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GOVERNMENT OF THE DISTRICT OF COLUMBIA
OFFICE OF THE ATTORNEY GENERAL

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Public Advocacy Division
Social Justice Section

March 6, 2020

Ms. Brinda Westbrook-Sedgwick
Public Service Commission
Of the District of Columbia Secretary
1325 G Street, NW, Suite 800
Washington, DC 20005

Re: 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.

Dear Ms. Westbrook-Sedgwick:

On behalf of the District of Columbia Government (DCG), please find enclosed for filing the Direct Testimony of Courtney Lane. This document is preliminarily identified as Exhibit DCG (A), with exhibits attached and preliminarily identified as Exhibits DCG (A)-1 through DCG (A)-15. If you have any questions regarding this filing, please contact the undersigned.

Sincerely,

KARL A. RACINE
Attorney General

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BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO IMPLEMENT A MULTIYEAR RATE PLAN FOR ELECTRIC DISTRIBUTION SERVICE IN THE DISTRICT OF COLUMBIA	))))))))	**Formal Case No. 1156**

Direct Testimony of

Courtney Lane

On Behalf of

The District of Columbia Government

Regarding the Company's Proposed Multi-Year Rate Plan and

Performance Incentive Mechanisms

March 6, 2020

Exhibit DCG (A)

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Courtney Lane. I am a Senior Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency (EPA), U.S. Department of Energy (DOE), U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 30 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have 15 years of experience in energy policy and regulation. At Synapse, I have worked on issues related to utility regulatory models and performance incentive mechanisms. Prior to working at Synapse, I was employed by National Grid as the Growth

Management Lead for New England where I oversaw the development of customer products, services, and business models for Massachusetts and Rhode Island. Part of this role included the development of performance incentive mechanisms. In previous roles at National Grid, I worked on the deployment of non-wires alternatives and grid modernization efforts and led the development of annual and three-year energy efficiency and system reliability procurement plans. Prior to joining National Grid, I worked on regulatory and state policy issues pertaining to energy conservation, retail competition, net metering, and the Alternative Energy Portfolio Standard for Citizens for Pennsylvania's Future (PennFuture). Prior to that, I worked for Northeast Energy Efficiency Partnerships, Inc. where I promoted energy efficiency throughout the Northeast.

I hold a Master of Arts in Environmental Policy and Planning from Tufts University and a Bachelor of Arts in Environmental Geography from Colgate University. My resume is attached as Exhibit DCG (A)-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the District of Columbia Government (DCG or the District).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Potomac Electric Power Company's (Pepco or the Company) proposed Performance Based Regulation proposal (PBR), which consists of a Multiyear Rate Plan (MRP) and Performance Incentive Mechanisms (PIMs).

Q. Have you testified before the Public Service Commission of the District of Columbia (Commission) previously?

A. No.

Q. Have you previously submitted testimony in proceedings before other state or federal commissions or agencies?

A. Yes. I have testified under oath and participated in regulatory proceedings before the Rhode Island Public Utilities Commission and the Pennsylvania Public Utility Commission. In Rhode Island I testified on matters pertaining to energy efficiency, system reliability procurement, and power sector transformation. In Pennsylvania I testified on matters related to energy efficiency and retail electric markets. A list of my previous testimony is attached as Exhibit DCG (A)-1.

Q. What materials did you rely on to develop your testimony?

A. The sources for my testimony and exhibits are public documents and responses to discovery requests, as well as my personal knowledge and experience.

Q. Are there any exhibits accompanying your testimony?

A. Yes. I am sponsoring Exhibits DCG (A)-1 through DCG (A)-15. Exhibit DCG (A)-1 is my resume. Exhibit DCG (A)-2 is an order I discuss from the Minnesota Public Utilities Commission approving the Integrated Distribution Planning Requirements for Xcel Energy. Exhibits DCG (A)-3 through DCG (A)-15 are Pepco's responses to data requests in this proceeding that I relied upon in my testimony.

Q. Did you prepare or direct the preparation of this testimony and accompanying exhibits?

A. Yes.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Do you support the Company's PBR proposal?

A. No, I do not support the Company's PBR proposal for the reasons provided below.

Q. Briefly summarize why you do not support the Company's PBR proposal in its current form?

A. Briefly, as discussed in more detail below, I cannot support the Company's PBR proposal (either the MRP or PIMs proposal), as it does not comply with the Commission's principles for alternative forms of regulation (AFOR), but instead shifts substantial risk onto ratepayers without advancing the energy policy goals of the District. In particular, the Company's proposal suffers from the following four flaws:

1. The Company's MRP proposal does not provide appropriate incentives to the Company to contain costs or protect customers from unreasonable rates. Instead, the proposal is akin to a formula rate plan, albeit with some minor adjustments;

2. The Company's proposal shifts risk to customers by exacerbating existing information asymmetries through the use of cost forecasts that are not anchored in comprehensive grid modernization or distribution system plans, and through a lack of transparency in its proposed cost variance reporting;

3. Pepco's proposal does not sufficiently advance or otherwise align with the District's public policy goals, such as grid modernization, the adoption of distributed energy resources (DERs), and the development of non-wires alternatives (NWAs);

4. Pepco's proposal does not adequately qualify, quantify, or measure benefits its proposal would provide to its customers

5. The Company's proposed PIMs do not advance the energy goals of the District, as they target only those activities that the Company is already required to perform under Commission regulations, such as reliability, safety, and interconnection.

Q. Please summarize your recommendations.

A. I offer the following recommendations:

1. The Commission should reject the Company's proposed MRP and require that any future MRP (1) not be permitted to include reconciliations of utility under-earnings, (2) include an index-based cost escalation, and (3) provide for more transparency pertaining to grid modernization efforts.

2. The Commission should reject the Company's proposed PIMs and require that proposed PIMs advance the District's energy policy goals. I intend to elaborate on this recommendation in my rebuttal testimony.

3. Regardless of whether Pepco operates under an MRP, we recommend that the Commission consider the following actions:

    a) Require Pepco to develop and file an integrated distribution resource plan and comprehensive grid modernization plan that includes a system needs assessment, technology investment roadmap, timeline, and benefit-cost analysis. Any permitted cost recovery should be predicated on the filing and approval of such plans. The requirements of these plans should be based on best practices and incorporate the stakeholder input provided during the working groups in Formal Case 1130 from 2018 to 2019.

b) Establish a Commission mandate for (i) transparency, coordination, and data sharing with DER technology providers and manufacturers that would enable the deployment of DER technology based on system needs, and (ii) updating the Company's load forecast assumptions to improve accuracy and reliability, including demand intensity of new and renovated buildings, that may be outdated;

c) Establish explicit metrics and targets to guide Pepco's activities for grid modernization; and

d) Consider explicit metrics and incentives to encourage Pepco to utilize DERs to cost-effectively avoid traditional capital investments through the use of open-sourced requests for proposals and process participation by key stakeholders such as DCG, the Office of People's Counsel, and the Commission. Incentives for NWAs could include financial rewards for especially successful adoption of NWAs, and penalties in situations where the Company did not adequately evaluate or implement NWAs.

III. PEPCO'S PROPOSAL SHOULD BE REJECTED AS IT DOES NOT SUFFICIENTLY ADVANCE THE DISTRICT'S ENERGY GOALS

The Role of PBR

Q. Please define what you mean by PBR?

A. Performance based regulation is a departure from traditional cost of service regulation intended to create different incentives for the regulated utility to improve its performance. PBR generally consists of two components: MRPs and PIMs.

An MRP is a set of rules governing the rates or allowed revenues of the utility for multiple years into the future, with a regulatory requirement that the utility not have another rate case until the end of a stay-out period. Allowed revenues or rates are designed to change in a known or formulaic fashion from year to year, fully or partially independent of utility costs. Since utility profits depend on the difference between revenues and costs, this structure provides an incentive for the utility to contain and reduce costs over multiple years.

PIMs are sets of metrics with targets and financial implications. PIMs can serve as a useful regulatory mechanism to positively influence utility behavior towards the advancement of energy policy goals that are not directly aligned with a distribution company's public service obligations or existing financial incentives.

Q. What are the advantages and disadvantages of implementing PBR in the District of Columbia?

A. As correctly noted by the Commission, AFORs, such as PBR, can serve "as a potential tool in assisting the District in achieving its clean energy and environmental goals to the benefit of District residents and ratepayers," and "facilitate achieving the District's aggressive goals regarding greenhouse gas emission reductions, transportation electrification, renewable energy development, grid modernization, and other District goals."[1]

However, the Commission also correctly raised concerns that any AFOR must be designed protect customers and be in the public interest.[2] This concern is well founded, as both MRPs and PIMs can undermine the public interest if not designed well.

Q. Please describe how PBR can undermine the public interest?

A. PBR plans are generally designed by utilities, which operate under a strong profit motive, and can therefore be expected to have a bias that favors the utilities. For example, potential pitfalls associated with a poorly designed PBR proposal could include:

- Ability of the utility to recover its costs more quickly, without providing increased benefits to customers or advancing energy policy objectives beyond what would have been achieved through traditional cost of service regulation;
- A reduction in regulatory lag (and the cost containment incentives associated with regulatory lag) with no commensurate strengthening of cost containment incentives elsewhere;

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[1] Public Service Commission of the District of Columbia, Order No. 20273, December 20, 2019, at i.
[2] *Ibid.*

- Shifting risk onto ratepayers by requesting that the Commission pre-approve investments and costs, thereby substantially reducing the risk of later determinations of imprudence;
- Exploitation of information asymmetries, particularly through reliance on cost forecasts, to increase profits for the utility; and
- PIMs that do not advance the District's public policy goals and reward the utility for performance easily achieved or already required to be achieved pursuant to Commission Orders or regulations.

Q. Has Pepco proposed a PBR mechanism in this proceeding?

A. Yes. Pepco's PBR proposal consists of an MRP and PIMs. The MRP component of the proposal would set revenues for a three-year term for the years 2020, 2021, and 2022. The PIM component includes five proposed financial PIMs with incentives and penalties on specific utility performance, as well as one tracking-only metric.

Q. What principles should be followed when designing a PBR Proposal?

A. In Order No. 20273, the Commission provided overarching framework principles for a utility seeking an AFOR, including Pepco's proposal.[3] The framework principles indicate that Pepco's proposal should demonstrate the following:

[3] Public Service Commission of the District of Columbia. Order No. 20273. 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 Services in the District of Columbia. December 20, 2019.

1) (A) Protection of consumers; (B) ensuring the quality, availability, and (C) reliability of regulated utility services; and that it is in the interest of the public, including shareholders of the utility;

2) Advancement of public safety, the economy of the District of Columbia, 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) A ratemaking mechanism that advances or otherwise aligns with the District's public policy goals;

4) Identification of baseline revenue and cost information, and a clear explanation of what process or mechanism the utility used to project revenues and expenses;

5) Benefits that are measurable, quantitative, and qualitative to customers, as opposed to solely focusing on benefits to the utility;

6) Impacts to the operational incentives of the utility with respect to maintaining a high level of customer service, while fostering productivity and cost control; maintaining the financial strength, credit ratings, and financial flexibility of the utility; and helping to ensure a consistently high level of energy delivery system reliability, while promoting safe and reliable operations over time;

7) Revenue requirements that 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) Mitigation of risk related to over-earning a utility's authorized return during the duration of the MRP for the benefit of the customers, while also preserving the Commission's ability to conduct cost prudency reviews as needed;

9) An appropriate level of transparency and reporting into the utility's operational and capital plans to ensure that the plans will be maintained during the duration of the MRP; and

10) The avoidance of any unreasonable shifting of risk to utility customers.[4]

<u>Summary of Pepco's PBR Proposal</u>

Q. Please summarize Pepco's PBR proposal.

A. The MRP component of the Pepco's proposal would set revenues for a three-year term for the years 2020, 2021, and 2022. Pepco uses calendar year 2018 as the historical test year and the 2019 budget as the bridge year. Pepco proposes three rate adjustments for each year of the MRP based on the Company's projected capital investments and operating and maintenance costs for years 2020-2022. The MRP also includes a reconciliation mechanism with a deadband of +/- 25 basis points around the target proposed Return On Equity (ROE) of 10.3 percent for each MRP term year. If Pepco's

[4] *Id.* at ¶ 94.

earned ROE exceeds the upper bound of the deadband, then 75 percent of the overearnings is automatically returned to customers. If Pepco earns below the lower bound of the deadband, Pepco would file a request for a rate adjustment with the Commission with justification for the deviation. If approved by the Commission, then rates would be adjusted to bring the Company's ROE to 75 percent of the difference between the lower end of the deadband and its earned ROE.

The PIM component includes five proposed financial PIMs with incentives and penalties on specific utility performance: (1) System Average Interruption Duration Index (SAIDI) (2) System Average Interruption Frequency Index (SAIFI): (3) Customer Service Level; (4) Call Abandonment; and (5) Level 1 DER Interconnection Review Timeframe. Pepco also proposes a tracking metric related to collecting and reporting Customers Experiencing at least 4 Multiple Interruption (CEMI-4) performance that is not tied to an incentive or penalty.

<u>Critical Flaws in Pepco's Proposal</u>

Q. Does Pepco's PBR proposal align with the framework principles outlined in Commission Order No. 20273?

A. No, it does not.

Q. Please summarize the key critical flaws in Pepco's PBR proposal as they pertain to the Commission's AFOR framework principles.

A. There are several critical flaws in Pepco's PBR proposal. These include the following:

1) Pepco's proposal does not provide adequate cost containment incentives, nor does it mitigate the risk of over-earning its authorized return. Therefore, the proposal fails to:

- Protect consumers (¶ 94, Item #1A)
- Foster productivity and cost control (¶ 94, Item #6)

2) Pepco's proposal shifts risks to ratepayers by exacerbating existing information asymmetries through the use of cost forecasts that are not anchored in comprehensive grid modernization or distribution system plans, and through a lack of transparency in its proposed cost variance reporting. Therefore, the proposal fails to:

- Clearly explain what process or mechanism the utility used to project revenues and expenses (¶ 94, Item #4)
- Provide 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 (¶ 94, Item #9)
- Avoid any unreasonable shifting of risk to utility customers (¶ 94, Item #10)

3) Pepco's proposal does not sufficiently advance or otherwise align with the District's public policy goals, including grid modernization and the development of NWAs. Therefore, the proposal fails to:

- Advance the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments (¶ 94, Item #2)
- Advance or otherwise align with the District's public policy goals (¶ 94, Item #3)

4) Pepco's proposal does not adequately qualify, quantify, or measure benefits its proposal would provide to its customers. Therefore, the proposal fails to:

- Provides benefits that are measurable, quantitative, and qualitative to customers (I¶ 94, Item #5)

IV. PEPCO'S MRP PROPOSAL PROVIDES INSUFFICIENT COST CONTAINMENT INCENTIVES

Q. Please explain how Pepco's proposal fails to provide adequate cost containment incentives, thereby failing to protect consumers or foster productivity and cost control.

A. Pepco's proposal contains a mechanism that prevents its earned ROE from deviating far from its allowed ROE, even if it vastly overspends compared to its approved cost forecasts and revenue requirement. This mechanism provides very weak cost containment incentives and makes Pepco's proposal more similar to a formula rate plan than to an MRP.

<u>Pepco's Proposal is More Akin to a Formula Rate Plan than an MRP</u>

Q. Please explain how the Company's proposal is designed to prevent its earned ROE from deviating far from its allowed ROE?

A. The Company proposes to reconcile all elements of its rate base and earnings, including the difference of the revenue requirement impact.[5] If the variance causes Pepco's ROE to be more than 25 basis points below its allowed ROE, Pepco proposes to recover 75% of the underearning (below the deadband) from customers. If the variance causes Pepco's ROE to exceed its allowed ROE by more than 25 basis points, Pepco proposes to retain 25% of the excess earnings above the deadband.

Q. How does this proposal affect the utility's cost containment incentives?

A. The proposal prevents the utility's ROE from deviating far from its allowed ROE, while shifting the majority of the risk of overspending to customers. Outside of the small deadband of 25 basis points, the Company would be allowed to recover 75% of any cost overruns unless a cost was found to be imprudent.

Q. Is such a reconciliation mechanism common in MRPs?

A. No. While it is fairly common to institute earnings sharing mechanisms (ESMs) for utility *overearnings*, reconciliations of utility under-earnings are virtually unheard-of. Instead, reconciliations of utility under-earnings are commonly found in formula rate plans.

[5] Direct Testimony of T.W. Wolverton, PEPCO (C), May 2019, at 36.

