PUBLIC VERSION

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

	*	
IN THE MATTER OF THE APPLICATION		Case No. 9702
OF POTOMAC ELECTRIC POWER	*	
COMPANY FOR ADJUSTMENTS TO		
ITS RETAIL RATES FOR THE	*	
DISTRIBUTION OF ELECTRIC ENERGY		

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PANEL DIRECT TESTIMONY

OF

PAUL J. ALVAREZ

AND

DENNIS STEPHENS

ON BEHALF OF THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

December 15, 2023

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Exhibit PJA-4: Brattle, *An Assessment of Electrification Impacts on the Pepco DC System* (Aug. 27, 2021)
Exhibit PJA-5: *Pepco's Capital Grid Annual Project Status Report Docket*, No. FC1144-263 (D.C. PSC, April 17, 2023)
Exhibit PJA-6: *Pepco's Downtown Resupply Plan*, Docket No. PEPACR2021-0114 (D.C. PSC, Nov. 22, 2021)
Exhibit PJA-7: Paul Alvarez, Dennis Stephens *et al.*, *Alternative Ratemaking in the U.S.: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers?* 35 Electricity J. 107200 (2022)

PANEL RESPONSE TESTIMONY OF PAUL J. ALVAREZ & DENNIS STEPHENS

I. INTRODUCTIONS, PURPOSE, AND PREVIEW

Q. Please state your names and business addresses.

A. (Alvarez) My name is Paul J. Alvarez, and my business address is PO Box 620756, Littleton, CO 80162. (Stephens) My name is Dennis Stephens, and my business address is 1153 Bergen Parkway, Suite 130, Evergreen, CO 80439.

Q. Please state your occupations.

A. (Alvarez) I am the head of a consultancy, the Wired Group, which specializes in distribution utility business planning, investment, and performance. (Stephens) I am an independent distribution utility business advisor, and I often serve as the Wired Group's Senior Technical Consultant.

Q. On whose behalf are you testifying?

A. (Alvarez) Mr. Stephens and I are testifying on behalf of the Maryland Office of People's Counsel as a panel regarding the second Multi-year Rate Plan ("MRP 2") and associated rate increase requested by Potomac Electric Power Company ("Pepco" or "the company").

Q. Mr. Stephens, please provide an overview of your professional background and education.

A. After graduating from the University of Missouri with a bachelor's degree in electrical engineering, I began work for Xcel Energy (then Public Service

Company of Colorado) as an electrical engineer in distribution operations. In a series of electrical engineering and management roles of increasing responsibility, I gained experience in distribution planning, operations, asset management, and the innovative use of technology to assist with these functions. Positions I held with Xcel Energy included Director, Electric and Gas Operations for the City and County of Denver Colorado; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments for all of Xcel Energy.

In 2007, I was asked to lead parts of Xcel Energy's SmartGridCity™ demonstration project in Boulder, Colorado, the first of its kind at the time, covering 46,000 customers. I developed the technical foundations for the project, including the development of all concepts presented to the Xcel Energy Executive Committee for project approval, and including the negotiations with technology vendors on their contributions to the project. As Director of Utility Innovations for Xcel Energy, I also worked with many software providers—including ABB, IBM, and Siemens—helping them develop their distribution automation ideas into practical software applications of value to grid owner/operators. I retired from Xcel Energy in 2011, and now work as a consultant for the Wired Group on a part-time basis.

I was directly responsible for distribution grid reliability in several of these roles, and indirectly responsible for grid reliability in all other roles. This is highly relevant in proceedings, such as this one, in which grid reliability is employed by a

utility as justification for massive increases in grid investment. For a good portion of my career at Public Service Company of Colorado, capital spending was constrained. My experience maintaining strong distribution grid reliability in the face of growing distributed energy resources and strict capital constraints is highly relevant to this testimony.

Q. Mr. Stephens, have you testified before the Maryland Commission previously?

A. Yes. I testified with Mr. Alvarez on behalf of the Office of People's Counsel ("OPC") in the proceedings concerning Baltimore Gas and Electric Company's ("BGE") and Pepco's initial multi-year rate plan applications, Case Nos. 9645 and 9655, respectively. I also recently testified with Mr. Alvarez on behalf of OPC in Case No. 9692, BGE's second multi-year rate plan application. Further, Mr. Alvarez and I helped develop comments on OPC's behalf in multiple proceedings concerning distribution planning and distribution performance in Case No. 9353.[1] Mr. Alvarez and I also helped OPC develop comments on distribution planning filed in PC44 on March 11, 2021.

In addition, I have testified before ten other state utility regulatory commissions (California, Georgia, Illinois, Indiana, Massachusetts, Michigan, North Carolina, Oklahoma, Washington, and Virginia) on distribution grid

[1] *See* ML# 230626 (OPC comments filed June 8, 2020); ML# 235643 (OPC comments filed June 4, 2021); ML# 241553 (OPC comments filed July 21, 2022).

planning, investment, asset management, and performance measurement issues. I have also served as a technical consultant to parties providing commentary in many other state utility regulatory proceedings. My Curriculum Vitae, attached as Exhibit DS-1 to this testimony, includes all appearances in the last ten years with jurisdictions, proceeding numbers, and dates.

Q. Mr. Alvarez, please provide an overview of your professional background and education.

A. After a career with several Fortune 500 companies in financial and product management and marketing roles, I took my first electric utility industry position with Xcel Energy, one of the largest investor-owned utilities in the U.S., in 2001. As a product developer and then product development manager, I developed or oversaw the development of new demand-side management ("DSM") programs for residential and commercial and industrial customers, as well as programs and rates in support of voluntary renewable energy purchases and renewable portfolio standard compliance.

In 2008, I left Xcel Energy to establish a utility practice for a small sustainability consulting firm. There, I utilized the DSM program benefit measurement and verification and cost-effectiveness testing experience I gained at Xcel Energy to lead two comprehensive evaluations of smart grid deployment

performance.[2] To my knowledge, these were the first two of only five comprehensive evaluations of smart grid deployment performance ever completed.

I started the Wired Group in 2012 to focus exclusively on distribution utility investment, customer value creation, performance measurement, and regulation on behalf of consumer, business, and environmental advocates. On occasion, I teach a graduate course on the electric utility industry at the University of Colorado's Global Energy Management Program and sessions on distribution utility performance measurement and grid modernization at Michigan State University's Institute for Public Utilities. I have authored papers, many with my co-panelist Mr. Stephens, that have been published in The Electricity Journal, Public Utilities Fortnightly, and the ICER Chronicle (an industry regulator publication popular in Europe). I am also the author of *Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment* published in 2014 and updated with a second edition in 2018. I received an undergraduate degree in finance and marketing from Indiana University's Kelley School of Business in 1983, and a master's degree in management from the Kellogg School at Northwestern University in 1991.

[2] *Smart Grid City Demonstration Project Evaluation Summary*, Direct Testimony of Michael G. Lamb, Exhibit MGL-1, Docket No. 11A-100E (Col. Pub. Util. Comm'n, Dec. 14, 2011); *Duke Energy Ohio Smart Grid Audit and Assessment*, Docket No. 10-2326-GE-RDR (Ohio Pub. Util. Comm'n, June 30, 2011).

Q. Mr. Alvarez, have you testified previously before the Maryland Commission?

A. Yes, I testified on a panel with Mr. Stephens in all the proceedings he referenced above. I also submitted testimony on behalf of the Coalition for Utility Reform in Case No. 9361.[3] I also worked with Mr. Stephens to help OPC develop multiple sets of comments submitted in Case No. 9353 and PC 44, as Mr. Stephens described above.

In the last ten years, I have also testified before 17 other state utility regulators in dozens of proceedings related to distribution grid and business investment, value creation, performance measurement, and regulation, including California, Georgia, Illinois, Indiana, Kansas, Kentucky, Massachusetts, Michigan, New Hampshire, New Jersey, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Virginia, and Washington. My Curriculum Vitae, including all jurisdictional appearances, proceedings, and testimony dates, is attached as Exhibit PJA-1.

Q. Please provide a preview of your panel testimony.

A. This testimony addresses Pepco's application to increase rates through a second multi-year rate plan ("MRP 2"). As an initial matter, the witnesses collaborated closely in the development of this testimony. However, Sections II and VI were

[3] *In the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.*, ML# 161223 (Case No. 9361, Dec. 8, 2014). The Coalition for Utility Reform was a coalition comprising of municipal and non-profit entities and officials, including the cities of Rockville, Takoma Park, Garrett Park, Somerset, Greenbelt, and College Park.

developed primarily by Mr. Alvarez, and Sections III, IV, and V were developed primarily by Mr. Stephens.

The results of Pepco's first MRP ("MRP 1")—and Pepco's proposal for its second— further confirm the concerns we expressed in prior testimonies to the Commission. Cost-ineffective, premature, and unsupported investments—encouraged by multi-year ratemaking and rationalized with claims of advancing state and local policy goals—underly Pepco's ever-increasing electric rates, to the detriment of the company's Maryland customers. With regard to Pepco's second MRP, this testimony discusses multiple examples of a theme we identified in our testimony concerning Pepco's MRP 1—Pepco's inadequate capital spending governance.

Our testimony begins in **Section II** with lessons learned from Pepco's first MRP. We begin with a discussion of the Commission's objectives for multi-year ratemaking, finding that almost none have been met. We then turn to the unintended consequences associated with multi-year ratemaking, explaining how multi-year ratemaking practically eliminates cost disallowance risk, reduces utility capital spending governance, exacerbates information asymmetry, and introduces moral hazard into MRP development. Section II also addresses the challenges presented by the MRP reconciliation mechanism. Section II concludes with a discussion of predictable utility responses to multi-year ratemaking, including

investments beyond the point of diminishing returns in reliability and resilience, and premature grid "readiness" investments.

Sections III through V of this testimony recommend disallowances of historical capital spending (2021 and 2022) and reductions of capital spending proposed in MRP years 2024–2027. **Section III** addresses system performance investments that are not cost-effective, including prospective substation equipment replacement; the Benning 69kV substation rebuild; and 69kV (subtransmission) line rebuilds. **Section IV** addresses premature investments in capacity expansion, including spending on a new National Harbor substation, and the Downtown Resupply investment program. **Section V** addresses unsupported increases in specific capital spending forecasts relative to historical levels, including underground cable replacements, priority feeder improvements, new commercial connections, and emergency underground replacements.

Section VI brings the testimony full circle. We connect the deficiencies in multi-year ratemaking identified in Section II with the capital spending excesses identified in Sections III through V and present our recommendations for the Commission's consideration.

Our primary recommendation is for the Commission to reject Pepco's proposed MRP. The excessive capital investments and commensurate rate increases Pepco proposes far outweigh the limited customer benefits of multi-year ratemaking. We also explain how the Commission could implement this

recommendation. However, if the Commission chooses to accept Pepco's MRP, we provide secondary recommendations for improving multi-year ratemaking as practiced in Maryland. These include:

- eliminating the opportunity for recovery of overspending through the MRP adjustment rider;
- completing a review of MRP lessons learned as envisioned by Order No. 89482;
- improving capital spending governance and mitigating information asymmetry by increasing stakeholder participation in MRP capital plan development and requiring utilities to support proposed investments with risk-informed benefit-cost analyses.

Q. Please summarize the cost disallowances and reductions in proposed MRP 2 spending you recommend.

A. Table 1 provides recommended capital reductions by category. Amounts in years 2021 and 2022 represent recommended disallowances of costs already incurred, while amounts in years 2024 through 2027 represent recommended reductions to the capital spending proposed for the company's MRP 2.

Table 1: Summary of recommended electric distribution capital cost disallowances and Plan reductions

($ in millions)	2021	2022	2024	2025	2026	2027
System Performance Spending That Is Not Cost Effective						
Prospective Substation Equip. Replacement	13.5	19.9	22.9	27.1	26.8	28.3
Benning 69kV Substation Rebuild	0.0	0.1	8.7	17.0	19.4	17.8
69kV Line Rebuilds	n/a	n/a	1.8	11.3	28.7	15.1
Premature Capacity Expansion Spending						
National Harbor Substation/Livingston Road Energy Storage	2.2	0.9	1.2	4.0	5.1	39.2
Downtown Resupply Investment Program	2.3	5.2	7.4	11.6	26.9	40.6
Unsupported Increases in Capital Spending Forecasts						
Underground Cable Replacements	n/a	n/a	0.0	7.3	12.7	15.7
Priority Feeder Improvements	n/a	n/a	0.0	0.0	0.0	8.4
New Customer Connections	n/a	n/a	10.3	14.7	17.7	19.1
Emergency Underground Cable Replacements	n/a	n/a	4.2	5.8	4.4	5.5
Total Capital	18.1	26.1	56.5	98.9	141.5	189.6

Our recommended disallowances and reductions in MRP capital spending are reflected in revenue requirement adjustments presented in the testimony and exhibits of OPC witness Mr. David J. Effron.[4]

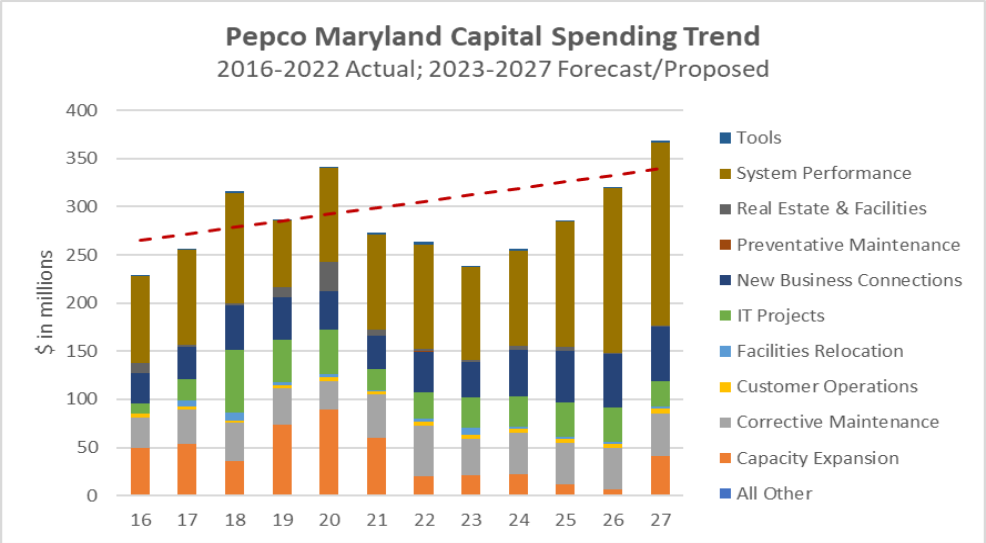
Q. Before proceeding with your discussion of Pepco's MRP, could you contextualize Pepco's historical capital spend and reliability performance?

A. Yes. A history of Pepco capital expenditures over time provides important context as the Commission considers its options in this case. As Figure 1 below shows, approving the capital spending Pepco proposes for its second MRP results in a 44 percent increase in the company's annual electric distribution plant additions from 2016–2027. Most of the increase is attributable to system performance spending, which will nearly double from $99 million in 2017 to $190 million by 2027. Given that Pepco's reliability performance is within the top ten percent among investor-owned electric utilities in the U.S.,[5] we believe this significant increase in spending to be superfluous. Pepco does not even estimate the reliability improvements it hopes to secure from various system performance projects, let alone compare those expected improvements to project costs. The company's customers, and Maryland's economy, deserve better.

[4] We are not recommending any disallowances in 2023 spending at this time. It is our understanding that 2023 spending will be evaluated as part of the annual informational filing/spending reconciliation that will occur in 2024.

[5] System average interruption duration (Pepco MD 54.7 minutes/year), without major event days, 2022, as reported on Energy Information Administration Form 861. (65 minutes/year or less constituted top 10 percent performance in 2022.) *See* https://www.eia.gov/electricity/data/eia861m/.

Figure 1: Annual Pepco Electric Distribution Plant Additions 2016-2027



While spending to improve reliability that is already excellent may seem wasteful, there is widespread support for developing an electric distribution grid with the capacity to accommodate broad use of distributed energy resources ("DER"), electric vehicles ("EV"), and building electrification. But to benefit Pepco's customers and the State's economy, these grid investments must also be completed in a cost-effective manner. Securing a higher-capacity grid at an affordable cost will require careful, unbiased planning and difficult trade-offs that must be informed by data-driven, risk-informed capital investment planning. Pepco's capital spending decision-making process does not include these elements. And the proposed capital investments we discuss in this testimony exemplify Pepco's ineffective capital spending controls. Pepco's lack of capital spending governance was the primary theme of our testimony on Pepco's first

multi-year rate plan.[6] Our review of Pepco's second MRP indicates that the company's capital spending governance has not improved.

II. LESSONS LEARNED FROM PEPCO'S FIRST MULTI-YEAR RATE PLAN (ALVAREZ)

Q. Please preview this section of testimony.

A. This section of testimony begins with a discussion of the Commission's objectives for multi-year ratemaking, finding that almost none have been met. I then turn to the problems arising from multi-year ratemaking, beginning with the practical elimination of standard ratemaking's cost disallowance risk. I explain how cost disallowance risk provides capital spending governance and mitigates information asymmetry—crucial components of investor-owned monopoly utility regulation that have been the regulatory standard for about 100 years. I then explain exactly how MRPs practically eliminate cost disallowance risk; effectively shift the burden for demonstrating prudence away from utilities; and introduce moral hazard in utility investment planning.

I conclude that Pepco's MRP shows how Maryland's MRP construct cannot produce just and reasonable rates in the public interest. The outcomes of multi-year ratemaking are biased in favor of private shareholder interests and

[6] Panel Direct Testimony of Paul J. Alvarez and Dennis Stephens ("Alvarez/Stephens MRP 1 Testimony"), ML# 234018 (Case No. 9655, March 3, 2021).

fail—as substitute for competition—to provide the right investment and performance signals to utilities.

Section II also addresses the issues caused by the MRP reconciliation mechanism. I find that the reconciliation process is more likely to result in rate increases than rate decreases and reduces utility incentives to maintain capital and O&M spending within the levels budgeted in an MRP. Section II concludes with a discussion of predictable utility responses to multi-year ratemaking, including proposals for investments beyond the point of diminishing returns in reliability and resilience, and premature investments in grid "readiness"[7] for increased adoption of DER, EV, and building electrification.

