values of the District.[369] BWLDC requests that the Commission include the following provisions in any rate plan proposal to promote the District's economic and social equity values: (1) promote local hire and quality job creation targets on utility construction projects (including compliance reports to assess the utility's performance in meeting employment goals, and information on the wage and benefit levels of these jobs); (2) PIMs that penalize the utility for mistreatment of workers, whether direct employees or contractor employees; (3) require transparency of a utility's and its contractors' labor practices to assure compliance with state and federal employment laws, and worker safety and health regulations; (4) require the utility to select its contractors using Best Value Contracting; and (5) encourage the use of Project Labor Agreements or Community Workforce Agreements for construction projects so that the contracted-out construction workforce earns a prevailing wage, receives health and retirement benefits, and worker representation.[370]

77. Before designing any framework for alternative ratemaking, BWLDC wants the Commission to investigate whether alternative forms of regulation are a better vehicle for accomplishing the mission of the Commission as well as the District's broader public policy goals compared to traditional ratemaking.[371] Lastly, BWLDC maintains that this investigation must be done and it should "detail how alternative rate plans provide greater transparency of utility capital

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[367] BWDLC's Comments at 4.

[368] BWDLC's Comments at 5.

[369] BWDLC's Comments at 5.

[370] BWLDC's Comments at 6-10.

[371] BWDLC's Comments at 10-11.

investments and costs; improve safety and reliability outcomes; promote greater economic prosperity; advance social equity; enhance environmental protections; and accomplish the District's progressive energy agenda."[372]

F. DCCA

78. DCCA filed written comments responding to the discussion and questions at the Technical Conference. DCCA states that a public utility supporting an alternative form of regulation proposal "must show evidence that an alternative form of regulation is better than the current form," with that evidence "taken from actual experience elsewhere (including abroad), not only from claims of benefits (e.g. that it would cut costs, achieve better service, or better achieve DC policy goals)."[373] DCCA explains that the benefits of alternative forms of regulation come in two forms: (1) "standard ones like lower costs and better service (including the reduction or removal of the utility's financial incentive to invest more than is necessary to meet demand)," and (2) "social ones like reduced greenhouse gas emissions, more equal levels of service across socio-economic groups, and more equal levels of compensation for utility workers and management."[374] Additionally, DCCA states that the "primary risk is that the utility may be offered rewards for doing what it should be doing as a matter of normal efficient operation."[375] DCCA states that to assure ratepayers that they are paying only for prudent and efficient costs, "[t]he Commission should ensure that all reasonable options for achieving a valid objective . . . are evaluated by their proponents, and [the Commission] should then check their evaluations in detail," which would require the Commission to have "additional trained staff."[376]

79. As to the identification of key decision factors for the Commission to use to evaluate and select an alternative form of regulation, DCCA states that "[i]deally the Commission would want the alternative form of regulation yielding the most benefit per unit of costs" where the benefit is the "incremental good that comes from achieving" the goal and the cost is "the incremental costs of achieving those goals through performance incentives."[377] DCCA asserts that performance incentives should address goals such as "the proposal's impact on greenhouse gas emissions (its climate impact), reliability, energy bills (level and predictability), resilience, safety, security, worker compensation, and financial viability of the utility."[378] DCCA further explains that "[i]n comparing several alternative forms of regulation, the Commission should examine the

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[372] BWDLC's Comments at 11.

[373] DCCA's Comments at 1.

[374] DCCA's Comments at 2.

[375] DCCA's Comments at 2.

[376] DCCA's Comments at 2.

[377] DCCA's Comments at 3.

[378] DCCA's Comments at 3.

possible combinations of goals and ways to achieve them."[379] DCCA indicates that it does not have any other goals than what are included in Question 4 and that such goals are applicable to both electric and gas utilities.[380]

80. DCCA asserts that its performance targets for Pepco are: (1) on increasing renewable DER deployment, which Pepco influences through "its interconnection policies, aggressive implementation of IEEE 1547-2018 advanced inverter standards and other means to increase hosting capacity, feed-in tariffs (with Commission approval) and advertising;" and (2) adopting "measures to optimize system operation[al] efficiencies over the electric distribution grid, including volt/var optimization, …."[381] DCCA asserts that its performance targets for WGL are: (1) "reduc[ing] gas leakage;" (2) "minimiz[ing] stranded assets; and (3) reduc[ing] the demand for natural gas consistent with the District's Clean Energy DC 2032 goal."[382] DCCA identifies two areas of performance where further study would aid the establishment of performance targets: (1) "a study of hosting capacity potential under full adoption of the IEEE 1547-2018 advanced inverter standard functionalities;" and (2) a "study of the state-of-the-art technology available for heating and cooling by natural gas appliances vs. electric appliances."[383]

81. DCCA expresses support for utilities acknowledging that imprudently incurred costs under a MRP would be subject to refund.[384] DCCA also supports the recovery of the costs of specific, clearly identified capital projects under alternative forms of regulation "if the specific capital projects are the least-cost ways for ensuring reliability, meeting load forecasts, …" and subject to periodic reporting on the status of projects.[385] DCCA also states that "[w]hen reports or other information show that a capital project is no longer appropriate, the Commission should halt it."[386] DCCA explains that a utility's "ROE should reflect the level of risk faced by the utility" and "alternative form of regulation should involve a mixture of incentives, obligations and guarantees that remove the perverse incentive on the utility to invest more than necessary, caused by rates set to meet a target ROE."[387]

82. DCCA comments that the discussion at the Technical Conference about other states' experiences with alternative forms of regulation "pointed to the importance of careful, thorough preparation for adopting multiyear rate making" and lead DCCA to "urge the DC

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379 DCCA's Comments at 4.

