COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY EACH D/B/A NATIONAL GRID

D.P.U. 23-150

JOINT DIRECT TESTIOMNY OF

Paul Alvarez and Dennis Stephens

On behalf of

THE OFFICE OF THE ATTORNEY GENERAL

March 29, 2024

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I. INTRODUCTIONS, PURPOSE, AND PREVIEW

Q. Mr. Alvarez, please state your name and business address.

A. My name is Paul Alvarez. My business address is Wired Group, PO Box 620756, Littleton, CO 80162.

Q. What is your occupation?

A. I am the President of the Wired Group, a consultancy specializing in the optimization of distribution utility business planning, operations, investment, and performance measurement.

Q. On whose behalf are you submitting testimony?

A. I am testifying on behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy ("AGO").

Q. Please describe your work experience and educational background.

A. After a series of finance and marketing roles of progressive responsibility for large corporations, I began my utility career in 2001 with Xcel Energy, one of the largest investor-owned utilities in the United States. At Xcel Energy, I served as product development manager, overseeing the development of new demand-side management ("DSM") programs for residential, commercial, and industrial customers. I gained experience there overseeing DSM program cost-effectiveness testing.

In 2012, I started the Wired Group with a focus on distribution utility planning, investment, operations, and performance measurement. Wired Group clients include consumer, business, and environmental advocates. I serve as an adjunct professor at the University of Colorado's Global Energy Management Program, where I teach an elective graduate course on electric technologies, markets, and policy. I also occasionally serve as an instructor at Michigan State University's Institute for Public Utilities, where I instruct new regulators and staff on grid modernization issues and distribution utility performance measurement.

I am the author of *Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment*, a book that helps laypersons understand smart grid capabilities, economics, optimum designs, and post-deployment performance optimization. I received an undergraduate degree 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. Both degrees featured concentrations in financial management and marketing management.

Q. Have you appeared previously before the Massachusetts Department of Public Utilities ("Department")?

A. Yes. I appeared on behalf of the AGO in grid modernization proceedings, including D.P.U. 15-120; D.P.U. 15-121; D.P.U. 15-122/123; D.P.U. 21-81/-82/-83; and D.P.U. 22-40/-41/-42. I also played a role in the Grid Modernization Advisory Council's review of the

Electric Sector Modernization Plans ("ESMPs") prepared by Massachusetts electric distribution companies ("EDCs"). Mr. Stephens and I were part of the consulting team assembled by the Department of Energy Resources ("DOER"), along with Synapse Energy Economics and GreenerU. I have also testified before state utility regulators in 16 other states regarding distribution planning, investment, operations, and performance measurement. My Curriculum Vitae is attached as Exh. AG-WG-2.

Q. Mr. Stephens, please state your name and business address.

A. My name is Dennis Stephens. My business address is Wired Group, PO Box 620756, Littleton, CO 80162.

Q. What is your occupation?

A. I am a utility industry consultant specializing in distribution grid planning, investment, operations, asset management, and reliability performance. I frequently work with Mr. Alvarez to support Wired Group client projects.

Q. On whose behalf are you submitting testimony?

A. I am testifying on behalf of the AGO.

Q. Please describe your work experience and educational background.

A. After an honorable discharge from the United States Air Force, and 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, investment, operations, and asset management, and in the innovative use of new information technologies to assist with these functions. Positions I've held over the years at Xcel Energy include Director, Electric and Gas Operations for the City and County of Denver Colorado; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments. In 2006, a team I led received the national Edison Award for Utility Innovation. I retired from Xcel Energy in 2011 and began working with Mr. Alvarez in 2016.

Q. Have you appeared before the Department previously?

A. Yes. I appeared on behalf of the AGO in grid modernization proceedings, D.P.U. 21-81/-82/-83 as well as D.P.U. 22-40/-41/-42. As Mr. Alvarez described above, I was also part of the consulting team supporting the Grid Modernization Advisory Council for its review of Massachusetts EDCs' ESMPs. I have also testified before state utility regulatory commissions in California, Georgia, Illinois, Indiana, North Carolina, Maryland, Michigan, Oklahoma, Virginia, and Washington on distribution grid planning, investment, asset management, and reliability issues in multiple proceedings. I have also served as a technical consultant to parties participating in state utility regulatory proceedings in Kentucky, Florida, Michigan, New Hampshire, and South Carolina, as well as in some of the states listed above. My Curriculum Vitae is attached as Exh. AG-WG-3.

Q. What is the purpose of your panel testimony in this proceeding?

A. We have been retained by the AGO to evaluate the base distribution rate case filing of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("Company" or "National Grid"), docketed as D.P.U. 23-150 ("Petition"). The scope of our assignment and of this testimony includes our reviews of the Company's proposed (investment) performance incentive metrics ("IPIMs" and "PIMs"); investments it proposes as part of its Comprehensive Performance and Investment Plan ("CPIP"); and capital investments placed into service from January 1, 2020, through March 31, 2023, for which the Company requests cost recovery in this proceeding.

Q. Please provide a preview of your Panel Testimony.

A. Our testimony begins with context and perspective for National Grid's Petition, coinciding as it does with multiple other Company investment proposals, such as for its smart meters; its capital investment projects ("CIPs"); and its ESMP. We provide perspectives for the Department's consideration on the size of the Company's capital spending proposals; on preparing the grid for widespread electrification; on reliability and resilience spending; and on the adverse impact we expect of proposed rate increases on the adoption of electric vehicles ("EVs") and heat pumps.

Our testimony continues with one section each in support of our recommendations regarding proposed PIMs, CPIP spending reductions, and cost disallowances. The section

on PIMs describes how each PIM the Company proposes violates at least one of the Department's threshold principles or design guidelines for an incentive mechanism. The section on CPIP spending reductions begins with an overview of National Grid's capital project review/authorization process and five-year capital budget (i.e., CPIP) development processes. We find these processes do not adequately evaluate the economics (in terms of benefits to customers relative to customer costs) of discretionary projects and programs. The section continues with several examples of programs that will not deliver benefits to customers in excess of costs, including the replacement of assets based on subjective assessments of condition; the proposed installation of fault location, isolation, and service restoration ("FLISR") on 80 percent of the Company's circuits; the proposed doubling of the Company's underground cable replacement program; and a proposed 33-fold increase in overhead circuit hardening relative to historical spending. Our findings are validated by the fact that reliability improvements expected from core CPIP spending (as indicated by the Company's Service Quality PIM) will not be sufficient to exceed core CPIP costs to passed on to customers via rate increases.

Finally, the section on cost disallowances identifies multiple projects that were unnecessary for safe and reliable service and that will not deliver benefits to customers in excess of costs. These projects illustrate inadequate capital spending governance at the Company and highlight the deficiencies associated with subjective, rather than data-driven, project

justification.

Q. Please preview your recommendations.

A. First, we recommend the Department reject all the Company's proposed PIMs and exclude performance incentives and penalties from National Grid's rates. However, should the Department prefer to include some PIMs, we provide suggestions for metrics in three performance areas we believe to be most critical to the achievement of the Commonwealth's energy goals: Affordability; Reliability; and Clean Energy Adoption.

Second, we recommend the Department reduce capital spending in the Company's proposed CPIP ($3.949 billion) by $1.092 billion as summarized in the table below. We note that even if the Department adopts all our recommended reductions, capital spending in the five-year CPIP will still be $1.162 billion (69%) greater than capital spending in the five-year period ending 2024 ($1.695 billion).

Project/Program ($ in millions)	2025	2026	2027	2028	2029	Totals
CPIP capital spending proposed	577	734	807	876	954	3,949
Customer and Public Requirements	(30)	(34)	(40)	(47)	(55)	(206)
Asset Condition	(6)	(42)	(52)	(53)	(47)	(200)
System Capacity and Performance	(79)	(138)	(146)	(159)	(163)	(685)
Total recommended reductions	(114)	(215)	(238)	(260)	(265)	(1,092)
CPIP recommended by AG	463	519	569	616	689	2,857

Finally, we recommend the Department order disallowances of $124.2 million in capital costs National Grid presents for recovery in its Petition. Specifically, we find the justifications for multiple projects to be subjective, rather than data-driven, illustrating inadequate capital spending governance and resulting in unnecessary capital spending that will not deliver benefits to customers in excess of costs. Recommended disallowances are summarized in the table below.

Project/Program	Disallowance Amount
Lynn Substation Replacement	$ 30.7 million
Recloser Replacement Programs	4.6 million
Hendersonville Substation	22.2 million
Revere to Winthrop 23kV Underground Cable Replacement	23.7 million
Melrose Substation Replacement	9.4 million
Gloucester Substation Replacement	33.7 million
Total	$124.2 million

II. CONTEXT AND PERSPECTIVE (ALVAREZ)

Q. Please introduce this section of testimony.

A. This section of testimony provides context and perspective for the Department's consideration. It is designed to encourage the Department to avoid examining National Grid's Petition in isolation, because the "core" business spending in the instant Petition is

only one component of the massive Massachusetts capital plan described in the Company's CPIP. As the CPIP will result in exceptional rate increases for the Company's customers — thereby possibly inhibiting customer adoption of the building and vehicle electrification Massachusetts policy specifically encourages — I urge the Department to consider the "big picture" as it evaluates National Grid's Petition.

This section begins by illustrating the massive scale of the Company's CPIP; its likely impact on distribution rates (which would almost double by 2029); and the impact of such rate increases on customer adoption of technologies such as building and vehicle electrification. It continues by considering EDC capital bias and its influence on "grid readiness" spending, and by providing perspective on previous periods of exceptional growth in U.S. electricity use. The law of diminishing returns is then presented and applied to reliability and resilience spending. This section concludes with rate increase mitigation strategies for Department consideration, including a discussion on the relationship between the timing of grid readiness spending and rate increases. In summary, this section is intended to help the Department recognize that high distribution rates are fundamentally in conflict with the Commonwealth's policy goals, and that opportunities to balance affordability with grid readiness (for electrification) are available.