Q. Please define a formula rate plan.

A. A formula rate plan (FRP) ensures that a utility's earned ROE closely tracks its allowed ROE by reconciling revenues and costs. A report by the Edison Electric Institute describes an FRP as "a wide-scope cost tracker designed to help a utility's revenue track its cost of service."[6] The report further explains this mechanism as follows:

> FRPs have earnings true up mechanisms that adjust rates so that earnings variances are reduced or eliminated… The earnings true up mechanism plays a key role in an FRP. Some mechanisms compare the earned ROE to the target ROE and then calculate the rate adjustment needed to reduce the ROE variance. Others adjust rates for the difference between revenue and pro forma cost of service calculated using a rate of return target.[7]

Q. Why are formula rate plans problematic?

A. While formula rate plans reduce regulatory lag and allow utilities to earn their allowed ROEs, they do so by shifting risk onto ratepayers and eviscerating any cost containment incentives that the utility has. As the Commission correctly noted "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."[8]

An FRP filed by Entergy Arkansas, Inc. (Entergy) provides an example of these problematic outcomes. Entergy filed an FRP pursuant to Act 725 of 2015 with a revenue cap increase of 4% per year. In each subsequent year of the FRP, Entergy requested rate

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[6] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 47.
[7] Ibid.
[8] Public Service Commission of the District of Columbia, Order No. 20273, FC 1156, December 20, 2019, at 35.

increases exceeding 4%. This led the Arkansas Public Service Commission to note that the FRP has not provided appropriate cost containment incentives.

Specifically, the Arkansas Commission wrote, "An FRP is an annual rider. It fundamentally accomplishes a higher level of certainty of recovery thus reducing risk to the utility… The ability to increase revenues 4% each year is a considerable risk reduction for the utility."[9] The Commission further noted that annual rate adjustments incentivize spending, indicating there is no clear incentive to contain costs between annual FRP 4% increases.[10]

Utility commissions have been reluctant to adopt FRPs due to the problematic incentives they provide and recognition that these plans shift risk onto ratepayers. For example, the Maryland Public Service Commission noted that problems with FRPs include a "tendency to shift financial risks toward customers, a concern that automatic adjustments may curtail the thorough review of utility costs, and reduced incentives for utilities to control costs."[11] In other words, when revenues are trued up to equal the utilities actual costs, it erodes the utility's efficiency incentive to contain costs. In January 2020, the Maryland Commission rejected Staff's proposal for an annual reconciliation of all costs

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[9] Arkansas Public Service Commission Staff, Initial Brief Pursuant to Order No. 18, Docket 16-036-FR, January 11, 2019, at 17.
[10] Id., at 18-19.
[11] Maryland Public Service Commission, Order 89226, PC51, August 9, 2019, at 53.

and revenues, stating that such a proposal "strikes the wrong balance by placing all of the risk on customers, and none on the utility."[12]

V. PEPCO'S PROPOSAL SHIFTS RISKS TO RATEPAYERS AND LACKS TRANSPARENCY

<u>The Use of Cost Forecasts Shifts Risks to Customers</u>

Q. Please explain how the Company's proposal shifts risks to ratepayers.

A. A key means by which the Company's proposal shifts risks to ratepayers is through the use of cost forecasts. Because of information asymmetry, this creates opportunities (and risk for ratepayers) for forecasts to be gamed by the utility to advance its own profits.

Q. Please explain what you mean by information asymmetry.

A. Asymmetry of information simply means that the utility has more information than the regulator or stakeholders. Because of this, it is notoriously challenging for regulators to ensure that cost forecasts are reasonable. As explained by the National Regulatory Research Institute:

> "Information asymmetry reflects the relatively less knowledge that a regulator has (relative to the utility's) on the correlation between forecasted costs and utility-management competence. When a utility files a cost forecast, how does the regulator know whether it reflects competent management? The analyst or auditor can evaluate the forecast applying state-of-the-art techniques; still, however, a level of uncertainty remains

[12] Maryland Public Service Commission, Order 89482, Case No. 9618, February 4, 2020, at 36.

> that leaves unknown the utility's level of managerial competence embedded in the forecast."[13]

Because regulators and stakeholders can never completely vet the accuracy of forecasts, utilities have an inherent bias to overstate their costs and understate revenues. This bias has been well-recognized by commissions and by organizations such as the National Regulatory Research Institute (NRRI). The bias exists because the utility may expect the regulator to lower its cost forecasts, and because there is little payback for a utility that underestimates costs since any overrun would jeopardize its rate of return and penalize its shareholders.[14]

Q. How would Pepco benefit from inflating its cost forecasts?

A. Pepco would benefit financially if it overstates its cost forecast and then produces cost "savings." In this scenario, the utility would keep 100% of the first 25 basis points of any cost "savings," plus 25% of any additional "savings" outside of the deadband. If these are not true savings, but instead the result of inflated cost forecasts, then ratepayers benefit very little from this plan, while the utility would take home a higher ROE. In short, under Pepco's proposal, it would be the ratepayer that bears the majority of the risk of cost overruns and forecast errors.

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[13] Costello, "Multiyear Rate Plans and the Public Interest," 35–36.
[14] Costello, Ken, "Multiyear Rate Plans and the Public Interest" (National Regulatory Research Institute, October 2016), at 36.

Q. Under Pepco's proposal, the Company must seek approval from the Commission to recover 75% of the any overspend that falls outside the deadband.[15] Would this mitigate the risk that the Company would overspend its cost forecasts?

A. No. The practical burden of proving imprudence of costs incurred is high, as it requires extensive time and resources by the challenger, as well as a vast amount data regarding exactly what the utility knew and when. All of this information is far more readily available to the utility than to the intervenors or the Commission. As a result, it is generally impractical and burdensome to establish imprudence of costs in all but the most egregious cases.

Transparency of Forecasts

Q. The Company claims that its MRP "provides significant information upfront on the Company's planned capital and operation and maintenances spending."[16] Does this mitigate your concerns regarding cost forecasts?

A. No. Approving Pepco's MRP forecasts requires that regulators and stakeholders do much more work up-front to review for reasonableness, but without the benefit of having actual ex-post data. Further, Pepco's cost forecasts are not provided within the broader context of an integrated distribution system plan, which prevents stakeholders from adequately assessing the need for the proposed investments and whether lower cost alternatives (such as NWAs) exist.

[15] Second Supplemental Testimony of Kevin McGowan, (PEPCO 3B), at 10.
[16] Second Supplemental Testimony of Kevin McGowan, (PEPCO 3B), at 10

Q. What is an integrated distribution plan?

A. As summarized by ICF, an integrated distribution plan (IDP) "involves two general efforts: 1) multiple scenario-based studies of distribution grid impacts to identify "grid needs," and 2) a solutions assessment including potential operational changes to system configuration, needed infrastructure replacement, upgrades and modernization investments, and potential for non-wires alternatives."[17] These studies are generally conducted annually with a 5- to 10- year planning horizon and with considerable input from stakeholders regarding planning assumptions. IDPs also tend to use forecasts with multiple load and DER scenarios to "to assess current system capabilities, identify incremental infrastructure requirements and enable analysis of the locational value of DERs."[18]

Q. Have other commissions required utilities to undertake integrated distribution planning?

A. Yes. For example, Minnesota has been a leader in this area and requires its utilities to conduct comprehensive, coordinated, and transparent integrated distribution plans on an annual basis. Minnesota's IDP requirements for Xcel Energy are attached as Exhibit (A)-2.

Q. How should the costs contained in an MRP relate to an IDP?

A. An IDP would be beneficial to vetting and justifying any proposed costs within the MRP. Without an IDP, the Commission and stakeholders do not have the information necessary

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[17] ICF International, *Integrated Distribution Planning,* Prepared for the Minnesota Public Utilities Commission, August 2016, at vi. Available at https://www.energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf

[18] *Ibid.*

to understand whether Pepco's proposed investments optimize grid assets and minimize total system costs.

Q. Is Pepco's distribution construction program (described in the Construction Report (PEPCO (I)-1 to (I)-3) similar to an IDP?

A. No. The Company's construction report is a short-term investment plan based on a single, deterministic load forecast, rather than considering multiple scenarios with various levels of DER adoption and electrification. Pepco's construction report provides little information on how its investments will facilitate continued development of DERs on the system (other than through distribution automation), nor any information regarding what investments will be needed in the future to support increased DER adoption and address barriers to DER integration. Notably absent from Pepco's construction report is any form of long-term grid modernization and investment plan.

Q. Is Pepco's distribution construction program transparent?

A. No. While Pepco indicates key inputs to its load forecast include "Prospective New Business (PNB) information received by the Company, load transfers identified during the studied period, and DER installations,"[19] the Company objected to DCG's request for more information regarding these critical inputs that will determine system needs.[20] This further exacerbates the information asymmetry in reviewing proposed justification for costs in the MRP. As noted by the Commission, the utility's AFOR should include

[19] *See* FC 1156 Pepco Response to DCG DR 2-3, attached hereto as Exhibit DCG (A)-3.
[20] *See* FC 1156 Pepco Response to DCG DR 5-18, attached hereto as Exhibit DCG (A)-4.

information as to how it "identifies baseline revenue and cost information, and clearly explains what process or mechanism the utility used to project revenues and expenses."[21]

Q. Does Pepco's construction program adequately consider alternatives?

A. No. The "alternatives" listed in Pepco's construction report only consist of traditional solution alternatives, with no consideration of NWAs, except for one battery pilot for Alabama Ave (ITN Name: 71138). There is no documentation that the other $225.7 million in load growth related capital projects from 2020-2023 were screened for more cost-effective NWA solutions.[22] In contrast, an IDP would include a process for seeking the least cost solution to identified system needs, giving equal weighting to consideration of NWAs through open-sourced solicitations to third-parties and through Company-specific actions, including the targeted deployment of demand response, energy efficiency, and time-varying rates. Pepco has not demonstrated that its proposed MRP Capital Budget adequately considers such alternatives. Thus, Pepco's cost forecasts are not adequately supported or justified.

<u>Transparency of Cost Variances</u>

Q. Does the Company's proposal provide an appropriate level of transparency and reporting for cost variances?

A. No. As described in Exhibit Pepco Exhibit (C), the variance report would be provided at the Pepco-DC distribution level, and not on a project basis.[23] When further prompted in

[21] Public Service Commission of the District of Columbia, Order No. 20273, FC 1156, December 20, 2019, at 37.
[22] F.C. 1156 Pepco Response to DCG DR 6-8(A) & Attachment attached hereto as Exhibit DCG (A)-5.
[23] Wolverton Direct Pepco (C) at 37.

discovery, Pepco indicated it would include "a narrative explanation of the major drivers of the change. For instance, if an explanation is warranted for electric plant in service, Pepco might identify the major capital projects that were driving the variance from the forecast, and provide a reason for why they were different (for example, permitting issues causing delays, etc.)."[24] However, the decision to include project level costs in the variance report appears to be subjective and left up to the Company. Further the Company only indicates it "might" identify the capital project driving the variance.

Finally, in the event one capital project had a cost overrun due to poor project management while another project was under-budget due to unforeseen cost savings, the net effect on Pepco's distribution level variance may be minimal, in which case Pepco would not report on it. If parties were provided with project level variances, however, the unforeseen cost savings would be passed on to customers and the cost overrun may be disallowed for recovery by the Commission, resulting in a benefit for ratepayers that will not be realized with only Pepco-DC distribution level data.

This lack of transparent reporting creates information asymmetry and will place more burden on stakeholders and regulators during the Annual Reconciliation Filing to obtain project specific cost data and explanations at a more granular level.

Pepco should be required to include more detail in its Annual Reconciliation Filing. At a minimum, this should include the information provided for in Attachment C of its Annual

[24] *See* FC 1156 Pepco Response to OPC DR 13-21, attached hereto as Exhibit DCG (A)-6.

Consolidated Report (ACR) plus a list of (1) all projects and/or programs proposed in the MRP and in the Company's capital budget that were eliminated, with supporting explanation; (2) a list of all new projects and/or programs that were added, with supporting explanation; and (3) for all projects and/or programs, including new and eliminated projects and/or programs, the actual amount spent as compared to the forecasted budget amounts.[25]

VI. PEPCO'S PROPOSAL DOES NOT SUFFICIENTLY ADVANCE THE DISTRICT'S PUBLIC POLICY GOALS

Q. How does the Company claim its proposed MRP will support the District's public policy goals?

A. Pepco states its proposed MRP "creates a more balanced regulatory environment that facilitates the types of investment necessary to support [the District's] goals," and "will allow the Company to be better positioned to pursue the necessary framework in a transparent and collaborative way. Coupled with the introduction of PIMs that promote reliability and resiliency, improved customer service, and small generator interconnection, the MRP will help the utility support the District of Columbia in achieving its energy goals."[26] Further, Pepco claims that "The proposed MRP helps the

[25] An example of this reporting structure can be found in Appendix 22 of the Joint Proposal for Consolidated Edison Company of New York, Inc. Cases 16-E-0060 and 16-G-0061, September 19, 2016. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={971AFDDE-A9A3-437B-8283-543762C5514B}

[26] McGowan Direct Testimony Pepco (B) at 26.

Company to align these long-term goals with the Company's long-term planning process."

Q. Does Pepco's proposal adequately advance or otherwise align with the District's public policy goals?

A. No. While it is certainly possible for a well-designed MRP to "facilitate achieving the District's aggressive goals regarding greenhouse gas emissions reductions, transportation electrification, renewable energy development, grid modernization, and other District goals,"[27] Pepco's proposal falls far short of doing so and would need to be extensively modified in order to support achievement of the District's policy goals.

Q. Why do you claim that Pepco's proposal does not adequately advance the District's policy goals?

A. Although Pepco Witness McGowan and Witness Velazquez reference the District's key energy priorities, they do not transparently indicate how the proposed MRP or the Company's long-term planning process will support these goals. Further, the proposed PIMs focus on core responsibilities of the utility, rather than providing innovative solutions to advance the District's clean energy goals.[28] Specifically:

- Although claiming that an MRP will enable Pepco to modernize its grid more quickly, the Company only proposes to make investments in distribution automation and has provided no specific details regarding any broader grid modernization plan

[27] McGowan second supplemental Pepco 3(B)at 21 and Order No. 20273 at paragraph 87.
[28] McGowan Direct Pepco (B) at 25 and 26 and Zarakas (Pepco J) at 4

that would facilitate integration of DERs and other goals, and certainly does not do so in a "transparent and collaborative way," as indicated by Pepco's objections to DCG's questions regarding load forecasts and long-term grid modernization plans.[29]

- While the Company states that the MRP will facilitate investment and allow the company to respond to a changing landscape and allow it to become more innovative and proactive,[30] there are no details in its Distribution Construction Program Report to support these statements.

- The Company's proposal does not demonstrate how it will support additional renewable energy development or reductions in greenhouse gas emissions.[31] Further, in his deposition, Company witness McGowen stated that "There's no specific investment I recall that is targeted to… lower greenhouse gas emissions,"[32] and that he did not have an estimate of greenhouse gas emissions reductions that would result from the MRP.[33]

- While the Company states that the MRP will promote resiliency, neither the Company's proposed PIMs nor any other aspect of the Company's MRP advance

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[29] *See* F.C. 1156 Pepco's Objection to DCG 5-13, 5-15, 5-17, 5-18, 5-36, 5-60, 5-61, 5-62, 5-63, 5-64, 5-73 (January 14, 2020), attached hereto as Exhibit DCG (A)-7.

[30] McGowan Direct Pepco (B) at 26

[31] Pepco's proposed interconnection PIM does not adequately support additional renewable energy development. There are existing standards for Level 1 Interconnection Average Authorization to Install (ATI) performance of five days and the Company has not quantified how performance better than five days provides a net benefit to customers or an increase in renewable resources. Pepco's interconnection PIM also fails to address Levels 2-4 interconnections or delays in the interconnection of Community Renewable Energy Facilities (CREFs).

[32] OPC-SI, page 159, lines 7-13.

[33] OPC-SI, page 169 lines 9-22 and page 170 lines 1-3.

resiliency in the District of Columbia; instead the Company's proposal focuses only on traditional reliability metrics.[34]

I describe each of these failures in more detail below.

Grid Modernization

Q. Would approval of Pepco's proposed MRP increase the Company's efforts to modernize the grid and empower customers to reduce overall system costs?