380 DCCA's Comments at 4.

381 DCCA's Comments at 4-5.

382 DCCA's Comments at 5.

383 DCCA's Comments at 5-6.

384 DCCA's Comments at 6.

385 DCCA's Comments at 6.

386 DCCA's Comments at 6.

387 DCCA's Comments at 7.

Commission to heed the experience of other jurisdictions in this respect and build on their best practices."[388] Lastly, DCCA states its "support an expansion of Commission budget resources to enable it to hire additional staff needed to capture the potential benefits of alternative forms of regulation."[389]

G. DCG

83. DCG states that "MRPs represent a fundamental change from cost of service regulation and offer the promise of increased benefits for both ratepayers and the utility. However, MRPs also present substantial peril if not designed well."[390] DCG begins its analysis by recognizing that "plans that are put forth are generally designed by utilities . . . and can therefore be expected to have a bias that favors the utilities" and thus the Commission and Stakeholders should "carefully dissect MRP and PIM proposals in order to examine the incentives they provide (including perverse incentives), as well as the risks they pose, and to ultimately determine whether the plan will benefit ratepayers and the District of Columbia as a whole."[391]

84. DCG cautions against approving MRPs that "are MRPs in name only, but which function like formula rate plans" because formula rate plans "do not provide utilities with strong incentives to contain costs and they shift risks to ratepayers."[392] DCG observes that "if designed well, MRPs can provide benefits to customers and help achieve public policy goals. Stand-alone PIMs, layered on top of cost of service regulation, can also help to achieve policy goals without requiring a wholesale adjustment to the regulatory framework."[393] DCG explains that under a MRP a "utility's revenues are de-linked from its actual costs in combination with a rate case moratorium (typically lasting from three to five years)."[394] DCG observes that jurisdictions implement MRPs to achieve the following goals:

> (1) Provide the utility with cost containment incentives.
> (2) Encourage innovation by allowing the utility to manage business decisions with greater flexibility, rather than the regulator micro-managing the utility's investments.
> (3) Reduce regulatory costs and burdens by lengthening the time between rate cases.

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388 DCCA's Comments at 7.

389 DCCA's Comments at 7.

390 DCG's Comments at 1.

391 DCG's Comments at 1.

392 DCG's Comments at 3.

393 DCG's Comments at 3.

394 DCG's Comments at 3.

(4) Provide utilities with greater regulatory guidance and assurance regarding investments in new and innovative technologies to better align utility investments with energy policy goals.[395]

Additionally, DCG identifies "four key design elements" to accomplish these goals:

(1) Rate Case Moratorium: A "stay-out" provision limits the ability for rates to be reset during the plan.
(2) Revenue Cap: Revenues for each year of the plan are capped at certain predetermined levels.
(3) Incentive to Improve Efficiency: Utilities are incentivized to reduce costs during the plan by retaining some or all of the savings from efficiency gains, while ratepayers are protected from poor utility performance during the rate plan by being insulated from some or all of any increase in costs above the revenue cap.
(4) Attrition Relief Mechanism (ARM): The initial year revenues may be escalated based on an index or cost forecast determined at the outset of the rate plan, or they can be frozen until the next rate case. Cost trackers may be added to the ARM for certain costs, particularly "exogenous" costs over which the utility has no control.[396]

85. DCG explains that both MRPs and formula rate plans feature formulas but in "formula rate plans formulaically ensure that revenues track costs, often measured as deviations in return on equity (ROE) from the utility's target ROE . . . Importantly, in contrast, MRPs do not adjust revenues to equal costs during the plan."[397] DCG states that "Because revenues do not increase in lock step with costs, the utility has an incentive to reduce costs to increase its profits for the duration of the rate plan. At the end of the MRP term, these cost reductions can then be passed on to ratepayers when rates are reset in a rate case."[398] It is on this basis that DCG concludes that "FRPs or MRPs that essentially resemble FRPs are not in the public interest."[399]

86. DCG presents a detailed list of the benefits of MRPs and their corresponding risks, as well as a series of tools for mitigating those risks.[400] Similarly, DCG, citing work by Lawrence

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395 DCG's Comments at 3-4.

396 DCG's Comments at 4.

397 DCG's Comments at 5.

398 DCG's Comments at 5.

399 DCG's Comments at 7.

400 DCG's Comments at 7-9.

Berkley National Laboratories, presents a detailed list of the benefits of PIMs and their corresponding risks, as well as a series of tools for mitigating those risks.[401]

87. DCG also highlights that "[i]t is imperative that the Commission ensure that it has adequate resources and staff to review the utilities' filings and ensure that they are in the best interest of ratepayers" and points out that the New York Public Service Commission has on average 109 staff per investor-owned utility while the Massachusetts Department of Public Utilities has on average 64 staff per investor-owned utility.[402]

88. DCG presents detailed evaluation criteria for both MRPs and PIMs.[403] DCG also makes a recommendation that "the revenue requirement be based on a historical test year (with necessary adjustments as currently allowed by the Commission), as these are the only costs that are truly known and measurable" but that these costs "can then be escalated based on an external cost index to provide the allowed revenue for each year of the plan."[404] While DCG does not recommend allowing the use of forecasted costs, if forecasted costs are allowed DCG identifies a number of mitigation strategies to address information asymmetry between the regulator and the utility.[405]

89. As to the use of true-up or reconciliation, DCG "emphasize[s] that cost true-ups are inappropriate and are unlikely to produce just and reasonable rates, but revenue true-ups (*i.e.*, revenue decoupling mechanisms) may be reasonable if they are well-designed."[406] DCG does recognize some limited cases where revenues could be trued up to actual costs.[407] DCG states that it "does not oppose truing up actual revenues to allowed revenues, such as through a revenue decoupling mechanism. This removes the utility's incentive to increase sales in order to increase revenues and removes the effects of weather and energy efficiency."[408]

90. DCG recognizes that a MRP incentivizes utilities to cut costs and that "to combat this incentive, regulators have historically coupled MRPs with PIMs to prevent service quality degradation" but that "it is generally appropriate for these PIMs to be penalty-only, as they relate to the core duties of a public utility (*i.e.*, safe, reliable service)."[409] DCG also notes that "[f]urther,

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401 DCG's Comments at 10-11.