Q. Please begin with your illustration of the Company's CPIP presentation.

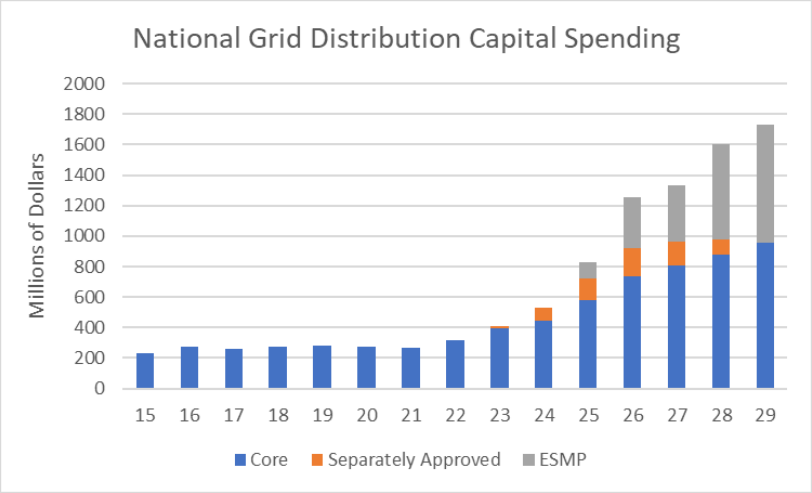
A. National Grid's CPIP presents capital spending plans for the 2025–2029 timeframe in three components: (1) what the Company calls its "core" business spending ($3.95 billion); (2) programs and projects the Department has already approved or is currently considering (such as for smart meters, grid modernization, and CIP spending to accommodate utility-scale distributed energy resources ("DER)") ($587 million); and (3) ESMP spending ($2.2 billion, largely on grid readiness for building and vehicle electrification). While the instant Petition concerns only the core business spending, and the Company's request to recover that spending through its proposed Infrastructure, Safety, Reliability, and Electrification ("ISRE") mechanism, the size of the spending the Company proposes in the other CPIP components demands that these other components be considered together as the Department evaluates National Grid's Petition.

National Grid's CPIP proposes annual capital spending that will sextuple from 2019 ($279 million) to 2029 ($1.73 billion; see Figure 1, below). While increased grid investment may be one objective of ratemaking innovations such as rider cost recovery, there is a vital need for a counterbalance. Without a counterbalance, and given utilities' capital bias,[1] spending is likely to occur too early, be cost-ineffective, or even be counterproductive. ("Capital

[1] Harvey Averch and Leland L. Johnson, *The Behavior of the Firm Under Regulatory Constraint*, 52 American Economic Review, at 1052 (Dec. 1962).

bias" describes EDC incentives to maximize profits by increasing capital spending.) Moreover, given informational asymmetries between utilities on the one hand and regulators and consumer advocates on the other, recognizing such negative outcomes could prove difficult.

Figure 1. National Grid distribution capital spending, 2015–2023 actual, 2024–2029 projected.



In this testimony we will argue that the ratemaking pendulum is swinging too far in favor of unfettered investment, driving associated rate increases that will slow progress toward the Commonwealth's electrification goals. We estimate National Grid's spending plans, in total, will *double* revenue requirements from 2023 ($946 million) to 2029 ($1.862 billion; see Exh. AG-WG-4 for summary calculations). Given low projected sales volume

growth between 2023 and 2029,[2] we expect distribution rates will almost double from 2023 to 2029. Doubled electricity distribution rates will not encourage customers to adopt building and vehicle electrification, and in fact increases of such magnitude will undermine adoption at precisely the time that Massachusetts' Clean Energy and Climate Plans ("CECPs") call for significant increases in EV and heat pump use.

As electric rates grow, any economic advantage to consumers of switching from fossil-fueled vehicles and heating to electric versions deteriorates and may reverse. Indeed, National Grid itself has already identified the problem that high electric rates pose for heat pump adoption: as part of its most recent Three-Year Energy Efficiency Plan, National Grid's Potential Study asserted that the "[e]lectrification potential of natural gas-fueled heating is influenced by the current low prices of natural gas. In many cases, this yields unfavorable customer economics and low adoption rates for this form of electrification."[3]

Q. How do you believe capital bias has influenced the Company's CPIP?

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[2] *See* Exh. AG-1-13, at 1 (forecasting sales volume growth of less than one percent per year through 2028); Exh. AG-5-15, Att. AG-5-15.

[3] *Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid*, D.P.U. 21-128, Exh. 1, Appx. F.5*, Massachusetts Energy Efficiency, Electrification, and Demand Response Potential Study for 2022–2024*, at175 (Nov. 1, 2021).

A. We understand that Massachusetts has aggressive goals for distributed energy resources ("DER"), EVs, and electric heating (heat pump) adoption. We also understand that an electric grid that can reliably accommodate those goals is in the Commonwealth's interest, and that significant grid investment by National Grid and other EDCs will be needed to meet these goals. However, there is great uncertainty regarding how much grid investment will be needed, what such investments should be spent on, and how far in advance those investments should be made. We believe capital bias encourages EDCs, including National Grid, to use these goals as justification for proposed spending that is both greater in amount and earlier in time than necessary.

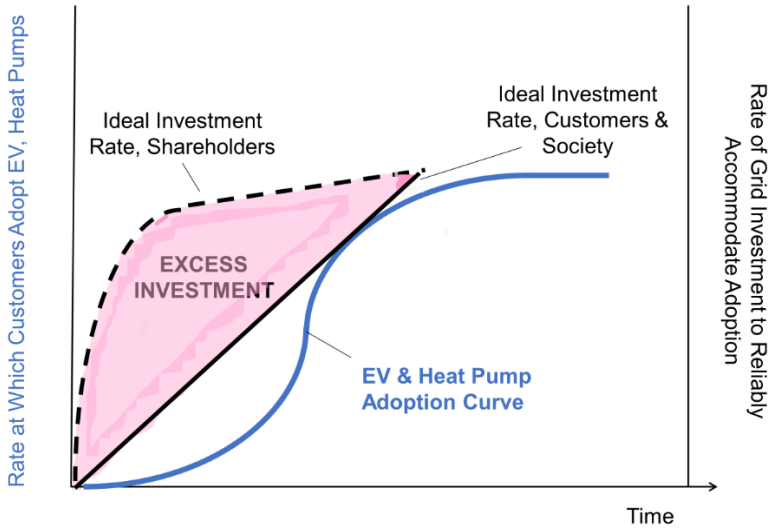
Consider the classic new product adoption curve, [4] as it may apply to building and vehicle electrification, provided in Figure 2 below. The new product adoption curve is well known in the consumer marketing discipline and has been validated by all significant new consumer product introductions over time.[5] The new product adoption curve describes typically slow initial adoption of a new product by consumers upon introduction, followed

[4] Joe M. Bohlen and George M. Beal, *The Diffusion Process*, at 117, presented at a Farm Foundation meeting, 1956, https://ageconsearch.umn.edu/record/17351?v=pdf.

[5] Examples of new consumer products that have followed the new product adoption curve include black-and-white televisions in the 1950s, color televisions in the 1960s, home video players in the 1970s, compact audio discs in the 1980s, personal computers in the 1990s, smart phones in the 2000s, and flat-screen televisions in the 2010s.

by rapid adoption as economies of scale and competition cause prices of the new product to fall. Growth slows at the end of a new product's lifecycle, as every consumer likely to adopt the new product already has one. The adoption of electric vehicles and heat pumps is extremely likely to follow the same pattern, as represented by the blue line in Figure 2.

Figure 2. New Product Adoption Curve: Electric Vehicles and Heat Pumps



The solid black line illustrates the minimum grid investment rate needed to be ready for EV and heat pump adoption. As the solid black line indicates, a steady level of advance grid investment will indeed be needed if the grid is to be ready for peak adoption of EV and heat pumps. However, excess grid investment in advance of electricity sales volume increases from EV and heat pump adoption will ultimately be borne by ratepayers in the form of massive rate increases. The closer National Grid can time investments to

appropriately coincide with sales volume increases, the lower the resulting rate increases will be, as we discuss further below.

As a result, it is critical to evaluate how much advance grid investment is appropriate. It is indeed possible for National Grid and other EDCs to invest too much and too early in grid "readiness" for EV and heat pump adoption.

The dashed black line describes the impact of capital bias on EDC capital budgeting, including the capital budgets in National Grid's CPIP. Although some amount of advance grid investment is appropriate, EDCs such as National Grid would prefer to invest more capital than necessary and earlier than necessary because of the resulting increase to earnings under cost of service ratemaking and, by extension, increases in National Grid share prices. Absent vigilant regulation, EDCs could use concerns over grid readiness as justification to invest more than necessary, earlier than necessary.