A. No. Aside from distribution automation, which only makes up 2% of the proposed capital budget,[35] Pepco's MRP proposes no specific investments to modernize the grid.[36] This is most clearly evidenced by the fact that Pepco has no cohesive grid modernization plan,[37] despite claiming that without an MRP, its ability to invest as quickly in grid modernization would be constrained.[38]

Q. Do Pepco's proposed reliability investments constitute grid modernization?

A. No. While a reliable grid is a necessary precondition for a modern grid, these investments do not in themselves modernize the grid. Instead, Pepco's reliability investments represent traditional infrastructure investments, characterized by Witness Clark as "replacement of existing infrastructure, upgrades to reduce outages and improve system

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[34] Pepco Witness Zarakas refers to "resilience" as "as hardening assets and making the grid smarter so that it can come back from outages due to extreme and unavoidable events (such as major storms) quickly and efficiently." (Zarakas Direct (Pepco J) at page 4). However, Pepco's proposed SAIDI and SAIFI PIMs exclude Major Service Outages (MSOs) (B.L. Clark Direct Exhibit (I), page 8) and therefore do not promote resiliency.

[35] Calculated from B.L. Clark Direct Exhibit (I)-2.

[36] OPC-SI, page 158, lines 17-22 and page 159 lines 1-6.

[37] OPC-SI, page 160, lines 13-21.

[38] Second Supplemental Testimony of Kevin McGowan, (PEPCO 3B), at 17.

performance, and cost of emergency replacement of failed equipment during storms and other events."[39]

Q. What types of investments fall under the category of grid modernization?

A. The Commission has outlined a vision for a modern grid that is "sustainable, well-planned, encourage[s] distributed energy resources, and preserve[s] the financial health of the energy distribution utilities in a manner that results in an energy delivery system that is safe and reliable, secure, affordable, interactive, and nondiscriminatory."[40]

As explained by the U.S. Department of Energy (U.S. DOE), operating a modern grid consistent with the Commission's vision "will require a wide variety of new analytics and simulation solutions and will rely on robust and secure communications to bring situational awareness of the distribution grid much closer to real time."[41] According to the U.S. DOE, the types of investments necessary for the modern grid can be grouped in the following categories:

- Distributed Resource Management,
- Field Automation,
- Substation Automation,
- Operational Communications Infrastructure,
- Sensing and Measurement,

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[39] PEPCO (I) at i.
[40] DC PSC, MEDSIS Vision Statement, February 14, 2018, at A-2.
[41] U.S. Department of Energy, Modern Distribution Grid, Volume II, at 13, available at https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-II_v1_1.pdf

- Operational Analytics, and
- Optimization Analytics.

The types of investments that fall within these categories are shown in the figure below, reproduced from the U.S. DOE's *Modern Distribution Grid* report.

Figure 1. Types of Distribution System Investments

Source: U.S. Department of Energy, Modern Distribution Grid, Volume II, at 14

Q. Has Pepco made any investments in these categories?

A. Yes, as noted above, Pepco has made or proposes to make some investments in advanced technologies, such as advanced metering and distribution automation. However, there are many areas where Pepco has not yet proposed to make grid modernization investments, particularly in areas related to distributed energy resource optimization and management. Further, Pepco has not developed any overarching plan for grid modernization that would allow it, or stakeholders, to prioritize investments and coordinate across solutions to ensure that the investments represent the optimal mix and produce the desired outcomes.

Q. Why do you claim that Pepco has no cohesive grid modernization plan?

A. I make this claim because no grid modernization plan was provided as part of the MRP and Pepco stated that it "has not prepared a separate plan for new technology investments in the District of Columbia" in regards to plans focused on grid modernization in the District of Columbia.[42] DCG requested more detail on reports from the planning and analysis team focused on grid modernization, but Pepco objected to the request and did not provide any information.[43] Further, Pepco indicates that "Distribution Automation (DA) is one aspect of Pepco's larger smart grid implementation strategy."[44] However, other than DA, there has been no documentation within the MRP or in response to

[42] F.C. 1156 Pepco Response to FC 1156 DCG DR 6-1(C), attached hereto as Exhibit DCG (A)-8.
[43] F.C. 1156 Pepco Response to FC 1156 DCG DR 5-13, *see* Exhibit DCG (A)-9.
[44] PEPCO (I)-1 at 25

discovery questions detailing this "implementation strategy," such as timing or any planned investments other than DA over the course of the MRP.[45]

When Pepco was asked to provide a list of specific projects contained in the Distribution Construction Program Report that fall under the grid modernization rubric as envisioned through the MEDSIS proceeding, Pepco responded with a list of three battery storage NWA solutions it had considered,[46] only one of which is included in the Construction Report (No: 64 Alabama Ave.).[47] Pepco states that it does not categorize and identify projects as grid modernization projects.[48] This leads to the conclusion that there is no list or comprehensive plan to Pepco's grid modernization efforts.

Q. Does an MRP provide an alternative to a grid modernization plan?

A. No. Witness McGowan states in his Direct Testimony that "An MRP will allow stakeholders to review and better understand the investments is planning to make to address changing customer needs and evaluation the costs to make those investments relative to the goals they are designed to achieve."[49] However, Pepco's MRP investments are presented primarily as a disjointed list of projects without adequate explanation for

[45] *See* F.C. 1156, Pepco's response to DCG 5-11, attached hereto as Exhibit DCG (A)-10, which simply provides a high-level overview of grid modernization objectives (i.e., improving reliability, increasing resilience, enabling distributed generation, electrification, and deploying smart infrastructure in the community), rather than any specific plans (timelines, investments) to achieve these goals.
[46] *See* F.C. 1156, Pepco's response to DCG DR 2-20, which references Pepco's response to DCG DR 2-15, together attached hereto as Exhibit DCG (A)-11.
[47] B.L. Clark Direct Exhibit (I)-2 at 79.
[48] *See* F.C. 1156, Pepco's response to DCG DR 4-22, attached hereto as Exhibit DCG (A)-12.
[49] Pepco Witness McGowen Direct Testimony Exhibit B at page 21, 22.

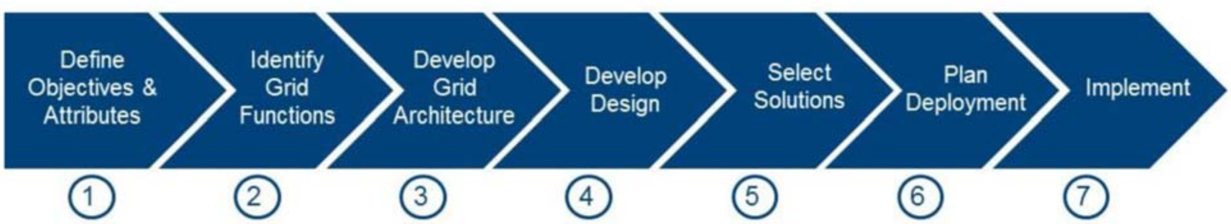
how these projects will achieve the District's clean energy goals and the MEDSIS Vision Statement.

Further, DCG submits that the kind of stakeholder review and understanding envisioned by the Commission cannot be achieved without a comprehensive plan that details the Company's grid modernization goals and investment plans as it pertains to changing customer needs.

Q. How should Pepco develop a grid modernization plan?

A. The development of a comprehensive grid modernization plan should follow the seven-step process outlined by the U.S. Department of Energy, summarized in the chart below and include a process for stakeholder review and comment.

Figure 2. Modern Grid Decision Process



Source: U.S. Department of Energy, Modern Distribution Grid, Volume III, at 11.

Such a process should begin by identifying the objectives that grid modernization is trying to achieve, identify multiple solutions, utilize benefit-cost analysis to facilitate decisions, and provide a strategy for the timing and sequencing of investments.

In other words, the plan should address questions of "how" to modernize the grid, "when" to make investments, and "how much" investment to make. Moreover, the solutions should not be limited to utility capital investments, but instead should explore solutions offered by third parties or operational expenditures instead of capital (e.g., software-as-a-service (SaaS), and DER options).

Q. Is an MRP necessary to support other types of investments that would further the District's clean energy goals?

A. No, the MRP has very little bearing on other initiatives that the Company plans to undertake, as these are generally funded through other means. Specifically, the other high-level initiatives that Witness Clark lists (implementation of battery storage; deployment of public purpose microgrids; deployment of electric vehicle charging infrastructure; continuing the deployment of community solar projects; advancing energy efficiency and demand response; and implementing new uses for Advanced Metering Infrastructure (AMI))[50] are either largely dependent on other parties, or are generally funded through other means and are not specifically included in the Company's MRP budget. As such, the MRP will have no impact on these initiatives.[51]

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[50] Clark Direct Pepco(I) at 21 and 22

[51] For example, 1. Pepco's transportation electrification is funded through the creation of a regulatory asset to track EV expenditures for "make ready" infrastructure and for the coordination/management expenses such as billing, customer enrollment and outreach, program management, system interface and updates, and analysis and reporting (FC1130 & 1155, Order No. 19898 at P 58.) 2. Pepco has not proposed any energy efficiency programs as it waits for the Commission to act on the working group (OPC-SI, page 147, lines 10-18).

Clean Energy Goals

Q. Please describe how Pepco's proposal fails to advance the District's clean energy goals.

A. The Company's proposal does not demonstrate how it will advance the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments. In particular:

- No PIMs proposed by the Company make a meaningful contribution to achieving the District's clean energy goals. The proposed Level 1 interconnection timeline PIM is a core responsibility of Pepco and is already governed under existing regulations. Further, Pepco acknowledges that the other four proposed PIMs and tracking metric do not create alignment with the District's or the Commission's energy and climate goals, nor were they developed to address certain goals.[52]

- Pepco's proposal does not align the Company's financial incentives with the development of NWAs.

- Pepco has not quantified any incremental greenhouse gas reductions anticipated from the implementation of its MRP.[53]

[52] OPC-SI, page 167, lines 18-22 and page 168, lines 1-4.
[53] OPC-SI, page 169, lines 21-22 and page 170, lines 1-3.

Pepco's PIMs Do Not Promote the District's Energy Policy Goals

Q. What PIMs does the Company propose?

A. Pepco proposes financial PIMs with incentives and penalties on specific utility performance for SAIDI, SAIFI, Service Level, Call Abandonment Rate, and DER Interconnection Review Timeframe.

Q. Do the proposed PIMs align with the District's energy policy goals?

A. No. Pepco has not proposed any PIMs that meaningfully advance achievement of the District's clean energy goals. For example, Pepco has proposed no PIMs related to the goals of reduced greenhouse gas emissions, microgrids, modernization of the electric grid, or electrification of public transportation.

Instead, Pepco's proposed PIMs all encourage activities that are required by existing standards and regulations, and that Pepco should be delivering as part of its core service obligations. For example, as explained below in more detail, Pepco already has standards it must meet for SAIDI and SAIFI and has an inherent incentive to improve reliability. Likewise, there are existing standards for Level 1 Interconnection Average Authorization to Install (ATI) performance of five days. Further, Pepco's interconnection PIM fails to address Levels 2-4 interconnections – an area where Pepco's performance has been lacking, particularly for Community Renewable Energy Facilities (CREFs).

Q. Would Pepco's proposed interconnection PIM promote the development of DERs?

A. No. The Company is already required to meet the Level 1 Interconnection Average ATI performance standard of five days, and it has generally been performing at this level.

Moreover, Pepco's PIM fails to address Authorization to Operate (ATO) timelines, Level 2-4 interconnections, or more complex DERs, such as projects with storage or third-party microgrids.

Pepco's Proposal Does Not Align the Company's Financial Incentives with NWAs

Q. How can PBR encourage NWAs?

A. A utility can be provided with incentives to pursue NWAs through two ways: (1) NWA PIMs, and (2) strong cost-containment incentives that enable the utility to profit more from low-cost NWAs than from making capital investments. The Company's proposal contains neither.

Q. In what ways does Pepco's MRP proposal not enable the utility to profit more from low-cost NWAs than from making capital investments?

A. Under Pepco's proposal, the utility would retain only 25% of any cost savings that cause its ROE to rise above the 25 basis point deadband. My interpretation of Pepco's proposal is that the retention of this cost savings would only last until the end of the MRP period (i.e., at most three years). Further, the magnitude of the cost savings would only be measured in terms of differences in annual revenue requirements. Thus, an NWA would need to produce substantial annual cost savings in order to offset the utility's incentive to invest in the more-expensive traditional wires solution.

Q. Can you provide an example of how large the cost savings of an NWA would need to be in order to offset the incentive to invest in a traditional wires solution?

A. Yes. Consider an NWA with a cost of $7 million versus a traditional capital investment of $10 million, both of which the utility is allowed to capitalize, and both of which have a service life of 20 years. At an ROE of 9% and a debt-equity ratio of 50%, the utility would earn a return of approximately $3 million (net present value) over 20 years on the traditional solution. In contrast, the utility would only earn a return of $2 million (net present value) on the lower-cost NWA.

The difference in revenue requirements between the two solutions would initially be approximately $350,000 per year (and would decline over time). If the utility were allowed to retain the entire savings for three years (i.e., the maximum amount of time until the conclusion of the MRP term), the utility would likely be indifferent to investing in the NWA relative to investing in the traditional wires solution. (Note that this is the best-case situation for the utility; in reality, the utility would likely only retain the difference in revenue requirement for one or two years.)

However, if the utility were only able to retain 25% of the difference in revenue requirements, then it is highly unlikely that the utility would happily choose to forego $1 million in additional earnings from the traditional wires solution. This is especially true when one considers the perceived risk of the utility in investing in DERs or customer-sided solutions in lieu of a traditional investment. In short, Pepco’s proposal is unlikely to encourage it to invest in NWAs.

Pepco's Proposal is Unlikely to Result in Greenhouse Gas Reductions

Q. Will Pepco's proposal result in a reduction in greenhouse gas emissions beyond what would have occurred otherwise?

A. Pepco has provided no evidence that an MRP would result in greater greenhouse gas reductions than would otherwise have occurred. When asked whether Pepco has quantified such impacts, the Company replied that it had not.[54] Further, while Pepco states that investments in its EV and solar hosting capacity map (feeder capacity for EV planning purposes), ongoing LED light conversion of all PHI Facilities, and employee workplace charging are greenhouse gas reduction initiatives, there is no quantification of these impacts and these are already underway and therefore not contingent on the MRP.[55] Given that the Company's MRP investments are focused on traditional investments, the MRP would not provide sufficient NWA incentives, and the Company has proposed no PIMs that would facilitate additional greenhouse gas reductions, I conclude that it is unlikely that the MRP would achieve any measurable greenhouse gas emission reductions beyond what would have otherwise occurred.

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[54]OPC-SI, page 169, lines 21-22 and page 170, lines 1-3.
[55] See FC 1156 Pepco Response to DCG DR 6-2(D), attached hereto as Exhibit DCG (A)-13

VII. PEPCO'S PROPOSAL LACKS MEASURABLE BENEFITS TO CUSTOMERS

Q. What "incremental benefits to customers over the status quo" does the Company claim the MRP would provide?

A. Witness McGowan claims that an MRP would provide incremental benefits to customers above the status quo.[56] However, the design of Pepco's MRP is unlikely to deliver on these benefits, and many of the benefits could be achieved without an MRP. Below I list the purported benefits identified by the Company and explain why they are unlikely to represent an improvement over the status quo.

1. The Company claims an MRP will facilitate investments that support the District's energy policy goals. However, as demonstrated above, the Company's proposal contains very little in the way of investments that would further grid modernization, greenhouse gas reductions, increased renewable energy, or other policy goals. Further, the Company has provided no evidence that the MRP would improve these outcomes relative to traditional cost of service regulation, other than potentially allowing faster investments due to faster revenue increases. Yet this "benefit" could also be accomplished through limited cost riders or trackers for specific types of investments (such as grid modernization).

2. The Company claims an MRP will provide customers, the Commission, and interested parties a longer-term view of future capital investments and O&M plans. Yet the Company has provided no integrated distribution system plan or grid

[56] Second Supplemental Testimony of Kevin McGowan, (PEPCO 3B), at 9-12

modernization plan as context for its proposed investments. Such plans would provide much more insight into the Company's long-term strategy to modernize the grid and meet the District's clean energy goals, and could be conducted in the context of traditional cost of service regulation, potentially with a rider to provide additional funding between rate cases.