402 DCG's Comments at 12.

403 DCG's Comments at 12-14.

404 DCG's Comments at 14.

405 DCG's Comments at 15-17.

406 DCG's Comments at 17.

407 DCG's Comments at 17-18.

408 DCG's Comments at 18.

409 DCG's Comments at 23.

continual improvement in reliability and customer service may provide diminishing returns."[410] DCG observes that "PIMs should be developed carefully and be specifically designed to address performance gaps," and, in-line with DOEE's comments in *Formal Case No. 1130*, has identified the following gaps which should be addressed through metrics of full PIMs:

> (1) Collection of, and access to, real-time system performance data and hosting capacity by government agencies and third parties, including technology specific hosting capacity, downloadable data, and a public map of interconnection queue at the feeder level;
> (2) Improvements in Distributed Energy Resources (DER) and load forecast modeling;
> (3) Quantification of the values of DER services and costs;
> (4) Implementation of appropriate tariffs and compensation schedules for grid services provided by DER, including microgrids and Virtual Power Plants, for the development of distribution-level ancillary markets and the provision of better price signals to customers;
> (5) Implementation of cost-effective smart grid sensing, controls, and communication devices that enable coordinated, real-time interaction between customer-sided resources and the distribution grid;
> (6) A technology investment roadmap and timeline for the installation of a smart grid infrastructure that includes a benefit-cost analysis of the Company's proposal;
> (7) Implementation of a fully-integrated, robust, and transparent distribution system planning process;
> (8) Implementation of cost-effective NWAs; and
> (9) Greenhouse gas emission reductions from utility infrastructure investments and operations.[411]

91. Lastly, DCG includes proposed rules and identifies a detailed list of case studies of alternative rate plans.[412]

H. GRID2.0/DC CUB[413]

92. GRID2.0 and DC Consumer Utility Board (jointly referred to as "GRID 2.0/DC CUB") submitted joint comments responding to the Technical Conference questions and discussion, in which they note that while they are not a party to *Formal Case No. 1156*, their

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410 DCG's Comments at 23.

411 DCG's Comments at 23-24.

412 DCG's Comments at 26-27 (Proposed Rules), and 27-32 (Case Studies).

413 *See also* GRID 2.0's Second Comments.

"members observed and participated in the Technical Conference."[414] As a general matter, GRID2.0/DC CUB stated that they found the Technical Conference "to be most informative" and that it "generated solid discussions and important general information in response to the questions and issues that the Commission Staff raised in each of the Panels."[415] However, GRID2.0/DC CUB states that:

> the questions and issues were taken up in a "generic" manner, and, therefore, were not evaluated concretely in light of the Commission's MEDSIS (Modernizing the Electric Delivery System for Increased Sustainability, Order No. 19984) Vision Statement and Principles, or based on the record of the MEDSIS proceeding, which aimed to set a course of action to achieve the policy mandates of DC's Clean Energy Act and to support the implementation of DC's Clean Energy Plan.[416]

93. GRID2.0/DC CUB state that the "issues taken up in the conference relate more broadly to the appropriate use of vital administrative alternative ratemaking tools as a means for bringing about the changes to which the Commission is committed that were the focus of the entire MEDSIS proceeding."[417] GRID2.0/DC CUB assert that "[a]lternative ratemaking tools need to be evaluated from the standpoint of the fundamental and transformational kinds of changes in the electricity system that were addressed in the MEDSIS proceeding and that are reflected in the MEDSIS Vision Statement and Principles."[418]

94. GRID2.0/DC CUB observe that all speakers at the Conference agreed that "the design and implementation of alternative ratemaking tools need to be based on the nature of policy objectives and goals to be achieved."[419] GRID2.0/DC CUB state that the "MEDSIS proceeding made clear that the Commission's goals are 'transformational' in nature and will necessitate fundamental changes in the way in which the distribution system plans, procures and operates."[420] Given this, GRID2.0/DC CUB state that "to achieve DC's Clean Energy Act mandates and to support DOEE's DC Clean Energy Plan, the Commission will need to evolve overtime an 'Integrated Grid' – one that recognizes and takes fully into account new distributed resources in utility planning and operations."[421] GRID2.0/DC CUB further explain that "[c]ast within this

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414 GRID2.0/DC CUB's Comments at 1.