Q. Does excess investment reduce the risk that the grid will not be ready for EV and heat pumps?

A. We appreciate the concern shared by some stakeholders that the grid will not be ready for the added demands placed on it by peak EV and heat pump adoption and DER. However, history indicates that this concern may well be overblown. Due to capital bias and the profit motive, EDCs have always made the investments needed to ensure that the grid can accommodate growing loads. Figure 3, below, compares:

(1) electricity usage in the United States from 1920 to 1944 (driven by refrigeration, rural electrification, and war efforts) to;

(2) electricity usage from 1945 to 1969 (driven by economic development and air conditioning); and to

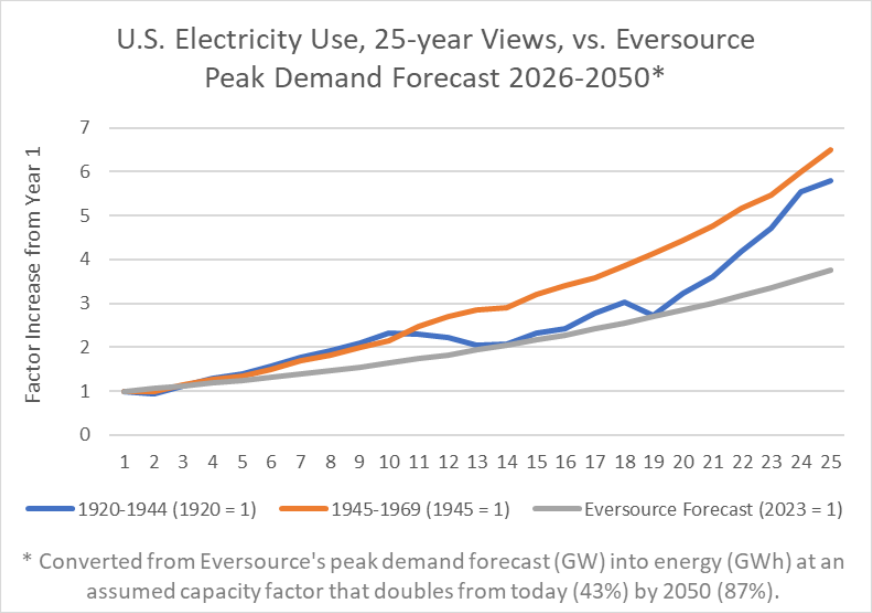
(3) my estimate of growth in electricity usage from 2023 through 2047 in the NSTAR Electric (d/b/a Eversource Energy) service territory[6] using information provided by NSTAR Electric in its ESMP.[7]

As Figure 3 indicates, while growth in electric use from 2023–2047 due to EV and heat pump adoption will be significant, it is likely no more significant than the load growth EDCs, including National Grid's predecessor companies, have accommodated in the past.

[6] National Grid did not provide sufficient information in its ESMP to enable development of a similar chart for the National Grid service area. However, EV and heat pump adoption in National Grid's service area is not likely to be dramatically different from adoption in the NSTAR Electric service area.

[7] *Consultant Comments on the 2024 Massachusetts Electric Sector Modernization Plans: Submitted to the Massachusetts Grid Modernization Advisory Council, at* 9 (Feb. 22, 2024), https://www.mass.gov/doc/consultant-comments-on-the-2024-esmps/download.

Figure 3. U.S. Electricity Use, 25-Year Views, compared to expectations for 2023–2047 in the Eversource service area based on Eversource's ESMP peak demand forecast 2026–2050.



Q. Was National Grid's distribution grid, especially in rural areas, historically ready for the addition of utility-scale DER?

A. No. But we encourage the Department to differentiate between the grid's readiness for utility-scale DER in rural locations and the grid's readiness for EV and heat pump load growth. National Grid's rural grids, like all rural grids, were designed to transmit relatively small amounts of electricity over relatively long distances. The introduction of utility-scale DER on a rural circuit requires that circuit to transmit many multiples of electricity relative to current levels with much less lead time than electrification offers (decades). It would have been inappropriate for National Grid to have built its rural grid for utility-scale DER

interconnections that could not have been foreseen. In short, the fact that National Grid did not design its rural grid for utility-scale DER does not necessarily mean National Grid cannot accommodate load growth from electrification.

Q. In what other ways do you believe capital bias has influenced National Grids CPIP?

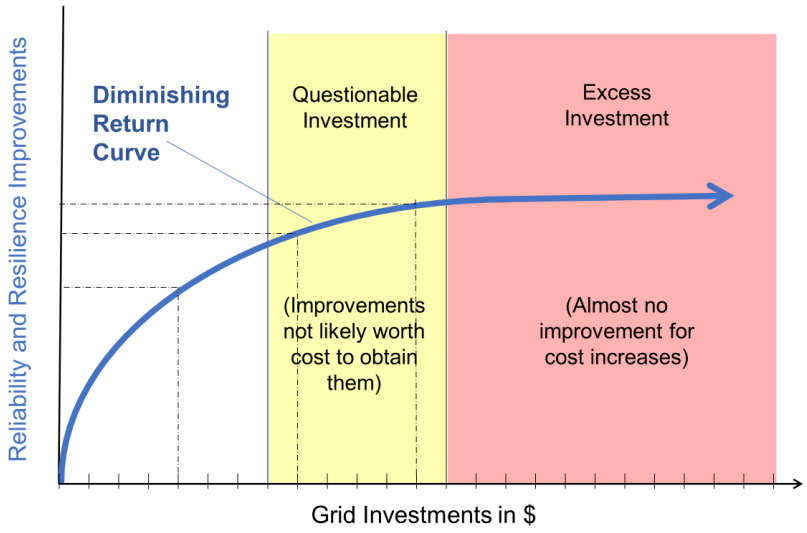
A. Capital bias also encourages EDCs to overspend on reliability and resilience. This testimony will provide multiple examples later, but for the moment it is sufficient to understand that reliability and resilience improvements are subject to the law of diminishing returns.[8]

The law of diminishing returns refers to the economic principle that as inputs, such as capital, into a business process increase, the marginal improvement in process productivity from each additional unit of input declines. At some point, the productivity improvements become so small that they no longer justify additional increases in inputs. This is known as the point of diminishing return. Although a business operating in a competitive market would never invest past the point of diminishing return, a monopoly EDC with capital bias

[8] *See, e.g.*, Turgot, *Observations on a Paper by Saint-Peravy* (1767) ("Even if applied to the same [agricultural] field, [the product] is not proportional [to advances to the factors], and it can never be assumed that double the advances will yield double the product.")

such as National Grid will — absent effective regulation. Figure 4 applies the diminishing return curve to EDC reliability and resilience investment.[9]

Figure 4. Reliability and Resilience Improvements in Relation to Spending: Diminishing Returns as Applied to EDC Reliability and Resilience Investment



Although it is in the Commonwealth's interest to maintain a grid that is ready for EVs heat pumps, and other electrification efforts, affordable electricity rates are also in Massachusetts' interest and will help accelerate electrification. Indeed, as mentioned

[9] Paul Alvarez and Dennis Stephens et. al., *Alternative Ratemaking in the US: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers?*, 35 Electricity Journal, at 107200 (2022).

above, high electricity rates will discourage the electrification that Massachusetts's ambitious environmental policies have been carefully crafted to encourage. As a result, capital spending, including the capital spending National Grid proposes in its CPIP, must be governed and carefully targeted to the projects and programs delivering the greatest progress toward the Commonwealth's policy goals for the least cost (and, as a result, the lowest possible amount of rate increase).

Q. What are the primary drivers of rate increases?

A. In addition to the rate of return on capital the Department authorizes, rate increases are driven primarily by: (1) the amount and type of spending and (2) the timing of that spending.

Spending amounts and types. The amount of money a utility spends is a primary driver of rate increases, especially capital spending. While this conclusion may be intuitive, greater detail is extremely illustrative, as different types of spending affect rates more than others.

Capital spending costs customers dramatically more than Operations and Maintenance ("O&M") spending. For example, while $1 million spent on O&M costs customers $1 million, $1 million spent on a piece of capital equipment will ultimately cost customers the equivalent of $1.4 million in today's dollars, owing to profits, state and federal income

taxes, property taxes, and uncollected revenue paid by customers on top of utility capital spending.

Further, certain investments can result in asset "churn" that customers could be asked to cover through rate increases. For example, a 4kV substation rebuilt today as part of a discretionary "equipment condition" decision may have to be rebuilt again as a 13kV substation in one or two decades due to load growth from electrification.[10] Given that a substation and its primary equipment can easily last 60 to 80 years, and assuming no immediate reliability imperative, it may make more sense to utilize an existing 4kV substation for an additional one or two decades rather than to replace it.

Excessive capital spending can also increase customer costs in other ways. Premature capital spending can cause stranded costs through the retirement of equipment with book value remaining that customers may also have to cover through rates. Capital spending that delivers economic value in excess of customer costs, such as through reliability or resilience improvements, have a positive economic impact to the Commonwealth's economy. Capital spending that is not cost-effective, however, acts as a drain on the economy. Further, higher electricity cost burdens make less money available for

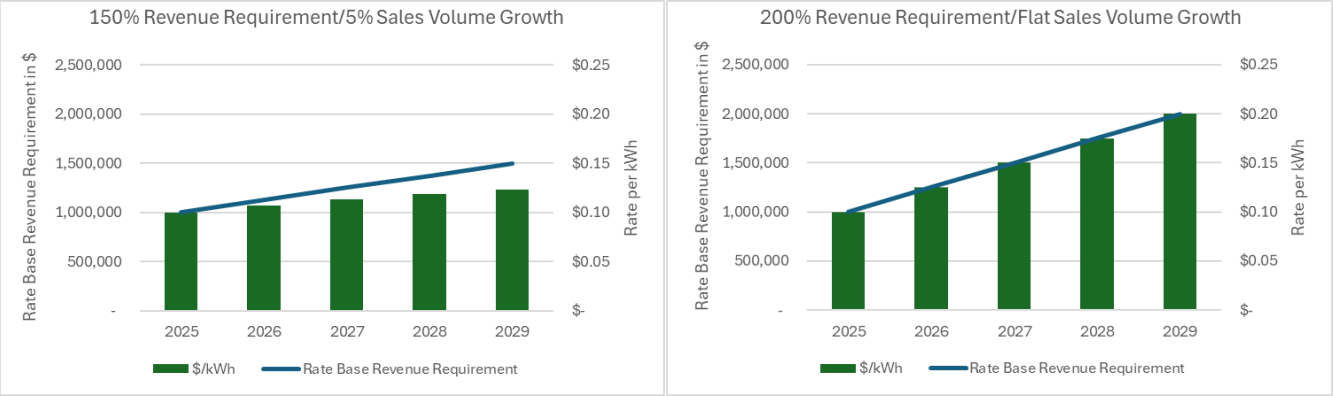
[10] A 13kV substation has three times the capacity of a 4kV substation.

households to invest in EV and heat pumps — to say nothing of daily necessities — which often have initial costs that are higher than fossil-fueled alternatives.