3. The Company claims an MRP will provide customers with rate predictability over the MRP term. While this may be true for most MRPs that have limited cost reconciliation mechanisms (to the extent they have any), Pepco's proposed cost reconciliation mechanism could lead to significant annual rate adjustments. Furthermore, the Company acknowledges that it may request additional cost recovery for investments needed to comply with the DC Power Path Order as part of the annual reconciliation.[57]

4. The Company claims an MRP will decrease administrative burden and cost for the Commission and stakeholders. However, under Pepco's reconciliation proposal, if Pepco's ROE fell below the deadband, cost variances and the prudence of investments would need to be examined, resulting in a mini rate case. Further, basing revenue adjustments on a cost forecast essentially asks that the regulator pre-approve investments and their associated costs. This unduly shifts risks from the utility to the

[57] OPC-SI, page 153, lines 17-22 and page 154, lines 1-7.

regulator and ultimately to ratepayers while substantially increasing the up-front administrative burden for regulators and stakeholders.

5. The Company claims an MRP will provide cost containment incentives and incentivize operational efficiencies. While this may be true for MRPs that have a firm revenue cap, Pepco's MRP is designed to more closely resemble a formula rate plan than a traditional MRP. Because Pepco's proposal would prevent large deviations from the Company's allowed ROE and permit the Company to recover the majority of any cost overruns, the Company would have less incentive to control costs than under traditional cost of service regulation where regulatory lag delays the ability of the Company to recover costs above its approved revenue requirement.

6. The Company claims that the MRP would ensure that rates reflect the current costs to provide service. While this is generally true of the Company's proposal, this is more likely to be a benefit to the Company, than it is to customers, as costs are projected to rise steeply under the MRP.

7. The Company claims that the MRP would increase the level of transparency and reporting. However, as discussed above, the Company's investment plans consist of a patchwork of disjointed individual investments, rather than a cohesive plan for modernizing the grid and achieving the District's clean energy goals. Thus, the transparency that the Company provides is akin to looking at individual pieces of a jigsaw puzzle without any insight into the larger picture. In addition, the Company's

proposed variance reporting is wholly inadequate for determining whether the Company implemented the investments that it proposed.

8. Similar to the above point, the Company claims that the MRP will enhance oversight through advance review of the Company's total capital spending plan and proposed performance levels, with annual reporting and reviews of certain variances. Again, without a more comprehensive distribution system plan or detailed variance reporting, it is difficult, if not impossible, to understand how the proposed costs of the Company's investments compare to the benefits that may be provided, and how such investments will (or will not) advance the District's public policy goals.

9. The Company claims that its proposal would impose significant automatic financial penalties for not meeting PIM targets. However, the Company's proposed PIMs for SAIDI, SAIFI, and Level 1 Interconnection, are already addressed by existing standards, which enable the Commission to impose penalties for non-compliance.

10. The Company claims that the MRP enhances certainty of spending for the MRP term, leading to improved investment planning that create jobs and promote economic development. While this may be true, it is not at all clear that this enhanced certainty regarding revenue increases for Pepco merits the risks and additional costs that would be imposed on ratepayers by Pepco's proposal.

VIII. PROPOSED MODIFICATIONS TO PEPCO'S PROPOSAL

Q. How should Pepco's proposal be amended to promote the public interest?

A. I recommend that Pepco's proposal should be amended in the following five ways:

1. Apply an external index for business-as-usual costs: The revenue requirement from the historical test year should be escalated for each year of the MRP according to an inflation index, rather than being based on cost forecasts.

2. Cost forecasts should be limited to large and unusual investments that support the District's energy policy goals, if used at all: Allowed revenues for large, unusual costs (such as specific grid modernization investments with specified and measured performance outcomes) would be set based on the utility's three-year cost forecast, as approved by the Commission. The cost forecasts should be thoroughly supported and justified and should clearly and transparently demonstrate how the investments are consistent with the utility's least-cost distribution system plan and a comprehensive grid modernization plan.

3. Require one-way (downward) reconciliations for costs based on a cost forecast, but no reconciliations for indexed costs.

4. Implement an earnings sharing mechanism for over-earnings with a larger deadband to incentivize Pepco to seek cost savings where possible.

5. Implement well-designed PIMs that clearly advance the District's clean energy goals. We will discuss our recommended PIMs in our rebuttal testimony.

I explain each of these recommendations in more detail below.

External Index for Business-as-Usual Costs

Q. Why do you recommend use of an external index for most costs?

A. Escalating allowed revenues based on an external cost index is a common and effective means of addressing information asymmetry concerns in MRPs. Because they allow increases in revenue requirements from year to year, MRPs are often adopted where it is recognized that traditional cost of service regulation is not providing sufficient revenues to allow a utility to maintain its financial strength while making the necessary investments to support energy policy goals. However, basing revenue increases on utility forecasts is problematic and shifts risk to ratepayers because utilities have an information advantage.

To address information asymmetry, external indices are often used instead of cost forecasts, since this approach "permits the utility to continue making necessary investments and avoid revenue attrition, while avoiding concerns regarding strategic behavior (i.e., gaming of forecasts) and information asymmetry that are present in forecast-based [Attrition Relief Mechanisms]."[58] The basis for such indices vary by jurisdiction, but the indices are often based on inflation rates and productivity factors. In some cases, different categories of costs are escalated at different rates based on separate cost indices.

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[58] M. Whited, C. Roberto. 2019. *Multi-Year Rate Plans: Core Elements and Case Studies*. Synapse Energy Economics Synapse prepared for Maryland PC51 and Case 9618 at 10.

Index-based revenue adjustment mechanisms have many advantages over cost forecasts:

- External cost indices do not require that specific costs be reviewed and pre-approved at the beginning of the MRP. In contrast, basing revenue adjustments on a cost forecast essentially asks that the regulator pre-approve investments and their associated costs. This unduly shifts risks from the utility to the regulator and ultimately to ratepayers. Further, it increases the administrative burden for regulators and stakeholders.

- External cost indices do not rely on utility cost forecasts that may be subject to error or may be inflated.

An index-based mechanism avoids the above challenges, but still allows utility revenues to increase over the term of the MRP, allowing for longer time between rate cases, without unduly shifting risk to ratepayers.

Q. What are the Pros and Cons of a stair-step vs. index (I-X) approach?

A. Whether Pepco applies a stair-step or an index (I-X) approach is largely immaterial; rather the key questions is whether the annual rate adjustments over the course of the MRP are based on a Company-specific forecast or an external index. A stair-step approach can use either an external index or utility forecasts to set the trajectory of annual revenue changes. Although Pepco proposes a stair-step approach based on forecasts of capital investments and operating and maintenance costs through 2022, a stair-step can also be based on external cost indices.

Q. Can you provide any examples of stair-step approaches that rely on external cost indices?

A. Yes. Southern California Edison (SCE) and the other major California investor-owned utilities use indices to create an agreed upon stair-step revenue adjustment trajectory:

- For non-labor O&M costs, SCE uses IHS Global Insight escalation rates to calculate post-test year revenue requirements.

- For capital-related cost increases, a composite escalation rate is developed from IHS Global Insight forecasts of the Handy-Whitman Index of Public Utility Costs,[59] as well as a utility-specific index based on recorded General Plant costs for recent years as recorded in SCE's FERC Form 1.[60] These various escalation rates are then averaged for the plan term and applied to test year capital additions. For the most recent term, of the calculated average escalation rate was 2.49%.[61]

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[59] SCE notes that the "Handy-Whitman Indexes are published by Whitman, Requardt, and Associates, LLP, located in Baltimore, Maryland, as they have been since 1924. SCE has used Handy-Whitman indexes in various General Rate Cases. Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Gas Company use various Handy-Whitman indexes in constructing their respective escalation indexes in their General Rate Cases." *See:* Southern California Edison (U 338-E) 2018 General Rate Case Application 16-09-001 (SCE-09, Vol. 1) at 85.

[60] Southern California Edison (U 338-E) 2018 General Rate Case Application 16-09-001 (SCE-09, Vol. 1) at 85.

[61] Public Utilities Commission of the State of California, Decision 19-05-020, Application 16-09-001, May 16, 2019, at 284-285.

Limited Use of Cost Forecasts

Q. Why do you recommend that cost forecasts be limited to large, unusual investments that support the District's energy policy goals?

A. I recommend that the use of cost forecasts in an MRP be restricted to a limited number of large and unusual types of costs. These include investments that are part of a holistic plan, such as a grid modernization plan that has been vetted and approved by stakeholders and the Commission. For example, SCE and San Diego Gas & Electric have preapproved multiyear cost forecasts for AMI.[62] In addition, the Massachusetts Department of Public Utilities ordered a three-year preauthorization of grid-facing investments as part of grid modernization plans filed by Eversource, National Grid, and Unitil. Costs are tracked through a Grid Modernization Factor (GMF) and each company is required to submit a GMF rate adjustment and reconciliation filing containing its proposed grid modernization factors, as well as testimony and supporting documentation, regarding documentation of projects completed, cost variances, and prudency.[63]

Q. How can Pepco's planning process be improved to make it more transparent and open to the Commission and ratepayers?

A. We recommend that the Commission direct Pepco to develop and file a comprehensive grid modernization plan that is coordinated with an IDP and is open to stakeholder review and comment. The current MRP proposal does not adequately tie in the proposed capital

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[62] MN Lowry, J Deason, M Makos, L Schwartz, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (U.S. Department of Energy), July 2017, 4.5.

[63] Commonwealth of Massachusetts Department of Public Utilities, Order on D.P.U. 15-120; D.P.U 15-121; D.P.U. 15-122. May 10, 2018.

investments to a long-term distribution planning strategy. Due to this fact, parties do not have access to current system needs or data on prioritization of investments based on a benefit-cost assessment. Consequently, it is not possible for parties to determine whether an investment is in the best interest of customers or whether there may be issues related to an investment's technological obsolescence.

Grid modernization is a complex issue that includes grid-side and customer-side investments. These investments are long-lasting and carry significant expense so it is important to have a long-term plan that details: distribution system needs by location, benefit-cost analysis of any proposed projects, impact on GHG emissions, customer education and engagement plan, opportunities for market participation and solutions, rate designs, and a near-term investment plan with detailed budgets, priority investments, and timelines.

Q. What forecasts should be filed for subsequent rate years, after the initial historic base year, including capital expenditures?

A. As discussed above, cost forecasts should generally only be used in the initial proceeding to set allowed revenues for a limited number of large, unusual investments. As discussed previously in this testimony, a key challenge associated with the use of cost forecasts is that the utility has an incentive to inflate cost projections.

However, other types of forecasts, such as load forecasts and distribution system investment forecasts, can provide helpful information in an MRP. It is reasonable for the Commission to require frequent updates to load forecasts and investment forecasts related to grid modernization plans and distribution system plans. I recommend that grid modernization plans and distribution system plans be updated frequently with new load forecasts and new DER forecasts in order to avoid unnecessary investments in the grid.

<u>Reconciliations</u>

Q. How can the increased risk to ratepayers from cost forecasts be mitigated?

A. The risk to ratepayers cannot be fully mitigated if cost forecasts are used. However, the risk shifted to ratepayers can be reduced by allowing only a one-way, downward reconciliation of costs.

Q. How does a one-way (downward) reconciliation of costs lower the risk shifted to ratepayers?

A. A one-way reconciliation mechanism reduces the benefit that the utility receives from inflating its cost projections and protects customers from utility under-spend. The one-way nature of the reconciliation also encourages the utility to keep costs below the projections and ensures that over-spends are not approved until a prudency review in the subsequent rate case.

Q. Do other jurisdictions use one-way reconciliations for cost forecasts?

A. Yes. Where cost forecasts are used, the reconciliation mechanisms are typically downward only, so that any cost overruns are borne by the utility. For example, Minnesota and New York both use cost forecasts to project revenue requirements associated with capital investments but have coupled the forecasts with a one-way (downward) reconciliation mechanism.[64]

Q. Why do you not recommend reconciliations for indexed costs?

A. MRPs can provide powerful cost efficiency incentives to utilities by capping revenues at pre-set levels and de-linking revenues from actual costs. As explained in the Edison Electric Institute's survey of alternative regulation mechanisms, "[t]he rate adjustments provided by [attrition relief mechanisms] are largely "external" in the sense that they give a utility an allowance for cost growth rather than reimbursement for its actual growth."[65] 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.

In contrast, Pepco's proposal would reconcile all elements of its rate base and earnings and allow for an adjustment of rates if costs deviated far from revenues. Because of this reconciliation, Pepco's proposal would largely erode any incentive Pepco would have during the MRP to reduce costs since it would benefit little from implementing cost efficiencies and endure little risk if its costs exceed expectations. Thus, in order to create

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[64] Minnesota Public Utilities Commission, Findings of Fact, Conclusions, and Order, Docket E-002/GR-15-826, June 12, 2017.
Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014, at 29-30.
[65] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 34.

an adequate cost containment incentive, the MRP should remove the link between Pepco's revenues and its actual costs.

Earnings Sharing Mechanism

Q. Do you support an earnings sharing mechanism for over-earnings?

A. Yes, I support earnings sharing mechanisms where forecasts are not used. However, I propose that the utility should be allowed to retain a greater proportion of cost savings in order to strengthen the utility's incentive to find cost efficiencies.

Q. How did the Company develop its proposed 25 basis point deadband?

Pepco's Witness Wolverton indicates in his Direct Testimony that the Company reviewed similar mechanisms throughout the industry to determine its deadband parameters.[66] However, there is little evidence to support this argument. For utilities with an MRP containing an earnings sharing mechanism, it is more common to have a deadband of 100 basis points or more. For example, in Massachusetts, National Grid and Eversource have earnings sharing mechanisms that trigger a sharing of earnings with customers on a 75/25 basis when the actual distribution ROE exceeds 200 basis points above the ROE.[67]

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[66] T.W. Wolverton Direct Testimony. PEPCO (C), page 40.

[67] Massachusetts Department of Public Utilities (18-150) "Petition of Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of General Increases in Base Distribution Rates for Electric Service." September 30, 2019.
Massachusetts Department of Public Utilities (17-05) "Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism." November 30, 2017.

Similarly, Hydro One Networks in Ontario and Central Maine Power have deadbands of 100 basis points.[68]

<u>Trackers</u>

Q. Should Pepco's MRP contain any tracking mechanisms?

A. Tracking mechanisms are appropriate only for a very limited set of costs that are outside of a utility's control. For example, costs such as taxes, pensions, and market supply costs are sometimes passed through via a tracker. In addition, one-time extraordinary costs that were incurred reasonably (such as extraordinary storm response costs) could be recovered through a tracker.

For example, in New York, reconciliation and/or deferral accounting mechanisms have been used for costs including: taxes, pensions/other post-employment benefits, environmental remediation costs, Regional Greenhouse Gas Initiative costs, system benefits charges, market supply charges, and costs associated with the low income customer charge discounts.[69] In addition, New York's MRPs allowed cumulative major

[68] Ontario Energy Board, Decision and Order 2017-0049, "Hydro One Networks, Inc. Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022". March 7, 2019.
State of Maine Public Utilities Commission Docket Nos. 2007-215 and 2008-111. "Central Maine Power Company Request for Approval of Post-Merger Alternative Rate Plan (ARP 2008) and Annual Price Change for Remaining Items from ARP 2000". ARP 2008 Stipulation. June 6, 2018.
[69] Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014.

storm damage expenses in excess of a certain threshold to be deferred. The expenses would be subject to New York Department of Public Service Staff review.[70]

As another example, Massachusetts has approved an "exogenous cost factor" in the Eversource MRP for "costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry."[71]

PIMs that Advance the District's Goals

Q. Please explain your recommendation that a Pepco's proposal be modified to include well-designed PIMs that clearly advance the District's clean energy goals.

A. 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). PIMs should only be used to incent behavior the utility would otherwise not take, meaning there is a disincentive or lack of incentive to achieve the desired outcome. However, Pepco's PIMs are focused on core obligations of the utility, rather than advancing the District's clean energy goals. Further, Pepco has not quantified the incremental benefits customers will receive from the higher performance levels it is proposing in the PIMs.[72] Thus, I recommend that Pepco's PIMs be rejected or made

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[70] Joint Proposal, CASE 09-E-0428- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, November 24, 2009, at 24.

[71] Massachusetts Department of Public Utilities (17-05) "Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism." November 30, 2017. At 396.

[72] See FC 1156 Pepco Response to DCG DR 6-12(A), attached hereto as Exhibit DCG (A)-14

penalty-only, and that several well-designed PIMs that advance the District's policy goals be added upon review of proposals in rebuttal testimony.

Q. What concerns do you have with Pepco's reliability PIMs?

A. Pepco proposes two Reliability PIMs, SAIDI and SAIFI. The first concern focuses around the principle that PIMs should only be applied where the utility has a disincentive to align its performance with the public interest. However, as part of its public service obligation, Pepco is already responsible for providing reliable electric service to its customers. Further, Pepco earns an ROE on its capital investments, and therefore has an incentive to invest in its system to improve reliability.