415 GRID2.0/DC CUB's Comments at 1.

416 GRID2.0/DC CUB's Comments at 1-2.

417 GRID2.0/DC CUB's Comments at 2.

418 GRID2.0/DC CUB's Comments at 2.

419 GRID2.0/DC CUB's Comments at 3.

420 GRID2.0/DC CUB's Comments at 3.

421 GRID2.0/DC CUB's Comments at 3.

context, alternative ratemaking tools will need to be designed and implemented in stages that can effectuate a transition from the current centralized generation/delivery utility model towards a decentralized model that includes a new Distribution System model."[422]

95. GRID2.0/DC CUB state that the Commission would need to develop a "Framework" "that will address the design and development of alternative ratemaking tools . . . based on the policy goals and objective that the Commission delineated within the MEDSIS proceeding and based on the priorities that the Commission needs to establish in implementing these goals and objectives."[423] Further, GRID2.0/DC CUB state that:

> A "Framework" based on the Commission's MEDSIS objectives cannot be developed based on a two-day Technical Conference . . . but will, instead, require a formal rulemaking proceeding, in which there is wide stakeholder participation and which will allow the Commission to weigh and evaluate the pros and cons relating to the different tools, as well as to balance the full array of stakeholder interests that are impacted by the new "PowerPath" agenda.[424]

GRID2.0/DC CUB goes on to state that this approach "will also enable the Commission to address more fully the asymmetry of information that currently exists to determine how alternative ratemaking tools can be used to provide greater transparency and assure the availability of material information, with appropriate safeguards."[425]

96. GRID2.0/DC CUB "believe that a 'Framework' needs to reflect a staged approach to the use of alternative ratemaking tools, stages that will help guide in determining which tools will be needed at which stage and in what types of combinations" based on the "nature and magnitude of the policy objectives and mandates that the Commission is seeking to achieve."[426] Under this staged approach, GRID2.0/DC CUB outline the following stages:

> (1) Modifications to the Cost of Service Model: where the current regulatory model is examined and the Commission utilizes alternative ratemaking tools to "address the inadequacies of the current model with respect to achieving the Commission's policy objectives" while developing "ways for using the new tools to re-align the utility's financial interests to support the new goals and objectives."[427]

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422 GRID2.0/DC CUB's Comments at 3.

423 GRID2.0/DC CUB's Comments at 3.

424 GRID2.0/DC CUB's Comments at 3-4.

425 GRID2.0/DC CUB's Comments at 4.

426 GRID2.0/DC CUB's Comments at 4.

427 GRID2.0/DC CUB's Comments at 4.

> (2) Creating a Level Playing Field for New Renewable Energy and Distributed Resources: where the Commission "evolve[s] the design of the tools, including going beyond metrics, targets and information tracking and reporting to setting reasonable and measured financial incentives" while using Commission developed "'Benefit-Cost Analytical Framework' for consistent valuation of distributed resources" and "an 'Integrated Distribution Resources Planning Framework.'"[428]
> (3) Shaping a New Utility Regulatory Model: where the Commission "re-evaluate[s] the alternative ratemaking tools and evolve[s] them to achieve further precision with respect to the transformational goals that the Commission is pursuing" to "should assure the re-alignment of utility performance and financial interests in a manner that the utility will seek cost-effective solutions indifferent to the source of such solutions and fairly compare and evaluate alternative distributed and renewable solutions with conventional investments."[429] With an effort "to orient the application of such tools to supporting greater reliance upon market forces over administrative proceedings."[430]

I. GSA

97. GSA states that an alternative ratemaking proposal is a dramatic shift from the traditional approach to ratemaking and recommends that "the impacts of any alternative ratemaking proposal on customers be carefully considered, and that a proposal such as a MRP only be approved if it provides significant net benefits to customers, including reduced risk and lower rates, as compared to traditional ratemaking."[431] GSA states that the utility should carry the burden of proof to show that the proposals are clearly in the public interest and will provide greater benefits to customers than the current methodology.[432] GSA asserts that the Commission should only adopt an alternative rate proposal "if there are clear and compelling reasons to abandon traditional ratemaking, including reasonably-certain, demonstrable, and significant net benefits, including lower rates, to all customers."[433]

98. According to GSA, "there is no generally-accepted, compelling rationale or justification for moving to a MRP," there are only a few states that have moved from traditional

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[428] GRID2.0/DC CUB's Comments at 4-5.

[429] GRID2.0/DC CUB's Comments at 5.

[430] GRID2.0/DC CUB's Comments at 5.

[431] GSA's Comments at 1-2 and 19. GSA states that its comments are to address some technical and policy concerns the government has with MRPs and associated alternative ratemaking proposals.

[432] GSA's Comments at 2.

[433] GSA's Comments at 3.

ratemaking to MRPs, and there is no consensus that multi-year plans are in the public interest.[434] Nonetheless, GSA asserts that in addressing the framework for evaluating an alternative ratemaking proposal, the Commission should carefully assess six issues. First, GSA believes that the overarching standard that the Commission should use in determining whether to approve a MRP is assessing "[w]hether the alternative ratemaking proposal will result in definite and significant net benefits, reduced risks, and lower rates to all customers compared to traditional ratemaking."[435] GSA states that utilities benefits of a MRP are clear in that they include: (1) reduction in regulatory lag when costs are rising; (2) increased likelihood of earning or over-earning the utility's allowed ROE; (3) more rate increases with fewer rate cases; and (4) opportunities to enhance revenues through performance incentives. However, GSA argues that from the customers perspective it is unclear what benefits they receive under a MRP. GSA believes that the benefits to customers are theoretical or speculative at best and asserts that the purported benefit of providing customers with rate predictability is questionable since a utility would have opportunities to adjust rates (including through the reconciliation process) over the term of the MRP.[436]