Timing. The timing of spending also has a direct impact on rate increases. Capital spending too far in advance of sales volume growth means that associated increases in revenue requirements are spread over today's sales volumes, not tomorrow's relatively higher volumes. Spending increases concurrent with sales volume growth result in much smaller rate increases than spending increases absent sales volume growth.

Although an oversimplification, the basic formula for determining a rate per kilowatt hour (kWh) is to divide an EDC's revenue requirement by the EDC's expected sales volumes. Thus, a $1 million revenue requirement spread over a 10 million kWh sales volume expectation results in a rate of $0.10 per kWh ($1 million/10 million kWh). This example is depicted in the line and first bar on the left-hand chart in Figure 5 below. As can be seen in this left-hand chart, a 50 percent revenue requirement increase results in only a 20 percent rate increase (from $0.10 to $0.12) when sales volumes are increasing (in this example, by 5 percent annually).

Figure 5. The impact on rate increases of variation in investment amounts, timing, and sales volume.



Compare that result to the result shown in the chart on the right. In that example, a 100 percent increase in the revenue requirement results in a 100 percent rate increase (from $0.10 to $0.20) when sales volumes are flat. This dynamic explains why considering both the amount of spending as well as the timing of spending are important in moderating rate increases.

Deferring spending increases to coincide with sales volume growth, to the greatest extent possible, is a rate increase mitigation strategy the Department should consider, as failing to do so will increase rates and slow customer adoption of electric vehicles and heat pumps and delay associated emission reduction benefits. The challenge for regulators today is to balance the competing priorities of grid "readiness" with maintaining affordable electric

distribution rate increases. This is particularly true given the negative impact of electric distribution rate increases on electrification.[11]

Q. What grid planning strategies exist to meet these ratemaking challenges?

A. Strategies are available to better balance the competing priorities of grid "readiness" and distribution rate increases. These strategies include accurately identifying grid goals and prioritizing grid spending; encouraging "just in time" grid spending to the greatest extent possible; and governing grid spending.

Accurately identify grid goals and prioritize spending. Increased consumer reliance on efficient electric heating will require Massachusetts EDCs to virtually eliminate long-duration service interruptions. Yet the types of efforts and spending required to eliminate long-duration service interruptions (resilience) can be different from those to improve day-to-day ("blue sky") reliability. A strategy that focuses on storm response readiness and more aggressive tree trimming will pay bigger resilience dividends per dollar than undergrounding overhead lines and rebuilding circuits with covered conductors. However, National Grid's spending plan focuses on the latter, not the former.

[11] Please note that we have yet to consider the rapid rises in transmission and generation rates, which are simultaneously impacting a Massachusetts economy that already has some of the highest electricity rates in the United States.

Embrace "Just in Time" investment to the greatest extent possible. Because spending in advance of electrification (and associated increases in electric sales volume) increases rates, efforts can be made to time capital spending to coincide with sales volume increases. Grid capacity should be in place in advance of need, but not too far in advance of need.

Govern spending. Information asymmetry means that the EDCs — not the Department, Staff, or stakeholders — will know best how to optimize spending within constraints. This does not mean that the ESMP process cannot improve capital spending governance. Ideally, the ESMP process can help instill the capital-spending governance practices missing currently, thereby identifying spending that is too early, or cost-ineffective, or even counterproductive.

National Grid already has an incentive under traditional cost of service ratemaking to invest (to increase its profits), and this incentive has no practical limit (due to capital bias). Thus, regulation must also be the means by which to moderate spending and rate increases. Due to information asymmetry, encouraging EDCs to govern their own spending is the best approach. Later, this testimony explains how the Department can influence National Grid's capital project review/authorization and capital planning processes in ways that increase capital spending governance, though we believe the ESMP process can help as well.

EDCs can constrain spending by making informed trade-offs, such as considering the impacts of rate increases versus the risk to grid readiness. The quantification of risk reductions in dollars, as the California Public Utilities Commission has ordered for California EDCs,[12] is the best way to identify risks that have yet to rise to a level requiring immediate capital spending, and it can also help identify cost-reducing investment deferrals. Armed with perspective and context for National Grid's CPIP, this testimony now turns to the specifics of the Company's Petition, beginning with PIMs.

III. PERFORMANCE INCENTIVE MECHANISMS (ALVAREZ)

Q. Please introduce this section of testimony.

A. Here, I provide an overall perspective on performance mechanisms and performance-based ratemaking, including a summary of the Department's threshold principles and incentive mechanism design guidelines. I explain how each of the PIMs the Company proposes contravenes one or more principles or design guidelines. On this basis, I go on to recommend that the Department reject the Company's proposed PIMs in their entirety, and to exclude performance-based incentives and penalties from rates altogether. However, in

[12] *Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities*, Cal. Pub. Utils. Comm'n Rulemaking 20-07-013, Decision 22-12-027, Appx. A (Dec. 21, 2022), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K014/500014668.PDF.

the event the Department prefers to retain some PIMs, I make several suggestions regarding PIMs for performance areas I believe to be most critical, including Affordability, Reliability, and Clean Energy Adoption.

Q. Please provide your overall perspective on PIMs.

A. The Department has found that performance incentives can be useful in advancing public policy goals as long as threshold regulatory principles and incentive mechanism design guidelines are met.[13] I concur with this perspective, and with the threshold principles and incentive mechanism guidelines the Department has established.[14] But my overriding concern regarding performance-based ratemaking ("PBR") is that the spending required to perform at the levels indicated by the metrics is never adequately addressed in the metrics. In my opinion, the overall challenge in EDC spending generally, and in capital planning specifically, is how to secure the best outcomes for the least cost. In my experience, few performance-based ratemaking programs or PIMs are designed to influence utility decision-making in this manner.

Q. Does National Grid propose PIMs as part of its proposed cost recovery mechanisms?

[13] *See National Grid*, D.P.U. 18-150, at 120 (Sept. 30, 2019).
[14] *Id.*, at 121.

A. Yes. In our testimony we address the design of the IPIMs and PIMs (collectively, in this section, "PIMs") that National Grid proposes as part of these mechanisms and provides PIM recommendations for Department consideration in the event the Department elects to employ incentives and penalties in some form or fashion. The Company proposes four IPIMs pertaining to capital spending performance and five PIMs pertaining to operational performance:[15]

- FLISR (IPIM, count of schemes deployed);
- Underground Cable Replacement (IPIM, percentage of sections fault free);
- Overhead Hardening (IPIM, miles completed);
- Service Quality (IPIM, system average interruption duration index);
- Affordability (PIM, net change in low-income rate enrollment);
- Electric Vehicles (PIM, count of National Grid vehicles converted from fossil fuel);
- First Call Resolution (PIM, percent of customer issues resolved on initial call);
- Digital Engagement (PIM, count of digital interactions);
- Distributed Energy Resources (PIM, count of MW interconnected).

Q. Can you please summarize the Department's threshold principles for performance-based ratemaking and its design guidelines for PIMs?

[15] *E.g.*, Exh. NG-CPIP-7.

A. The Department requires that PIMs pass two threshold principles, including: (1) the PIM advances public policy goals; and (2) the affected activity is clearly outside the public service obligations of an electric distribution company ("EDC").[16] Further, the Department has appropriately specified design guidelines for PIMs, which require that a PIM:

1. Encourage program performance that best achieves Massachusetts energy goals;
2. Enable comparison of quantifiable goals, activities, and benefits relative to cost;
3. Be limited to activities where the EDC plays a distinct and clear role in bringing about the desired outcome;
4. Be consistent across Massachusetts EDCs, with any deviations clearly justified;
5. Avoid perverse incentives; and
6. Ensure no duplication of reward for the same actions through another mechanism.[17]

Q. Do the PIMs proposed by the Company violate one or more of the threshold principle or design guideline?

A. Yes. Every PIM proposed by National Grid constitutes an existing public service obligation, thus violating the Department's second threshold principle. Beyond that, the design guideline most frequently violated by the Company's proposed PIMs is the

[16] D.P.U. 18-150, Order, at 121.
[17] *Id.,* at 120–121.

guideline that PIMs should not duplicate a reward available for the same action through another mechanism.

Q. Please explain.

A. The opportunity to earn a return on all capital investment is a reward for capital spending. Thus, any PIM that can be secured simply by spending more capital constitutes a duplication of a reward for capital spending. The PIMs that can be secured simply by spending more capital include:

1. FLISR[18] scheme installations;
2. Underground Residential Distribution (URD) cable replacement;
3. Overhead hardening; and
4. Fleet electrification.

The Company's opportunity to increase earnings by reducing O&M spending between rate cases is also a reward as it enhances the Company's earnings. Thus, any PIM regarding an activity that reduces the Company's O&M spending constitutes a duplication of a reward. These activities include:

[18] FLISR is an acronym for Fault Locations, Isolation, and Service Restoration. It is a combination of field hardware, communications technology, and software within a broader category of investment known as distribution automation.

1. Increases in first call resolutions (as the more customer calls the Company can resolve without the need for a follow-up, the lower the Company's O&M spending),
2. Increases in digital engagement (as the more that the Company's customers employ self-service via online transactions, the lower the Company's O&M spending).