A. Pepco's MRP shows how the Commission's goals for multi-year ratemaking have not been met.

Q. Why did the Commission implement multi-year ratemaking?

A. The Commission believed that a future of DER and EV required a new approach to ratemaking, and that multi-year ratemaking was the best "alternative ratemaking" approach available. As the Commission explained in Order No. 89226, alternative forms of ratemaking—such as MRPs—"may be helpful, if carefully implemented, in facilitating the achievement of the State's ambitious goals regarding electrification, renewable development, pipeline replacement,

[7] Grid readiness for customer adoption of these technologies is largely represented by adequate circuit capacity, measured in megawatts.

development of new customer solutions, grid resiliency, and other state goals."[8] In that order, the Commission identified certain potential benefits that warranted pursuing implementation of multi-year rate plans: "shortening the cost recovery period, providing more predictable revenues for utilities and more predictable rates for customers," and "decreasing administrative burdens on regulators."[9]

The Commission also identified several perceived drawbacks to standard cost-of-service ratemaking it hoped to address through MRPs, including "a failure to equitably distribute risk, limited capabilities to monitor costs, limited ability to achieve policy outcomes and potential restrictions on utility innovation, and arguably regulatory lag, which can impede the utilities' ability to earn their authorized ROR."[10] The Commission's description of standard ratemaking also bemoaned "a lack of transparency in utilities' short-term planning for grid modernization and integrating distributed resources," and utilities' preference for "iron in the ground investments."[11]

Q. How has multi-year ratemaking fared relative to these goals and improvement opportunities?

A. In my opinion, multi-year ratemaking has fared abysmally for customers and extremely well for utilities, and has significantly increased litigation and

[8] Order No. 89226 at 52-53, *In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or a Gas Company* (Case No. 9618, Aug. 19, 2019).
[9] *Id*. at 54.
[10] *Id.* at 52.
[11] *Id.* at 52–53.

administrative burdens for Staff, OPC, and other stakeholders. With multi-year ratemaking, the utilities win and customers lose. MRPs have not led to any appreciable improvement in the ability to achieve state policy objectives, nor in the ability to cost-effectively meet reliability standards, relative to standard ratemaking and other regulatory processes available to the Commission.

Maryland law requires utilities to make the investments needed for providing safe and reliable service.[12] In exchange, utilities are awarded a reasonable opportunity to earn a fair rate of return on their capital investments.[13] There is no evidence that a grid with sufficient capacity to accommodate DER, EV, and building electrification cannot be achieved without multi-year ratemaking. Table 2 below is my assessment of whether MRPs have achieved the Commission's stated goals in pursuing multi-year ratemaking.

Table 2: Summary of MRP goals and results

MRP Goal	Result
Better achieve State policy goals	Not clearly or demonstrably better than standard ratemaking to date, but certainly more costly, as evidenced by the capital spending examples provided later in this testimony.
Shorten cost recovery	Achieved to utilities' benefit, but at high cost, including curtailed Commission ability to exercise cost disallowance rights and information asymmetry mitigation (to be discussed later in this testimony).

[12] Md. Code Ann., Pub. Util. Art. ("PUA") § 5-303.
[13] PUA § 4-101(3).

Spreading out rate increases for customers/more predictable rates.	From a customer perspective, this means accelerating rate increases. Formerly implemented only after an investment is used and useful, rate increases now occur concurrent to investment. In addition, a utility that overspends its MRP budgets can recover those costs years later through a rider, on top of base rates—the exact opposite of "rate stability." These are not benefits to customers.
Decreasing administrative burden	Due to information asymmetry mitigation lost with MRP, Staff, OPC, and other intervenors' burdens increase. Further, costs are reviewed multiple times under MRP: during the initial case, when the annual information filing is made, and when reconciliation occurs during the subsequent base rate proceeding. This is not a benefit to Staff, OPC, or other stakeholders.
More equitable risk distribution	Due to the reduction in the opportunity for the Commission to exercise cost disallowance rights associated with MRP, risk for excessive investment or spending falls entirely on customers. This is not a benefit to customers.
Limited cost monitoring	Annual informational filings provide limited information but lead to a reconciliation process more likely to result in rate increases than decreases and eliminate a utility's incentive to reduce spending proposed in an MRP.
Utility Innovation	Not clearly or demonstrably better than standard ratemaking to date.
Grid planning transparency	Though projected budgets are now available for review, the utilities develop MRPs in black boxes with no stakeholder participation. The reconciliation process adds some transparency, but these benefits are outweighed by a utility's reduced incentive to contain capital spending.
Utility preference for capital spend	Utility preference for capital spending has only increased under MRP, due to lower cost disallowance risk and improved opportunity to over-earn authorized rates of return on capital.

Q. Are you concerned that no formal review of the MRP construct has been completed?

A. Yes. Such a review was outlined in the Commission's Order establishing an MRP

pilot,[14] but the review has not been completed. I further note that the Commission did not establish any metrics or targets to measure MRP results against the Commission's stated goals. Other than the indicators of failure I list above, there is no objective measure of the success or failure of multi-year ratemaking at achieving the Commission's goals.

Another concern is the Commission's expansion of MRPs beyond the initial BGE pilot. Order No. 89482 invited *one* utility to apply to be the "pilot utility." BGE accepted this invitation when it filed the MRP application initiating Case No. 9465. *Before the Commission issued its Order in Case No. 9465, Pepco filed its first MRP.*[15] Despite the absence of any guiding regulations or legal standards by which to review Pepco's MRP, the Commission approved it. The Commission has subsequently approved an MRP for Delmarva Power and Light Company,[16] and the Commission just issued its order approving BGE's second MRP.[17] Despite any formal review of the results of the pilot MRP, multi-year ratemaking appears to be becoming regular practice.

[14] Order 89482 ("Pilot Order") at 13 ¶ 25, *In the Matter of Alternative Rate Plans* (Case No. 9618, Feb. 4, 2020).
[15] In separate statements, Commissioners Michael T. Richard, Odogwu Obi Linton, and Mindy L. Herman expressed significant concerns about Pepco filing its MRP before conclusion of BGE's initial pilot. While Commissioner Richard concurred in judgment, Commissioners Herman and Linton dissented. In particular, Commissioner Linton noted that by approving Pepco's first MRP, the Commission missed the learning opportunities afforded by reviewing the pilot MRP filed by BGE. *See* Order No. 89868, Dissenting Statement of Commissioner Odogwu Obi Linton.
[16] Order 90445 (Case No. 9681, Dec. 14, 2022).
[17] Order No. 90948, *Application of Baltimore Gas and Electric for a Multi-Year Plan* (Case No. 9692, Dec. 14, 2023).

The expansion of MRPs beyond the initial BGE pilot should concern the Commission. The Commission should be further concerned that multi-year ratemaking has effectively become the default regulatory construct for all of the Exelon utilities, which serve the vast majority of the State's utility customers. Given the poor results of multi-year ratemaking highlighted in Table 2—and the lack of any formal review of whether the current MRP construct can assure just and reasonable rates—further expansion of MRPs in Maryland is inappropriate.

Q. Do you agree that multi-year ratemaking is necessary to ensure sufficient utility investments to meet the State's policies regarding grid reliability and "readiness" for DERs, EVs, and electrification?

A. No, I do not. While state policies call for increases in DERs and envision widespread transportation and building electrification—and it is undisputed that utilities will have to increase investment over time to meet those policy objectives—there is no support for concluding that multi-year ratemaking is necessary to accomplish those goals. Maryland law requires public utilities to invest the capital required to provide safe and reliable service.[18] And Maryland law requires any Commission-authorized rates to "yield a reasonable return on the fair value of the [utility's] property used and useful in providing service to the public."[19]

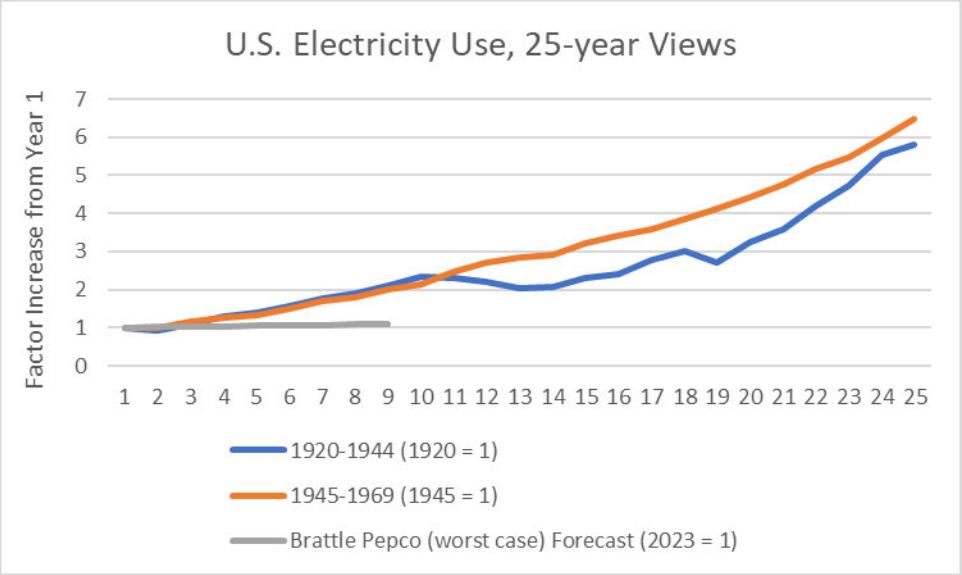
[18] PUA § 5-303 ("A public service company shall furnish equipment, services, and facilities that are safe, adequate, just, reasonable, economic, and efficient, considering the conservation of natural resources and the quality of the environment.").
[19] PUA § 4-101(3).

Standard cost-of-service ratemaking has encouraged and secured investments from utilities like Pepco to accommodate rapid load increases in the past. Utilities were able to handle the refrigeration driven load-growth in the 1930s and 1940s and air conditioning load growth in the 1950s and 1960s. Accommodating load growth related to DERs, EVs, and building electrification should be no different.

Figure 2 illustrates this point. The chart presents historical electricity use in the United States in 25-year views. Over the 25-year period from 1920 to 1944, U.S. electricity use grew six-fold. In the following 25-year period, from 1945-1969, electricity use grew another six-fold.[20] The chart also presents a forecast completed by the Brattle Group for increased electric use on the Pepco system from 2022–2031.[21]

[20] Historical U.S. electricity usage data from Cleveland CJ et al., *United States Electric History in Four Charts*, Institute for Global Sustainability, Boston University (Feb. 21, 2023, https://visualizingenergy.org/united-states-electricity-history-in-four-charts/.
[21] Exhibit PJA-3 (Brattle Group, *Draft Appendix the Final Report*, presented to the Electrification Study Working Group, at 55 (Nov. 13, 2023)).

Figure 2: Electric use over various 25-year time periods, historical and forecast



As Figure 2 shows, standard cost-of-service ratemaking has not impeded utilities from being able to accommodate significant increases in load in the past. Figure 2 also indicates that Pepco will be in the very early stages of electrification-related load growth for some time, and that no need for capacity expansion to accommodate such load growth is imminent. Further, other work from the Brattle Group indicates load growth due to electrification through 2050 is unlikely to exceed the load growth rates Pepco has successfully accommodated in the past.[22] Nothing shows that accommodating electrification-related load growth in the future will be much different from accommodating rapid load growth in the past. And if the Commission finds grid investment insufficient in the future, there are a

[22] Exhibit PJA-4 (Brattle, *An Assessment of Electrification Impacts on the Pepco DC System* at 3 (Aug. 27, 2021)).

number of alternative ratemaking constructs—such as rider cost recovery limited to certain types of investments—the Commission could consider implementing.

Q. Are you aware of the Climate Solutions Now Act?

A. Yes. I understand the Climate Solutions Now Act, passed by the General Assembly in 2022, instructs the Commission to "adopt regulations or issue orders to implement specific policies for electric distribution system planning and improvements in order to promote the state's policy goals."[23] State policy goals include increases in DER, EVs, and building electrification. But the Act does not instruct the Commission to alter any of its regulatory constructs. Of particular relevance to this testimony, to be addressed later, is the Act's goal to implement "transparent stakeholder participation in ongoing electric distribution system planning processes."[24] Next, I will explain how multi-year ratemaking fundamentally sends the wrong investment and performance signals.

[23] 2022 Md. Laws Ch. 38 § 5 (codified at PUA § 7-804). The CSNA's stated policy goals include reducing greenhouse gas emissions through DER and EV adoption, as well as through energy efficiency and demand response. PUA § 7-802. including distribution grid reliability and resilience. The Commission must report to the General Assembly annually on progress on assigned goals.
[24] PUA § 7-802.11.

B. Multi-year ratemaking fundamentally alters the ratemaking process decidedly in shareholders' favor and fails to send the proper investment and performance signals to utilities.

Q. What is the purpose of regulating investor-owned monopoly utilities?

A. Regulation aims to align the private behavior of investor-owned utilities with the public interest,[25] such as customers' interest in reliable and affordable service and state policy goals for energy efficiency and greenhouse gas emissions reductions. A well-designed regulatory construct enables the Commission to identify the result that meets the public interest standard and, among other things, meets the needs of customers, advances state policies, and provides just compensation for the utility's private interests.

From a capital investment perspective, regulation serves as a substitute for competition. A non-regulated entity looks to the competitive market for investment, performance, and price signals. Since, by design, monopoly investor-owned utilities do not operate in a competitive market, those same signals come from the regulatory construct that governs the utility's operations. A well-designed regulatory construct ensures that a utility is able to make the investments necessary to provide safe and reliable service and advance state policy goals, at a reasonable cost to customers.

[25] Scott Hempling, *Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction* (Second Edition) (Amer. Bar. Ass'n 2021).

Q. Your testimony to this point has frequently employed the term cost disallowance risk. Can you please explain cost disallowance risk and its role in ratemaking?

A. Cost disallowance risk is the possibility that a state utility regulator might prevent a utility from recovering, through customer rates, the costs the utility has incurred for a certain program or project. Cost disallowances are severely consequential to a utility's return, and utilities have historically gone to great lengths to avoid them.

Cost disallowances arose in the earliest days of cost-of-service ratemaking—a ratemaking construct that almost all state utility regulators, including this Commission, employ to this day.[26] Cost-of-service ratemaking can effectively control utility profit *percentages*; that is, the ratio of profits to capital investment. However, cost-of-service ratemaking does a poor job of controlling utility profit *amounts*. To increase profit amounts, a utility must simply increase capital spending, resulting in an incentive known as *capital bias*.[27] Thus, investor-owned utilities have every incentive to maximize capital spending.

To address this problem, state utility regulators reserved the right to *disallow costs* from recovery through customer rates. A regulator can impose a

[26] *E.g., Missouri ex rel. Southwestern Bell Telephone Co. v. Pub. Serv. Comm'n of Missouri*, 262 U.S. 267, 303 (1923) ("Many commissions, like that of Massachusetts, have declared recently that 'capital honestly and prudently invested must, under normal conditions, be taken as the controlling factor in fixing the basis for computing fair and reasonable rates.'") (footnote omitted); *Acker v. U.S.*, 298 U.S. 426, 430–31 (1936) ("The contention is that the amount to be expended for these purposes is purely a question of managerial judgment. But this overlooks the consideration that the charge is for a public service, and regulation cannot be frustrated by a requirement that the rate be made to compensate extravagant or unnecessary costs for these or any purposes.").

[27] Harvey Averch and Leland L., Johnson, *The Behavior of the Firm Under Regulatory Constraint*, 52 Am. Econ. Rev. 1052 (Dec. 1962).

heavy economic penalty on shareholders by disallowing cost recovery on capital investments deemed not used or useful or imprudently incurred (representing excess capital spending) in the provision of safe and reliable service. Cost disallowance risk encourages utilities to moderate distribution grid capital spending.

Q. How have utilities responded to cost disallowance risk?

A. Historically, utilities have adopted processes similar to those employed by businesses operating in competitive markets to keep their capital spending to the minimum required for safe and reliable operations. These businesses apply risk-informed benefit-cost analyses to projects and programs in a portfolio of potential investments. The businesses select for implementation only those projects and programs which appear likely to deliver economic benefits in excess of costs.

In some instances, businesses in a competitive market defer for future consideration projects and programs which deliver only small benefits in excess of costs. These decisions are typically made due to a lack of capital, or due to a relatively high cost of capital, or out concern for potential benefit variation and the need for a "margin of error" in project or program benefit projections. However, utilities' "obligation to serve all customers" in a defined service area[28] requires utilities to make certain investments regardless of the results of a benefit-cost

[28] PUA § 5-103(a)(2) ("Unless authorized by the Commission, a public service company may not discontinue or abandon a service under a franchise, right, or permit.").

analysis. Investments not immediately required by the utility's service obligations are discretionary; these are proposed by utility employees or departments, and typically pass through a strict vetting process enforced by utility management. Known generally as *capital spending governance,* utilities designed these vetting processes to reduce (if not eliminate) the risk that a project or program would be found imprudent by a state utility regulator. Benefit-cost analyses—and rigorous assessments of the value and likelihood of adverse event avoidance—could (and should) be employed as part of capital spending governance processes. We will revisit these concepts later in this testimony.

Q. How have regulatory staff and stakeholders responded to cost disallowance risk?

A. Regulators, Staff, OPC, and other intervenors rely on cost disallowance risk—and the capital spending discipline it instills—to effectively control capital spending. In addition to encouraging capital spending governance from utilities, cost-disallowance risk mitigates the effects of *information asymmetry*. Information asymmetry refers to the difficulty for regulatory staff and intervenors to know as much about a utility's systems and operations as the utility itself knows. The experience required to understand grid operations, engineering, technologies, planning, and asset management is typically acquired through employment in utility grid functions. Without this experience, absent exceptional efforts, it is difficult for intervenors to effectively challenge technical utility justifications for

distribution grid capital spending.

It is difficult to overstate the value of cost disallowance risk to mitigating the effects of information asymmetry. The ability of regulatory staff and intervenors to rigorously evaluate or effectively challenge all utility capital spending proposals is greatly inhibited because they simply do not have the information, experience, and resources needed to thoroughly do so. Distribution grid planning cycles are characterized by thousands of investment decisions. Given the time and resources, it is possible for Staff, OPC, and other intervenors to gain the information and experience needed to rigorously evaluate and—where appropriate—effectively challenge a utility's proposed capital investments. But, with limited resources available to regulatory staff and intervenors, cost disallowance risk—and the internal controls utilities themselves have historically applied to reduce that risk—functions as the primary regulatory mechanism governing utility capital spending.