99. The second issue is "[w]hether the benefits of approving multiple rate increases at once and using forecasted costs to set rates outweigh the risks of doing so, and whether such an approach will result in lower rates and better utility performance."[437] GSA states that the current ratemaking approach allows for only one rate increase per rate case based on an historical test year or partially forecasted test year with adjustments for known and measurable charges.[438] This approach allows the Commission to review and verify the utility's actual cost for setting rates.[439] However, GSA states that the MRP would be a new paradigm that could allow a utility to seek approval for multiple rate increases in one case and set rates on projected hypothetical costs opposed to verifiable historical costs.[440] In addition, GSA, asserts that the benefits of a MRP should be weighed against the risks to customers of abandoning the traditional approach.[441]

100. As to the third issue, what GSA wants the Commission to consider is "[w]hether a review/reconciliation process will protect customers and ensure that only reasonable and prudently-incurred costs are included in rates."[442] GSA is concerned with an annual reconciliation for adjusting rates during the MRP period based on the actual earned ROE for the period opposed

434 GSA's Comments at 4.

435 GSA's Comments at 2 and 4.

436 GSA's Comments at 5-6.

437 GSA's Comments at 2 and 6.

438 GSA's Comments at 6.

439 GSA's Comments at 7.

440 GSA's Comments at 7.

441 GSA's Comments at 6-9.

442 GSA's Comments at 2 and 11.

to the projected ROE. GSA states that an annual reconciliation mechanism may provide customers' protection against a utility over-earning its allowed ROE outside of a specified band-width but would also lock in gains if the utility over earns and would protect the utility against under earning.[443] However, a true-up mechanism may not properly incentivize a utility to reduce costs and operate more efficiently in the absence of regulatory lag. Moreover, a true-up mechanism may result in an increase in the utility's rates and returns and a shift of risk associated with earning its authorized rate of return.[444] Such a mechanism may provide the utility with incentive to game the system by over-forecasting cost and over-spending.[445] GSA notes that any annual reconciliation process should be robust and include an after the fact review of project costs and provide ample time to consider all issues. Any reconciliation process with true-ups should consider how costs are to be flowed through to customers (*i.e.*, class-specific or system-wide, and reducing inter-class subsidies).[446]

101. GSA's fourth issue for consideration is "[w]hether PIMs are necessary and appropriate, and if so, how they should be designed to provide the proper incentives to the utility without providing an opportunity for a windfall and higher rates."[447] GSA states that with a MRP, PIMs generally operate to offset the disincentives a utility may have to operate inefficiently and control costs.[448] GSA notes that although PIMs are proposed with MRPs, traditional ratemaking does not incentivize the utility to meet reliability and operational standards.[449] GSA is concerned that "symmetrical" PIMs may only provide the utility with an opportunity to increase rates for things it is already responsible for doing (*i.e.*, providing reliable service – SAIDI/SAIFI).[450] GSA states that if PIMs are included in a MRP, the Commission will need to determine "whether the PIMs should operate primarily to reduce the risk to customers, as opposed to reward opportunities [for the utility]."[451] GSA suggests that the Commission consider PIMs that incorporate penalties for failure to meet reliability standards and performance targets but do not provide rewards for

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443 GSA's Comments at 12.

444 GSA's Comments at 13.

445 GSA's Comments at 13.

446 GSA's Comments at 14.

447 GSA's Comments at 3 and 15.

448 GSA's Comments at 15. GSA notes that Pepco's proposal has five PIMs (SAIDI, SAIFI, service level, abandonment rate, and DER installation.

449 GSA's Comments at 15.

450 GSA's Comments at 15.

451 GSA's Comments at 16.

meeting those targets.[452] Also, GSA believes that the Commission should consider whether the PIMs should include reporting requirements opposed to financial penalties or rewards.[453]

102. As for the fifth issue, GSA asserts that the Commission should consider "[w]hether the alternative ratemaking proposal represents a reasonable vehicle to address cost allocation, revenue spread, and rate design issues."[454] GSA raises the issue of the Commission's treatment of residential class customers negative RORs and the interclass subsidy paid by commercial class customers.[455] GSA is concerned with perpetuating or worsening the allocation problem over the term of a MRP.[456] To address this issue, GSA suggests that the Commission may need to approve a revenue spread for each year of the MRP to reduce the interclass subsidy with a goal towards eliminating it.[457] In addition, the Commission should consider if: (1) a MRP is an appropriate vehicle for eliminating interclass subsidies; and (2) the rate design should be fixed for the term of the MRP or provide opportunities to modify the rate design.[458]

103. The sixth and final issue is "[w]hether an alternative ratemaking approach is necessary when the current regulatory regime in the District includes elements and features which limit a utility's risk, and if so, what modifications should be made to the utility's proposal and/or other elements of the existing rate and regulatory structure to better balance the risks between the utility and its customers."[459] GSA points out that the District's regulatory framework already has elements of alternative ratemaking (*i.e.*, streamlined approval and cost recovery process for major categories of build – DC PLUG, the BSA, and the use of partially forecasted test year) that limit Pepco's risk and increase the Company's opportunity to earn its allowed return.[460] When considering a MRP the Commission will need to determine whether alternative forms of ratemaking will streamline the regulatory structure or whether existing mechanisms (BSA) should be phased out to eliminate redundancy or prevent windfalls to the utility and simplify the rate structure. Some features may need to be modified in light of the reduced risks to utilities.[461] Given the extra benefits and safeguards utilities receive under a MRP, in order not to shift the risks from the utility, the Commission should consider a significant reduction in the utility's authorized rate

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[452] GSA's Comments at 16.

[453] GSA's Comments at 16.

[454] GSA's Comments at 3 and 17.

[455] GSA's Comments at 16.

[456] GSA's Comments at 16-17.

[457] GSA's Comments at 17.