Q. Do you believe that any of the Company's proposed PIMs create "perverse incentives"?

A. Yes. I believe all metrics that measure process inputs, rather than performance outcomes, create perverse incentives. Achievement of the FLISR PIM, the URD replacement PIM, the Overhead Hardening PIM, and the EV PIM all depend on how much capital the Company spends (a process input) rather than the outcome of the spending (improved reliability or emission reductions). The perversity stems from the fact that not all FLISR schemes, URD cable replacements, or overhead hardening projects will deliver benefits in excess of costs. By encouraging more installations regardless of cost effectiveness, incentives for these process inputs encourages "reliability" spending beyond the point of diminishing return, and thus constitutes a perverse incentive. An outcomes measure of performance, such as SAIDI[19] or SAIFI[20] reduction per dollar of capital invested, would avoid such perverse incentives, and would more effectively encourage National Grid to secure the best outcome for the least cost. Similarly, measuring emission reductions per

[19] SAIDI measures (indexes) system average interruption duration in minutes.
[20] SAIFI measures (indexes) system average frequency per customer per year.

dollar (an outcome) eliminates the perverse incentive created by the EV PIM (which simply encourages more capital spending to purchase more EVs.)

Q. Do you believe that any of the Company's proposed PIMs violate the requirement that a PIM "enable comparison of quantifiable goals, activities, and benefits relative to cost"?

A. National Grid does not appear to have completed benefit-cost analyses for any capital spending projects or programs. As a result, three of its proposed PIMs violate this guideline:

1. FLISR benefits and installation costs vary dramatically by circuit, and the Company does not appear to take these into account when selecting circuits for FLISR. The Company projects a single FLISR scheme it is installing in 2024 will cost $8.9 million,[21] more than the cost of all 24 FLISR schemes installed in 2022–2024.[22] (The high cost is the result of ten miles of reconductoring required to complete the scheme.)
2. The optimum rate of URD replacement (miles per year) varies significantly by utility, with "optimum" defined as the value of avoided interruptions relative to costs. Variables include installed underground cable amounts; cable types and ratios to totals; soil conditions; environments (urban, suburban, or rural); costs; fault history; and other factors. As the Company does not appear to have completed analyses to identify the optimum URD replacement rate (miles) or budget annually,[23] no ability to compare benefits to costs is available.
3. Overhead hardening is expensive, at $1.8 million per mile.[24] Benefits vary by vegetation density, customer density per mile, and service interruption history.

[21] Exh. AG-6-3, Att. AG-6-3, tab "Question 3."
[22] *Id.,* at tab "Question 1."
[23] Exh. AG-6-3(14).
[24] Exh. AG-6-6(2).

Nevertheless, the Company has not completed an analysis comparing the benefits to the costs of overhead hardening under various conditions.[25]

Q. Do you believe that National Grid's Affordability PIM "encourages program performance that best achieves Massachusetts energy goals"?

A. No. As described earlier, rate increase mitigation (affordability) is critical to accelerating EV and heat pump adoption, and therefore to the achievement of Massachusetts energy goals. Further, affordability is a goal in its own right.[26] But the metric the Company proposes to measure affordability, "Increase in R2 (low-income rate) enrollment," [27] does not measure rate increases or affordability. As such, it is not a measure "that best achieves Massachusetts energy goals."

While the proposed metric might be a useful scorecard metric, it is not a useful metric for measuring affordability. A better affordability metric would be one that measures the National Grid rate increases that all the Company's customers, and the Commonwealth's economy, must accommodate. Examples include:

1. Increases in revenue requirements relative to the consumer price index (my preferred metric);

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[25] Exh. AG-6-6(7).

[26] *See* G.L. c. 25, § 1A ("In discharging its responsibilities… the [D]epartment shall… prioritize safety, security, reliability of service, affordability, equity and reductions in greenhouse gas emissions….").

[27] *E.g.*, Exh. NG-CPIP-7, tab "Affordability."

2. Average annual residential bill as a percentage of average state household income, or increases thereto; and

3. Disconnections for non-payment per 100 customers or increases thereto.

Q. What is your impression of the Company's proposed Service Quality (Reliability) and Clean Energy Adoption (DER) metrics?

A. Although reliability and DER interconnection performance are within National Grid's public service obligations (and thus related PIMs would violate the Department's second threshold principle), these are among the most critical of Massachusetts' clean energy goals. Further, reliability (Service Quality) incentives and penalties already exist. On balance, if the Department were to approve any PIMs, the newly designed PIMs, below, that measure Service Quality and Clean Energy Adoption, plus Affordability (above), are the only PIMs I would recommend.

Service Quality. Because the Company's average service interruption duration and frequency performance without major events is generally better than the national average for investor-owned utilities, I am not certain these are the most important reliability metrics. Given the impending transition to electric heating, the elimination of long-duration service interruptions may now be the most important reliability metric (or, perhaps more accurately, the most important resilience metric). Further, National Grid has

performed relatively poorly in storm response in the past.[28] The Department may wish to consider Service Quality performance metrics more relevant to future needs, such as those that measure service interruption duration and frequency with major event days, or percentages of customers without service for more than 24 hours.

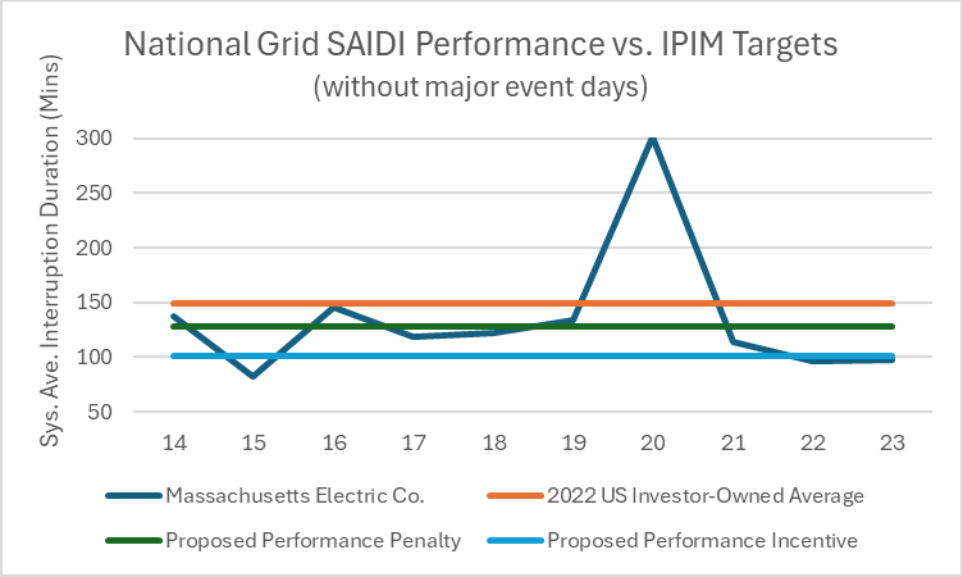
If the Department prefers to retain the Company's proposed metrics, I propose more challenging upper and lower "deadband ranges." The Company proposes 127.5 minutes of average interruption duration as a lower deadband (the point at which longer average interruption durations begin to incur penalties) and an upper deadband of 101.1 minutes (the point at which incentives begin). Although the Company bases these targets on its most recent five years' performance, a review of the past ten years indicates these targets may be insufficiently challenging.

As indicated in Figure 6 below, over the past ten years, these Company-proposed Service Quality PIMs would have resulted in three performance incentive years, four performance penalty years, and three deadband years (no penalty or incentive). Although these targets

[28] According to Form 861 data collected by the U.S. Energy Information Administration. the System Average Interruption Duration Index with major event days (generally, storm days) for U.S. investor-owned utilities in 2022 was 349.5 minutes. National Grid's reliability performance (as reported on Form 861) exceeded that amount in three years out of the last five (790.7 minutes in 2018; 452.2 minutes in 2020; and 471.5 minutes in 2021).

appear balanced at first glance, they ignore the massive reliability improvement investments being proposed. This means that while the proposed Service Quality targets may have been appropriate historically, they are insufficiently challenging given the billion-dollar capital cost increase the Company proposes to incur in its CPIP for 2025–2029 to improve upon its historical reliability performance.[29]

Figure 6. National Grid SAIDI Performance vs. IPIM Targets



[29] Exh. NG-CPIP-1, Table 3, at 60 ($921 million in System Capacity & Performance spending plus $746 million in Asset Condition spending 2025-2029 totals $1.667 billion); Table 4, at 61 ($225 million in System Capacity & Performance spending plus $444 million in Asset Condition spending 2018-2022 totals $669 million). $1.667B - $669M = $998M

National Grid proposes to spend 2.5 times more from 2025 to 2029 ($998 million)[30] than it spent from 2018 to 2022 on System Capacity and Performance and Asset Condition (a type of spending designed to improve reliability). Although we recommend significant reductions from these amounts, should the Department approve any parts of National Grid's proposed spending increase, more challenging reliability targets are needed to hold the Company accountable for performance improvements considering its proposed spending outlays and attendant rate increases.

The mid-point of the upper and lower bound of the Company's proposed average interruption duration IPIM is 114.3 minutes,[31] and the Company's average performance from 2014 through 2023 was 135.0 minutes.[32] I determined the present value to customers (in dollars) of a reliability improvement from 135.0 minutes to 114.3 minutes over the anticipated 40-year life of typical investments intended to improve reliability. To do so, I used the United States Department of Energy's Online Interruption Cost Estimator ("ICE") tool. Employing inputs specific to the Company (such as customer counts by class, and

[30] *See id*.
[31] Exh. NG-CPIP-7, Tab "SQ."
[32] *National Grid*, D.P.U. 24-SQ-11, 2023 Service Quality Report, Section 1, "Penalty Calculation" (SAIDI 2014-2023) (March 1, 2024).

discount rates), the tool generated a present value to customers of projected reliability improvements amounting to $1.009 billion dollars.