Q. How does multi-year ratemaking practically eliminate cost disallowance risk?

A. A multi-year rate case entails Commission review and approval of utility forecasted capital investment plans. Pre-construction review and approval of grid investment plans frustrates regulators' ability to identify and remove the costs of imprudent investments from customer rates. There are two reasons why.

First, a utility will argue that any stakeholder challenges to the investments proposed in its plan should have been raised during the consideration of the

utility's proposed MRP investment plan, rather than after capital has been spent. This argument will be difficult if not impossible for a regulator to dismiss; particularly when a regulator clearly states, as this Commission has, that project and spending details assessed during the MRP proceeding "serve as a guide for prudency."[29]

Second, due to the extremely large dollar amounts involved, cost disallowances have a material effect on utility earnings and a utility's cost of capital, which customers ultimately pay through rates. This effect of disallowance on utility earnings ties the regulator's hands when evaluating excess spending that the regulator had previously approved as part of a grid investment plan. If the regulator disallows recovery of excess spending, it will face arguments that the disallowance will harm customers by increasing a utility's cost of capital. As a result, utility regulators almost never exercise their right to disallow costs after they authorize a project or program for cost recovery through an alternative ratemaking mechanism (such as multi-year ratemaking).

In practice, authorizing an MRP based on investment after reviewing a utility's proposed capital investments—and their associated costs—amounts to pre-approval of that level of spending. This preapproval—combined with the

[29] Order 89482 at 24.

massive size of those investments—frustrates regulators' ability to exercise their rights to disallow costs.

The practical loss of cost disallowance risk resulting from advance approval of cost recovery for capital investments biases the outcome of MRP ratemaking to favor private shareholder economic interests over the broader public interest. In short, this fundamental shift undermines the regulator's ability to ensure utility rates align with the public interest.

Q. But can't Staff, OPC, and other stakeholders challenge MRP investments in advance?

A. In theory, yes, but in practice, there are significant challenges. Cost disallowance risk mitigates the effects of information asymmetry. Staff, OPC, and other intervenors who formerly relied—at least in part—on cost disallowance risk to encourage utility capital spending governance can no longer do so. In turn, reduced utility risk increases the burden of intervenors to examine the technical justifications utilities provide for their capital investments and identify those that are cost ineffective, premature, or unsupported. However, as discussed above, intervenors do not typically have the information on the utility's distribution systems or operations to make this possible. Moreover, intervenors are reviewing three years of proposed utility spending outside of the utility's long-term planning context. This review is especially challenging given the compressed schedule for reviewing and litigating an MRP.

Compressed procedural schedules present additional challenges. A procedural schedule that may have been appropriate for a standard rate case with cost disallowance risk is insufficient for Staff, OPC, and other intervenors, who are now required to examine the dozens of programs and hundreds or thousands of projects presented in an MRP—even with the extra time the General Assembly recently permitted for alternative forms of ratemaking.[30] There is simply insufficient opportunity to learn the specifics of any utility's distribution system—including the system's capabilities, constraints, technologies, designs, forecasts, operations, idiosyncrasies, and proposed investment programs and initiatives—in an 18-week MRP discovery period.

In short, multi-year ratemaking effectively shifts the prudence burden from utilities to stakeholders. Under standard ratemaking, utilities bear the burden of proving that their capital spending was prudent in a rate case. With MRPs, stakeholders must now demonstrate the imprudence of the utility's proposed MRP capital plans.

Q. To summarize, you theorize that MRP ratemaking practically eliminates cost disallowance risk, thereby eliminating utility capital spending governance, effectively shifting the prudence burden to stakeholders, and leading to excess utility capital spending. Is that correct?

A. Yes. But there is another problem associated with grid investment plan development under multi-year ratemaking: moral hazard. Under standard

[30] PUA § 4-204(b)(2)(ii) (allowing for additional 90-day extension of rate suspension period if rate filing "is for an alternative form of ratemaking").

ratemaking, all the "action" in a rate case is in response to capital the utility has *already* spent. This timing is essential to cost disallowance risk and necessitates the significant internal controls utilities put in place to scrutinize and govern capital spending.

While there is a big potential utility consequence to over-investment in standard ratemaking (cost disallowances), there is little consequence to proposing capital spending in an MRP that might be cost ineffective, premature, or unsupported. This is the moral hazard associated with utility grid investment plan development. A utility has nothing to lose—and everything to gain—by proposing expenditures in an MRP that would be too risky to pursue under the standard ratemaking construct. Moral hazard in investment plan development, combined with a lack of cost disallowance risk and information asymmetry mitigation, inflates the capital spending the utilities propose in their MRPs.

Q. How does multi-year ratemaking introduce moral hazard?

A. The concept of moral hazard figures prominently in our diagnosis of multi-year ratemaking's flaws. Moral hazard is the term economists use to describe a situation in which a person (or organization) is protected from the consequences of an adverse event.[31] In such instances, moral hazard predicts that a person (or organization) is less likely to take the steps necessary to avoid an adverse event

[31] John M. Marshall, *Moral Hazard*, 66 Am. Econ. Rev. 880 (Dec. 1976).

when protected from its consequences. Flood insurance is typically provided as an example of moral hazard. A person who can obtain flood insurance is more likely to buy a home in a flood plain than a person unable to get flood insurance. Without adverse event consequences, a person (or organization) is predisposed to taking adverse event risks.

Let's apply the moral hazard concept to the advance presentation of distribution investment plans such as MRPs. In standard ratemaking, when no investment plan is presented in advance, a utility tends to make more conservative grid investments, cognizant of the high consequence associated with the potential of an adverse event (a cost disallowance). Compare this to the consequence of proposing cost-ineffective or premature capital spending proposals in an MRP. In such a situation, a Commission might be persuaded to order reductions in the plan's capital spending. But there is no economic penalty associated with a reduction in plan size. A utility might not get to invest as much as it prefers, or to grow earnings by as much as it prefers, but these are only opportunity costs to a utility. Opportunity costs are of little overall consequence to a utility compared to the effects of an economic penalty disallowing recovery of an already-incurred capital cost.

Q. So over-investment in standard ratemaking risks the large consequence of cost disallowances, whereas offering a proposal in an MRP containing cost-ineffective or premature investment entails no consequences?

A. Precisely. The moral hazard that this leads to the results we see in Pepco's first and second MRPs. Given the lack of consequences for "over-proposing," Pepco's management team has nothing to lose—and everything to gain—by proposing more spending in an MRP than what it would spend under a standard ratemaking regime. Further, information asymmetry and constrained procedural schedules reduce the likelihood that cost ineffective, premature, or unsupported capital spending included in an MRP will be identified by Staff, OPC, or other intervenors.

Pepco's MRP exemplifies the effect of MRP-driven moral hazard. As our discussion of Pepco's proposed capital investments will show, the company's MRP is rife with excess capital spending. Further, given the reduced likelihood of cost disallowance risk, Pepco has little incentive to improve its capital spending governance.

C. The reconciliation process reduces utility incentives to reduce capital and O&M spending between rate cases.

Q. Do you find parts of MRP as practiced in Maryland particularly problematic?

A. Yes. The MRP reconciliation mechanism is particularly problematic. Not only is it unique among states practicing multi-year ratemaking, but it works to customers' disadvantage.

In other states in which we have worked that have implemented multi-year ratemaking (California and Georgia), rates established for future years as part of an MRP process are not re-visited.[32] Instead, utilities must manage spending to the capital and O&M levels authorized in their MRPs. Since the utility's revenue requirement is fixed for each MRP year—varying only by sales volume—excess spending thus reduces those utilities' earned rate of return. As a result, just like utilities operating under a standard ratemaking construct, utilities in MRP states without an opportunity to recover excess capital or O&M spending have some incentive to control capital and O&M spending during the MRP period.

Q. How does the spending reconciliation process work in Maryland?

A. In Maryland, the utilities provide an annual informational filing that reports actual spending (capital and O&M) compared to the amounts authorized in the MRP. These annual informational filings serve as a guide for the consolidated reconciliation that occurs during the subsequent rate case and the final reconciliation that occurs after the conclusion of the MRP period. For instance, the reconciliation and prudence review for years 2021 and 2022 are occurring during this proceeding. The reconciliation for 2023 will occur after the conclusion of this

[32] We are also familiar with multi-year ratemaking in Illinois, where the opportunity to increase rates between MRP processes is now available. Unlikely the MRP constructs in California, Georgia, and Maryland—which were developed by utility regulators—the Illinois construct was established legislatively.

case. With utility overspending more likely than underspending, these reconciliations are much more likely to result in rate increases than refunds.

Q. Does the reconciliation process impact utility incentives?

A. Yes, it does. Suppose a utility's O&M spending exceeds levels authorized in an MRP. The penalty—a reduction in a utility's rate of return—is only temporary, due to the opportunity for a utility to recover its overspend through the MRP adjustment rider. If a utility underspends on O&M, the reward—an increase in the utility's rate of return—is also temporary, given the possibility of customer refunds resulting from the reconciliation. The opportunity for a refund thus eliminates any incentive for a utility to reduce O&M spending between rate cases. This incentive—to keep O&M spending levels lower—exists in standard ratemaking and in the multi-year ratemaking constructs implemented by California and Georgia, but not under Maryland's MRP construct. The utility incentive to reduce O&M spending between rate cases benefits customers, as customers recognize the benefits of utilities' O&M spending reductions in future rate cases. Without an incentive to reduce O&M spending between rate cases, O&M spending is likely to be higher over time than it would otherwise be, and customers must cover these higher O&M costs.

Q: How does the reconciliation affect a utility's capital spending?

In the short term, the impacts on capital spending are the same as on O&M spending: overspending results in a short-term penalty, and underspending results

in a short-term reward. But, unlike O&M spending, excess capital spending secures a long-term reward for the utility—the ability to earn a return *on* its capital investment over the duration of the investment's lifespan. If a Maryland utility overspends its MRP capital budget, the long-term gains of earning its return on that investment far outweigh the short-term reduction in profitability.

Q. How has the reconciliation process worked out for Pepco's customers so far?

A. Not well. In 2021, Pepco's electric distribution capital spending was $12.2 million (4.1 percent) over the MRP budget.[33] In 2022, Pepco's electric distribution capital spending was $20.5 million (6.6 percent) over the MRP budget.[34] For these capital overspends, and for some additional O&M overspending, the company seeks to recover an additional $9.1 million in 2024 through the MRP adjustment rider, *on top of its proposed base rate increases*.[35] Such unexpected increases are not consistent with the rate stability goal the Commission hoped to secure with multi-year ratemaking.

[33] Schedule RTL-8, at 5–6 (Year 2021 Annual Information Filing
[34] Schedule RTL-10, at 5–8 (Year 2022 Annual Information Filing).
[35] Supplemental Direct Testimony of Robert T. Leming ("Leming Supplemental Direct") at 4, lines 1-3.

D. Utilities respond to MRP by making cost-ineffective and premature investments.

Q. In what ways are the investments Pepco is proposing in its MRP 2 larger than the investments Pepco would be making under standard ratemaking?

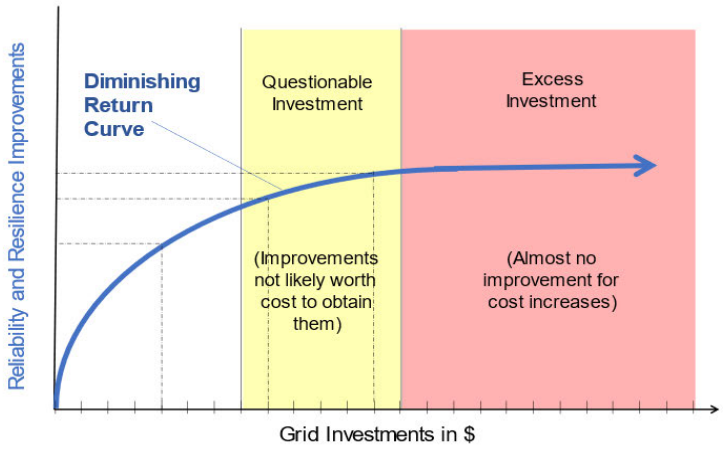
A. Pepco's MRP 2 capital spending is larger than it would be under standard ratemaking in three ways. First, I believe the company is proposing investments that are not cost effective. For example, many of the system performance investments the company proposes are unlikely to deliver reliability improvements of sufficient value to justify their costs. This is called investing beyond the point of diminishing return. Second, Pepco's MRP 2 is larger than it would be under standard ratemaking because it proposes investments in grid readiness (capacity expansion to accommodate DERs, EVs, and building electrification) that are unnecessarily early. Finally, certain Pepco capital spending forecasts exceed historical trends without quantifiable support for such increases. Multiple examples of all three issues are provided later in this testimony.

Q. What is the law of diminishing returns, and how does it apply to utilities' reliability- and resilience-related investments?

A. The law of diminishing returns observes that beyond some optimal level of resource input, the level of incremental improvement from an activity (in this case, capital investments to improve reliability) falls ratably with each additional increment of resource input (in this case, capital investment costs). At some point, the value customers receive from incremental improvements in reliability will be

less than the cost required to secure those improvements—this is the point of diminishing return. While a competitive business would never invest past the point of diminishing return, a utility with capital bias and no capital spending governance will. Figure 3 below applies the diminishing return curve to reliability-related grid investment.[36]

Figure 3: The Law of Diminishing Returns applied to reliability- and resilience-related utility investments.



Q. Are you suggesting that Pepco has reduced capital spending governance since the introduction of multi-year ratemaking in Maryland?

A. I am not convinced that Pepco's capital spending governance was ever as strong as it should have been, but it is clear to us that a utility's incentive to control capital spending falls as cost disallowance risk falls. It is also clear to us that Pepco has not improved its capital spending governance at all since our review of its first

[36] Exhibit PJA-7 (Paul Alvarez, Dennis Stephens *et. al., Alternative Ratemaking in the US: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers?* 35 Electricity J. 107200 (2022)).

MRP in Case No. 9655. We will address examples Pepco's cost-ineffective, premature, and unsupported investments—and Pepco's generally inadequate capital spending governance—throughout the remainder of this testimony. It is also worth noting that while distribution grid reliability and readiness concerns underlie the Commission's initial inquiry into MRPs, Pepco's lack of interest in capital spending governance applies to all capital spending, not just distribution system capital spending. Thus, while the Commission may have intended multi-year ratemaking to increase grid investment, I note that multi-year ratemaking encourages capital spending increases in general and intangible plant as well.

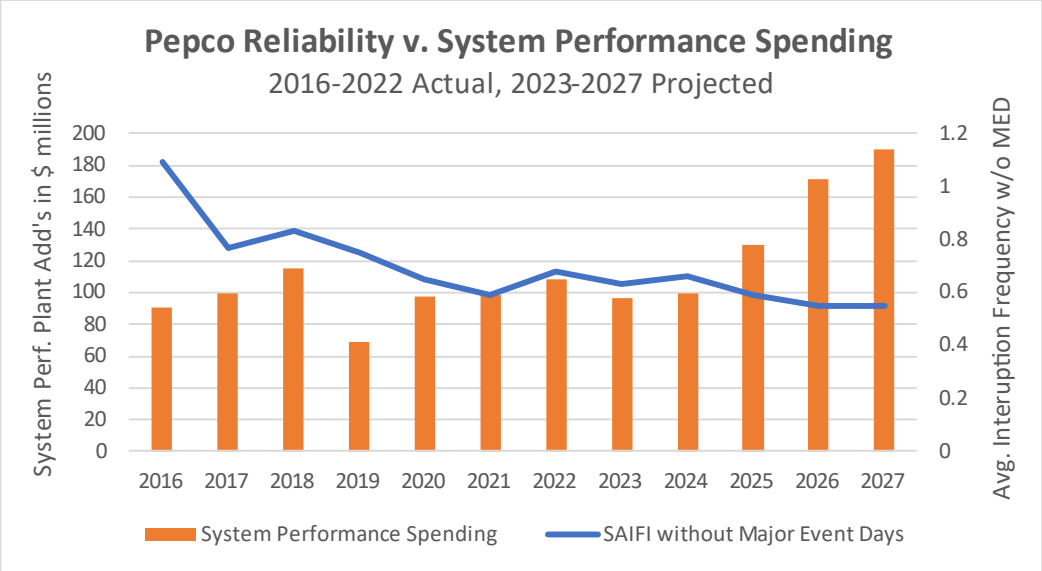
Q. How do you know Pepco's MRP 2 proposes investments beyond the point of diminishing return?

A. Section III of this testimony provides specific benefit-cost analyses Mr. Stephens has completed. These analyses identify system performance projects and programs that do not deliver benefit value that exceeds costs. While his analyses are certainly a clear indication that a system-wide point of diminishing return has been reached with respect to system performance spending, additional indicators support this conclusion.

First, historical and projected data on capital spending and reliability performance shows that Pepco is expecting ever-smaller reliability improvements in exchange for ever-larger system performance capital spending. Figure 4 compares the reliability improvements the company recently projected for 2024–

2027 [37] to the system performance spending forecast in the proposed MRP. The fact that reliability improvements (lower is better) are slowing while capital spending is accelerating is a clear indication that Pepco's reliability investments now exceed the point of diminishing return. An increase in capital spending (the input) with little to no corresponding improvement in reliability (the output) is the very definition of the point of diminishing return.

Figure 4: Pepco Reliability vs. System Performance Spending, 2016–2027.



Q. But Pepco must certainly make advance investments to prepare for growth in DERs, EVs, and building electrification, right?