[458] GSA's Comments at 17.

[459] GSA's Comments at 3 and 17.

[460] GSA's Comments at 17-18.

[461] GSA's Comments at 18-19.

of return in comparison to what the utility would have been allowed under the traditional ratemaking.[462]

J. IBEW-Local 1900

104. IBEW does not reject the idea of alternative ratemaking but asserts that any proposal should be consistent with the following three points: (1) a MRP should be limited to a three year period; (2) the Commission should not establish PIMs that incentivize cost cutting; and (3) the Commission should start by using PIMs that do not have financial incentives (where appropriate incrementally introduced incentives).[463] With respect to limiting the time period of a MRP, IBEW asserts that this would give the Commission an opportunity to evaluate, and if necessary adjust the plan and limit the concerns of whether utility companies can provide accurate long-term forecasts.[464]

105. When addressing the issue of financial incentives, IBEW is concerned that implementing PIMs which incentivize cutting costs will lead to unintended consequences outweighing any potential benefits.[465] These types of incentives can lead the utility to game the system "by having large expenditures during the test year, and then deferring necessary work in order to create artificial savings."[466] In addition, IBEW is concerned that cost-cutting PIMs could encourage utility companies to "sacrifice safety and service."[467] IBEW argues that "cost-cutting PIMs could incentivize short-term 'savings' at the expense of long-term investments by causing Pepco to reduce investments in its own workforce and increase the amount of work it contracts to third-party contractors."[468] IBEW avers that ratepayers benefit by receiving safe, high quality services from a skilled and experienced workforce when Pepco retains the human capital and trains its own workforce.[469] IBEW argues that by using its own employees, it should be easier to forecast labor costs because the work is covered by a collective bargaining agreement ("CBA"). If the Commission decides to implement cost-cutting PIMs, the Commission should take steps "to ensure utilities do not cut costs at the expense of safety, service, or workforce investment."[470]

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462 GSA's Comments at 19.

463 IBEW's Comments at 1.

464 IBEW's Comments at 1-2.

465 IBEW's Comments at 2.

466 IBEW's Comments at 2.

467 IBEW's Comments at 2. Expenditures for appropriate staffing levels, grid modernization, and workforce development are necessary for the provision of high-quality services to ratepayers in a manner that is safe for public workers.

468 IBEW's Comments at 2.

469 IBEW's Comments at 2-3.

470 IBEW's Comments at 3.

106. With respect to IBEW's proposal to start with PIMs that do not provide financial incentives, IBEW suggests getting baseline data, the Commission should start by establishing goals and reporting requirements without financial incentives. This data would then be used for future financial incentives by tracking certain metrics.[471] IBEW believes that workplace accidents or injuries for its employees or contractors' employees are worth tracking but should not be incentivized because of potential for the utility to under report.[472] IBEW recommends that any PIMs established with financial incentives should start out small and increase incrementally to allow the Commission to determine the effectiveness of the PIMs, its ability to measure performance, and whether there are unintended consequences.[473]

K. MDV-SEIA

107. MDV-SEIA states that "[PBR] of electric utilities, including MBR and PIMs, is a powerful tool to align utility incentives with public policy objectives" and its implementation in the District "must result in a regulatory framework where utility profitability is driven by performance in meeting defined public policy objectives."[474] MDV-SEIA further states that PBR should "not be used as a vehicle to enhance utility earnings" but be used as tool to "transition from traditional cost-of-service based earnings to performance-based earnings" for the utility.[475] Citing North Carolina's experience, MDV-SEIA cautions that "MRP could undermine the District's clean energy goals if it provides for pre-approved rate increases without Commission review and without stabilizing mechanisms such as PIMs and automatic cost relief."[476]

108. MDV-SEIA states that it "supports PBR as a regulatory tool to align utility incentives with the District's clean energy goals" and:

> recommends that the Commission's policy framework for evaluating Pepco's proposal ensure that Pepco is incentivized to facilitate renewable energy deployment in the District also maintaining transparent and predictable rates so that customers can predict their energy costs and accurately quantify the financial benefit from investing in a distributed solar facility, subscribing to a Community Renewable Energy Facility, or purchasing renewable energy from a competitive supplier.[477]

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[471] IBEW's Comments at 3-4.

[472] IBEW's Comments at 4.

[473] IBEW's Comments at 4.

[474] MDV-SEIA's Comments at 2.

[475] MDV-SEIA's Comments at 2.

[476] MDV-SEIA's Comments at 2.

[477] MDV-SEIA's Comments at 2.

109. MDV-SEIA explains that this is "critical for low- and moderate-income solar customers that would be hardest hit by a change in regulatory structure that undermines the economics of their investment in solar net metering."[478] MDV-SEIA recommends consideration of "some of the District's key grid modernization goals, as part of PowerPath DC," such as "integration of more non-wire alternatives through Pepco's improved distribution system planning process;" deployment of more DER, and greater data access by customers and third-parties.[479] MDV-SEIA specifically recommends that the Commission adopt a policy framework that promotes: grid planning; development of renewable and demand response resources; enabling DER markets; facilitation and administering CREF development; customer choice and engagement; and supporting energy efficiency and conservation.[480] Lastly, MDV-SEIA recommends that the Commission consider the Hawaii PV Coalition's [ ] Phase 2 Initial Comprehensive Proposal . . . and the applicability of those proposals in the District" including the Customer Engagement PIM, the Interconnection Experience PIM, and DER Asset Effectiveness PIM.[481]