The second concern relates to the principle that PIMs should not offer a utility more financial benefit than is necessary to align its performance with the public interest. Pepco's SAIDI level has improved by 58% between 2013 and 2018 and its SAIFI level has improved by 40% over the same timeframe. The Company has also been meeting the more stringent reliability standards set forth in the Merger commitments.[73] The Company has achieved these goals with a penalty-only structure. There is no justification for why the Company should receive additional financial benefit for meeting standards it has been able to meet without such an incentive.

[73] Clark Direct at pg 5 Pepco(I)

Q. What changes would you recommend?

A. I recommend that the PIMs proposed for SAIDI and SAIFI be rejected or revised as penalty only. As discussed above the current penalty-only structure has been effective in driving the Company to exceed the SAIDI and SAIFI performance metrics in Merger Commitment 54. A penalty will also help to address the concerns of Pepco to ensure that its performance does not deteriorate due to the cost savings incentives over the MRP period.[74]

<u>Customer Service Performance</u>

Q. Please describe the Company's proposed Service Level and Call Abandonment Rate PIMs.

A. The Company proposes two Customer Operations PIMs -- Service Level and Call Abandonment Rate. Pepco is proposing customer service PIMs to incentivize performance levels that are in the first quartile relative to its peers in the industry. Pepco is proposing a Service Level PIM starting with 2020 performance, including target performance of 90%, with a deadband of +/- 3 points around that performance level. In this case the deadband represents a range of Service Level of 87% to 93%. This would be a 20-point improvement upon the EQSS performance level. For Call Abandonment, Pepco is proposing a PIM starting with 2020 performance, including target performance of 1.5%, with a deadband of +/- 1 point around that performance level. This represents an

[74] McGowan direct at p. 41 PEPCO (B)

8.5 point improvement upon the EQSS performance level. The Company is proposing a symmetrical -/+ 2.5 basis points penalty/reward structure for each PIM.

Q. Do you support these PIMs?

A. No. I do not support these PIMs.

Q. What concerns do you have with these proposed PIMs?

A. I have several concerns with the proposed Customer Operations PIMs. The first concern focuses around the principle that PIMs should only be applied where the utility has a disincentive to align its performance with the public interest. Utilities already have a vested interest in improving customer satisfaction. For example, customer satisfaction metrics like the J.D. Power rating is an important signal to regulators when reviewing a utility rate increase and to rating agencies when assessing the financial strength of investments. It is also not uncommon for utility executives to have financial goals and bonuses tied to achieving certain customer satisfaction ratings. This appears to be the case for Pepco as Company Witness Poncia indicates that "certain performance metrics are incorporated in the employee Annual Incentive Program (AIP), which is designed to incent high performance that aligns with the goals of Pepco, PHI, and Exelon, for high levels of Customer Satisfaction and Operational Performance."[75] Further, Pepco has demonstrated its commitment to improving customer satisfaction through the level of recent investment. Witness McGowan indicates that the Company has made several improvements to its call center operations over the past several years including an

[75] Poncia Direct at 11 and 12. Pepco(Q)

Interactive Voice Recognition system, increased training for first-call resolution, and an enhanced customer website. The Company attributes these investments to improvements in key call center metrics over the past two years.[76] These investments were not driven by a PIM.

The second concern relates to the principle that PIMs should not offer a utility more financial benefit than is necessary to align its performance with the public interest. The Company has already shown an increase in performance levels related to these PIMs with a penalty-only structure. For example, Exhibit Pepco (Q), Table 5 shows increased performance from 2013 to 2018 in both Service Level and Call Abandonment. In 2017 and 2018, Pepco's Service Level was at 92 percent, higher than the proposed PIM's Service Level target of 90 percent. Likewise, Pepco's Call Abandonment rate was at 0.7 in 2017 and 0.9 percent in 2018, lower (i.e. better) than the proposed PIM target of 1.5%.

Q. What changes would you recommend?

A. I would recommend that the Service Level and Call Abandonment Rate PIMs be removed from the proposal. The Company is already performing at the proposed PIM target levels without a positive financial reward. In addition, based on internal goals of the Company, it already has an incentive to improve customer service. The Company should continue tracking-only metrics related to its performance in these categories.

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[76] McGowen Direct at 11. Pepco (B)

DER Interconnection Timeline

Q. Please describe the Company's proposal for a DER interconnection PIM.

A. Pepco proposes a PIM based on the average number of days for Level 1 Approval To Install (ATI), with a target set at five days to mirror the Commission's January 2019 interconnection timeline rule. The Company is proposing a deadband of plus or minus 0.5 days with an asymmetrical reward structure of – 5 basis points as a penalty and a + 10 basis points as a reward.

Q. Do you support this PIM?

A. No. I do not support this PIM.

Q. What concerns do you have with this PIM?

A. My concern is that this PIM would provide an incentive for an existing regulation. As the Company notes, in January 2019, the Commission promulgated a new rule that "accelerates the timeline for the vast majority of interconnection review and approvals. Specifically, the size of Level 1 interconnection requests has been increased from 10kW to 20KW, and the time to complete the approval to install has been decreased from 15 days to five days."[77]

Witness Clark indicates that, using 2018 interconnection data, Pepco would have underperformed with regards to the new timelines in this rule for Level 1 ATI. Under the new five-day timeline, Pepco's performance would be at 46.62%.[78] Pepco uses this

[77] FC 1156 Pepco Response to OPC DR 11-7 attached hereto as DCG (A)-15
[78] Witness Clark Direct at 34. Pepco(I)

performance to justify the need for an interconnection PIM. However, since the five-day standard was established by the Commission on January 25, 2019, Pepco has generally met the performance standard without any positive financial incentive.

Q. Have you analyzed any data regarding Pepco's compliance with the new 5-day ATI standard?

A. Yes, I analyzed data from Pepco's Quarterly Compliance Reports Covering Interconnection Applications for 2019 Q2 through Q4. Although Pepco does not report missed deadlines separately by interconnection level, we know that CREFs generally fall within Level 2. Table 1 below summarizes the number of missed deadlines for quarters 2 through 4 of 2019, with and without CREFs.

Table 1. Summary of Pepco 2019 Quarterly Interconnection Reports FC 1050 by Quarter Timeliness to ATI

Quarter	ATI Including CREF		ATI Excluding CREF	
	Deadlines Missed	% Deadlines Met	Deadlines Missed	% Deadlines Met
Q2	58	90.10%	6	98.90%
Q3	72	88.64%	1	99.82%
Q4	1	99.85%	0	100.00%

Q. What does your analysis indicate?

A. When excluding CREFs, Pepco's performance has been very high in each of the past three quarters. The vast majority of missed deadlines are due to CREFs, which highlights the need to focus Pepco's attention on meeting Level 2 and higher deadlines, rather than Level 1. Pepco's recent performance indicates that there is no need for a Level 1 PIM that would reward Pepco for compliance with an existing standard at performance levels that it is already achieving.

Q. What changes would you recommend?

A. I recommend rejecting the PIM and replacing it with a penalty-only PIM for compliance with each Commission-established timeline milestone for Levels 1-4.

Q. Why do you propose that the interconnection PIM be penalty-only?

A. Pepco is already required by the Commission to comply with existing interconnection standards, indicating that the Commission has determined that interconnecting DERs in a timely manner is a core responsibility of the utility. Pepco should not be rewarded for fulfilling its core responsibilities; rather, Pepco should face penalties for failure to comply with these requirements.

Q. What specific PIMs do you propose to add to Pepco's proposal?

A. DCG is collaborating with Pepco and other stakeholders to gain a better understanding of the data available for PIMs at this time. In accordance with Commission Order No. 20273, I will propose any additional PIMs in my rebuttal testimony.

IX. CONCLUSION AND SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

A. Due to the fact that the Company's MRP proposal does not provide appropriate incentives to the Company to contain costs and the PIMs proposal does not provide appropriate incentives to the Company to modernize the grid and empower customers to reduce overall system costs through the adoption of DERs, I recommend the following:

1. The Commission should reject the Company's proposed MRP and require that any future MRP not be permitted to include reconciliations of utility under-earnings, include an index-based cost escalation, and provide for more transparency pertaining to grid modernization efforts.

2. The Commission should reject the Company's proposed PIMs.

3. Regardless of whether Pepco operates under an MRP, we recommend that the Commission consider the following actions:

    a) Require Pepco to develop and file a comprehensive grid modernization plan that includes a system needs assessment, technology investment roadmap, timeline, and benefit-cost analysis. Any permitted cost recovery should be predicated on the filing of such a plan.

    b) Establish a Commission mandate for transparency, coordination, and data sharing with DER technology providers and manufacturers that would enable the deployment of DER technology based on system needs;

    c) Establish explicit metrics and targets to guide Pepco's activities for grid modernization with specific and measurable performance outcomes; and

    d) Consider explicit metrics and incentives to encourage utilities to utilize DERs to cost-effectively avoid traditional capital investments. These could include financial rewards for especially successful adoption of NWAs, and penalties in situations where the Company did not adequately evaluate or implement NWAs, including the use of open-sourced request for proposal for alternatives and evaluation by key stakeholders such as DCG, the Office of People's Counsel, and the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

I declare under penalty of perjury that the foregoing testimony is true and correct to the best of my knowledge, information, and belief.

Executed this _6_ day of March 2020.

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Courtney Lane

Courtney Lane, Senior Associate

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clane@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Senior Associate,* November 2019 – Present.

Provides consulting and researching services on a wide range of issues related to the electric industry including performance-based regulation, benefit-cost assessment, rate and bill impacts, and wholesale electric retail markets.

National Grid, Waltham, MA. *Growth Management Lead*, *New England,* May 2019 – November 2019, *Lead Analyst for Rhode Island Policy and Evaluation,* June 2013 – April 2019.

- Portfolio management of product verticals including energy efficiency, demand response, solar, storage, distributed gas resources, and electric transportation, to optimize growth and customer offerings.
- Strategy lead for the Performance Incentive Mechanisms (PIMs) working group.
- Worked with internal and external stakeholders and led the development of National Grid's Annual and Three-Year Energy Efficiency Plans and System Reliability Procurement Plans for the state of Rhode Island.
- Represented energy efficiency and demand response within the company at various Rhode Island grid modernization proceedings.
- Led the Rhode Island Energy Efficiency Collaborative; a group focused on reaching consensuses regarding energy efficiency plans and policy issues for demand-side resources in Rhode Island.
- Managed evaluations of National Grid's residential energy efficiency programs in Rhode Island, and benefit-cost models to screen energy efficiency measures.

Citizens for Pennsylvania's Future, Philadelphia, PA. *Senior Energy Policy Analyst*, 2005–2013.

- Monitored and evaluated wholesale and retail energy market policies and practices that impacted renewable energy, energy efficiency, and demand response.
- Tracked and analyzed federal and state policy to determine how proposed laws and regulations would affect renewable energy and demand-side markets.
- Served as an expert witness and testified before the Pennsylvania Public Utility Commission (PUC) and advised law staff on utility rate cases.
- Wrote and submitted comments to the PUC on various proceedings including energy.
- Performed market research and industry investigation on emerging energy resources including wind, solar, energy efficiency and demand response.

Northeast Energy Efficiency Partnerships, Inc., Lexington, MA. *Research and Policy Analyst,* 2004–2005.

- Drafted comments and testimony on various state regulatory and legislative actions pertaining to energy efficiency.
- Tracked energy efficiency initiatives set forth in various state climate change action plans, and federal and state energy regulatory developments and requirements.
- Participated in Regional Greenhouse Gas Initiative (RGGI) stakeholder meetings.
- Analyzed cost-effectiveness of various initiatives within the organization.

Massachusetts Executive Office of Environmental Affairs, Boston, MA. *Field Projects Extern,* 2003.

- Worked for the Director of Water and Watersheds at the EOEA, examining the risks and benefits of different groundwater recharge techniques and policies throughout the U.S.
- Presented a final report to both Sea Change and the EOEA with findings and policy recommendations for the state.

EnviroBusiness, Inc., Cambridge, MA. *Environmental Scientist,* July 2000 – May 2001

- Conducted pre-acquisition assessments/due diligence assignments for properties throughout New England. Environmental assessments included an analysis of historic properties, wetlands, endangered species habitat, floodplains, and other areas of environmental concern and the possible impacts of cellular installations on these sensitive areas.
- Prepared and managed NEPA reviews and Environmental Assessments for telecommunications sites.

SKILLS

Software: SPSS, Arcview GIS, Access, Dreamweaver, Front Page, Microsoft Excel, Word, Power Point

EDUCATION

Tufts University, Medford, MA
Master of Arts; Environmental Policy and Planning, 2004.

Colgate University, Hamilton, NY
Bachelor of Arts; Environmental Geography, 2000, *cum laude.*

TESTIMONY

Rhode Island Public Utilities Commission (Docket No. 4888): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2019 Energy Efficiency Program (EEP). On behalf of National Grid. December 11, 2018.

Rhode Island Public Utilities Commission (Docket No. 4889): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2019 System Reliability Procurement Report (SRP). On behalf of National Grid. December 10, 2018.

Rhode Island Public Utilities Commission (Docket No. 4755): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2018 Energy Efficiency Program (EEP). On behalf of National Grid. December 13, 2017.

Rhode Island Public Utilities Commission (Docket No. 4684): Oral testimony of Courtney Lane regarding the RI Energy Efficiency and Resource Management Council (EERMC) Proposed Energy Efficiency Savings Targets for National Grid's Energy Efficiency and System Reliability Procurement for the Period 2018-2020 Pursuant to §39-1-27.7. On behalf of National Grid. March 7, 2017.

Rhode Island Public Utilities Commission (Docket No. 4684): Oral testimony of Courtney Lane regarding National Grid's 2018-2020 Energy Efficiency and System Reliability Procurement Plan. On behalf of National Grid. October 25, 2017.

Rhode Island Public Utilities Commission (Docket No. 4654): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2017 Energy Efficiency Program Plan (EEPP) for Electric & Gas. On behalf of National Grid. December 8, 2016.

Rhode Island Public Utilities Commission (Docket No. 4580): Oral testimony of Courtney Lane regarding the Narragansett Electric Co. d/b/a National Grid - 2016 Energy Efficiency Program Plan (EEPP) for Electric & Gas. On behalf of National Grid. December 2, 2015.

Pennsylvania Public Utility Commission (Docket No. P-2012-2320369): Direct testimony of Courtney Lane regarding the Petition of PPL Electric Utilities Corporation for an Evidentiary Hearing on the Energy Efficiency Benchmarks Established for the Period June 1, 2013 through May 31, 2016. On behalf of PennFuture. October, 19, 2012.

Pennsylvania Public Utility Commission (Docket No. P-2012-2320334): Direct testimony of Courtney Lane regarding the Petition of PECO Energy for an Evidentiary Hearing on the Energy Efficiency Benchmarks Established for the Period June 1, 2013 through May 31, 2016. On behalf of PennFuture. September 20, 2012.

Pennsylvania Public Utility Commission (Docket No. I-2011-2237952): Oral testimony of Courtney Lane regarding the Commission's Investigation of Pennsylvania's Retail Electricity Markets. On behalf of PennFuture. March 21, 2012.

Committee on the Environment Council of the City of Philadelphia (Bill No. 110829): Oral testimony of Courtney Lane regarding building permitting fees for solar energy projects. On behalf of PennFuture. December 5, 2011.

Pennsylvania Public Utility Commission (Docket No. M-00061984): Oral testimony of Courtney Lane regarding the En Banc Hearing on Alternative Energy, Energy Conservation, and Demand Side Response. On behalf of PennFuture. November 19, 2008.

PRESENTATIONS

Lane, C. 2019. "The RI Test." Presentation for AESP Webinar: Emerging Valuation Approaches in Cost-Effectiveness and IRPs, October 31, 2019.

Lane, C., A. Flanders. 2017. "National Grid Rhode Island: Piloting Wireless Alternatives: Forging a Successful Program in Difficult Circumstances." Presentation at the 35th Annual Peak Load Management Association (PLMA) Conference, Nashville, TN, April 4, 2017.

Lane, C. 2013. "Regional Renewable Energy Policy Update." Presentation at the Globalcon Conference, Philadelphia, PA, March 6, 2013.

Lane, C. 2012. "Act 129 and Beyond." Presentation at the ACI Mid-Atlantic Home Performance Conference, October 1, 2012.

Lane, C. 2012. "Act 129: Taking Energy Efficiency to the Next Level." Presentation at the Energypath Conference, June 28, 2012.