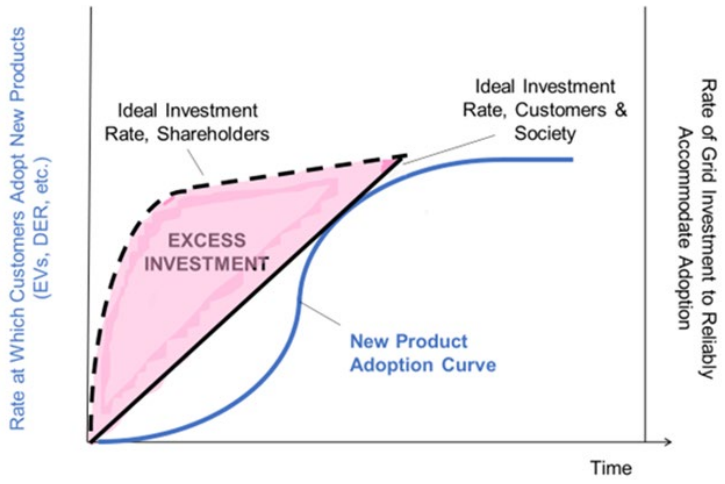
A. Yes, but investments in new capacity for these types of loads is no different than investments in new capacity for any other types of loads. And in what capabilities and new capacity, over what time frames, and on what circuits and substations, are

[37] *Pepco 2024-2027 Reliability Standards*, Figure 14, page 20, ML#239387 (March 1, 2022).

such investments required? Generic utility representations of "need" are alone insufficient to justify these investments. Rather, utilities should provide objective documentation in support of specific capital spending requests on a circuit-by-circuit, substation-by-substation basis. If utility justifications are limited to the former, a utility is almost certain to invest more than necessary, earlier than necessary, in capacity expansion for grid "readiness." Figure 5 illustrates how the standard "S" curve for technology adoption[38]—applied to DERs, EVs, or building electrification—is likely to require an increased rate of utility grid investment. Figure 5 also illustrates that whatever the "right" amount of investment in grid readiness might be, an investor-owned utility with capital bias (assuming no capital spending governance) will always prefer to invest more, and earlier, than necessary to meet DER, EV, and building electrification load growth needs.

[38] The "S Curve" for technology adoption has been employed by product managers in consumer product companies for many decades. Regardless of technology, the curve reflects how new technologies are adopted by society— slowly at first, and then accelerating over time, until leveling off at market saturation (the point at which everyone likely to adopt a new technology already has). The adoption curve is relevant to any consumer technology, from color televisions in the 1960's to smart phones in the early part of this century. It also applies to DER and EV.

Figure 5: Ideal investment rates in grid "readiness", shareholder vs. customer perspectives



Q. Is it realistic to expect a utility to complete a circuit-by-circuit assessment of grid needs as part of distribution investment plan development?

A. It is not only realistic, but such a process for distribution grid planning has been common practice among utilities in the U.S. for many decades, as documented by the NARUC-NASEO Task Force's Jade Cohort Roadmap.[39] We will return to the subject of distribution plan development processes later in this testimony. But before turning to our recommendations, the next three sections of testimony provide multiple examples of Pepco grid investments that are cost-ineffective, premature, or unsupported. These illustrate the shortcomings of multi-year ratemaking and serve as the basis for recommended disallowances of costs

[39] NARUC-NASEO Task Force on Comprehensive Electricity Planning. Jade Cohort Roadmap, page 5. A link to the document is available at https://www.naruc.org/taskforce/resources-for-action/roadmaps/

incurred in 2021 and 2022, and our recommended MRP 2 reductions for 2024–2027.

III. COST-INEFFECTIVE SYSTEM PERFORMANCE SPENDING (STEPHENS)

Q. Please provide a preview of this section of testimony.

A. This section of testimony identifies three system performance spending programs that will not deliver sufficient reliability improvement value to customers relative to costs. These include: (1) prospective replacement of substation equipment that has passed functional and diagnostic tests; (2) rebuilding the Benning 69kV (subtransmission) substation; and (3) rebuilding several 69kV circuits. I recommend capital spending disallowances of $13.5 million in 2021 and $20.1 million in 2022, along with $224.8 million in MRP 2 spending reductions, for these capital spending programs.

Prospective Replacement of Substation Equipment

Q. Which specific capital projects does this section discuss?

A. I identified 40 projects in Pepco's MRP 2 that appear to involve prospective replacement of substation equipment. However, these projects are not a part of a distinct program identified in Pepco's proposed capital plan. Rather, they are scattered throughout the capital projects detailed in the workpaper Pepco provided in discovery. As will be discussed in Section VI of this testimony, the lack of a

specific investment program for prospective substation equipment replacements significantly increased the burden on stakeholders to identify the nature and extent of this spending.

Q. How do you define prospective replacement of substation equipment?

A. I define it as the replacement of substation equipment that has passed functional and diagnostic tests. All utilities, including Pepco, routinely subject major substation equipment (power transformers, circuit breakers, relays, switchgear, and switches) to functional and diagnostic testing. The purpose of these tests is to proactively identify equipment at risk of failure, and to repair or replace equipment that fails such tests. Pepco is replacing substation equipment that has passed functional and diagnostic tests, citing equipment age and "expert opinion" regarding equipment condition.[40] Yet the company has completed no analysis indicating that the dollar value to customers of reliability improvements from prospective replacement exceeds the incremental cost of such replacements.[41]

Q. Is Pepco spending a lot of capital on prospective equipment replacement?

A. Yes. My review of Pepco's actual spend for 2021 and 2022 indicates that Pepco spent $13.5 million prospectively replacing substation equipment in 2021 and $20.1 million prospectively replacing substation equipment in 2022. In MRP 2, Pepco proposes to expand prospective substation equipment replacements by

[40] Exhibit PJA-2 (OPC DR 6-48 (a)).
[41] Exhibit PJA-2 (OPC DR 6-65).

spending $26.3 million on average annually 2024–2027, nearly double the annual amount it spent in 2021.[42]

In recent years, I have noticed an increase in prospective substation equipment replacement by utilities receiving preferential cost recovery for grid "modernization." In every instance, my analyses have indicated the practice is dramatically cost-ineffective. My analysis of Pepco's program delivers the same result. But perhaps just as concerning is the fact that, as in its first MRP, Pepco does not present prospective substation equipment replacement as a significant capital spending program in its MRP 2. Nor has Pepco presented prospective substation equipment replacement as a capital spending request for management's review.[43] If not for our careful review of Pepco's discovery responses—which enabled us to identify prospective replacement through dozens of individual substation system performance projects—we would never have identified prospective equipment replacements as a significant capital spending program amounting to $28 million annually by 2027.[44]

Q. Doesn't it make sense for Pepco to replace older substation equipment?

A. In the abstract, yes. But on a case-by-case basis, no. This is where functional and diagnostic testing of individual pieces of substation equipment comes into play.

[42] Voluntary Data Request 1-3 Attachment.
[43] Schedule ACY-2, Confidential Attachments A through CC.
[44] Indeed, in Pepco's first MRP, we (and all other stakeholders) failed to identify the nature and extent of Pepco's prospective substation equipment replacement spending.

Q. Please explain.

A. One phrase appears frequently in both approved capital authorization requests provided by the company in support of its application, and in company responses provided to us in discovery: "the equipment is reaching the end of its useful life." This explanation often underlies the company's rationale that equipment "needs" to be replaced. We note that "useful life" is not an operating concept used to justify equipment replacement; rather, it is an accounting concept used to determine equipment depreciation rates and depreciation expense.[45]

Q. What does "useful life" mean in a utility equipment context?

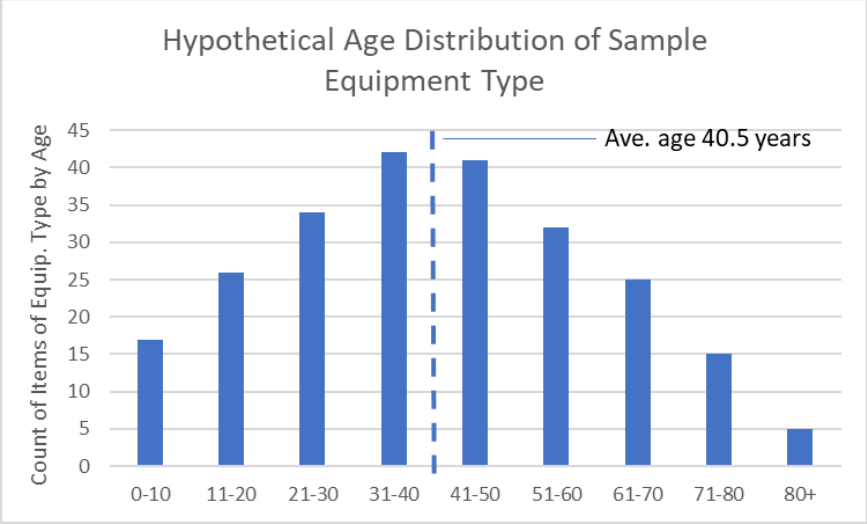
A. The U.S. Financial Accounting Standards Board defines "useful life" as "the period over which an asset is expected to contribute directly or indirectly to (an owner's) future cash flows."[46] It makes sense for the "expectation" for a type of equipment's useful life to be based on the average age of equipment of that type in service at a point in time. For example, a survey of almost any utility's substation power transformers would indicate that some transformers are new and others are still operating safely and reliably at ages in excess of 80 years. Indeed, I am aware of one substation power transformer that was still operating safely and reliably at 93 years of age. The point is that while the average age of a utility's substation

[45] See Financial Accounting Standards Board ("FASB"), ASC 360-10-35-3 ("Depreciation expense in financial statements for an asset shall be determined based on the asset's useful life."), https://asc.fasb.org/1943274/2147482190.
[46] *See* https://asc.fasb.org/MasterGlossary

power transformers—those transformers' "useful lives" in depreciation parlance—might be 40 years, this does not mean that substation power transformers should be replaced at 40 years of age, or even 60 years of age. To do so would potentially deprive ratepayers of decades of valuable service from equipment they have paid for in rates over time.

Figure 6 below provides a hypothetical age distribution for a type of substation equipment with an average age (or "useful life") of 40 years. Clearly, the average age or "useful life" of a piece of equipment should not be used to determine the need to replace it. This is precisely how functional and diagnostic testing arose as common practice for substation equipment. Such testing offers an objective way to improve reliability without unnecessary increases in equipment replacement costs.

Figure 6: Hypothetical age distribution for a type of equipment with an average useful life of 40 years



Q. How would the company respond to your criticism?

A. The company would explain that age is not the only criterion used to prioritize equipment for replacement, and that expert opinion in the form of "asset health indices" are also used to prioritize substation equipment for replacement. However, the fact that a piece of equipment is high on a replacement priority list does not necessarily mean that replacing that item will deliver reliability improvements of sufficient value to justify the incremental cost of prospective replacement. For that, a benefit-cost analysis is needed.

Q. Have you completed a benefit-cost analysis of Pepco's prospective substation asset equipment replacement program?

A. Yes, I have completed benefit-cost analyses of the company's prospective replacement of substation power transformers, circuit breakers, and relays. These analyses compare the average replacement cost for each one of these equipment types to the value of any associated reliability improvements delivered to customers. While Pepco estimates project costs for multi-year ratemaking, it apparently never estimates the benefits of projects "in the normal scope of Pepco's business."[47] While it is unnecessary to estimate benefits for required capital spending—such as new customer connections—benefit estimation (and comparison to cost) is essential for discretionary capital spending. Pepco's

[47] Exhibit PJA-2 (OPC DR 20-5 (a) and (b)).

decision to prospectively replace equipment that has passed functional and diagnostic tests is an example of a discretionary capital spending decision.

Q. How does one estimate the benefits of a discretionary capital spending project, such as a program to prospectively replace equipment?

A. Estimating the benefits of a discretionary capital spending project involves answering a few simple questions:

- What is the adverse event (in this case a service interruption) the investment intends to avoid?
- What reduction in the likelihood of this adverse event will the investment deliver?
- What is the consequence (in dollars) to customers of the adverse event if it were to occur?

With answers to these questions in hand, the benefits of a discretionary capital spending project can be estimated and compared to costs. To estimate benefits, the dollar consequence to customers of the adverse event is simply multiplied by the reduction in the likelihood of the adverse event. For example, a 1 percent reduction in the annual likelihood of an adverse event with a $1 million consequence cost to customers amounts to a $10,000 annual benefit ($1 million consequence multiplied by a 1percent annual reduction in likelihood).

I believe utilities should use this approach to quantify the dollar benefits of risk reductions for all discretionary capital spending. The California Public

Utilities Commission—the state utility regulator most experienced with multi-year ratemaking—recently required that utilities use this approach to quantify the benefits of capital spending proposed to improve reliability or safety.[48]

Q. Did you complete this analysis for the prospective replacement of substation power transformers, circuit breakers, and relays?

A. Yes. To estimate the reduction in the annual likelihood of a service interruption, I used historical Pepco data on the annual rates of in-service failure for each equipment type, along with historical Pepco data on the counts of customers and durations of service interruptions associated with the in-service failures.[49] Because of periodic testing regimes, equipment failures in service are extremely rare. And the back-up capacity utilities make available to cover in-service substation equipment failures makes it even more rare for such failures to result in service interruptions. Thus, the annual likelihood of an in-service failure of a piece of substation equipment resulting in a customer service interruption is extremely small to begin with.

To calculate the consequences of service interruptions to customers in dollar terms, I use data from the U.S. Department of Energy's online Interruption

[48] *See* Decision 22-12-027 (*Phase II Decision Adopting Modifications to the Risk-Based Decision-making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots*) at 30–35, Rulemaking 20-07-013 (Cal. Pub. Util. Comm'n, Dec. 21, 2022). Appendix A to the decision documents the formula.

[49] Inputs include equipment counts in service by type; average rate of failures in-service annually over the last five years by type; and average customers interrupted and customer minutes interrupted per in-service failure by type.

Cost Estimator tool. The Interruption Cost Estimator was designed to impute a cost to customers of service interruptions by type (residential vs. commercial) and duration (momentary, 2 hours, 4 hours, etc.). By multiplying these costs by the counts of customers (by type) and interruptions of various durations avoided by prospective equipment replacement, the dollar value of the practice to customers can be calculated.[50] These dollar values can then be compared to costs. The results of my analyses for various equipment types are presented in Table 3 below. This type of analysis, which estimates the value of risk reductions in dollars, could (and should) be applied to almost any investment not immediately required for safe and reliable service (i.e., those investments that are discretionary as to timing, location, or extent).

Table 3: Benefits and Costs of Prospective Substation Equipment Replacement

Substation Equipment	Customer value of reliability improvements over 30 years in today's $	Average Cost to Replace[51]
Power Transformers	$134,292	$4,000,000
Circuit Breakers	$37,355	150,000
Relays	$959	200,000

[50] I used the following inputs in my analysis: (1) a breakdown of customers into commercial and non-commercial types as indicated by Pepco on its Energy Information Administration Form 861 for Maryland; (2) the cost of average service interruptions of appropriate durations by customer type from the ICE tool cost study; (3) the annual inflation rate applied to the cost of service interruptions to customers by type since the latest ICE tool cost study was completed (2013, I use 2.5 percent); (4) the number of years' over which the replacement of an asset with a new one is expected to reduce in-service failure rates (I use 30 years, after which the replaced asset is no longer "new"); and (5) the discount rate to translate the benefits over 30 years into present day values (I use the Company's requested pre-tax weighted average cost of capital in this proceeding, or 9.78 percent).

[51] Exhibit PJA-2 (OPC DR 1-6 Attachment).

Q. What is your recommendation regarding prospective substation equipment replacement?

A. If an investment is neither required for safe and reliable service (and replacement of equipment that has passed its tests certainly qualifies as not required), nor delivers benefits to customers in excess of costs, it cannot be prudent. Thus, I recommend that recovery of all prospective substation equipment replacement spending in 2021 and 2022 be disallowed, and that all proposed prospective replacement spending in Pepco's MRP 2 be eliminated. In place of prospective replacement, I recommend Pepco continue its historical practice of repairing or replacing substation equipment that fails functional or diagnostic tests.

Benning 69kV Substation Rebuild

Q. Please summarize Pepco's proposal to rebuild the Benning 69kV substation.

A. For Maryland customers, Pepco forecasts $61.5 million in capital spending for this project in MRP 2 alone,[52] with additional costs anticipated after 2027. As a subtransmission substation, the Benning 69kV Substation distributes power to four distribution substations in the District of Columbia. In the summer of 2019, one of these distribution substations (the Florida Street substation) went completely offline, resulting in a service interruption of about 50 minutes to 15,926 customers, and a service interruption of about 12 hours to an additional 5,537

[52] Voluntary Data Request 1-3 Attachment, lines 58, 59, 110, and 190.

customers.[53] [BEGIN CONFIDENTIAL CEII] [redacted]

[redacted]. [END CONFIDENTIAL CEII]

[BEGIN CONFIDENTIAL CEII] [redacted]

[redacted] [END CONFIDENTIAL CEII] In short, the Benning Substation is being completely rebuilt in response to the summer 2019 Florida Street substation outage.

[53] Exhibit PJA-2 (OPC DR 37-5).
[54] Exhibit PJA-8 (OPC DR 7-1 (c)(i) Confidential Attachment, at 2).
[55] Exhibit PJA-8 (OPC DR 20-3(a) Confidential Attachment).

Q. What is your impression of the Benning 69kV substation rebuild project?

A. The project will not come close to delivering reliability improvements commensurate with its costs. [BEGIN CONFIDENTIAL CEII] [redacted].[57] [END CONFIDENTIAL CEII]

Further, gas-insulated switches are filled with Sulfur Hexaflouride (SF_6)—the most potent greenhouse gas known with 23,500 times the heat-trapping power of Carbon Dioxide (CO_2).[58] When the gas leaks—and some of it will—it is lost to the atmosphere where it will remain for 3,200 years. (SF_6 is an extremely stable compound.)[59] Indeed, the company reports it spilled SF_6 equivalent to 11,034

[56] Exhibit PJA-8 (OPC DR 37-3 (a)).
[57] Exhibit PJA-8 (OPC DR 41-1 (b)).
[58] U.S. Environmental Protections Agency, *Sulfur Hexafluoride (SF6) Basics*, https://www.epa.gov/eps-partnership/sulfur-hexafluoride-sf6-basics.
[59] *Id.*

metric tons of CO_2 emissions from 2018 to 2022.[60] If anything, given SF_6 potency and the inability to recover spilled SF_6, the company should be working to extend the lives of air- and oil-insulated equipment, rather than accelerating the replacement of such equipment with SF_6-filled equipment.

[BEGIN CONFIDENTIAL CEII] [redacted] [END CONFIDENTIAL CEII]

Standards almost never demand retroactive application to equipment that satisfied the standards applicable at the time of installation (as long as the installed equipment continues to pass functional tests), and NERC Standard PRC-002-2 does not specify retroactive application. Furthermore, even if replacements were warranted, such replacements could be completed without rebuilding the entire substation.