Although this calculation appears to indicate a break-even proposition for customers at first glance, recall that $1.00 of National Grid capital spending translates into customer costs of $1.40 (due to profits, taxes on profits, property taxes, and uncollected revenue customers must pay). As a result, the Company's proposal to increase System Capacity and Performance and Asset Improvement spending $998 million for 2025–2029 over 2018–2022 is not remotely cost effective if the Company can only secure a 20.7-minute improvement in average service interruption duration.

Due to multiple examples described later in this testimony, Mr. Stephens and I recommend dramatic reductions to these spending categories. Should the Commission decide to approve some level of spending increases despite our recommendations, we recommend establishing dramatically more challenging reliability improvement targets.

Clean Energy Adoption. I perceive the Company's proposed metric — megawatts (MW) of DER interconnected — to be an inappropriate measure of the Company's contributions to clean energy adoption. First, there are too many influences on this measure beyond the Company's control — including interest rates, market prices for energy and capacity, DER equipment costs, and so forth — to make this an appropriate metric. Second, there is no

cost-effectiveness aspect to the metric. With no cost-effectiveness aspect, the Company is encouraged to spend as much capital as it wishes to hit the target.

If the Department prefers to provide a Clean Energy Adoption PIM, we recommend a metric of MW hosting capacity added per million dollars of capital investment. The performance measured by this metric is not only under the Company's control, but it includes a cost-effectiveness aspect.

Q. What are your specific recommendations for the proposed PIMs?

A. Given that each PIM the Company proposes violates a Department threshold principle or design guideline, I recommend the Commission reject the proposed performance incentives and penalties, and associated PIMs, in their entirety.

If the Department wishes to include PIMs despite this recommendation, I recommend that the Department cut back to the three most important performance areas: Affordability, Service Quality, and Clean Energy Adoption.

The Affordability metric the Company proposed should be rejected in favor of a broader measurement, such as revenue requirement increases relative to inflation.

The Service Quality metric should be made dramatically more challenging if the Department approves a substantial portion of the Company's reliability improvement capital spending request. The Department should consider modifying the Service Quality

metric to be more consistent with future needs related to electric heating, such as "count (or percent) of customers out of service for more than 24 hours," with a target value of zero.

The Company's proposed Clean Energy Adoption Metric should be rejected in favor of a metric that is more directly controlled by the Company and includes a cost-effectiveness aspect. I recommend a metric that measures MW of hosting capacity added per $1 million of capital spending.

IV. RECOMMENDED CPIP SPENDING REDUCTIONS (STEPHENS)

Q. Please introduce this section of testimony.

A. First, I review National Grid's capital project/program funding authorization process, as well as the Company's overall process for developing five-year capital plans (like the CPIP). I will describe the deficiencies I observe in these processes, and the associated implications I believe the Department should consider as it evaluates the Company's Petition. I will also provide support for recommendations to reduce the Company's proposed capital spending increases in three categories, including Customer and Public Requirements; Asset Condition; and System Capacity and Performance. Examples are used to support the Asset Condition and System Capacity and Performance category reductions. Recommended reductions are presented in the table below.

Project/Program ($ in millions)	2025	2026	2027	2028	2029	Totals
CPIP capital spending proposed	577	734	807	876	954	3,949
Customer and Public Requirements	(30)	(34)	(40)	(47)	(55)	(206)
Asset Condition	(6)	(42)	(52)	(53)	(47)	(200)
System Capacity and Performance	(79)	(138)	(146)	(159)	(163)	(685)
Total recommended reductions	(114)	(215)	(238)	(260)	(265)	(1,092)
CPIP recommended by AG	463	519	569	616	689	2,857

Q. Please summarize your understanding of National Grid's capital planning and capital project funding authorization processes.

A. National Grid's capital planning and capital project/program funding authorization processes are two distinct processes, but they are interrelated. To understand how capital budgets are set within National Grid through capital planning, I will first review the capital project/program funding authorization process and work from the bottom up.

Company distribution managers recommend capital projects and programs. These proposals, called "U.S. Sanction Papers," ("USSPs") provide high-level rationale for the recommended project or program, as well as thorough technical plans and associated cost projections. Once a project or program cost projection reaches $2.5 million, review by the Company's U.S. Sanctioning Committee ("USSC") is triggered. A Delegation of

Authority ("DOA") prescribes the project/program level (in dollars) a particular level of personnel (director, vice president, etc.) is authorized to approve for funding, although personnel from multiple departments (finance, operations, customer service, etc.) appear to serve on the USSC. When a project's spending level subsequently appears poised to exceed authorized capital spending by more than ten percent, a new U.S. Sanction Paper requesting additional capital, and an additional USSC review, are required.[33]

National Grid's USSC/DOA review process foresees three primary rationales for approving a project or program for capital: 1) spending that is required for safe and reliable service; 2) spending that corrects an impending violation of distribution capacity planning guidelines; and 3) spending that is discretionary. I describe discretionary spending as a project or program a distribution manager would prefer to see completed, generally to manage reliability, but for which an immediate need does not exist. More information on each rationale is provided below.

Spending required for safe and reliable service. Capital spending that would fall under this rationale includes replacement of failed or damaged equipment, connecting new

[33] This summary, and additional detail presented in the paragraphs that follow, represents my understanding as developed from three sources: 1) Exh. NG-CPIP-1, at 63–69; 2) a discovery conference hosted by National Grid on March 18, 2024, in which I participated; and 3) reviews of multiple, approved USSPs provided by the Company in Exhs. NG-BJM-6 and NG-BJM-6A.

customers to the grid, and facility relocations requested by customers or government agencies (such as the Massachusetts Department of Transportation). Spending for these projects and programs are included in the Company's CPIP Core capital spending budgets as either "Customer and Public Requirements" spending or "Damage/Failure" spending.

For spending deemed necessary for safe and reliable service, the Company does not complete cost-effectiveness testing. As these types of projects and programs are not optional, a cost-effectiveness test adds no value. Such projects and programs must be completed regardless of cost-effectiveness, or lack thereof. I concur with this approach, as long as the definition of "required" is strict and does not include projects or programs that distribution managers would *prefer* to complete (which are more properly considered as discretionary projects or programs, as more fully described a bit farther below).

Spending to correct violations of distribution capacity planning guidelines. Projects justified under this rationale include increases in substation or circuit equipment capacity that are required, as indicated by near-term load growth forecasts relative to the capacity ratings of existing equipment. As the "need" to increase capacity is somewhat variable, and best represented by a range, the Company's Distribution Planning Guide specifies limitations on permitted risk tolerances. For example, the Company's guide specifies that capacity must be increased once the forecasted customer load at risk of interruption during

a contingency configuration (one source of supply already compromised) exceeds 16 MWh.[34]

Capacity increase project/program capital spending is included in the Company's "System Capacity and Performance" budgets. As with spending deemed required for safe and reliable service, spending to avoid Distribution Planning Guide capacity violations is not subject to a cost-effectiveness test. I concur with this approach, as long as near-term growth forecasts are supported by bona-fide customer projects highly likely to be completed (such as real estate developments, data centers, and industrial plant expansions), or by circuit-specific forecasts for electric vehicle or heat pump adoption. Capacity *should not* be expanded based on non-specific economic development promised by developers or encouraged by zoning changes. In my experience, customer loads might not materialize for a decade or more in these situations, so continuously updating the growth forecast is necessary.

Discretionary spending, generally to improve reliability and resilience. These projects are also included in the Company's "System Capacity and Performance" budget, as well as in its "Asset Condition" budget. As described above, discretionary projects are those distribution managers would prefer to see completed, but for which no immediate need

[34] Discovery conference hosted by National Grid March 18, 2024.

exists. A proposed project is discretionary when failure to complete the project in the near term would not reduce the safety and reliability of the service customers currently receive.

Critically, National Grid completes no cost-effectiveness testing for discretionary projects and programs. Instead, discretionary projects and programs are subjectively evaluated, by both the distribution managers recommending the projects, and by the USSC, on the project's or program's ability to deliver "value." "Value," such as reliability value or safety value, is qualitatively determined through a scoring system based on questionnaires completed by employees.[35] The list of discretionary projects is then prioritized based on these scores and other factors, such as personnel availability. This process leads directly to decisions to approve discretionary projects that are not driven by data but instead by distribution managers' preferences for — and personal interests in — work they would like to see completed.

A cost-effectiveness test would involve estimating the reliability or resilience improvements or other benefits from proposed projects; translating these into the economic (dollar) value customers would receive; and then comparing this dollar value to customer costs (that is, rate increases). National Grid's process for evaluating discretionary spending involves none of these steps to test for cost effectiveness. In my view, the lack of cost

[35] *See* Exh. AG-13-16(2).

effectiveness testing for discretionary projects is unacceptable and leads to approval of projects and programs that will not deliver reliability and resilience (or other) benefits in excess of costs to customers.

Q. Please provide your understanding of the Company's five-year capital planning process.

A. The capital planning process runs parallel to the capital project and program funding authorization process. When developing a five-year capital plan such as the CPIP, higher-level managers of the Company review all the projects and programs already underway, as well as those for which capital has been authorized (through the USSC/DOA process described above), but that have yet to commence. Working with National Grid's corporate finance department, these higher-level managers create a five-year capital plan by prioritizing these projects and programs.[36]

Projects that are already underway as well as projects and programs deemed necessary for safe and reliable service are the first items included in the capital plan. It appears that these projects are deemed top priority and are always funded as part of the five-year capital plan, which I believe to be appropriate for capital budgeting purposes.