L. SBUA

110. SBUA comments that small businesses are under resourced and are not equipped to fully engage in the Commission proceedings. It states that it is a national non-profit organization is an expert in representing small businesses in utility rate cases, is working with the Micro Business Network, a local effort, in *Formal Case No. 1156*. SBUA works primarily in states with Intervenor Compensation programs whereby the utility reimburses intervenors in representing different constituencies. The District, according to SBUA, does not have such a program despite the vast number of micro enterprises throughout the city, and comments that it would be good fiscal management, ensure lower rates, and improve efficiency to explore such a program as there is no uniformity in how micro enterprises are charged or classed or billed.[482]

111. SBUA comments on the problems faced by micro enterprises. SBUA asserts that these commercial consumers struggle to keep their doors open, sometimes barely making enough to pay their overhead and hope there is enough left over to live on.[483] SBUA complains that with the recent surge in skyrocketing commercial rent and competition from big box stores closing in from one side and the rise in costs from improving long-awaited-and-needed worker protections and wage increases from the other side, micro businesses are experiencing economic pressure.

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478 MDV-SEIA's Comments at 2-3.

479 MDV-SEIA's Comments at 4, quoting *Formal Case No. 1130*, Order No. 19984 at Page No. iii (Staff Proposed Opinion and Order), rel. August 2, 2019.

480 MDV-SEIA's Comments at 4.

481 MDV-SEIA's Comments at 4. Citations to the Hawaii PV Coalition Phase 2 Comprehensive Proposal, attached to MDV-SEIA's Comments are omitted.

482 SBUA's Comments at 1.

483 SBUA's Comments at 1.

112. SBUA explains that some owner operators have not gotten a raise until the minimum wage was increased in the District, requiring that they pay themselves a higher wage. SBUA comments on the dilemma of the extremely long hours of hands-on business ownership, the greatest need after commercial rent, is to curb rising utility costs. Specifically, SBUA states that for small stores with a need for multiple refrigeration units or cooling systems for food and beverage sales or other operations that require higher usage, the lack of representation in Commission proceedings have allowed runaway commercial consumer rates to disparately impact under-represented micro enterprises.[484]

113. SBUA complains that service interruptions, storms and other natural disasters, and maintenance and construction throughout the city have created major problems for its members. SBUA contends that the utility's performance directly impacts sales and profits.[485] In addition, SBUA asserts that because many owner operators of micro enterprises do not own their building or property, there is an interest in renewable energy and other alternatives, but typically require landlord or property owner approval. And even if approval were granted, sometimes the benefits in reduced utility bills are not passed on to the business owner.[486]

114. Because micro enterprises are located in a multitude of spaces, SBUA contends that no uniform rate class is set aside for micro enterprises.[487] SBUA points out the anomaly that some of the owner operators with whom it does business have two shops providing the same service in the same square footage and will pay two completely different utility rates and monthly bills because of the location of the business (one in a downtown commercial retail building and one in a Capitol Hill row home).[488] Complaining that the utility related challenges faced by micro enterprises are a barrier to their survival in a rapidly gentrifying city, SBUA urges the Commission to ensure that their needs are taken into consideration.[489]

115. SBUA proposes the following recommendations: (1) Study of Intervenor Compensation programs around the country and how it can be structured and implemented in DC. (See attachment on Intervenor Compensation programs). SBUA claims that such a program could ensure that under-represented consumers have a voice in rate cases and other proceedings; (2) Creation of a separate rate class for micro enterprises, much like the protected class for low-income or senior residential consumers, to support start-ups and independently-owned outfits. This, SBUA contends, would be a self-identified opt-in by micro enterprises and commercial consumers of an agreed upon size or revenue for lower or subsidized rates. SBUA professes that it would like to work with the Commission and the Utility to set criteria for who can opt in to ensure that the program supports the businesses in the most need and contribute to community led economic development and local hires; (3) Development of energy efficiency programs that

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484 SBUA's Comments at 1.

485 SBUA's Comments at 1.

486 SBUA's Comments at 1-2.

487 SBUA's Comments at 2.

488 SBUA's Comments at 2.

489 SBUA's Comments at 2.

incentivize micro enterprises regardless of whether or not they own their buildings. SBUA asserts that the city has many programs which are moving in this direction but targeting these consumers and implementation within the commercial sector is far off, because there has been a focus on low-income residents first. SBUA contends that support from the utility to develop this program and begin implementation in 2020 would be ideal; and (4) Tracking, reporting, and evaluating programs for small businesses to determine their effectiveness. SBUA claims that many times, owner operators do not have time to learn about new programs or to complete complicated paperwork. SBUA maintains that it would be important to collect data regarding whether existing programs are reaching the micro enterprises community and if those programs are actually being utilized. SBUA recommends that annual monitoring of outreach, applications, and actual use of programs, incentives, credits, or rebates should set the standard for improvement year after year.[490]

116. SBUA states that it and the Micro Business Network want to work with residents, customers, and workers to find solutions for a thriving local economy and contribute to a sustainable environment.[491] SBUA also supports the comments of the Laborers International Union of North America about worker treatment and agree that mistreated workers lead to service errors and unnecessary costs which increase rates for our members. Lastly, SBUA comments that the Commission has jurisdiction and the responsibility to address all of these issues.[492]

M. WGL

117. WGL comments that it views its participation in this proceeding as an observer and does not plan to file testimony in the case. It adds that it has not prepared or filed a similar three-year MRP in any of its jurisdictions. WGL asserts that a decision on whether that filing will be a historical test year, a forecasted test year, a MRP, or a formula rate plan has not yet been finalized.[493]

118. WGL contends that contrary to what some parties argued at the Technical Conference, a MRP is not "unique or novel." WGL argues that the word "mainstream" may be a better term, due to the acceptance of the MRP around the country.[494] WGL argues that parties opposed to a MRP create the false notion that a MRP is a major change from the current process. A comparison of a MRP with traditional rate case filings would dispute this notion. WGL contends that under both a MRP and traditional rate case filing: rates will be set through regulatory review before the Commission; all stakeholders and customers have the opportunity to participate; and the Commission makes a final decision based on finding of just and reasonable rates.[495]

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490 SBUA's Comments at 2-3.