Lane, C. 2011. "Pennsylvania's Model Wind Ordinance." Presentation at Harvesting Wind Energy on the Delmarva Peninsula, September 14, 2011.

Lane, C. 2011. "Electric Retail Competition and the AEPS." Presentation at the Villanova Law Forum, November 4, 2011.

Lane, C. 2009. "Act 129: Growing the Energy Conservation Market." Presentation at the Western Chester County Chamber of Commerce, March 25, 2009.

Resume updated March 2020

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

In the Matter of Distribution System Planning for Xcel Energy

ISSUE DATE: August 30, 2018

DOCKET NO. E-002/CI-18-251

ORDER APPROVING INTEGRATED DISTRIBUTION PLANNING FILING REQUIREMENTS FOR XCEL ENERGY

PROCEDURAL HISTORY

Over the last several years, the Commission has investigated the modernization of the electric grid and distribution-system planning as they relate to rate-regulated utilities.[1] At the April 19, 2018 agenda meeting, the Commission reviewed staff-proposed draft integrated distribution planning (IDP) filing requirements informed through a Commission-led stakeholder process, and heard party comments.[2] The proposed IDP filing requirements would direct utilities to engage in a stake-holder process and to file plans addressing: short-term and long-term distribution system modifications and investments, considerations used in related planning processes, non-traditional distribution system alternatives, and long-term distribution system forecasts, among other requirements.

At the May 31, 2018 agenda meeting, the Commission requested Xcel Energy (Xcel) to file a Grid Modernization Report,[3] as required under Minn. Stat. 216B.2425, in combination with any IDP filing the Commission may direct the Company to make in this docket.

On June 8, 2018, the Commission issued a notice of comment period on the draft IDP requirements for Xcel. The notice requested that Xcel file a narrative on the Company's

[1] *See generally* Docket No. E-999/CI-15-556 (grid modernization) and Docket No. E-002/M-17-776 (Xcel 2017 Biennial Report).

[2] In addition to Xcel, the Commission has established individual dockets and released proposed utility-specific IDP filing requirements for the following rate-regulated utilities: Docket No. E-017/18-253 (Otter Tail Power); Docket No. E-015/18-254 (Minnesota Power); and Docket No. E-111/ 18-255 (Dakota Electric Association).

[3] Docket Nos. E-002/M-17-775 and E-002/M-17-776, Order Approving Pilot Program, Setting Reporting Requirements, and Denying Certification Requests (August 7, 2018).

proposed distributed energy resource penetration scenarios for its 2018 IDP requirements. The Notice also included a list of topics for party comments, including:

1. Should the draft IDP requirements be modified? If so, provide specific edits with rationale and indicate the intent of the proposed change.
2. Are there specific scenarios, inputs, or assumptions that Xcel should consider in its initial filing? What are reasonable medium and high scenarios?
3. Please address the following areas (in reference to the attached IDP requirements):
   a) Are the annual or biennial filing requirements reasonable?
   b) Are there additional parameters or requirements that should be part of stakeholder meetings:
   c) Should the categories under financial data be modified? Are there consistent categories across utilities that could be utilized?
   d) Should the long-term distribution system plan components be on a 10-year (shorter term) outlook or a 15-year outlook (to correspond with the integrated resource plan timing?
4. Are there other issues or concerns related to this matter?

On July 6, 2018, the following parties submitted comments on Xcel's draft IDP:

- Center for Energy and the Environment
- Citizens Utility Board of Minnesota
- Minnesota Department of Commerce, Division of Energy Resources (Department)
- Fresh Energy
- Interstate Renewable Energy Council
- Kandiyo Consulting, LLC
- Office of the Attorney General - Residential Utilities Division (OAG)
- Xcel

On July 20, 2018, the following parties submitted reply comments:

- Center for Energy and the Environment
- Citizens Utility Board of Minnesota
- Department
- Fresh Energy
- Interstate Renewable Energy Council
- Xcel

On August 9, 2018, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

I. Background of Commission Grid Modernization Efforts

Since 2016, the Commission has considered a phased process for efforts to modernize the electrical grid. The Commission determined that distribution system planning was the most reasonable way to assist in grid evolution, and commenced efforts to create a comprehensive and coordinated integrated distributed system planning process in Minnesota, guided by the following principles and planning objectives:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies.
- Enable greater customer engagement, empowerment, and options for energy services.
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products and services, with opportunities for adoption of new distributed technologies.
- Ensure optimized use of electricity grid assets and resources to minimize total system costs.

In October 2016, the Commission held a workshop seeking stakeholder input and discussion of a Minnesota-based distribution system planning effort. In 2017, the Commission issued, and assessed utility and stakeholder responses to a questionnaire designed to ascertain 1) each utility's current planning for its distribution system, 2) the status of each utility's current-year distribution plan, and 3) the utilities' recommendations for improving the current distribution planning process.

In April 2018, the Commission established individual IDP dockets for each rate-regulated utility and authorized the release of utility-specific draft IDP filing requirements for utility and stakeholder comment. Each utility's draft IDP was released for comments in June 2018.[4]

II. Xcel IDP Filing Requirements

A. Overview of Party Comments

The parties generally agreed that Xcel's distribution system is evolving, and that through IDP, the Commission can help to ensure that utilities are systematically planning their respective distribution systems – to maintain safe, reliable, and affordable service for customers as technological advancements are developed and proposed to come online. The parties also agreed that it is prudent to begin a planning process to ensure that the Commission's consideration of utility distribution system investments is well informed.

After two rounds of comments on the proposed IDP filing requirements, the parties generally agreed on the majority of topics raised. No party opposed the process or indicated that there was no need for an IDP. All party comments in this docket were thoughtful, thorough, and useful to the process as it unfolded.

[4] Xcel's IDP filing requirements are the first to be considered by the Commission.

Commission staff prepared a detailed summary of the party comments and proposals, mapping out where suggestions came from and which were included in the final proposal, appended as Exhibit A to the staff briefing papers for the August 9, 2018 agenda meeting. At the Commission meeting, all parties supported use of the proposed IDP planning requirements as adapted and modified by Commission staff, and raised no objections to their use.

Certain parties also raised issues for future consideration, or deferral to a different docket. The Citizens Utility Board of Minnesota recommended that efforts should be continued to maximize the integration of distributed energy resources for all customers, minimize what might otherwise be stranded assets, and maximize existing product life. Fresh Energy raised hosting capacity as one area for additional improvement, but acknowledged that issues related to hosting capacity will likely be addressed in an existing hosting capacity docket, and the annual hosting capacity analysis to be filed November 1.

The OAG asked that in the future Xcel make efforts to provide the Commission with better information on its additional planning objectives, such as its investment plans for the near future in order to ensure ratepayer benefits. The Department's suggestions focused on ratepayer protection and benefit, and harmonizing the IDP requirements with other dockets relevant to IDP, such as hosting capacity.

Finally, Xcel stated that it understands that the filing requirements to be imposed in the IDP docket will apply to all of Xcel's IDP distribution planning, not just the discretionary 15-20 percent of its budget the utility discussed in its comments herein. Xcel also stated that it recognizes that it must provide and discuss its entire distribution budget in its upcoming November 2018 filing.

III. Commission Action

The Commission appreciates the participation and thorough analysis by the utilities and stakeholders on the myriad issues raised in this IDP docket. Stakeholder input into the iterative process has been a valuable resource in developing appropriate IDP requirements, solidifying planning objectives, clarifying draft language, and making modifications as appropriate. With the upcoming initial filing by Xcel, which will be made by November 1, 2018, as proposed by the Company, stakeholders and regulators should be able to better determine what information and detail is needed to meet the before-referenced planning objectives for IDP.[5]

The Commission hereby adopts the proposed IDP filing requirements for Xcel, as discussed and agreed upon in this docket and attached hereto.

[5] See *infra* at 3.

ORDER

1. The Commission adopts the IDP filing requirements for Xcel as set forth herein and attached hereto.

2. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

This document can be made available in alternative formats (e.g., large print or audio) by calling 651.296.0406 (voice). Persons with hearing loss or speech disabilities may call us through their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

MINNESOTA
PUBLIC UTILITIES COMMISSION

MINNESOTA INTEGRATED DISTRIBUTION PLANNING REQUIREMENTS
For Xcel Energy
Docket E002/CI-18-251

Planning Objectives: The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and,
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.
- Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

Commission review of annual distribution system plans are not meant to preclude flexibility for Xcel to respond to dynamic changes and on-going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments.

For filing requirements which Xcel claims is not yet practicable or is currently cost-prohibitive to provide, Xcel shall indicate for each requirement:

1. Why the Company has claimed the information is not yet practicable or is currently cost-prohibitive;
2. How the information could be obtained, at what estimated cost, and timeframe;
3. What the benefits or limitations of filing the data in future reports as related to achieving the planning objectives;
4. If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.

Distribution System Plan Process

1. **Filing Date:** Require Xcel to file annually with the Commission beginning on November 1, 2018 an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. The Commission will either accept or reject a distribution system plan by June 1 (to the extent practicable) of the following year based upon the plan content and conformance with the filing requirements and Planning Objectives listed above. The plan will be reviewed and may be combined with the Biennial Distribution System Plan required by Minn. Stat. 216B.2425 and associated certification requests, as authorized in that docket (E002/M-17-776).

2. **Stakeholder Meeting(s):** Xcel should hold at least one stakeholder meeting prior to the November 1 filing of the Company's MN-IDP to obtain input from the public. The stakeholder meeting should occur

in a manner timely enough to ensure input can be incorporated into the November 1 MN-IDP filing as deemed appropriate by the utility.

At a minimum, Xcel should seek to solicit input from stakeholders on the following MN-IDP topics: (1) the load and distributed energy resources (DER) forecasts; (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP.

Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, an additional stakeholder meeting may be held in combination with the comment period to solicit input.

3. **Filing Requirements:** For purposes of these requirements, DER is defined as "supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter."[1] This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.[2]

A. Baseline Distribution System and Financial Data:

System Data

1. Modeling software currently used and planned software deployments
2. Percentage of substations and feeders with monitoring and control capabilities, planned additions
3. A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)
4. Number of customer meters with AMI/smart meters and those without, planned AMI-investments, and overview of functionality available
5. Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans
6. Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology

[1] See *Minnesota Staff Grid Modernization Report, March 2016*.
[2] ICF Report, Integrated Distribution Planning, August 2016, prepared for Minnesota Public Utilities Commission, Docket No. E999/CI-15-556, available online: See eDockets ID: 20169-124836-01.

7. Discussion if and how IEEE Std. 1547-2018[3] impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability and advanced inverter functionality)
8. Estimated distribution system annual loss percentage for the prior year
9. For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system
10. Total distribution substation capacity in kVA
11. Total distribution transformer capacity in kVA
12. Total miles of overhead distribution wire
13. Total miles of underground distribution wire
14. Total number of distribution premises
15. Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).
16. Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)
17. Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
18. Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
19. Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
20. Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)
21. Total number of electric vehicles in service territory
22. Total number and capacity of public electric vehicle charging stations
23. Number of units and MW/MWh ratings of battery storage
24. MWh saving and peak demand reductions from EE program spending in previous year
25. Amount of controllable demand (in both MW and as a percentage of system peak)

Financial Data

26. Historical distribution system spending for the past 5-years, in each category:

    a. Age-Related Replacements and Asset Renewal
    b. System Expansion or Upgrades for Capacity

[3] IEEE Standard 1547-2018, published April 6, 2018.

c. System Expansion or Upgrades for Reliability and Power Quality
d. New Customer Projects and New Revenue
e. Grid Modernization and Pilot Projects
f. Projects related to local (or other) government-requirements
g. Metering
h. Other

The Company may provide in the IDP any 2018 or earlier data in the following rate case categories:

a. Asset Health
b. New Business
c. Capacity
d. Fleet, Tools, and Equipment
e. Grid Modernization

For each category, provide a description of what items and investments are included.

27. All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g. CSG, customer-sited, PPA and other) and location (i.e. feeder or substation).
28. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects
29. Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include:
    a. Age-Related Replacements and Asset Renewal
    b. System Expansion or Upgrades for Capacity
    c. System Expansion or Upgrades for Reliability and Power Quality
    d. New Customer Projects and New Revenue
    e. Grid Modernization and Pilot Projects
    f. Projects related to local (or other) government-requirements
    g. Metering
    h. Other
30. Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement

DER Deployment

31. Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)
32. Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.
33. Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.

B. Hosting Capacity and Interconnection Requirements

1. Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources[4], and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.
2. Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.[5]

C. Distributed Energy Resource Scenario Analysis

1. In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first.

2. Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.

3. Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.

4. Include information on anticipated impacts from FERC Order 841[6] (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators)

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[4] Minn. Stat. 216B.2425, Subd. 8

[5] Forthcoming Order, E999/CI-16-521, MN DIP 3.2 Initial Review

[6] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶61,127 (February 28, 2018)

D. Long-Term Distribution System Modernization and Infrastructure Investment Plan

1. Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and the DER future scenarios.

2. Xcel shall provide a 5-year Action Plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:
    - Overview of investment plan: scope, timing, and cost recovery mechanism
    - Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.[7]
    - Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.
    - System interoperability and communications strategy
    - Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)
    - Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)
    - Customer anticipated benefit and cost
    - Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)
    - Plans to manage rate or bill impacts, if any
    - Impacts to net present value of system costs (in NPV RR/MWh or MW)
    - For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis
    - Status of any existing pilots or potential for new opportunities for grid modernization pilots

3. In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-

[7] https://gridarchitecture.pnnl.gov/

year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.

E. Non-Wires (Non-Traditional) Alternatives Analysis

1. Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.
2. Xcel shall provide information on the following:
    - Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
    - A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)
    - Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed
    - A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 2

QUESTION NO. 3

In Excel spreadsheet format, provide the economic growth assumptions by forecast year over the Company's 10-year load forecast.

RESPONSE:

Pepco does not base its 10-year load forecast on economic growth assumptions. Thus, the requested information is not available.

Pepco does not base its 10-year load forecast on economic growth assumptions. Rather, as Pepco has explained in other rate cases and formal proceedings, Pepco uses a "90/10" forecasting methodology and "bottom up" approach to develop short- and long-term load forecasts. Key inputs to the forecasts are Prospective New Business (PNB) information received by the Company, load transfers identified during the studied period, and DER installations.

SPONSOR: Bryan L. Clark

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 5

QUESTION NO. 18

Regarding Pepco's distribution planning process and peak load forecasts:

A. By Ward and substation, provide Pepco's estimates regarding future new load from Prospective New Businesses for each year of the forecast.

B. By Ward and substation, provide Pepco's estimates regarding the quantity of solar PV and storage that will be adopted by customers for each year of the forecast.

C. By Ward and substation, provide Pepco's estimates regarding load reductions from energy efficiency programs (such as those implemented by the DCSEU) for each year of the forecast.

D. By Ward and substation, provide Pepco's estimates regarding load reductions from new building codes and standards for each year of the forecast.

RESPONSE:

Pepco objected to this data request in its Objections filed on January 14, 2020.

SPONSOR: Bryan L. Clark

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 6

QUESTION NO. 8

Refer to the Direct Testimony of Bryan Clark PEPCO (I) and Pepco's DC Construction Report, PEPCO (I)-2.

A. Provide a working electronic spreadsheet with the annual budgets of the proposed investments contained in this report that are primarily driven by load growth.
B. Does the Company periodically compare the accuracy of its load forecasts to actual load growth to assess how accurate its previous forecasts were?
C. If the Company compares the accuracy of its load forecasting to actual load growth to assess the accuracy of its previous forecasts, describe the granularity (e.g., feeder level, Ward level) at which the comparisons are made and the frequency of such comparisons.
D. If the Company compares the accuracy of its historical load forecasts to actual load growth, provide the results of such comparisons.
E. If the Company compares the accuracy of its historical load forecasts to actual load growth, describe what actions the Company has taken to improve the accuracy of its load forecasts.
F. If the Company does not compare the accuracy of its historical load forecasts to actual load growth, explain why not.

RESPONSE:

A. See FC 1156 DCG DR 6-8 Attachment.

B – F. No. As the Commission found in Order No. 20274, "Pepco's load forecasting methodology as presented in this case provides a reasonable basis for assessing the need for the Mt. Vernon Substation. The Commission's conclusion is consistent with what Pepco describes in its Reply Comments: "a 90/10 approach is generally regarded in the industry as providing an appropriate level of risk management against the risk of equipment damage and failure leading to long-duration and possibly widespread outages during an extreme loading event. . . The Commission believes that the 90/10 weather normalization and the bottom-up approach components of Pepco's load forecasting methodology are reasonable, well-founded and adhere to industry standards." (paragraphs 73-74). Comparison of the forecasted load to actual load is not relevant in the forecasting of load and does not demonstrate the accuracy of the Company's load forecasts.