[36] As above, this summary, and additional detail presented in the paragraphs that follow, represents my understanding as developed from three sources: 1) Exh. NG-CPIP-1, at 63–69; 2) a discovery conference hosted by National Grid on March 18, 2024, in which I participated; and 3) reviews of multiple, approved USSPs provided by the Company in Exhs. NG-BJM-6 and NG-BJM-6A.

Following projects that have started as well as those considered necessary for safe and reliable service, projects deemed necessary to correct impending violations of the Distribution Planning Guide are the next priorities included in the capital plan. It appears to me that such projects are always funded as part of five-year capital plans, as is appropriate in my view for the purpose of capital planning. However, I repeat that projects based on generic expectations of future load growth, such as zoning changes unaccompanied by developers' building permits, should not be prioritized as part of five-year capital plans. Capacity increase projects rationalized by future expectations of load growth, but without concrete construction plans from potential new customers, are more accurately categorized as discretionary projects.

Finally, after capital plans are established for these priority purposes, the capital to be made available for discretionary projects is determined. It appears to me that the Company attempts to complete as many discretionary projects as possible within the funding made available by the corporate finance department.[37] As I previously stated, National Grid performs no cost-effectiveness tests on discretionary projects. To me, this state of affairs is completely backward. Discretionary projects that are cost effective should be funded in the five-year capital plan, while funding for projects that are not cost-ineffective should be

[37] Per commentary provided by National Grid employees in a discovery conference provided for AG experts on March 18, 2024.

excluded. However, because the Company does not know which (if any) discretionary projects are cost effective, the Company's corporate finance department governs the amount of discretionary projects funded without regard to the cost-effectiveness of those projects.

Q. Please discuss your views on the implications of National Grid's capital authorization and capital planning processes.

A. National Grid, like most corporations, will funnel as much capital as it can into the business opportunities that offer the highest rate of return at the lowest risk.[38] In the regulated utility paradigm, the rate of return is authorized by state regulators, and the likelihood that those returns will be achieved is governed in large part by the cost recovery methods and cost disallowance risk determined by state regulators. As a subsidiary of a parent company that operates utilities in multiple jurisdictions, National Grid's corporate finance department will provide funding for more discretionary projects in the jurisdictions that offer the highest rate of return and lowest risk. If one assumes discretionary projects are all cost-effective for customers, this is fine. But since we cannot determine which, if any, discretionary projects are cost-effective for customers, such an approach is not in customers' best interest.

[38] *See* Exh. AG-13-19(2).

Q. What are the implications of National Grid's capital project/program authorization and capital planning processes for the Department's review of the Company's Petition?

Q. Because the Department exerts control over the Company's rate of return, cost recovery methods, and cost disallowance risk, the Department therefore controls the level of cost-ineffective projects that National Grid implements. By authorizing relatively high rates of return, offering very attractive cost recovery, and presenting virtually zero risk of cost disallowance, the Department encourages cost-ineffective spending by National Grid. Conversely, the Department can discourage cost-ineffective spending by authorizing relatively low rates of return as well as by increasing cost recovery and cost disallowance risk.

If the Department offered a less attractive regulatory construct, Massachusetts Electric Company and Nantucket Electric Company would receive less funding from National Grid's corporate finance department for discretionary spending. This would force distribution managers to better focus and prioritize their spending on the most essential grid preparedness and reliability and resilience opportunities. Making these difficult choices is exactly the challenge businesses operating in competitive markets face: finding ways to reduce operating risks for the least amount of capital spending. As the primary role of for-profit monopoly regulation is to serve as a stand-in for competition, the Department is in an excellent position to improve the readiness and resilience of National

Grid's Massachusetts grid at the least cost to customers through the regulatory construct the Department defines.

Q. Have you observed other state utility regulators adopting your perspective?

A. Yes. Recent orders from the Illinois Commerce Commission have forced EDCs owned by corporate parents operating EDCs in multiple jurisdictions to prioritize capital spending choices to the benefit of consumers. In response to a grid investment plan proposed by Commonwealth Edison ("ComEd") that resulted in a proposed 60.5 percent revenue requirement increase over five years,[39] as well as a similar investment plan proposed by Ameren Illinois, the Illinois Commerce Commission rejected the plans and authorized relatively low rates of return (e.g., 8.905 percent for ComEd).[40] In its refiled grid investment plan, ComEd reduced its proposed capital spending plan by 10.65 percent ($909 million). Yet, ComEd states that its revised grid investment plan "will allow ComEd to continue moving towards a decarbonized future,"[41] and that "a reprioritization . . . was performed to determine which programs could be deferred beyond the current Refiled Grid Plan."[42] These statements imply to me that the investment plan reductions brought about

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[39] *Illinois Com. Comm'n v. Commonwealth Edison Co.*, Ill. Com. Comm'n Docket 22-0486, AG Exh. 1.0, at 48 (May 22, 2023).
[40] Ill. Com. Comm'n Docket 22-0486, Order, at 470 (Dec. 14, 2023).
[41] Ill. Com. Comm'n Docket 22-0486, ComEd Exh. 87.0 RGP, at 10:210 (March 13, 2024).
[42] Ill. Com. Comm'n Docket 22-0486, ComEd Exh. 90.0 RGP, at 7:129 (March 13, 2024).

by the Illinois Commerce Commission's orders deferred the least valuable and lowest priority projects. The deferral of low value/low priority projects in Massachusetts is precisely the type of action that I believe will deliver the grid that is required, by the time that it is required, for the least amount of rate increase.

I understand that the Department may seek to encourage grid investment to help achieve the Commonwealth's clean energy goals, and that it may feel the need to secure this outcome by offering relatively high rates of return and relatively low-cost recovery and cost disallowance risk. My testimony here is designed to illustrate the downside of such a regulatory strategy. The downside is that this regulatory strategy encourages premature and cost-ineffective investments that are not in customers' interest and will increase rates so severely as to impede the adoption of building and vehicle electrification by National Grid's customers, contradicting the Commonwealth's clean energy policies. Examples are provided in the remainder of this testimony.

Q. What are your recommendations for reductions to the Company's CPIP regarding Customer and Public Requirements?

A. As indicated in testimony above, Customer and Public Requirements spending is not discretionary, consisting largely of new customer connections and facility relocations. However, the Company proposes a massive increase in this spending category in its CPIP, and the increase must still be justified.

The Company's CPIP proposes a $1.527 billion budget for Customer and Public Requirements for 2025–2029. This is a dramatic increase relative to the five-year period ending 2022, when the Company spent just $399 million on Customer and Public Requirements. The Company is thus proposing a 3.8-fold increase in this budget category in its CPIP.

Q. How did the Company develop its Customer and Public Requirements budget?

A. To develop this budget, the Company began with baseline spending projected to be $171 million in 2024, and grew the 2025-2029 budget by applying a 21 percent annual growth rate experienced in recent years.[43] The $171 million projection for 2024 amounts to a 36 percent increase over 2023 spending ($126 million), which itself represented a 26 percent increase over 2022 spending ($100 million).[44] My concern about the Company's use of the 2024 projection as a starting point for the 2025-2029 Customer and Public Requirements budget is that the projection, as well as the 2023 actual spending on which the projection was based, represent exceptional spending that is not typical. I also note that Customer and Public Requirements spending is highly volatile. In 2019, spending fell 3 percent compared to 2018, and in 2021, spending fell 12 percent relative to 2020.[45]

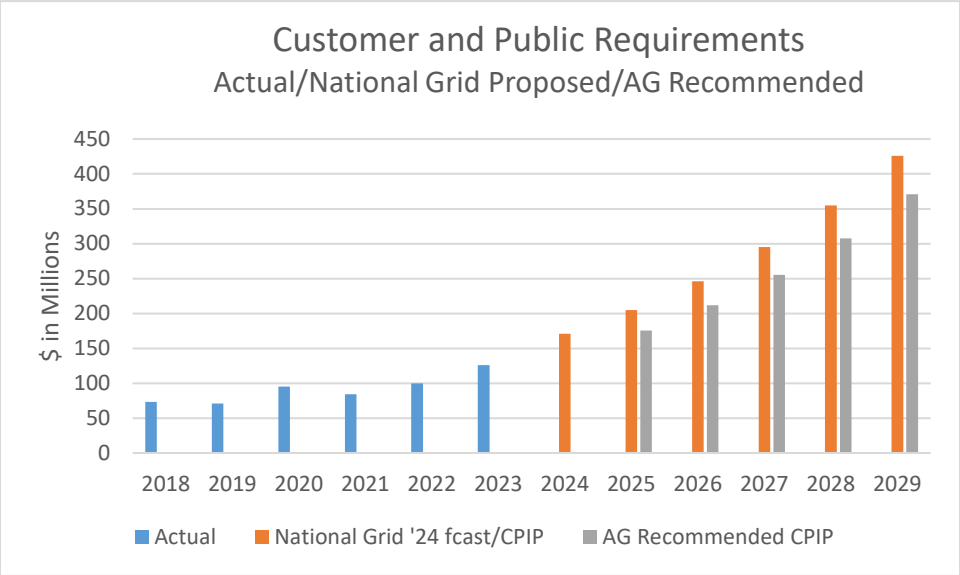
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[43] Exh. AG-5-2, Att. AG-5-2-1, tab "Customer Growth."
[44] *Id*.
[45] *Id*.

To summarize, the development of a 2025–2029 budget that starts with an artificially high baseline results in an artificially high 2025–2029 budget. By employing the more typical spending in 2022 as a starting point, and growing spending annually by 21 percent, I have calculated a more appropriate 2025–2029 budget of $1.32 billion. I note that the $1.32 billion budget that I calculated is still almost triple the actual spending in the five years ending 2023 ($476 million).[46] I therefore recommend the Department adopt my $1.32 billion budget, reducing the Customer and Public Requirements budget the Company proposed 2025–2029 by $207 million. Figure 7 below compares the capital budget I recommend based on the 2022 baseline to the capital budget National Grid proposes in its CPIP, with historical actual spending provided for reference.