Finally, while reliability improvements to the District of Columbia appear almost non-existent relative to costs, reliability improvements to Maryland will be

[60] Exhibit PJA-2 (OPC DR 1-7, Attachment).

even smaller, because *all the substations that will supposedly benefit from the project's alleged reliability improvements serve the District of Columbia.*

Q. If the purported benefits from the Benning 69kV substation rebuild accrue to Pepco's District of Columbia customers, why are project costs being charged to Maryland customers in the company's MRP 2?

A. The Benning 69kV substation is part of Pepco's subtransmission network. Generally, the subtransmission network consists of circuits between distribution substations, as well as the subtransmission voltage (34kV and 69kV) equipment in both distribution and transmission substations. The cost of subtransmission project work is split between the company's Maryland and District of Columbia customers according to a peak-load contribution formula established in 1969.[61] Currently, the split of the company's subtransmission costs per the formula is 60 percent to Maryland customers and 40 percent to District of Columbia customers.[62] It may be time for the Commission to revisit this formula.

Q. Did Pepco estimate the reliability improvements expected from the project?

No. All references to reliability improvement from the project are qualitative.[63]

Q. Does Pepco provide other justifications for rebuilding the substation?

A. Yes, but they are woefully insufficient justifications for such a large and expensive project. Pepco provided photos of fixable and non-urgent issues in discovery as

[61] Exhibit PJA-2 (Staff DR 7-47).
[62] Exhibit PJA-2 (OPC DR 32-13, Attachment).
[63] Exhibit PJA-8 (OPC DR 7-1 (c)(i), Confidential Attachment)).

justification for the rebuild.[64] [BEGIN CONFIDENTIAL CEII] [redacted]. [END CONFIDENTIAL CEII]

Pepco also claims the substation rebuild is justified by replacement of aging infrastructure. Of the ages of 26 major substation equipment items provided in discovery (including capacitor banks, circuit breakers, and transformers) that are in service today, only one item (transformer #8) was of a significant age, and even then only moderately so (50 years); 21 items were less than 20 years old, and four items were less than 10 years old.[65] As indicated earlier, major substation equipment can easily pass functional and diagnostic tests for fitness to remain in service at 70 years, 80 years, or even older ages. Furthermore, Pepco reports that equipment in the Benning 69kV Substation had a net book value of $15.1 million

[64] *Id.*, photos on p. 13–15.
[65] Exhibit PJA-2 (OPC DR 7-1 (b), Attachment).

at the end of 2022.[66] If the substation is rebuilt, customers will continue to pay depreciation expense on this equipment in rates for the next two decades.[67]

[BEGIN CONFIDENTIAL CEII] [redacted] [END CONFIDENTIAL CEII] However, a letter from Pepco's CEO to the Mayor of the District of Columbia, and copied to the D.C. PSC, does not commit to rebuilding the Benning 69kV substation, or to any kind of capital investment whatsoever. Rather, the letter commits only to "review the effectiveness of our processes and procedures . . . ."[69]

In short, Pepco has failed to justify the high cost of Benning 69kV substation. In my opinion, the project should never have been approved by Pepco management and is further evidence of a lack of capital spending governance.

Q. What are your recommendations regarding the company's proposal to rebuild the Benning 69kV substation?

A. I recommend the cost to rebuild the Benning 69kV substation be removed completely from the company's MRP 2 capital spending proposal.

[66] Exhibit PJA-2 (OPC DR 37-4 (b), Attachment).
[67] Based on a useful life of 40 years and average age of 20 years for equipment with book value.
[68] Exhibit PJA-8 (OPC DR 7-1 (c)(i), Confidential Attachment, at 6).
[69] Exhibit PJA-2 (OPC DR 38-1, Attachment A).

69kV Circuit Rebuilds

Q. Please summarize Pepco's proposal to rebuild 69kV circuits.

A. In its second MRP, Pepco proposes to spend $56.8 million rebuilding all or part of five 69kV circuits,[70] with additional costs to complete these projects expected beyond MRP 2. "Rebuilding" involves the replacement of wood poles with either steel poles or "H-shaped" double wood pole structures.[71] The work proposed in MRP 2 is a subset of 13 such projects proposed in MRP 1 that the Commission largely excluded from recovery through MRP 1. In Case No. 9655, the Commission cited concerns about the cost-effectiveness of the 69kV circuit rebuild program given its size, cost, and limited reliability improvement potential,[72] as our filed testimony in that case regarding the program noted.

Q. How did the company select a subset of 69kV circuits for rebuild in MRP 2?

A. The company appears to have selected the 69kV circuits that have experienced the most frequent equipment outages since 2016. For example, the company cites 74 equipment total outages since 2016 on three of the 69kV circuits it proposes to rebuild in MRP 2.[73]

Q. Isn't it appropriate to prioritize equipment replacements based on historical equipment outages?

[70] Voluntary Data Request 1-3 Attachment, lines 14-18 and 20-24.
[71] Direct Testimony of Amber C. Young ("Young Direct") at 45, lines 12-22.
[72] Order 89868 at 84–86 ¶¶ 204-206.
[73] *Id.* at 48, line 22 through p. 49, line 3.

A. In some cases, yes. But as discussed above, a prioritized list is no substitute for a benefit-cost analysis. Further, 69kV circuits are designed such that back-up capacity is almost always available to provide service in the event of a 69kV circuit outage. In discovery, the company reported that only one of the 74 69kV circuit outages since 2016 on the three 69kV circuits resulted in a sustained service interruption (greater than five minutes) to customers.[74] The lone service interruption amounted to 7.8 minutes for 1,009 customers.[75] There is simply no way that the avoidance of a single service interruption of 7.8 minutes over 7 years justifies a capital spending program that will cost Maryland customers a minimum of $56.8 million.

Q. Did the company consider less costly alternatives to the 69kV circuit rebuilds?

A. No. The only alternative the company claims to have considered was to underground the 69kV circuits.[76] The company correctly identifies that the undergrounding option would have incurred costs several times higher than the cost of replacing the existing wood poles.[77]

Q. What alternatives would you like to have seen the company consider?

A. The company should have quantified the benefits (in terms of the dollar value of the reliability improvement to customers) and the costs of multiple alternatives

[74] Exhibit PJA-2 (OPC DR 6-42, Attachment).
[75] *Id.*
[76] Young Direct at 49, lines 5-7.
[77] *Id.* lines 12-14.

available to rebuilding 69kV circuits. One such option would be to rebuild one 69kV circuit per grid planning cycle over the next several planning cycles. Another option would be to replace wood poles with steel towers one at a time, as identified by failures in the formal inspections and strength-tests all utilities complete periodically on wooden poles. The company does not appear to have quantified the reliability improvement benefits and costs of either of these options,[78] nor compared them to the benefits and costs of the proposed option. Further, I note that one of the 69kV rebuild projects the company included in MRP 2 has yet to be reviewed or approved by company management.[79] Finally, I note the company has spent $3.1 million in recent years hardening the circuits it proposes to rebuild in MRP 2.[80] If the Commission approves the 69kV circuit rebuild projects as requested, this spending would effectively be wasted.

Q. Does the company provide any other justifications for rebuilding 69kV circuits?

A. Yes. The company indicates that the 69kV circuits proposed for rebuilding serve some Energy Justice Dashboard communities.[81] However, I note that almost every 69kV circuit serves both Energy Justice Dashboard and economically-advantaged communities, and that this is true of the 69kV circuits proposed for rebuilding as

[78] Confidential Schedule ACY-2, Attachments J (Projects 70243/70100) and L (Projects 70241 and 70102).
[79] Exhibit PJA-2 (OPC DR 6-41).
[80] Exhibit PJA-2 (OPC DR 6-42 (b)).
[81] Direct Testimony of Ms. Amber C. Young at 15, lines 11-16.

well.[82] As such, I consider the fact that proposed 69kV circuits happen to serve some Energy Justice Dashboard communities to be a red herring.

Q. What are your recommendations regarding the company's request to rebuild 69kV circuits?

A. I recommend the Commission reduce the capital spending available for cost recovery under MRP 2 by the full amounts proposed for 69kV circuit rebuilds. Until the company can quantify the reliability improvement benefits and costs of all available alternatives and can show that the alternative proposed for MRP cost recovery is the most cost-effective, I recommend the Commission continue to reject 69kV circuit rebuild proposals.

IV. PREMATURE CAPACITY EXPANSION SPENDING (STEPHENS)

Q. Please provide a preview of this section of testimony.

A. In this section, I will discuss two examples of premature spending to expand distribution grid capacity in Pepco's MRP 2. These include (1) a proposal to begin construction of a new National Harbor substation; and (2) a program to expand the capacity of multiple substations serving the District of Columbia (the "Downtown Resupply" program). I recommend that the costs of the National Harbor substation and Downtown Resupply program be removed entirely from the MRP.

National Harbor Substation and Livingston Road Storage Project[83]

[82] Exhibit PJA-2 (OPC DR 32-19).
[83] *See* Schedule ACY-1, Projects 72727, 72730, and 72731 (National Harbor Substation, p. 106-108) and 64042 (Livingston Road Storage Project, p. 102).

Q. Please summarize Pepco's plan to begin construction of the National Harbor substation.

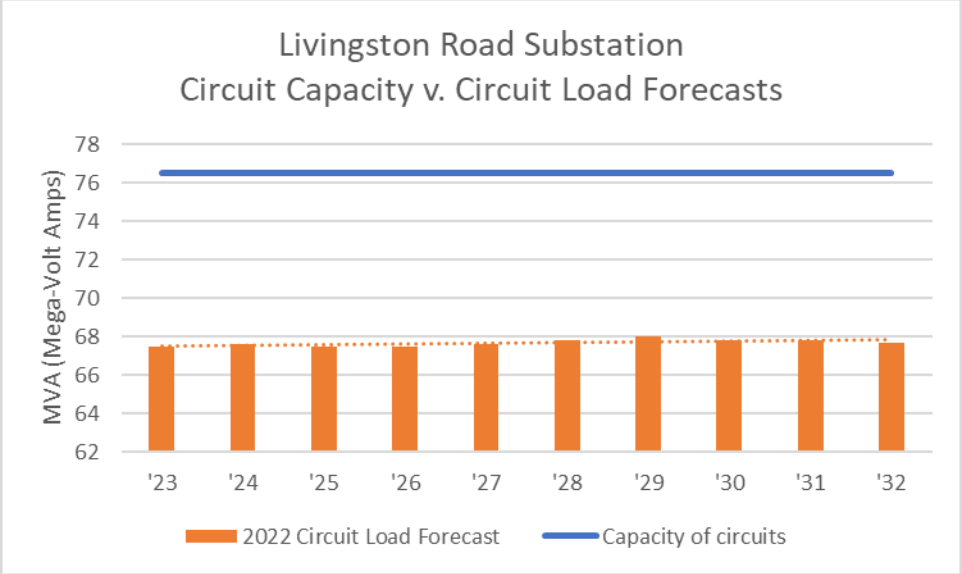
A. Pepco's MRP 2 includes $49.3 million to begin construction of a new substation, called National Harbor,[84] to replace the Livingston Road substation that currently serves the area. The company first proposed the National Harbor substation in MRP 1, but the Commission removed it from MRP cost recovery, citing a lack of forecasted load growth.[85]

Q. What are your concerns regarding the replacement of the Livingston Road substation with a new National Harbor substation?

A. Pepco describes the new National Harbor substation as a capacity expansion project. However, as Figure 7 below shows, Pepco's load forecast for the circuits served by the Livingston Road substation indicates almost zero load growth is expected, and that the circuits' existing capacity (76.5 MVA) is more than adequate for the foreseeable future.[86]

[84] Voluntary Data Request 1-3 Attachment, lines 435-437, Projects 72727, 72730, and 72731.
[85] Order 89868 at 94 ¶ 227.
[86] Exhibit PJA-2 (OPC DR 14-3 (a) and (b)).

Figure 7: Livingston Road substation capacity vs. 2022 load forecast



Q. What is your recommendation regarding the company's proposal to begin spending on the new National Harbor substation?

A. I recommend the Commission remove the entire $49.3 million National Harbor substation capital spending forecast from Pepco's MRP 2. Unless and until load forecasts—backed by construction commitments from qualified developers regarding specific new facilities, loads, and dates, or forecasts showing DER, EV, and building electrification driven load growth—indicate the capacity of the equipment will be exceeded within three years (to allow for substation design and equipment procurement), the Commission should continue rejecting Pepco's requests to replace the Livingston Road substation.

Q. Recently, Pepco notified the Commission of its determination that the energy storage project proposed for the Livingston Road substation is no longer in the public interest, and asked permission to submit an alternative project in

its place.[87] Does Pepco's notification/request impact your National Harbor substation recommendation?

A. No, it does not. In fact, Pepco's letter to the Commission only strengthens support for my recommendation, as it admits the company's Livingston Road substation load forecasts—which prompted the National Harbor substation project—were optimistic to begin with. The letter states that forecasted load growth failed to materialize owing to (1) "slow economic development" and (2) a microgrid combined with a large generator that had been installed by a significant customer in 2018.

Q. Does the company's letter to the Commission regarding the Livingston Road Substation energy storage project cause you to recommend disallowance of project costs incurred to date?

A. Yes. In light of Pepco's Sept. 11, 2023 letter, the $3.1 million in spending on the Livingston Road substation energy storage project to date should be disallowed from recovery from customers.[88] The company first proposed an energy storage project at the Livingston Road substation in Case No. 9619. In that application, Pepco cited the project's ability to defer replacement of the Livingston Road substation (ostensibly needed due to load growth) as a benefit in the site's selection for energy storage.[89] However, it appears that the company knew when it

[87] *Pepco Request to Amend Order No. 89664* ("Sept. 11 Letter"), ML# 304951 (Case No. 9619, Sept. 11, 2023).
[88] Schedule ACY-1 at 102.
[89] *Baltimore Gas Electric/Pepco Holdings Application*, at 60, ML# 229744 (Case No. 9619, April 15, 2020).

submitted its application for adding energy storage at the Livingston Road substation that no imminent need to replace the Livingston Road substation existed, and that no project deferral benefit was therefore available. Given the company's interconnection processes, the company knew that a major customer served by the substation had already installed a significant generating unit as part of the customer's microgrid in 2018. Further, the substation's load had been flat since at least 2013,[90] and was expected to continue to be flat through 2032 as exhibited by the load forecast completed in 2022 (depicted in Figure 7 above).

To summarize, the prudent decision would have been for the company to have abandoned this particular energy storage project prior to commencing spending. Pepco's failure to do so makes recovery of such costs inappropriate.

Q. Are there other reasons the Commission should disallow spending to date on the Livingston Road energy storage project?

A. Yes. It appears Pepco failed to adequately manage the performance of the contractor selected for the project. Pepco failed to monitor the ability of the contractor to do business in Maryland, and appears to have inadequately monitored the contractor's design, procurement, and permitting progress early in the project's lifecycle.[91] The company also asked its contractor to accommodate

[90] Exhibit PJA-2 (OPC DR 14-3).
[91] Sept. 11 Letter at 2–3.

project scope changes, indicating that Pepco may have failed to fully scope out the project prior to issuing a request for proposals.[92]

Pepco also appears to have downplayed associated project cost impacts of the delays. In a July 2022 request to extend the project operational deadline, Pepco stated that permitting and equipment procurement delays would not impact the project's cost nor the project's benefit-cost analysis.[93] Yet, Pepco's recent request to abandon the project associates a 200 percent project cost overrun with project completion.[94]

The deficiencies in the company's initial proposal and apparent lack of contractor performance monitoring is further evidence of the lack of capital spending governance identified throughout this testimony.

Q. What is your recommendation regarding the Livingston Road substation energy storage project costs?

A. Due to a lack of project benefit (substation replacement deferral) of which the company was aware at the time of its energy storage project application, and due to subsequent deficiencies in contractor progress monitoring and project management, I believe the $3.1 million in project costs incurred through 2022 are

[92] *Pepco Request for a Revised Project Operational Date for the National Harbor/Livingston Road Battery Energy Storage System Project located at Pepco's Livingston Road Substation in Prince George's County* at 2, ML# 301319 (Case No. 9619, Feb. 14, 2023).
[93] *Pepco Request for Approval of a Revised Project Operational Date for the National Harbor Storage Pilot Project* at 2, ML# 241693 (Case No. 9619, July 29, 2022).
[94] Sept. 11 Letter at 4.

imprudent. As a result, I recommend the Commission disallow recovery of those costs.

The Downtown Resupply Program

Q. Please describe the company's Downtown Resupply program.

A. Pepco's Downtown Resupply program is a program to increase sub-transmission supply capacity and provide reliability improvements to replace aging infrastructure in the District of Columbia.[95] The project entails a number of significant substation rebuilds expansions, and retirements. The project is currently estimated to cost $824 million.[96]

The company does not present the $824 million Downtown Resupply program, nor the $242 million share of costs that will likely be borne by Maryland customers,[97] anywhere in its MRP 2. Instead, the program is briefly mentioned in a few project justifications found in the schedules supporting witness Young's testimony.[98] Further investigation identified $86.6 million in Downtown Resupply project costs included in Pepco's MRP 2.[99] At OPC's request, the company held a discovery conference on November 3, 2023 to enable OPC and Staff to better understand the Downtown Resupply program.

[95] *See* Exhibit PJA-6 (*Pepco's Downtown Resupply Plan*, Docket No. PEPACR2021-0114 (D.C. P.S.C., Nov. 22, 2021)).
[96] Exhibit PJA-5 (*Pepco's Capital Grid Annual Project Status Report* ("Pepco Annual Status Report") at 11–12, Docket No. FC1144-263 (D.C. PSC, April 17, 2023)).
[97] Exhibit PJA-2 (OPC DR 23-1); Pepco Annual Status Report at 11–12.
[98] *See* Schedule (ACY)-1 at 57; Schedule (ACY)-2, Attachment S at 5, 14; Schedule (ACY)-2, Attachment U at 2, 6, 9, 11.
[99] Exhibit PJA-2 (OPC DR 23-1); Voluntary Data Request 1-3 Attachment (for MRP 2 Project costs).