491 SBUA's Comments at 3.

492 SBUA's Comments at 3.

493 WGL's Comments at 1-2.

494 WGL's Comments at 2.

495 WGL's Comments at 2-3.

119. WGL asserts that the goal of a MRP is to allow the utility to reduce regulatory lag, thereby providing a reasonable opportunity for a prudent utility to earn its authorized rate of return allowed by Commission orders.[496] WGL sums up its comments based on the issues presented by the Commission in its Amended Notice. WGL responds that, whether a public utility files a traditional rate case or a MRP, the burden of proof remains with the public utility. Thus, the evidence presented will be directly linked to the proposal submitted by the public utility.[497] With regard to the benefits of any alternative forms of regulation, including performance-based ratemaking ("PBR") or MRP/PIM, relative to its costs/risks, WGL responds that the benefits of a MRP include: a) reduction of the frequency and costs of rate cases; b) rate changes are more gradual over time when rates change moderately on an annual basis, rather than a single large rate increase following a traditional rate case; and c) allow customers to gain an early share of any cost efficiencies that the utility may develop.[498]

120. WGL comments that, based on the Commission decision in a MRP proceeding, the annual reconciliation may create savings to be shared with customers or retained by the public utility. In an effort to not create an incentive that may result in a reduction in the quality of service standards, PIM may help "balance" utility performance.[499] WGL adds that PIMs can be used to achieve other goals. For a gas utility, WGL states that this can include coordination with other on-going activities, such as accelerated pipe replacement, leak mitigation and customer service metrics.[500]

121. With regard to the issue of rate design, WGL comments that for a three-year MRP, changes can be made for each successive year of the MRP. WGL explains that the rate design approved in Year 1 influences succeeding years, which can reflect the prior year's impact on customer class returns. WGL concludes that the MRP rate design methodology will be consistent with the traditional rate case rate design methodology.[501]

122. Commenting on the parameters for a true-up or reconciliation process, WGL asserts that the reconciliation process should be performed on an annual basis, adding that the reconciliation will assist in verifying forecasted data presented in a MRP.[502] With regard to the issue of what terms, conditions, and procedures the Commission should establish to provide ratepayers with notice of a public utility's alternative forms of regulation plan and provide opportunities for ratepayers to comment and participate in the ratemaking process, WGL comments that public hearings used in traditional rate cases, can also be utilized for a MRP filing.

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496 WGL's Comments at 3.

497 WGL's Comments at 3.

498 WGL's Comments at 3.

499 WGL's Comments at 3.

500 WGL's Comments at 3-4.

501 WGL's Comments at 4.

502 WGL's Comments at 4.

WGL adds that the public utility can also use its website and various print messages to educate its customers on MRPs.[503]

123. In response to the question regarding experiences in other jurisdictions of alternative forms of regulation, including MRP, PBR, and PIMs, WGL comments that both Pepco and WGL serve customers in the Maryland jurisdiction.[504] WGL cites MD PSC staff member Juan Alvarado as having discussed at the Technical Conference a survey that MPSC Staff had performed in reviewing alternative rate plans in other jurisdictions as part of a proceeding to review alternative rate plans.[505] WGL states that the MD PSC approved the use of a MRP in an August 9, 2019 Order. In that Order, WGL asserts that the Commission provided its support for the MRP for the following reasons: it shortens the cost recovery period; it has more predictable revenues for utilities and customers; it spreads rate changes over multiple years; it lowers the administrative burden on regulators; there is transparency in the utility planning process; and it has annual reconciliation.[506]

124. Commenting on whether an alternative form of regulation should always require a proposal for a base year (historical test year), a bridge year and one or more forecasted test years, and on the relative pros and cons for different forms and proposals, WGL responds that as MRPs become commonplace in the District, the historical test year should only become a base in determining the revenue requirement for the three years of the MRP.[507] WGL reiterates that the goal of a MRP is to reduce regulatory lag. To WGL, an eighteen-month procedural schedule for the Pepco MRP does not assist in reducing regulatory lag.[508]

125. Commenting on how credit rating agencies have viewed the implementation of alternative forms of regulation for electric and natural gas distribution utilities, WGL cites the presentation of Lillian Federico of RRA at the Technical Conference, wherein she addressed regulatory lag and tools to assist in mitigating regulatory lag. WGL states that she presented a chart entitled - Alternative Regulation Plans - Becoming More Prevalent.[509] WGL adds that a quarterly review issued by RRA on August 15, 2019, raised the ranking of Maryland regulation. The change, according to WGL, was based on the MD PSC gradually beginning to implement policies to mitigate regulatory lag. WGL asserts that, along with other items, the ranking change recognizes the MD PSC's recent decision to move forward with respect to alternative regulation.[510]

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503 WGL's Comments at 5.

504 WGL's Comments at 5.

505 WGL's Comments at 5.

506 WGL's Comments at 5.

507 WGL's Comments at 5-6.

508 WGL's Comments at 5-6.

509 WGL's Comments at 6.

510 WGL's Comments at 6.