SPONSOR: Bryan L. Clark

ITN Name	2019	2020	2021	2022	2023
70096: 13kV Distribution Cutovers "F" St to "L" St (UDLPLM7W27)	7,266,286	7,732,829	9,933,124	9,501,517	7,493,684
70097: 13kV Distribution Cutovers from "I" St to "F" St & "L" St (UDLPLM7W28)	-	-	-	1,552,985	1,594,865
70251: 69kV Lines NRL Sub 168 to Blue Plains Sub 83 (UDLPRM8BB)	1,108,242	554	-	-	-
71138: Convert Alabama Ave. Sub 136 Feeder 15178 and 15165 from a 3-wire to a 4-	405,456	201	-	-	-
71411: Dist Feeder Load Relief - DC (UDLPLM7W)	3,706,825	5,977,173	4,428,074	8,098,935	9,951,764
71441: Distribution Feeder Load Relief DC (UDSPLM7W)	195,563	205,328	205,315	205,275	205,384
71630: F St Sub Rebuild (69kV) (UDSPLM718A)	701,922	5,976,665	1,321,187	1,378,896	1,966,459
71867: Harvard Rebuild - 13 kV Harvard Load Transfers (UDLPRM4WA6)	8,244,950	5,429,918	12,095,376	10,437,177	3,289,173
72004: Install 4th 230/69kV 224MVA transformer #12 at Benning (UDSPLM7		2,518,460	2,784,197	543,338	14,676
72137: L St Sub Capacity Expansion Work (UDSPLM722A)	508,911	556,145	1,114,851	1,600,020	525,875
72525: Mt Vernon Sq Sub: Construct 230/13kv Sub (UDSPLMV3)	548,209	8,077,222	13,292,145	20,173,942	6,326,650
72527: Mt Vernon Sq Sub: Extend 3 Distribution Fdrs - Relieve S052 (UD	14,535	15,547	4,062,840	3,817,598	783,918
72529: Mt Vernon Sq Sub: Extend LVAC (UDLPLMV1)	8,141	2,053,205	1,713,098	265,855	141,203
72530: Mt Vernon Sq Sub: Extend Second LVAC - Transfer 20 MVA (UDLPLNJ1)	468	499	535	315	93
72838: Northeast Sub New HV Grp, Transfer HV Load fm Sub. 161 to Sub.	-	-	-	15,530	2,073,198
72840: Northeast Sub. 212 East Network Group (NEW) (UDLPLM7W14)	8,845,406	7,084	-		
72909: PEP - Wedge for Load DC (UDLPLACR)	-	23,218	(5,596,711)	739,803	(558,744)
73452: Retire Anacostia 4kV and 13kV Substations (UDSPRD8RW1)	-	590,263	595,961	309	38
73684: Southwest Sub 18: Rearrange Central LVAC to South LVAC (UDLPLWF	-	-	-	-	2,275,072
73749: Sub. 12 to Sub. 124 to Sub. 21 Network Cutover (UDLPLGW1)	-	-	-	10,353	2,590,865
73787: Substation Retirements-DC. (UDSPRD8RN)	1,205,797	412,576	210,459	205,561	205,542
73839: Takoma to Sligo 69kV Line: Install Three 69kV Feeders (UDLPLM72	17,612,760	18,295,041	3,835,114	21,430	20,826
73902: Transformer Load Management (TLM) Pep - DC (UDLPLM7W21)	533,355	2,535,986	1,523,352	715,328	716,425
73918: Trinidad Sub 106 - Retire (UDSPRD8RO)	(6)	404,044	200	147,799	-
74083: Waterfront Sub - Establish Waterfront North LVAC Network Group	11,184,121	4,323	-	-	-
74084: Waterfront Sub - Install 4th Transformer (UDSPLM7WF4)	1,965,340	2,999	-	-	-
74085: Waterfront Sub - Install 5th Transformer (UDSPLM7WF3)		434,319	5,820,261	4,094,573	7,647
74087: Waterfront Sub-Extend Fdrs: Transfer HV, Metro, Distrib frm Sta	220,177	1,299,036	1,502,902	1,173,302	8,611
74093: Waterfront Sub: Construct Third LVAC Group (UDLPLWF6)	3,291,070	1,525	-	-	-
74349: Benning 4kV Area-Phase Balancing to Fix Voltage Drop Issues (UD	404,598	209	-	-	-

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO OPC DATA REQUEST NO. 13

QUESTION NO. 21

MRP Proposal Development, ESM. With reference to the Annual Reconciliation Filing Example attached to Mr. Wolverton's testimony as Exhibit Pepco (C)-5, please provide a narrative explanation of the type of information that will be provided in the variance description.

RESPONSE:

Pepco would provide a narrative explanation of the major drivers of the change. For instance, if an explanation is warranted for electric plant in service, Pepco might identify the major capital projects that were driving the variance from the forecast, and provide a reason for why they were different (for example, permitting issues causing delays, etc.).

SPONSOR: Tyler W. Wolverton

**PUBLIC SERVICE COMMISSION OF
THE DISTRICT OF COLUMBIA
FORMAL CASE NO. 1156**

**NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-13.**

Refer to the testimony of Bryan Clark - PEPCO (I), page 1, regarding Mr. Clark's leading "a planning and analysis team focused on grid modernization."

A. Provide all documents, memos, reports, presentations, and plans that were produced by the planning and analysis team focused on grid modernization. Include internal documents and presentations to the PHI Board of Directors, as well as public documents.

B. Discuss whether the planning and analysis team's grid modernization recommendations for Pepco DC differed from its grid modernization recommendations for Pepco Maryland, Atlantic City Electric Company, and Delmarva Power & Light Company.

C. Provide a brief summary of the status of grid modernization for each of PHI's other utilities (Pepco Maryland, Atlantic City Electric Company, and Delmarva Power & Light Company.)

D. Does Pepco DC have a separate planning and analysis team focused on grid modernization, or are those functions generally performed by the planning and analysis team within PHI's Regulatory group? If Pepco DC has a separate team, identify the members of the team and who leads that team.

PEPCO'S OBJECTIONS:

The data request references the biographical section of Company Witness Clark's testimony in which he discusses his role and the team he supervises. The data request is not related to the Company's Application for authority to implement a Multiyear Rate Plan for electric distribution service in the District of Columbia. The information sought by DCG is not likely to elicit discovery of admissible evidence that would be reasonably relevant and material to this proceeding. As the Commission recently stated in Order No. 20272, "the only alternative ratemaking proposal before us is the MRP proposed by Pepco. Since the Commission has not otherwise designated issues for this case, **only issues related to Pepco's rate case filing and the Company's MRP proposal for the District are relevant in this matter**." Formal Case No. 1156, Order No. 20272 at ¶18 (December 20, 2019)(emphasis added).

Furthermore, presentations or other information made to or prepared for the PHI Board of Directors regarding other Exelon distribution company affiliates in other jurisdictions are irrelevant to the current proceeding and have no impact on the issues before the Commission in this proceeding. In Order No. 20272, the Commission explicitly held:

> we find that evaluation and/or comparisons of Pepco's proposed ARM with ARMs proposed by Exelon and its affiliates in other jurisdictions would be speculative as well and not elicit discovery of admissible evidence or information that would be relevant to this proceeding. Although the inquiries may produce information about other jurisdictions' potential ARMs, that information would be unique to those jurisdictions based on their regulatory schemes, policies, and goals. Consequently, we find that the requested discovery would result with little or no probative value.

Id. at ¶22. Thus DCG's data requests for information on other Exelon affiliates are inappropriate in the context of this rate proceeding. To the extent DCG wishes to examine issues regarding grid modernization, these are more appropriately addressed in another proceeding such as PowerPath DC.

PUBLIC SERVICE COMMISSION OF
THE DISTRICT OF COLUMBIA
FORMAL CASE NO. 1156

NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-15.

Regarding Pepco's distribution planning process and peak load forecasts:

- **A.** **Provide Pepco's internal documentation regarding its load forecasting methodology and practices.**
- **B.** **Does Pepco utilize stochastic or deterministic methods for its forecasting and planning studies?**
- **C.** **Describe the limitations of current forecasting techniques and how the changing distribution system, including DER growth, will impact the forecasting process.**
- **D.** **Describe any major improvements to forecasting that the Company views may be necessary in the short-term and long-term in order to maintain forecast integrity as DER penetration grows.**

PEPCO'S OBJECTIONS:

The information DCG is requesting in DR 5-15(A)-(C) was just litigated in Formal Case No. 1144, the second phase of which was approved by the Commission on December 20, 2019. Most of the specifics that DCG is seeking in DR 5-15 are contained in the public record (either in data responses or comments) in Formal Case No. 1144 and are familiar to DOEE/DCG as an active litigant in that case. Moreover, as the Commission recently noted in Order No. 20272, "the only alternative ratemaking proposal before us is the MRP proposed by Pepco. Since the Commission has not otherwise designated issues for this case, only issues related to Pepco's rate case filing and the Company's MRP proposal for the District are relevant in this matter." Formal Case No. 1156, Order No. 20272 at ¶18 (December 20, 2019)(emphasis added).

DR 5-15(D) does not appear to address any specific issue related to Pepco's rate case filing or the Company's MRP proposal in Formal Case No. 1156. The Company therefore objects to DR 5-15(D) as the information sought by DCG is not likely to elicit discovery of admissible evidence that would be reasonably relevant and material to this proceeding. Subject to and without waiving its objections, Pepco will provide a response to DG DR 5-15(D).

PUBLIC SERVICE COMMISSION OF
THE DISTRICT OF COLUMBIA
FORMAL CASE NO. 1156

NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-17.

Refer to PEPCO (I)-1, Table 1: Historical District of Columbia Load by Ward, on pages 9-10.

A. By Ward and substation, provide actual new load from what were "Prospective New Businesses" for each year 2013 through 2018 (inclusive).

B. By Ward and substation, provide actual MVA or MW of load reductions from distributed generation for each year 2013 through 2018 (inclusive).

C. By Ward and substation, please provide actual MVA or MW of load reductions from energy efficiency for each year 2013 through 2018 (inclusive).

PEPCO'S OBJECTIONS:

The information DCG is requesting in DR 5-17 was just litigated in Formal Case No. 1144, the second phase of which was approved by the Commission on December 20, 2019. Most of the specifics that DCG is seeking in DR 5-17 are contained in the public record (either in data responses or comments) in Formal Case No. 1144 and are familiar to DOEE/DCG as an active litigant in that case. Moreover, as the Commission recently noted in Order No. 20272, "the only alternative ratemaking proposal before us is the MRP proposed by Pepco. Since the Commission has not otherwise designated issues for this case, only issues related to Pepco's rate case filing and the Company's MRP proposal for the District are relevant in this matter." Formal Case No. 1156, Order No. 20272 at ¶18 (December 20, 2019)(emphasis added).

PUBLIC SERVICE COMMISSION OF
THE DISTRICT OF COLUMBIA
FORMAL CASE NO. 1156

NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-18.

Regarding Pepco's distribution planning process and peak load forecasts:

A. By Ward and substation, provide Pepco's estimates regarding future new load from Prospective New Businesses for each year of the forecast.

B. By Ward and substation, provide Pepco's estimates regarding the quantity of solar PV and storage that will be adopted by customers for each year of the forecast.

C. By Ward and substation, provide Pepco's estimates regarding load reductions from energy efficiency programs (such as those implemented by the DCSEU) for each year of the forecast.

D. By Ward and substation, provide Pepco's estimates regarding load reductions from new building codes and standards for each year of the forecast.

PEPCO'S OBJECTIONS:

The information DCG is requesting in DR 5-18(A)-(C) was just litigated in Formal Case No. 1144, the second phase of which was approved by the Commission on December 20, 2019. Most of the specifics that DCG is seeking in DR 5-18(A)-(C) are contained in the public record (either in data responses or comments) in Formal Case No. 1144 and are familiar to DOEE/DCG as an active litigant in that case. Moreover, as the Commission recently noted in Order No. 20272, "the only alternative ratemaking proposal before us is the MRP proposed by Pepco. Since the Commission has not otherwise designated issues for this case, only issues related to Pepco's rate case filing and the Company's MRP proposal for the District are relevant in this matter." Formal Case No. 1156, Order No. 20272 at ¶18 (December 20, 2019)(emphasis added).

DR 5-18(D) would require Pepco to perform a special study that was not performed for this current rate case, which is not required under long-standing Commission precedent..

NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-36.

For each of Pepco's circuits in the District of Columbia, provide the peak day hourly load used for planning purposes and each circuit's rated capacity in a machine-readable Excel spreadsheet (i.e., in .xls or .xlsx format).

PEPCO'S OBJECTIONS:

The information DCG is requesting in DR 5-36 was just litigated in Formal Case No. 1144, the second phase of which was approved by the Commission on December 20, 2019. Most of the specifics that DCG is seeking in DR 5-36 are contained in the public record (either in data responses or comments) in Formal Case No. 1144 and are familiar to DOEE/DCG as an active litigant in that case.

NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-60.

What percentage of Pepco's customers, by customer class, are served by a microgrid?

PEPCO'S OBJECTIONS:

DCG DR 5-60 is not related to the Company's Application for authority to implement a Multiyear Rate Plan for electric distribution service in the District of Columbia. The information sought by DCG is not likely to elicit discovery of admissible evidence that would be reasonably relevant and material to this proceeding. As the Commission recently noted in Order No. 20272, "the only alternative ratemaking proposal before us is the MRP proposed by Pepco. Since the Commission has not otherwise designated issues for this case, **only issues related to Pepco's rate case filing and the Company's MRP proposal for the District are relevant in this matter**." Formal Case No. 1156, Order No. 20272 at ¶18 (December 20, 2019)(emphasis added). DCG DR 5-60 would appear to relate to a matter best suited for consideration in the Power Path DC proceeding not a distribution rate case such as this.

NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-61.

What are the barriers to the development of islanded micro-grids in Pepco's service territory?

PEPCO'S OBJECTIONS:

DCG DR 5-61 is not related to the Company's Application for authority to implement a Multiyear Rate Plan for electric distribution service in the District of Columbia. The information sought by DCG is not likely to elicit discovery of admissible evidence that would be reasonably relevant and material to this proceeding. As the Commission recently noted in Order No. 20272, "the only alternative ratemaking proposal before us is the MRP proposed by Pepco. Since the Commission has not otherwise designated issues for this case, **only issues related to Pepco's rate case filing and the Company's MRP proposal for the District are relevant in this matter**." Formal Case No. 1156, Order No. 20272 at ¶18 (December 20, 2019)(emphasis added). DCG DR 5-61 would appear to relate to a matter best suited for consideration in the Power Path DC proceeding not a distribution rate case such as this. Additionally, this information is publicly available as it was addressed by the Commission Staff in the MEDSIS Staff Report filed in Formal Case No. 1130 on January 25, 2017.

NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-62.

Is Pepco interested in owning microgrids in its service territory?

PEPCO'S OBJECTIONS:

DCG DR 5-62 is not related to the Company's Application for authority to implement a Multiyear Rate Plan for electric distribution service in the District of Columbia. The information sought by DCG is not likely to elicit discovery of admissible evidence that would be reasonably relevant and material to this proceeding. As the Commission recently noted in Order No. 20272, "the only alternative ratemaking proposal before us is the MRP proposed by Pepco. Since the Commission has not otherwise designated issues for this case, **only issues related to Pepco's rate case filing and the Company's MRP proposal for the District are relevant in this matter**." Formal Case No. 1156, Order No. 20272 at ¶18 (December 20, 2019)(emphasis added). DCG DR 5-62 would appear to relate to a matter best suited for consideration in the Power Path DC proceeding not a distribution rate case such as this.

NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-63.

Is Pepco interested in the role of being a microgrid operator in its service territory?

PEPCO'S OBJECTIONS:

DCG DR 5-63 is not related to the Company's Application for authority to implement a Multiyear Rate Plan for electric distribution service in the District of Columbia. The information sought by DCG is not likely to elicit discovery of admissible evidence that would be reasonably relevant and material to this proceeding. As the Commission recently noted in Order No. 20272, "the only alternative ratemaking proposal before us is the MRP proposed by Pepco. Since the Commission has not otherwise designated issues for this case, **only issues related to Pepco's rate case filing and the Company's MRP proposal for the District are relevant in this matter**." Formal Case No. 1156, Order No. 20272 at ¶18 (December 20, 2019)(emphasis added). DCG DR 5-63 would appear to relate to a matter best suited for consideration in the Power Path DC proceeding not a distribution rate case such as this.

NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-64.

Is Pepco interested in operating a transactive energy market for its distribution system?

PEPCO'S OBJECTIONS:

DCG DR 5-64 is not related to the Company's Application for authority to implement a Multiyear Rate Plan for electric distribution service in the District of Columbia. The information sought by DCG is not likely to elicit discovery of admissible evidence that would be reasonably relevant and material to this proceeding. As the Commission recently noted in Order No. 20272, "the only alternative ratemaking proposal before us is the MRP proposed by Pepco. Since the Commission has not otherwise designated issues for this case, **only issues related to Pepco's rate case filing and the Company's MRP proposal for the District are relevant in this matter**." Formal Case No. 1156, Order No. 20272 at ¶18 (December 20, 2019)(emphasis added). DCG DR 5-64 would appear to relate to a matter best suited for consideration in the Power Path DC proceeding not a distribution rate case such as this.

NOTICE OF OBJECTIONS
OF POTOMAC ELECTRIC POWER COMPANY
TO DCG DATA REQUEST NO. 5-73.

Is Pepco developing rules for DER islanding? If yes, provide any relevant documentation. If not, what are the barriers to creating such rules.

PEPCO'S OBJECTIONS:

DCG DR 5-73 is not related to the Company's Application for authority to implement a Multiyear Rate Plan for electric distribution service in the District of Columbia. The information sought by DCG is not likely to elicit discovery of admissible evidence that would be reasonably relevant and material to this proceeding. As the Commission recently noted in Order No. 20272, "the only alternative ratemaking proposal before us is the MRP proposed by Pepco. Since the Commission has not otherwise designated issues for this case, **only issues related to Pepco's rate case filing and the Company's MRP proposal for the District are relevant in this matter**." Formal Case No. 1156, Order No. 20272 at ¶18 (December 20, 2019)(emphasis added). DCG DR 5-73 would appear to relate to a matter best suited for consideration in the Power Path DC proceeding not a distribution rate case such as this.

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 6

QUESTION NO. 1

Referring to the Second Supplemental Direct Testimony of Kevin McGowan (PEPCO 3B), page 11, lines 10-12 regarding the Company's ability to invest more quickly in grid modernization and technology under a Multiyear Rate Plan (MRP) as opposed to a historic recovery approach:

A. Are there specific grid modernization investments or new technologies in Pepco's MRP that Pepco proposes to undertake if the MRP is approved, but would be delayed if the MRP were not approved?
B. Identify the specific grid modernization investments and new technologies in Pepco's MRP that Pepco proposes to undertake if the MRP is approved but would be delayed if the MRP were not approved.
C. Provide all documents, memos, reports, presentations, and plans that Pepco has developed that focus on grid modernization plans or investments in new technology in the District of Columbia. In your response, include internal documents and presentations to the PHI Board of Directors, as well as public documents.
D. For each of the documents produced in response to (C), identify whether any assumptions were made when developing the document regarding whether Pepco was operating under an MRP or under traditional cost of service ratemaking.

RESPONSE:

The question to 6-1(c) has been modified, as set forth below, based on discussions between counsel for Pepco and DCG:

"Has Pepco prepared any documents, memos, reports, presentations, or plans focused on grid modernization in the District of Columbia that show how Pepco's proposed MRP investments fit into a long-term grid modernization plan? If yes, please provide these documents, including internal documents and presentations to the PHI Board of Directors, as well as public documents."

A. See response to FC 1156 DCG DR 5-11 for a description of the grid modernization activities included in the MRP. As noted by Company Witness Velazquez, some of the investments needed to allow widespread adoption of the technologies, such as smart energy infrastructure, many distributed energy resources, transportation and electrification, are not in the current capital plan through 2022. The recent regulatory guidance provided by orders in the Capital Grid proceeding, the Transportation Electrification proceeding, the Energy Efficiency and Demand Response proceedings, and PowerPath DC will help the Company align its investments more closely with the District's goals. Moreover, by putting in place the MRP, Pepco may more closely align its planned investments with the goals of the District of Columbia, the Commission and customer expectations.

The Company has not identified which specific investments may be delayed if the MRP is not approved since the identification depends on the final plan that is approved by the Commission However, timely recovery of costs will enable the Company to invest at the level and pace required to fully support the District of Columbia, Commission and customer expectations. Under a historic recovery approach, the Company would be constrained in its ability to invest as quickly in grid modernization and technology, and any investments that go beyond the obligation to provide safe and reliable service could be deferred or eliminated.

B. Refer to Part A.

C. Refer to DCG 5-11 for grid modernization activities included in the MRP. The Company has not prepared a separate plan for new technology investments in the District of Columbia. The recent regulatory guidance provided by orders in the Capital Grid proceeding, the Transportation Electrification proceeding, the Energy Efficiency and Demand Response proceeding, and PowerPath DC will help to inform the types of new technology investments the Company will make in the District of Columbia in the future.

D. Refer to Part C.

SPONSOR: Kevin McGowan/Bryan Clark

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 5

QUESTION NO. 13

Refer to the testimony of Bryan Clark - PEPCO (I), page 1, regarding Mr. Clark's leading "a planning and analysis team focused on grid modernization."

A. Provide all documents, memos, reports, presentations, and plans that were produced by the planning and analysis team focused on grid modernization. Include internal documents and presentations to the PHI Board of Directors, as well as public documents.

B. Discuss whether the planning and analysis team's grid modernization recommendations for Pepco DC differed from its grid modernization recommendations for Pepco Maryland, Atlantic City Electric Company, and Delmarva Power & Light Company.

C. Provide a brief summary of the status of grid modernization for each of PHI's other utilities (Pepco Maryland, Atlantic City Electric Company, and Delmarva Power & Light Company.)

D. Does Pepco DC have a separate planning and analysis team focused on grid modernization, or are those functions generally performed by the planning and analysis team within PHI's Regulatory group? If Pepco DC has a separate team, identify the members of the team and who leads that team.

RESPONSE:

Pepco objected to this data request in its Objections filed on January 14, 2020.

SPONSOR: Bryan L. Clark

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 5

QUESTION NO. 11

Refer to the testimony of Bryan Clark - PEPCO (I), pages 22-23, regarding Pepco's plans for "modernizing the distribution grid to enable advanced command and control systems supporting the transition of the grid to a platform for the provision of advanced energy and information services."

A. Describe specifically what investments and actions Pepco plans to take to modernize the distribution grid.

B. Identify the revenue requirements associated with these actions and investments for each of the next five years.

C. Explain whether the revenue requirements identified in (b) are included in Pepco's multiyear rate plan revenue requirement forecast.

D. Explain what is meant by "the provision of advanced energy and information services." How does this differ from the energy and information services currently provided by Pepco?

RESPONSE:

A-D: Please see FC 1156 DCG DR 5-11 Confidential Attachment. In sum, modernization of Pepco's electric grid encompasses a number of components, which include:

- Improving reliability for customers by creating a smarter grid that can "self-heal" and minimize disruptions
- Increasing resiliency and security against threats - cybersecurity attacks and extreme weather events
- Enabling customers to adopt distributed generation (e.g. solar, storage) and ultimately transact as prosumers in an open marketplace
- Helping achieve climate change objectives, through electrification – transport, business and residential
- Providing better city services for citizens – working with other entities (e.g., gas and water utilities, telecom providers and cities) to coordinate deployment of smart infrastructure to serve a wide range of community

Each of these components can run simultaneously with the ultimate goal being a connected community. At the same time, the components build upon one another. Without a system that minimizes disruptions and is hardened against severe weather and cyber attacks, interconnection of increasing levels of DER and increasing levels of electrification are not possible. With the necessary investments in place, increased adoption of DER, and increased electrification, a connected community that provides better city services for citizens is possible. The connected community is enabled by the electric grid but reaches beyond the electric grid, allowing for smarter services such as waste management and water management.

Pepco has been investing in numerous projects to help meet these ends and continues to invest in these projects through the MRP period. For example, in Pepco I-2 Pepco shows numerous projects, such as distribution automation and the continued installation of Remote Monitoring Systems, as well as Area Reliability Plans, network transformer and protector replacements, and increased cybersecurity efforts, all with the aim to minimize outages and modernize the electric grid. Pepco (I)-2 provides details regarding each of these projects, including the scope of work, justification, and budgets through 2023.

In addition, it should be noted that providing customer choice and increasing DER adoption is enabled by these and other reliability and resilience investments, as is transportation and other electrification initiatives. These and other future investments will lead to a grid that supports the transition of the grid to a platform for the provision of advanced energy and information services, which differs both in scope and due to customer expectation from the services Pepco has traditionally offered.

SPONSOR: Bryan L. Clark

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 2

QUESTION NO. 20

Provide a list of specific projects contained in the Distribution Construction Program Report that fall under the grid modernization rubric as envisioned through the MEDSIS.

RESPONSE:

See Pepco's response to FC 1156 DCG DR 2-15 for current Pepco projects involving NWA solutions.

SPONSOR: Bryan L. Clark

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 2

QUESTION NO. 15

Provide a description of the Company's current approach to assessing NWAs to distribution construction projects and why the Company has concluded that there are no suitable NWA solutions in the Company's current Distribution Construction Program Report (see Exhibit PEPCO (I)-1).

RESPONSE:

Pepco has considered battery storage NWA solutions for the distribution projects listed below. Please also refer to the responses to FC 1156 DCG DR 2-16 and 2-17.

ID	Jurisdiction	Type	Location	Size	Comments
1	Pepco DC	Load Shaving	Alabama Ave. Sub. 136 Feeder 15166	1 MW, 3 MWh	Demonstration project to defer traditional solution.
2	Pepco DC	Load Shaving	Alabama Ave. Sub. 136 Feeder 15177	1 MW, 3 MWh	Not moving forward as an NWA due to the de minimus deferral benefit.
3	Pepco DC	Microgrid	New York Ave & Bladensburg Rd, NE	TBD	Pending Consideration - New Business project

SPONSOR: Bryan L. Clark

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 4

QUESTION NO. 22

In reference to Exhibit PEPCO (I), page i, entitled "PEPCO DISTRICT OF COLUMBIA CAPITAL CONSTRUCTION SUMMARY":

A. Provide an electronic Excel spreadsheet file with the total Distribution Construction spending amounts for grid modernization investments by year.
B. Going forward, would the Company consider expanding its three categories of capital construction spending (customer driven, reliability, and load) to include a fourth category for grid modernization?

RESPONSE:

A. Pepco does not categorize and identify projects as grid modernization projects. Pepco categorizes projects according to need.

B. Pepco does not categorize and identify projects as grid modernization projects. Pepco categorizes projects according to need. The current categorization of projects has existed for years and is well known to the Commission and stakeholders, and such categorization has been accepted by the Commission in previous rate cases. The projects that fall under these categories modernize the system by providing a reliable system with sufficient capacity to support new technologies or by adding new technologies to the system.

SPONSOR: Bryan L. Clark

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 6

QUESTION NO. 2

Refer to the Second Supplemental Direct Testimony of Kevin McGowan (PEPCO 3B) page 21 regarding the District's goals of grid modernization and greenhouse gas emission reductions, and Mr. McGowan's statement at lines 12-13 that "an MRP creates a more balanced regulatory environment that facilitates the types of investment necessary to support these goals." Refer also to page 22, lines 12-16 in which Mr. McGowan states that Pepco is "seeking to optimize the grid and to make new and innovative opportunities available to customers," and that "the proposed MRP and PIMs provide the transparency necessary and opportunity to advance these innovative investments…."

A. List the specific types of investments that Pepco needs to make to support the District's grid modernization goals.
B. List the specific types of investments that Pepco needs to make to support the District's greenhouse gas emission reduction goals.
C. What specific planned investments contained in the current MRP proposal does Pepco consider will enhance grid modernization?
D. What specific planned investments contained in the current MRP proposal does Pepco consider will facilitate greenhouse gas emission reductions?
E. What specific planned investments contained in the current MRP proposal does Pepco consider to be "innovative investments"?

RESPONSE:

A. Types of investments that the Company believes support the District's modernization goals include investments that improve reliability and resiliency, facilitate further interconnections of Distributed Energy Resources, advance opportunities to reduce carbon and those investments that enable a fully connected and integrated community. For examples of specific projects, see Pepco's response to FC 1156 DCG DR 5-11.

B. Specific investments to support the District's Greenhouse gas emission goals are:
   a. Investments that enable a large and cost-effective electrification of transportation infrastructure
   b. Investments that enable higher penetrations of solar
   c. Investments that enable energy storage
   d. Investments that promote energy efficiency and reduction of peak loads

C. A reliable and resilient grid is the foundation for grid modernization. Accordingly, the projects contained in the Construction Report, PEPCO (I)-2, provide the foundation to enable grid modernization. For examples of specific projects, see Pepco's response to FC 1156 DCG DR 5-11.

D. Similar to the investments required for grid modernization, greenhouse gas emissions reduction would come from investments that allowed for higher penetration of DER and energy storage as well as enabling transportation electrification and would also include those above in 6-2 C.

Specific GHG reduction initiatives currently underway and included in the MRP include the following:

- EV and Solar hosting capacity map (feeder capacity for EV planning purposes)
- Ongoing LED light conversion of all PHI Facilities
- Employee Workplace Charging

E. Specific innovative technologies within these plans include, but are not limited to the following:

a. Upgrades that include the addition of Smart Relays (GE F60) on feeders
b. Upgrades that include the ability to remotely monitor the underground and LVAC networks, Remote Monitoring Systems (RMS)
c. Dissolved Gas Analysis (DGA) systems for transformer heath monitoring
d. Distribution Automation upgrades, which include Automatic Sectionalizing and Restoration (ASR) schemes

SPONSOR: Kevin M. McGowan/Bryan Clark

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO DCG DATA REQUEST NO. 6

QUESTION NO. 12

Refer to the Second Supplemental Direct Testimony of Kevin McGowan (PEPCO 3B) page 11, which states "The PIMs are designed to enhance performance requirements, that if attained, will provide tangible incremental benefit to customers."

A. Has the Company quantified the incremental benefits that will result from achieving the goals proposed for each PIM? If yes, provide the quantified benefits for each proposed PIM.
B. Has the Company conducted a benefit-cost analysis for each of the proposed PIMs? If yes, please provide the benefit-cost analysis for each proposed PIM.
C. Are the costs associated with meeting the Service Level, Call Abandonment Rate, and Interconnection Review Timeframe targets included in the Company's proposed MRP revenue requirement?

RESPONSE:

A. The Company has not quantified the incremental benefits customers will receive from the higher performance levels it is proposing in the PIMs. However, the District of Columbia, the Commission and customers want higher reliability of the distribution grid, improved customer service and increased deployment of solar in the District. The proposed MRP includes higher performance levels in these areas of importance and go beyond the currently existing EQSS standards; achievement of the proposed PIMs related to reliability, customer service and interconnection will provide incremental benefits to customers.
B. The Company has not completed a cost benefit analysis.
C. Yes.

SPONSOR: Kevin M. McGowan

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA FORMAL CASE NO. 1156
RESPONSE TO OPC DATA REQUEST NO. 11

QUESTION NO. 7

PIM Development With respect to Mr. McGowan's testimony, Pepco (B) at 9:12-15, Mr. McGowan states that "the Company has improved the interconnection process to promote the use of solar connections, supported energy efficiency programs in the District of Columbia, and provided tools and information to customers to manage their energy usage, all for the benefit of our customers." Please identify any Performance Incentive Mechanism or similar program that incentivized the Company to make these improvements.

RESPONSE:

Many of the improvements to the interconnection process were agreed to by the Company and are included in the PHI/Exelon Merger Commitments. The Commission also promulgated a new rule on January 9, 2019 that accelerates the timeline for the vast majority of interconnection reviews and approvals. Specifically, the size of Level 1 interconnection requests has been increased form 10kW to 20KW, and the time to complete the approval to install has been decreased from 15 days to five days. Further, see Table 5 on pg. 34, of Company Witness Clark's Direct Testimony, Pepco_(I). Moreover, as grid modernization moves forward in the District of Columbia and Pepco is adding new technologies to its system, using new technologies in lieu of wires investments, and acting as a platform for energy transactions, continued improvement of the DER interconnection process will become increasingly important.

SPONSOR: Kevin M. McGowan

CERTIFICATE OF SERVICE

I certify that on March 6, 2020, a copy of the Direct Testimony of Courtney Lane on behalf of the District of Columbia Government was served via electronic mail on the following parties:

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