In the discovery conference OPC learned that the entire $824 million Downtown Resupply program was not prompted by any immediate need to increase capacity in the District of Columbia, nor to address any immediate threats to service reliability in the District. In its proposal to the D.C. PSC, Pepco identified both capacity increases and reliability improvements as benefits, but provided no load forecasts justifying the timing of capacity needs, nor any estimate of anticipated reliability improvements.[100] Load forecasts obtained in discovery indicate the substations in question are much more lightly loaded relative to their capacities than the Livingston Road substation presented in Figure 7, with similar low to zero load growth rates.[101] [BEGIN CONFIDENTIAL]

[redacted]

[100] *See Pepco's Downtown Resupply Plan*, Docket No. PEPACR2021-0114 (D.C. P.S.C., Nov. 22, 2021).
[101] Exhibit PJA-2 (OPC DR 30-1, Attachments A and B).
[102] Exhibit PJA-8 (OPC DR 19-20, Confidential Attachment, at 6.)

[103] [END CONFIDENTIAL]

Q. The Downtown Resupply program appears to relate to District of Columbia projects only. Why do you estimate that $242 million in program costs will be recovered from Pepco's Maryland customers?

A. The largest dollar projects for the Downtown Resupply program are distribution-level projects located in the District of Columbia, with costs recovered only from the company's customers in the District. However, a significant number of subtransmission level projects are also part of the program. While D.C. customers pay 100 percent of the distribution level costs incurred within the District, the company's subtransmission network costs are currently split 60 percent to its Maryland customers and 40 percent to its District of Columbia customers.

Q. What are your impressions of the Downtown Resupply program?

A. [BEGIN CONFIDENTIAL]

[103] Exhibit PJA-8 (Confidential Pepco Discovery Conference Presentation, slide 4 (Nov. 3, 2023)).

[redacted]. [END CONFIDENTIAL] While the Downtown Resupply program does have some ancillary value by increasing capacity, the anticipated load growth may take decades to develop; thus, such spending would be extremely premature. Regarding reliability improvement value, the company admits the reliability improvements associated with the project are essentially zero and not quantifiable.[104]

Q. Are there alternatives to retiring the substation that do not involve an $824 million chain of projects?

A. Of course there are. But Pepco only gave "brief consideration" to a single alternative, which was rebuilding the substation at its current location or nearby.[105] This alternative "was quickly eliminated because it did not provide any advantage over the existing plan."[106] Pepco did not estimate the benefits and costs of this alternative, nor did Pepco compare this alternative to the benefits and costs of its $824 million proposal, nor were any other alternatives identified or evaluated.[107] That an $824 million investment program could proceed without a rigorous evaluation of available alternatives is yet another example of a serious lack of capital spending governance at Pepco.

[104] Exhibit PJA-2 (OPC DR 30-4 (a) and (b)).
[105] Exhibit PJA-2 (OPC DR 32-21(d)).
[106] Exhibit PJA-2 (OPC DR 32-21(d)).
[107] Exhibit PJA-2 (OPC DR 32-21 (d)).

Q. What are your recommendations regarding the company's Downtown Resupply program capital spending?

A. I recommend that $7.5 million in Downtown Resupply program costs incurred in 2021 and 2022 be disallowed from recovery from Maryland customers, and that $86.6 million in capital spending forecast for the program be eliminated from MRP 2. I also recommend that, before approving any future recovery of Downtown Resupply program costs from the company's Maryland customers, the Commission require the company to identify, and rigorously evaluate the benefits and costs of, all available options to the "problem" of a substation located on leased property, including the option of continuing to lease the property. This testimony will provide additional recommendations regarding transparency in investment plan development later.

V. UNSUPPORTED INCREASES IN CAPITAL SPENDING FORECASTS (STEPHENS)

Q. Please preview this section of testimony.

A. This section of testimony reviews four MRP 2 capital spending forecasts which are significantly greater than what Pepco's historical spending trends indicate are necessary: (1) planned underground cable replacements in 2025–2027 (Project 70898); (2) priority feeder improvements in 2027 (Project 72995); (3) new customer connections in 2024–2027 (Project 75097); and (4) emergency underground cable replacement in 2024–2027 (Project 71613). In each instance, I asked the company to provide support for specific spending forecast increases. In

each instance, the support the company provided failed to justify increases over historical spending trends. I recommend the Commission reduce MRP 2 spending requests for each of these forecasts in a manner consistent with historical spending levels.

Planned underground cable replacement in 2025-2027 (Project 70898)

Q. What is planned underground cable replacement?

A. Like most utilities, Pepco replaces sections of underground cable that have a history of faults. Planning to replace the section begins when a section of underground cable is identified by fault history, and replacement is carried out in a reasonably prompt manner (for example, within a year or so).

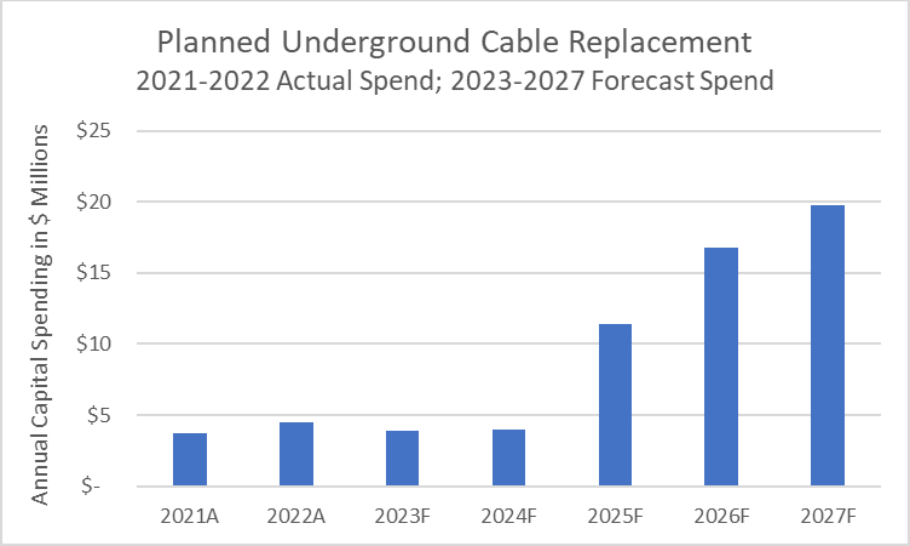
Q. Is Pepco forecasting a big increase in planned underground cable replacement in its MRP 2?

A. Yes. Figure 8 below indicates that the company's capital spending forecast for planned underground cable replacement will be five times higher by 2027 than underground cable replacement spending in 2021 and 2022. When asked to support this increase in discovery, Pepco stated "individual URD cable project locations are identified closer to the year of execution" and "corrective maintenance actions often identify long term investment needs for the system."[108] Pepco provided no quantified analysis indicating why the rate at which underground cable is being replaced needs to increase so dramatically, and

[108] Exhibit PJA-2 (OPC DR 6-66(a)).

completed no benefit-cost analysis to show its proposed spending increases are cost effective. Absent such analyses, Pepco's requested 500 percent increase in underground cable replacement capital spending is unsupported.

Figure 8: Planned underground cable replacement spending 2021-2027



Q. What is your recommendation regarding the company's planned underground cable replacement program?

A. I recommend the company's MRP 2 capital spending forecast be reduced to the average (actual or forecast) spending for 2021–2024, which is $4.05 million annually. I encourage the Commission to continue to reject increases in Pepco's planned underground cable replacement spending until the company provides analyses identifying the optimum annual mileage replacement rate as supported by quantified analyses.

Priority Feeder Improvements in 2027 (Project 72995)

Q. What is Priority Feeder Improvement?

A. Priority Feeder Improvement programs are also common among electric distribution utilities. Pursuant to COMAR 20.50.12.03, Maryland utilities identify the feeders (circuits) with reliability performance that is 250 percent worse than the average. Utilities then assess the outage causes on those feeders and take whatever actions may be appropriate so that the feeder does not reappear on the "poorest performer" list for at least three consecutive 12-month reporting periods.[109]

Q. Is Pepco forecasting a large increase in Priority Feeder Improvement spending?

A. Not until 2027, but the increase that year is significant, amounting to more than triple the average spending (actual or forecast) 2021–2026, which is $3.8 million.

Q. How does the company defend the increase?

A. The company claims that aging infrastructure is making it harder to complete priority feeder improvements at current funding levels, but the company provides no support for tripling the budget in 2027.[110] I therefore recommend the 2027 Priority Feeder Improvement forecast be reduced by $8.4 million in 2027, thus bringing it into alignment with Pepco's actual and forecasted spending for 2021–2026.

[109] COMAR 20.50.12.03A(4).
[110] Exhibit PJA-2 (OPC DR 6-67).

New customer connections in 2024-2027 (Project 75097)

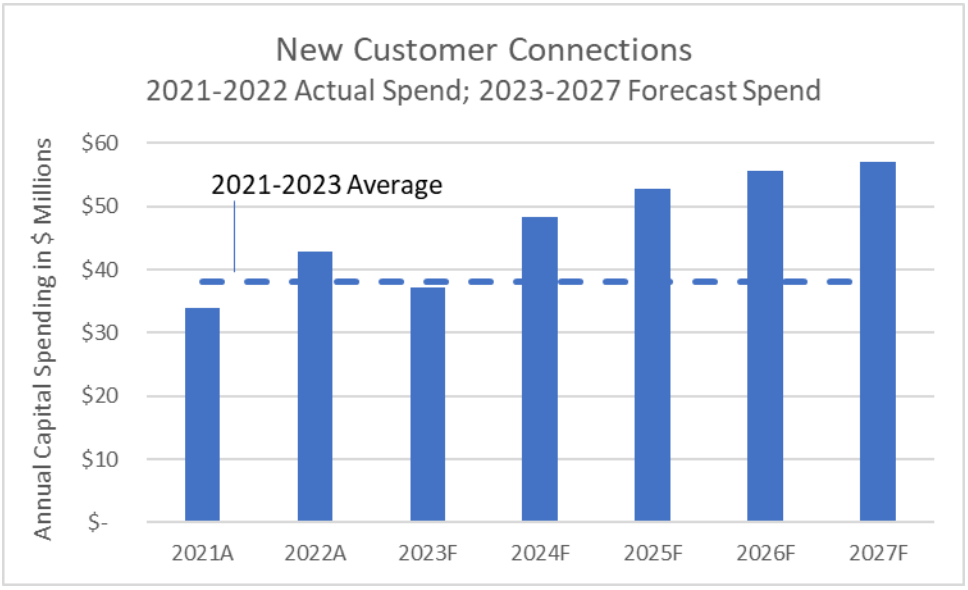
Q. What are new customer connections?

A. As part of the regulatory compact, a for-profit monopoly must provide service to all customers who request service in the utility's defined service area. Electric conductors—typically underground cable—must be installed between the nearest circuit and the new customer's electrical service entrance, where a meter is also installed. Installation of transformers, poles, or fuses may also be required. All these costs are covered by the new customer connection budgets, including one for commercial customers and one for residential customers. The greater the new customer counts, the greater the spending on new customer connections.

Q. Does the company forecast big increases in new customer connection spending?

A. Yes. As Figure 9 illustrates, Pepco's forecasted new customer connection spending for 2024–2027 is 40 percent higher than its actual/forecasted new customer connection spending for 2021–2023 ($38.0 million on average annually).

Figure 9: New customer connection spending 2021–2027, actual and forecast.



Q. Does the forecasted 40 percent increase in new customer connection capital concern you?

A. Yes. I would expect Pepco to sufficiently justify such a substantial increase in spending. For example, Pepco could provide quantified justifications in the form of new customer count forecasts, or schedules of expected new residential or commercial real estate projects. Yet, when asked in discovery to support its 40 percent increase, Pepco provides no such information. Instead, the company points to inflationary pressures. But it is extremely unlikely that inflation alone would justify a 40 percent increase over a three-year period.[111]

Furthermore, recent trends suggest that new customer connections could fall in the future. Higher interest rates underlying a sluggish housing market may

[111] Exhibit PJA-2 (OPC DR 6-68 and 6-69).

reduce the need for new residential connections.[112] And the continued prevalence of work-from-home appears to have reduced new commercial connections related to office space.[113]

Q. What is your recommendation for the company's proposed new customer connection capital spending forecasts?

A. I recommend the new customer connection capital spending forecasts proposed in Pepco's MRP 2 be reduced by $61.7 million, to the 2021–2023 average annual amount—$38 million.

Emergency underground cable replacement in 2024-2027 (71613)

Q. Please summarize Pepco's emergency underground cable replacement program.

A. Pepco distinguishes between underground cable replacements that can be addressed in a planned fashion, as described earlier, and underground cable replacements that must be completed immediately. The emergency underground cable replacement budget covers the latter type of replacement.

Q. Does the company forecast big increases in emergency underground cable replacement budgets?

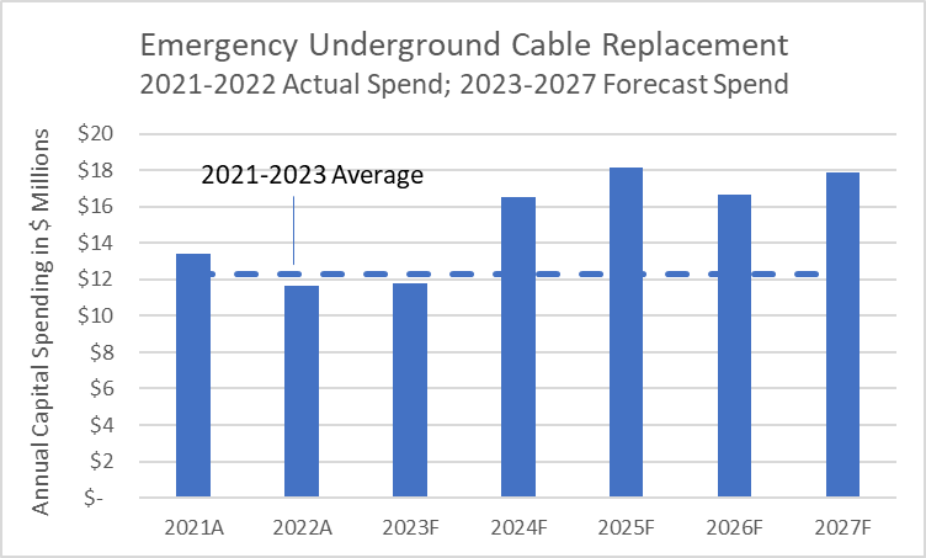
A. Yes. While the company spent an average of $12.3 million annually from 2021—2023 (2023 forecasted), it forecasts spending of $17.3 million on average annually

[112] The St. Louis Federal Reserve Bank reports that U.S. new housing starts in October, 2023 were 970,000 units, a 26.1 percent reduction from the post-Covid high of 1.3 million units in December, 2020, https://fred.stlouisfed.org/series/HOUST1F

[113] The Commercial Real Estate Development Association reports that new office space coming onto the market in 2021 was 26.9 percent less than the amount pre-Covid (2019),://blog.naiop.org/2022/05/u-s-office-market-trends-2022-q1/

during MRP 2. This 40 percent increase can be observed in Figure 10 below. In discovery, Pepco reported " . . . the cost to complete URD cable faults has increased significantly from 2018 to 2022."[114] In a DR, Pepco provided actual spending data 2018 to 2022 which indicated an 18 percent growth rate over 5 years, for a compound average growth rate of just 3.5 percent per year. [115] I do not dispute the need for an emergency underground cable replacement budget, but as emergent work, future levels are essentially impossible to predict. In such situations, historical spending provides as good a guide as any. With a historical growth rate of just 18 percent over five years, a 40 percent increase in spending over four years is unnecessary and unreasonable.

Figure 10: Emergency underground cable replacement spending 2021-2027, actual and forecast.



[114] Exhibit PJA-2 (OPC DR 22-5 (a)).
[115] Exhibit PJA-2 (OPC DR 22-5 (b)).

Q. What is your recommendation regarding the company's MRP 2 capital spending forecast for emergency underground cable replacement?

A. I recommend the Commission reduce the company's MRP 2 capital spending budget for emergency underground cable replacement to the $12.3 million annual average 2021–2023.

VI. RECOMMENDATIONS (ALVAREZ AND STEPHENS)

Q. Please provide a preview of this section of testimony.

A. In this section of testimony, we provide recommendations for Commission consideration. Our primary recommendation is for the Commission to reject Pepco's MRP. We also offer some ideas for how the Commission might manage a transition back to standard cost-of-service ratemaking.

If the Commission decides not to reject Pepco's MRP, we offer several recommendations on how to improve multi-year ratemaking. These include:

1. Eliminating the opportunity to recover overspending through the reconciliation mechanism; and
2. Completing the Lessons Learned for MRPs in Maryland, as envisioned in the Commission's MRP pilot order;
3. Improving capital spending governance and mitigating information asymmetry by increasing stakeholder participation in MRP capital plan development and requiring utilities to support proposed investments with risk-informed benefit cost analyses.

This section of testimony concludes with a recommendation that recovery of Pepco's Downtown Resupply program costs from Maryland customers be rejected.

A. The Commission should reject Pepco's MRP.

Q. Your testimony has identified a number of deficiencies of multi-year ratemaking, correct?

A. Yes. As we discussed in Section II of our testimony, problems inherent in the MRP construct include reduced capital spending governance, no appreciable mitigation of the impacts of information asymmetry, and the introduction of moral hazard into capital spending plan development.

Q. Are these problems reflected in Pepco's proposed MRP 2?

A. Absolutely. The examples of cost-ineffective, premature, and unsupported capital spending proposals presented in Sections III, IV, and V are indicative of these problems.

Q. Please identify examples from Pepco's proposed MRP 2 that indicate inadequate capital spending governance.

A. Our review of Pepco's proposed MRP 2 capital investment plan found the same deficiencies in Pepco's internal capital project review process that we identified in Pepco's first MRP, including:

- a lack of project benefit quantification—project benefits were qualitatively described as "improving reliability" or "reducing operational costs" without

quantifying the amount of improvement or savings anticipated;[116]

- a failure to quantify the value (in dollars) of project risk reductions (for example, the dollar value to customers of a reduction in the risk of a service interruption), thus precluding comparisons of project value to project costs;[117] and
- a failure to rigorously explore project alternatives—many identified project alternatives were dismissed as infeasible without adequate investigation, and in some cases, available alternatives went unidentified.[118]

In short, Pepco management reviews capital investments proposed by its Technical Services department only for technical feasibility. The size of project benefits relative to project cost appears to be a non-factor. In Case No. 9655, we identified this same problem in our review of Pepco's MRP 1 capital spending requests.[119] The Commission seemed to agree with our perspective. Regarding Pepco's $595 million proposal to rebuild 13 69kV circuits, the Commission cited "significant questions regarding the cost-effectiveness of the program."[120] Regarding the White Flint and National Harbor substation construction proposal

[116] *See* Panel Direct Testimony of Paul J. Alvarez and Dennis Stephens ("Alvarez/Stephens MRP 1 Direct") at 12, line 18 through p. 14, line 3, ML# 234018 (Case No. 9655, March 3, 2021).
[117] *Id.* at 14, line 13 through p. 15, line 7. The California Public Utilities Commission ordered that the value of reliability and safety improvements forecast from MRP project proposals be estimated in dollars. *See supra* n. 48.
[118] Alvarez/Stephens MRP 1 Testimony at 20, line 7 through p. 21, line 9.
[119] Alvarez/Stephens MRP 1 Testimony at 23, line 5 through p. 23, line 12.
[120] Order 89868 at 86 ¶ 205 (Case No. 9655, June 28, 2021).

totaling $210 million, the Commission stated that it was "not sufficiently confident in Pepco's load forecasting, consideration of alternatives, and cost-benefit considerations."[121]

Q. Are you suggesting Pepco fails to consider economics at all when reviewing capital spending requests?

A. No, I am suggesting that Pepco's failure to quantify project benefits relative to project costs, as well as the company's loose definition of project "need", are inconsistent with the concept of capital spending governance. When asked for benefit-cost analyses in support of project decisions, Pepco reported that it "does not complete benefit-cost analyses for projects within 'the scope of Pepco's normal business.'"[122] Instead, Pepco considers "the best cost solutions to solve the constraint" presented.[123] I will present my perspectives on the terms "best cost" and "constraint" in turn.

Assuming that "best cost" means 'lowest cost' might give some stakeholders comfort. Upon further examination, however, we recognize that Pepco's capital spending review process fails to quantify the consequences of the constraints it proposes to address. This standard is insufficient for capital spending review. Carried to an extreme, it means that any performance advancement—no matter how small—can justify any size project cost.

[121] *Id.* at 94 ¶ 227.
[122] Exhibit PJA-2 (OPC DR 7-1(h), OPC DR 20-5(a)).
[123] Exhibit PJA-2 (OPC DR 20-5(b).

Q. What could Pepco mean by "best cost"?

A. Pepco's use of the phrase "best cost" could refer to the "least cost, best fit" cost-effectiveness test recognized by the U.S. Department of Energy's Grid Modernization Laboratory Consortium.[124] However, this authority recognizes that "least cost, best fit" is appropriate to apply only in instances in which "the need for a particular project or investment is already established."[125]

This brings us to Pepco's interpretation of the word "constraint," or, stated otherwise, Pepco's perceived "need" to apply some sort of solution. Pepco appears to identify a "need" for projects without any quantitative evaluation or challenge. Pepco engineers then proceed to develop multiple capital-intensive solutions to satisfy the "need" the company has subjectively identified. Pepco's selection of the "best cost" solution from multiple capital-intensive alternatives is cold comfort when the "need" for the project itself is far from clear. In instances where the "need" to address a constraint is subjective, benefit-cost analyses should be used to determine if the reliability (or other) benefits from the implementation of a solution exceed its costs.

[124] *See* Time Woolf *et. al.*, *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*, Grid Modernization Laboratory Consortium, U.S. Dept. of Energy (Feb. 2021), https://eta-publications.lbl.gov/sites/default/files/gmlc_bca_final_report_20210202.pdf.
[125] *Id.* at 13.

Q, Can you provide an example in Pepco's MRP 2 which indicates that the need for a capital-intensive project is suspect?

A. The Benning 69kV substation rebuild proposal is an excellent example. Table 4 below compares the "needs" the company cites to rebuild the substation with associated realities identified in Section III. [BEGIN CONFIDENTIAL CEII]

[redacted]

[END CONFIDENTIAL CEII]

[126] Exhibit PJA-8 (OPC DR 7-1 (c)(i) Confidential Attachment).

That company management approved the costly Benning 69kV rebuild project based on such clearly exaggerated "needs" is a clear example of a lack of capital spending governance at Pepco.

Q. Does the company's $824 million Downtown Resupply program represent another example of inadequate capital spending governance?

A. Yes. The company's selection of an expensive capital solution to mitigate a seemingly minor O&M concern illustrates how multi-year ratemaking undermines capital spending governance. Other concerns described in Section IV include inadequate identification and evaluation of available alternatives and premature investment in capacity expansion to accommodate load growth that may take decades to realize.

Q. Are there any other examples?

A. The decision to prospectively replace substation equipment that has passed its tests without conducting any benefit-cost analysis, which Mr. Stephens discussed in Section III, serves as another example. Other examples are the unsupported increases in capital spending forecasts described in Section V. With more time, we think we likely could have identified many more examples.

Q. Does Pepco management ever reject capital projects presented as a solution to a "need" identified by company engineers?

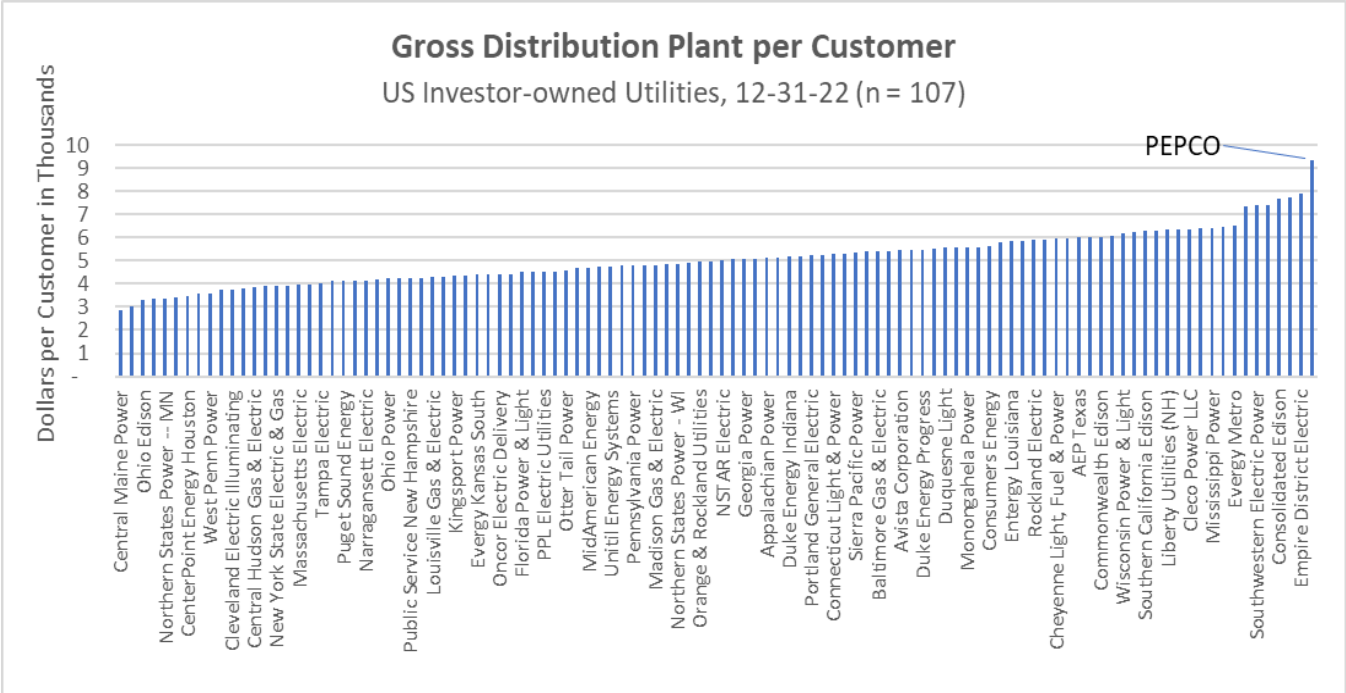
A. Apparently not. When requested in discovery, Pepco was unable to provide a single example of an MRP 2 grid capital spending request that was rejected by company management (though one project was approved with conditions).[127]

Q. Is there any further evidence that shows how the company's capital spending governance is inadequate?

A. Yes. Pepco's distribution rate base per customer provides the most significant evidence that Pepco's capital spending governance is inadequate. *Of all U.S. investor-owned utilities, Pepco has the highest rate base per customer.* In fact, Pepco's rate base per customer is 18 percent higher than that of the second-highest utility. In our experience, high rate bases per customer are usually associated with rural utilities, as more assets are required to reach customers. Yet, Pepco has one of the highest customer densities per line mile of any investor-owned utility, making Pepco's rate base per customer performance even more troubling. Figure 11 illustrates this unflattering data.[128]

[127] Exhibit PJA-2 (OPC DR 19-31 (b)).
[128] Distribution rate base data per FERC Form 1; customer count data per Energy Information Administration Form 861. Data synthesized by HData software, available by subscription at www.hdata.us.

Figure 11: Distribution rate base per customer, U.S. investor-owned utilities



Q. How is Pepco's lack of capital spending governance related to the MRP construct?

A. As we explained in Section II, the MRP construct practically eliminates cost disallowance risk, effectively shifts the burden of prudence from utilities to stakeholders suffering from information asymmetry, and introduces moral hazard into investment plan development. Given these effects of the MRP construct, we would expect a lack of capital spending governance. In our review of Pepco's MRP 2 capital spending proposals, that is exactly what we found.

Q. Please explain your conclusion that transparency in the development and presentation of Pepco's MRP is lacking?

A. Pepco's MRP contained a number of significant capital investments that were not identified and fully disclosed in its MRP 2 application. For instance, consider the

substation equipment replacements discussed in Section III of our testimony. In the aggregate, these investments carry a high incremental cost. Yet, spending on these equipment replacements is not detailed as a separate spending category; instead, they are divided among dozens of individual projects. As a result, these investments are nearly impossible to identify in Pepco's MRP 2 application. Thus, Staff, OPC, and intervenors thus bear an exceedingly high burden to identify and evaluate whether these expenses are justified and reasonable. Moreover, management does not appear to have reviewed prospective substation equipment replacement as a category of capital spending. This is another indication of inadequate capital spending governance.

The Downtown Resupply program also demonstrates a lack of transparency. The total cost of this program to Maryland customers will be at least $242 million. Despite the program's significant costs, it is never presented or described in the company's MRP 2 application. We had to devote significant time and resources just to *identify* this program and propound additional discovery in order to be able to evaluate the need for the program.

Finally, the adequacy of the company's responses to our data requests was extremely poor, and among the worst we have encountered among utilities. Almost 10 percent of the company's responses to data requests we issued were initially inadequate, requiring follow-up data requests. Some data requests required multiple follow-ups.

Q. But aren't MRPs supposed to improve transparency by allowing stakeholders the opportunity to review a utility's planned capital investments before any capital is spent?

A. In theory, yes. But, as Pepco's proposed MRP shows, the MRP construct does not inherently increase transparency. As we explained in Section II, MRPs increase the burden placed on Staff, OPC, and other intervenors for reviewing utility capital investments. The significant burden of identifying and evaluating the projects that Pepco failed to detail in its MRP 2 application shows how multi-year rate making does not inherently improve transparency. Given the limited time that stakeholders have to evaluate proposed MRP investment plans, problems with transparency undermine the ability of Staff, OPC, and other intervenors to adequately review a utility's proposed MRP. In such cases, MRPs offer no meaningful improvement in transparency and create an environment where intervenors may be unable to identify and dispute unjustified and unreasonable proposed spending. This exposes customers to a far greater risk of excessive rate increases compared to standard ratemaking.

Q. Given your conclusions about the problems inherent in multi-year ratemaking and Pepco's MRP, what do you recommend?

A. We recommend rejecting Pepco's MRP in its entirety. Our testimony has shown how the lack of capital spending governance encouraged by the MRP construct encourages cost-ineffective, premature, and unsupported capital spending. Whereas such an investment approach would be significantly risky to a company

operating in a competitive market, the MRP construct encourages Pepco's capital bias and fails to send the appropriate investment and performance signals.

Pepco's MRP 2 proposal illustrates the pitfalls of multi-year ratemaking. Pepco has done little to carry its burden and justify the high levels of spending it seeks to recover through customer rates. Rather, intervenors have engaged in burdensome discovery—far more burdensome than would be experienced in a standard rate case—with a limited time for thorough review and analysis of the information obtained purportedly supporting Pepco's spending forecasts. This biases the outcome of an MRP proceeding in favor of unnecessarily high rates, to the benefit of utility shareholders and the detriment of utility customers. A ratemaking construct with such an inherent bias is not in the public interest. We therefore recommend the Commission reject Pepco's requested MRP 2.

Q. If Pepco's MRP is rejected, could the Commission still set a rate to go into effect when Pepco's MRP 1 rate expires?

A. Absolutely. OPC witness Effron's testimony presents a stated rate that the Commission could put in place effective April 1, 2024.[129]

[129] Direct Testimony of David J. Effron at 4

B. If the Commission decides to approve Pepco's MRP, the Commission should consider certain improvements to the MRP construct.

1. The Commission should eliminate the opportunity to recover overspending through the reconciliation process.

Q. What if the Commission does not reject Pepco's MRP. Are there any improvements to the MRP construct that you recommend?

A. Yes. The Commission could prohibit Pepco from recovering any overspending through the reconciliation rider. This is consistent with MRP administration in other jurisdictions. Annual informational spending reports could of course continue, but prohibiting rate increases through a rider on top of base rates offers several improvements for customers. Of course, utilities can always seek to recover any capital overspending in a future rate case.

Q. What are the benefits of eliminating the opportunity to recover overspending through the reconciliation rider?

A. The most important benefit is that a utility must control its capital and O&M spending during the MRP period in order to earn its authorized rate of return. In turn, this has a mitigating effect on future rate increases, as reductions in O&M spending and better capital cost containment are realized in future rate cases. For these reasons, we recommend the Commission eliminate the MRP adjustment rider.

2. The Commission should complete the Lessons Learned review of MRPs in Maryland.

Q. Did the Commission contemplate a review of Pilot results?

A. Yes, in Order No. 89226 establishing an MRP pilot, the Commission envisioned a Lessons Learned proceeding to review the results of the Pilot MRP and establish regulations governing future MRP applications. The Commission approved a pilot MRP when it granted BGE's request for a multi-year rate plan in Case No. 9465. As BGE's first MRP concludes on December 31, 2023, there has been no comprehensive review of the results of multi-year ratemaking in Maryland.[130] We recommend the Commission complete the review of MRP contemplated in the order establishing the pilot program.[131]

3. The Commission could improve the MRP construct by restoring capital spending governance and mitigating information asymmetry.

Q. If the Commission elects to continue allowing multi-year ratemaking in Maryland, what else would you recommend?

A. Should the Commission decide to continue allowing multi-year ratemaking in Maryland despite our recommendation to end the practice, we recommend further reforms to restore capital spending governance and mitigate information asymmetry. These reforms would better align MRP results with the public interest.

[130] We acknowledge that a Lessons Learned proceeding was held in 2022, prior to BGE's filing of its second MRP. That proceeding culminated in changes to MRP filing requirements, but did not holistically evaluate the MRP construct.
[131] Order No. 89226 at 13 ¶ 25, *In the Matter of Alternative Rate Plans* (Case No. 9618, Feb. 4, 2020).

They include: (1) increasing stakeholder participation in MRP capital plan development, and (2) requiring utilities to support capital spending with risk-informed benefit cost analyses.

Q. Why do you recommend increasing stakeholder participation in MRP plan development?

A. One of the opportunities available to help restore capital spending governance and mitigate stakeholder information asymmetry issues in multi-year ratemaking is for stakeholders to participate in MRP development. The distribution planning process documented in the NARUC-NASEO Task Force's Jade Cohort roadmap, referred to earlier in this testimony, provides an excellent process for grid investment plan development. Stakeholders could conceivably be involved in almost every step of the NARUC-NASEO process. Not only would stakeholder participation in these steps increase capital spending governance, stakeholder understanding and knowledge would increase over time, thus mitigating information asymmetry. We also note that the Climate Solutions Now Act includes a goal for "transparent stakeholder participation in ongoing electric distribution system planning processes."[132]

[132] PUA § 7-802.11.

Q. Why do you recommend requiring utilities to conduct a risk-informed benefit cost analysis to support proposed capital spending?

A. Another opportunity to help restore capital spending governance and mitigate stakeholder information asymmetry is to require utilities to estimate, in dollars, the risk reduction benefits to customers of discretionary MRP investment proposals. Quantifying the dollar value of a proposed project's risk reduction benefits allows one to compare those benefits to the project's costs, as well as to the costs and benefits available for other project alternatives. These are sound capital spending governance practices that are missing from the company's capital request review process. Section III of this testimony demonstrated an approach for this, using the prospective replacement of substation equipment as an example. The California Public Utilities Commission recently required the approach demonstrated in Section III of all reliability- and safety-related investments utilities propose in MRPs.

Q. Does your testimony support any other recommendations specific to Pepco?

A. Yes. Before permitting any recovery of Downtown Resupply program costs from Maryland customers, Mr. Stephens recommends that the Commission require Pepco to fully examine and present alternatives to the proposed $824 million Downtown Resupply program for replacing the substation located on leased property.

VII. REVIEW AND CONCLUSION

Q. Please provide a review of this testimony.

A. The introductory section (I) provided important context for Commission consideration. Namely, the rate of capital spending and rate increases the company has been securing are not sustainable by its customers, or by Maryland's economy.

The lessons learned section (II) of this testimony focused on the results of multi-year ratemaking in Maryland, finding that:

- Pepco's MRP shows how the Commission's goals for multi-year ratemaking have not been met and that MRPs benefit utility shareholders at customer expense;
- the reconciliation process discourages utilities from reducing O&M and capital spending between rate cases, and harms customers.
- Advance approval of multi-year rate plans practically eliminates regulators' ability to exercise cost disallowance rights.
- As a result, capital spending governance and information asymmetry mitigation fall, and moral hazard in distribution investment plan development is introduced.
- These inherent problems of the MRP construct embolden utilities with capital bias to invest beyond the point of diminishing return in reliability, and to make excessive and premature investments in grid

readiness for distributed energy resources, electric vehicles, and building electrification.

Section III identified cost-ineffective spending designed to improve reliability, including (1) replacement of substation equipment that has passed functional and diagnostic tests; (2) the replacement of the Benning 69kV substation; and (3) the replacement of 69kV circuits.

Section IV identified premature capacity expansion spending, including (1) construction of the new National Harbor substation; and (2) the Downtown Resupply program.

Section V identified capital spending forecast increases over historical spending levels which the company has not quantitatively supported. These include (1) planned underground cable replacement; (2) priority feeder improvement; (3) new customer connections; and (4) emergency underground cable replacement.

Section VI of this testimony pulled together the MRP deficiencies in Section II with the examples of cost ineffective, premature, and unsupported capital spending proposed in Sections III, IV, and V. The examples indicated a lack of capital spending governance and appropriate internal project review, and a lack of transparency in MRP presentation. Section VI also detailed our recommendations for the Commission. Our primary recommendation is that the

Commission reject Pepco's MRP. Alternatively, if Commission decides to continue Pepco's MRP, we recommend:

- eliminating the opportunity to recover overspending through the MRP adjustment rider; and
- completing a lessons learned review of multi-year ratemaking in Maryland; and
- improving capital spending governance and mitigating information asymmetry by increasing stakeholder participation engagement in MRP capital plan development and requiring utilities to support proposed investments with risk-informed benefit cost analyses.

We also recommended that, before permitting any recovery of Downtown Resupply program costs from Maryland customers, the Commission require Pepco to fully examine and present alternatives for replacing the substation located on leased property other than the $824 million Downtown Resupply program the company has proposed.

In conjunction with these findings and recommendations, we recommend the cost disallowances and MRP 2 investment plan reductions presented in the table below.

($ in millions)	2021	2022	2024	2025	2026	2027
System Performance Spending that Is Not Cost Effective						
Prospective Substation Equip. Replacement	13.5	19.9	22.9	27.1	26.8	28.3
Benning 69kV Substation Rebuild	0.0	0.1	8.7	17.0	19.4	17.8
69kV Line Rebuilds	n/a	n/a	1.8	11.3	28.7	15.1
Premature Capacity Expansion Spending						
National Harbor Substation/Livingston Road Energy Storage	2.2	0.9	1.2	4.0	5.1	39.2
Downtown Resupply Investment Program	2.3	5.2	7.4	11.6	26.9	40.6
Unsupported Increases in Capital Spending Forecasts						
Underground Cable Replacements	n/a	n/a	0.0	7.3	12.7	15.7
Priority Feeder Improvements	n/a	n/a	0.0	0.0	0.0	8.4
New Customer Connections	n/a	n/a	10.3	14.7	17.7	19.1
Emergency Underground Cable Replacements	n/a	n/a	4.2	5.8	4.4	5.5
Total Capital	18.1	26.1	56.5	98.9	141.54	189.6

Q. Do you have any concluding thoughts?

A. We believe many regulatory and ratemaking paths are available to expand the capacity of the grid to accommodate DERs, EVs, and building electrification while maintaining reliability. Of these paths, only one can be the lowest cost, and it will not necessarily be easy to find. This testimony shows how multi-year ratemaking outcomes are biased towards the highest-cost path, leading to cost-ineffective, premature, and unsupported grid investment. Pepco's MRP 2, and multi-year ratemaking generally, are therefore not aligned with the public interest. We appreciate this opportunity to provide our perspectives and thank the Commission in advance for considering our recommendations.

Q. Does this conclude your panel direct testimony at this time?

A. Yes, it does (Alvarez)

A. Yes, it does (Stephens)

Curriculum Vitae – Dennis Stephens

DS Consulting, 1153 Bergen Pkwy, Evergreen CO 80439 dstephens@wiredgroup.net 303.434.0957

Profile

Mr. Stephens has over 40 years' experience in electric and gas distribution grid planning, design, operations management, and asset management, and the innovative use of technology to assist with these functions. He spent his entire career at Xcel Energy and its subsidiary Public Service Company of Colorado, a distribution utility serving 1.5 million electric customers and 1.4 million gas customers. After a series of electrical and gas engineering and management roles of increasing responsibility, Mr. Stephens retired as the Director of Innovation and Smart Grid Investments for all of Xcel Energy's electric and gas distribution businesses in 2011. He now works for the Wired Group and its clients on a part-time basis.

Career History (all positions with Public Service Company of Colorado or its parent, Xcel Energy)

1976 -- Planning Engineer. Performed electric distribution system planning for Southeast Denver, Boulder, Front Range and Cheyenne divisions, including system protection, voltage support and distribution system design.

1983 – Senior Engineer, Electric Distribution Planning. Provided direction and guidance for junior engineers. Led special projects relating to electric distribution system reliability and design. Promoted to Supervisor of Electric Distribution Planning with a staff of 12 electrical engineers with responsibility for capacity and reliability planning.

1988 -- Manager of Operations, Colorado Front Range Division. Responsible for all electric and gas distribution operations, including a high-pressure gas system (engineering, operations, and construction).

1994 -- Manager of Operations & Maintenance Engineering, Southeast Denver. Managed the design of gas and electric distribution system replacements.

1997 -- Manager, Distribution Reliability Assessment, Xcel Energy South (CO, WY, TX, OK). Led an engineering team focused on electric distribution grid reliability and capacity.

1998 -- Director of Electric and Gas Operations, Southwest Denver Division. Responsible for all aspects of electric and gas engineering, operations, and construction in the Southwest Denver Division.

1999 -- Director of Operations, City and County of Denver Division. Responsible for all aspects of electric and gas engineering, operations, and construction for Division, including downtown Denver. Promoted to Director, New Construction of electric and gas systems for the entire metro area.

2001 -- Director Electric Distribution Asset Strategy, Xcel Energy. Developed and implemented asset management strategies for all electric distribution assets in Xcel Energy's 8-state service area.

2005 -- Director of Utility Innovations and Smart Grid Investments. Led Xcel Energy's Utility Innovations department, developing and implementing new technologies and business processes in multiple electric and gas distribution functional areas. Advanced the concept of an Intelligent Network at Xcel Energy, and led several aspects of the SmartGridCity® demonstration project in Boulder, Colorado. Department secured a national Edison Award for Innovation in 2006. Retired in 2011.

2016 – Senior Technical Consultant, Wired Group.

Noteworthy Projects

Smart Grid Solutions Development, 2010. Worked with several large solution providers to develop and implement technical distribution grid solutions and innovations, including IBM, ABB, and Siemens**.**

DER Integration Strategy and Roadmap Development, 2009. Established DER integration strategy and road-maps for Xcel Energy, including technology and capability roadmap for high DER penetration geographies in Boulder, Colorado.

SmartGridCity™ Project Development, 2008. Developed the technical foundations for the SmartGridCity project in Boulder, Colorado (46,000 customers).

Distribution Automation Design, 2007. Worked with ABB Corporation to design software to identify and locate failures in underground cable. The ABB Smart Analyzer™ was programmed with three traps to capture detailed information using Oscillography/Digital Fault Records (O/DFR).

Utility Innovations Program Development, 2006. Led the development of Xcel Energy's Utility Innovations program, for which Mr. Stephens' team receive a national Edison Award.

Distribution Asset Optimization Process, 2005. Taking advantage of SPL's Centricity Outage Management Program and Itron's Real Time Performance Management system (RTPM), developed a Distribution Asset Optimization process by mining AMI meter data and asset utilization information in the development of an enhanced asset loading forecasting process. The process took advantage of the systems' abilities to forecast sudden changes in usage patterns to take proactive mediation of equipment overloading.

Distribution Asset Optimization Software Development, 2004. Worked with Itron on the development of a Distribution Asset Optimization software program.

Fixed AMI Communications Network Development, 2003. Worked with Itron to pilot one of the first applications of a fixed wireless radio network to collect data from customer meters.

Electric Asset Management Strategy Development, 2002. Developed Xcel Energy's Electric Distribution Asset Management Strategy

Automated Switching System Deployment, 2001. Worked with S&C Electric Corporation to deploy its Intelliteam™ devices on Xcel Energy's distribution grid to reduce the number of customers impacted by an outage by isolate faults through automated switching routines.

High Pressure Gas Pipe Replacement Program, 1988. Initiated and managed the renewal and replacement of 26 miles of high pressure gas pipe, over a 5 year period, reducing the likelihood of seam failures as outlined in an "Alert Notice" issued by the Department of Transportation's Office of Pipeline Safety. Project roles included community engagement, government and regulator relations (PUC, DOT, EPA), and contractor management. Project completed 1 year ahead of schedule and 14% under budget.

Regulatory Appearances

Evaluate BGE's Second Multi-Year Rate Plan (Electric Distribution Components 2024-2027) and Electric Distribution Spending 2021-2022. Panel testimony with Paul J. Alvarez on behalf of the Office of People's Counsel in Maryland PSC Case No. 9692. June 20, 2023.

Evaluate DTE Energy's Request for Strategic Capital Plan Cost Recovery and Infrastructure Recovery Mechanism Rider on behalf of the Attorney General and a group of environmental and consumer advocates in Michigan PSC U-21297. June 13, 2023.

Evaluate Commonwealth Edison's Multi-year Grid Plan. Panel testimony with Paul Alvarez on behalf of the Attorney General in Illinois Commerce Commission 22-0486. May 22, 2023.

Evaluate Ameren Illinois Corporation's Multi-year Grid Plan. Panel testimony with Paul Alvarez on behalf of the Attorney General in Illinois Commerce Commission 22-0487. May 11, 2023.

Evaluate the Technical Justifications for Public Service Oklahoma's $450 million Grid Enhancement and Resilience Plan. Testimony on behalf of the Attorney General in PUD-2022-000093. March 7, 2023.

Evaluate Georgia Power's Transmission and Distribution Spending Proposals. Panel testimony with Paul Alvarez on behalf of Public Interest Advocacy Staff. Georgia PSC 44280. October 20, 2022.

Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan. Panel testimony with Paul Alvarez on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan. Panel testimony with Paul J. Alvarez on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Oklahoma Gas & Electric Company Grid Modernization Spending and Plans. Testimony on behalf of the Office of Attorney General in PUD 202100164. April 27, 2022.

Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities. Panel testimonies with Paul J. Alvarez on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

Dominion Grid Modernization Plan Review. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. PUR-2021-00127. September 13, 2021.

Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Paul J. Alvarez on behalf of Public Counsel. WUTC 200900, 200901, and 200894. April 29, 2021.

Pepco's 2021-2023 Grid Investment and Plan. Panel testimony with Paul J. Alvarez on behalf of the Maryland Office of People's Counsel. MDPSC 9655. March 3, 2021

Baltimore Gas & Electric Company's 2021-2023 Grid Investment and Operations Plan. Panel testimony with Paul J. Alvarez on behalf of the Maryland Office of People's Counsel. MD PSC 9645. Aug 14, 2020.

Review of Maryland Utilities' 2019 Annual Performance Reports. Comments of the Office of People's Counsel. MD PSC 9353. June 8, 2020

Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission critiquing Duke Energy's Plan on behalf of a group of environmental and consumer advocates. NCUC E-7, Sub 1214 Feb 18, 2020 & E-2, Sub 1219 Mar 25, 2020.

Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. Testimony before the Indiana Utility Regulatory Commission on behalf of the City of Indianapolis critiquing Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

New Hampshire Public Utilities Commission Distribution Planning/Grid Modernization Proceeding. Comments in IR 15-296 describing a transparent, stakeholder-engaged distribution planning process.

Pacific Gas and Electric 2019 General Rate Case. Testimony in A.18-12-009 on behalf of TURN related to $270 million in proposed "Integrated Grid Platform" investments.

Southern California Edison 2017 General Rate Case. Testimony in A.16-09-001 on behalf of TURN related to $2.3 billion in proposed grid modernization investments.

Pacific Gas and Electric 2016 General Rate Case. Testimony in A.15-09-001 on behalf of related to $100 million in proposed grid modernization investments.

Notable Publications and Presentations

Alternative Ratemaking in the US: A Prerequisite for Grid Modernization, or an Unwarranted Shift of Risk to Customers? With Paul Alvarez, Kenneth Costello, and Sean Ericson. Electricity Journal. Volume 35 (October 2022).

Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Paul Alvarez and Sean Ericson. Electricity Journal. Volume 34 (August 2021).

Florida Storm Protection Plans: A Bonanza for Utilities, A Bust for Consumers and the State. Whitepaper co-authored with Paul J. Alvarez for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 to be published September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Paul Alvarez & Sean Ericson. Accepted for publication by Public Utilities Fortnightly. Anticipated publication June, 2019.

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Paul Alvarez for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Paul Alvarez for GridLab. October 5, 2018.

DistribuTECH 2010, Tampa, Florida. "Realizing the Benefits of DER, DG and DR in the Context of Smart Grid"

OSI 2008 User's Conference, Denver, Colorado; DistribuTECH 2007, San Diego, California. "Smart Grid City: A blueprint for a connected, intelligent grid community"

ABB 2007 World Conference, Jacksonville, Florida. "Use of Distribution Automation Systems to identify Underground Cable Failure"

North American T&D Conference 2005, Toronto, Canada; Itron 2005 User Conference, Boca Raton, Florida. "Xcel Energy Utility Innovations and Distribution Asset Optimization"

DistribuTECH 2005, San Diego, California. "How Advanced Metering Technology is Driving Innovation at Xcel Energy"

Education

Bachelor of Science Degree in Electrical Engineering, 1975, University of Missouri at Rolla.

Awards

Led Xcel Energy team that received a National Edison Award for Utility Innovations, 2006.

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed conflicts between ratemaking and benefit maximization. Since 2012 Mr. Alvarez has led the Wired Group, a boutique consultancy serving consumer, business, and environmental advocates, and regulators in matters of distribution planning, investment, and performance measurement.

Appearances and Research Projects in Regulatory Proceedings

Evaluate BGE's Second Multi-Year Rate Plan (Electric Distribution Components 2024-2027) and Electric Distribution Spending 2021-2022. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9692. June 20, 2023.

Evaluate DTE Energy's Request for Strategic Capital Plan Cost Recovery and Infrastructure Recovery Mechanism Rider on behalf of the Attorney General and a group of environmental and consumer advocates in Michigan PSC U-21297. June 13, 2023.

Evaluate Commonwealth Edison's Multi-year Grid Plan. Panel testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission 22-0486. May 22, 2023.

Evaluate Ameren Illinois Corporation's Multi-year Grid Plan. Panel testimony with Dennis Stephens on behalf of the Attorney General in Illinois Commerce Commission 22-0487. May 11, 2023.

Evaluate Public Service Oklahoma's $450 million Grid Enhancement and Resilience Plan and Request for Rider Cost Recovery from a Policy Perspective. Testimony on behalf of the Attorney General in PUD-2022-000093. March 7, 2023.

Evaluate Georgia Power's Transmission & Distribution Spending Proposals. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44280. October 20, 2022.

Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan. Panel testimony with Dennis Stephens on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Policy Issues and Precedents Associated with Oklahoma Gas & Electric Company's Grid Modernization Factor. Testimony on behalf of the Office of Attorney General in PUD 2021000164. April 27, 2022.

Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities. Panel testimonies with Dennis Stephens on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

Evaluate Dominion's Grid Transformation Plan. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. Virginia SCC PUR-2021-00127. September 13, 2021.

Investigate Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Dennis Stephens on behalf of Public Counsel. WUTC 200900. April 29, 2021.

Evaluate Kentucky Utilities/Louisville Gas & Electric's CPCN to Install Advanced Meters. Testimony on behalf of the Attorney General. Kentucky PSC 2020-00349/00350. March 5, 2021.

Examine Potomac Electric Power Company's Electric Distribution Spending and Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel. MD PSC 9655. March 3, 2021.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 18-1875-EL-GRD. December 17, 2020.

Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. Aug. 31, 2020.

Examine Oklahoma Gas and Electric's $800 million Grid Enhancement Plan. Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

Examine Baltimore Gas and Electric's 2021-2023 Grid Investment and Operations Plan. Panel testimony before the Maryland Public Service Commission with Dennis Stephens on behalf of the Office of People's Counsel. MDPSC 9645. August 14, 2020.

Critique of Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric. Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase. Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017. Also Unitil in 15-121 and Eversource in 15-122/123, March 10, 2017

Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research and report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

Alternative Ratemaking in the US: A Prerequisite for Grid Modernization, or an Unwarranted Shift of Risk to Customers? With Kenneth Costello, Sean Ericson and Dennis Stephens. Electricity Journal. Volume 35 (October, 2022).

Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Sean Ericson and Dennis Stephens. Electricity Journal. Volume 34 (August, 2021).

Florida Storm Protection Plans: A Bonanza for Utilities, a Bust for Consumers and the State. Whitepaper co-authored with Dennis Stephens for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean

Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Notable Presentations

NASUCA Electricity Committee Meeting. *Alternative Ratemaking and Grid Modernization: Considerations for Consumer Advocates.* With Dennis Stephens and Ken Costello. December 7, 2022.

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.

Pepco Responses to Data Requests

OPC Data Requests

Pepco Response to OPC DR 1-6
Pepco Response to OPC DR 1-7
Pepco Response to OPC DR 6-35, Attachment B
Pepco Response to OPC DR 6-41
Pepco Response to OPC DR 6-42, Attachment
Pepco Response to OPC DR 6-48
Pepco Response to OPC DR 6-65, Attachment
Pepco Response to OPC DR 6-66
Pepco Response to OPC DR 6-67
Pepco Response to OPC DR 6-68
Pepco Response to OPC DR 6-69
Pepco Response to OPC DR 7-1(b), Attachment A & B
Pepco Response to OPC DR 14-3
Pepco Response to OPC DR 19-31
Pepco Response to OPC DR 20-5
Pepco Response to OPC DR 22-5
Pepco Response to OPC DR 23-1
Pepco Response to OPC DR 30-1, Attachments A & B
Pepco Response to OPC DR 30-4
Pepco Response to OPC DR 32-13, Attachment
Pepco Response to OPC DR 32-15
Pepco Response to OPC DR 32-19
Pepco Response to OPC DR 32-21
Pepco Response to OPC DR 37-3
Pepco Response to OPC DR 37-4, Attachment
Pepco Response to OPC DR 37-5
Pepco Response to OPC DR 38-1, Attachment A

Staff Data Requests

Pepco Response to Staff DR 7-47