[46] *Id*.

Figure 7: National Grid proposed vs. AG recommended Customer and System Requirements budget



Q. What are your recommendations for reduction to the Company's Asset Condition budget?

A. As indicated above, I consider the replacement of assets based on their subjectively assessed condition to constitute a discretionary spending decision. Asset replacements based on objective assessments of a need to replace, such as equipment that fails diagnostic or functional tests, are funded under the "Damage/Failure" budgets; these are required equipment replacements and are not the subject of my concern. The Asset Condition budget funds the former, not the latter.

The Company proposes to increase Asset Condition spending by 68 percent from 2018–2022 to 2025–2029 (from $444 million to $746 million). Yet the Company has completed

no analysis to indicate that the incremental cost of replacing assets based on these subjective assessments of condition is justified by the value of associated reliability improvements.[47]

For decades, all utilities have used objective means to identify equipment in need of replacement. Critical substation equipment such as transformers, circuit breakers, relays, and switches are subjected to functional and diagnostic testing on a periodic basis; poles are periodically subjected to formal inspections and sometimes sounding and boring tests. Equipment that fails these tests is scheduled for relatively prompt repair or replacement.

However, National Grid's Asset Condition program replaces equipment — despite having passed objective tests — based on the subjective assessments of the qualitative "value" provided by replacement, as described earlier. Although the replacement of assets assessed to have "condition" issues, generally very old equipment, is intuitively appealing, it is not cost effective. Equipment testing has been common industry practice for decades specifically because it discounts, rather than elevates, subjective opinions of equipment condition.

I have analyzed the practice of replacing equipment based on subjective assessments of condition, despite the equipment having passed objective testing, many times. I have never

[47] Exh. AG-13-12.

found the practice to be cost effective. In this instance, when analyzing data provided by the Company in discovery, I again found this practice to be cost ineffective. The results of my analyses of the cost-effectiveness of subjective decisions to replace substation transformers and circuit breakers, using National Grid's own equipment failure rates, service interruption data, and replacement costs, are provided in the table below**.**

Summary data from AG analysis of the risk reduction value (in dollars) of decisions to replace equipment based on subjective assessments of condition relative to replacement cost. [48]

Item	Annual rate of Failure in service (a)	Customer Consequence Cost per Failure (b)	Annual risk reduction value (a x b)	Present value of annual risk reduction, 30 years	Cost to replace one unit (low estimate)
Substation Transformer	0.00221	$227,950	$503	$8,224	$3,000,000
Substation Circuit Breaker	0.00113	$290,759	$330	$5,396	$574,300

As the data in the table indicates, in-service substation equipment failure rates are extremely rare. The rate at which in-service substation equipment failures result in service interruptions is rarer still, owing to equipment redundancy that is part of almost all

[48] Data sourced from Exhs. AG-5-18, Att. AG-5-18-1; AG-5-25, Att. AG-5-25-1; AG-5-26; and AG-5-30, Att. AG-5-30.

substation designs; this is reflected in the relatively low customer consequence cost per failure.[49] By multiplying the consequence cost by the historical annual failure rate, I derived the annual value to customers of replacing equipment that has passed its objectives tests ($503 in the case of substation transformers and $330 in the case of substation circuit breakers). From there, it is a relatively simple matter of taking the present value to customers over the 30-year expected duration of the risk reduction and comparing that to average equipment replacement costs. As is clear, preemptively replacing substation equipment that has passed its objective tests is not remotely cost-effective.

Further, I find that the sense of urgency the CPIP Panel Testimony attempts to convey regarding the replacement of aging infrastructure is overblown. All EDCs operate infrastructure that is "aging," and all EDCs repair or replace equipment that fails objective tests over time. EDCs also replace equipment during facility relocations, or when load growth forecasts indicate equipment capacity ratings will be exceeded. The Company is not suddenly experiencing, nor do I expect it to experience, any kind of "wave" of aging

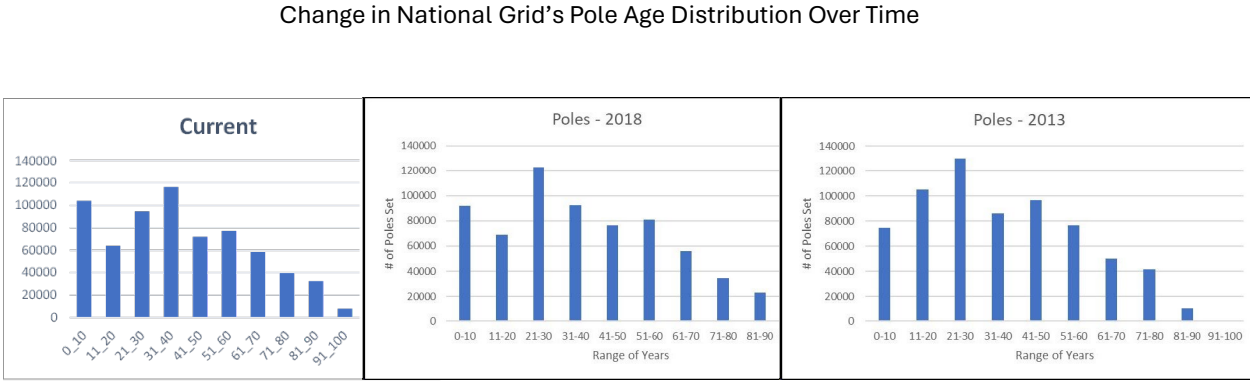
[49] Customer consequence cost employed historical service interruption data associated with equipment failures at National Grid, as well as data on the customer value of avoided service interruptions assumed by the U.S. Department of Energy's online Interruption Cost Estimator tool (grossed up for inflation, as the avoided cost data employed in the tool was published in 2015).

equipment that requires urgent replacement or dramatic increases in Asset Condition budgets.

The adequacy of current asset replacement programs and spending levels can be seen in the example of pole ages, presented in Figure 7 below. Note that the distribution of the Company's pole ages in 2013, 2018, and 2022 look remarkably similar.[50] This similarity of pole age distribution over time indicates the Company's current processes and spending levels for identifying and replacing equipment are appropriate. There is no data indicating that the Company should increase pole replacement frequency, as the Company's proposal to dramatically increase its Asset Condition capital spending suggests.

[50] Exhs. AG-5-41; AG-13-10. Please note that we requested similar charts over time for various types of substation equipment, but the Company stated it did not have the data available to complete such charts. The fact that the Company does not have this data over time for substation equipment is concerning in itself. However, if the data were available, I predict that age distributions for substation equipment would not change over time, either.

Figure 8. Change in National Grid's Pole Age Distribution over Time



Finally, replacing equipment that has passed its tests can be counterproductive. Consider the case of a substation transformer that has passed its tests but is replaced due to its subjectively assessed condition. Given approaching load growth due to electric vehicles and heat pumps, it is possible that the transformer will need to be replaced by one with greater capacity sometime in the near future in any case, resulting in duplicated costs for customers. Thus, if the transformer continues to pass its objective tests, it is most cost-effective to leave it in place until it *must* be replaced due either to test failure or a need to increase capacity.

Q. Are there other Asset Condition examples besides substation equipment and poles?

A. Yes. The Company proposes to increase its underground cable replacement budget from an average of $7.65 million annually 2021–2022[51] to $17.5 million annually 2025–2029.[52] By more than doubling the budget, the Company should be able to double the amount of underground cable it replaces annually. But increasing the underground cable replacement rate does not inherently improve reliability.

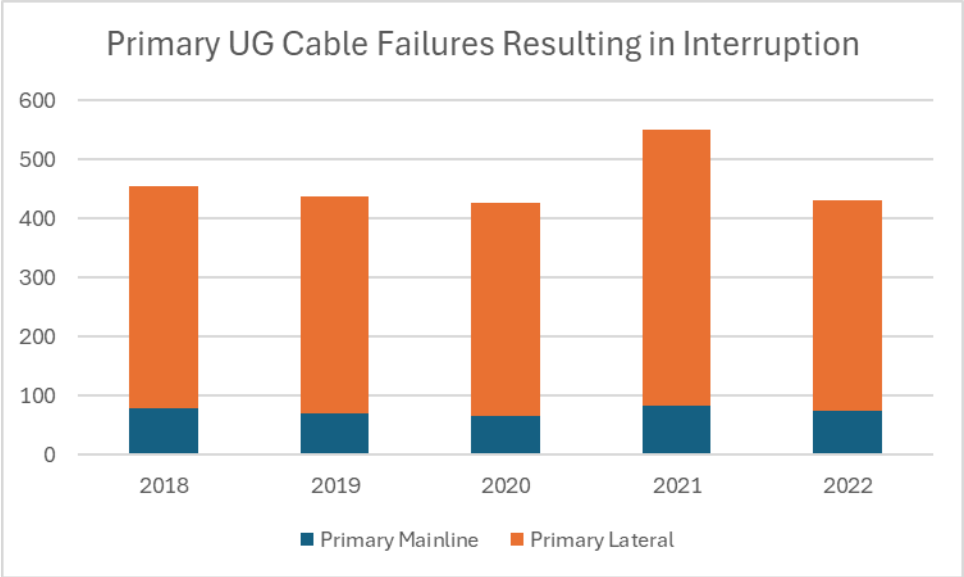
The program targets primary underground cable. About one-third of the Company's underground cable is direct-buried (without conduit), while about two-thirds is buried in conduit. Since 1993, the Company's standard for new installations is to install underground primary cable in conduit.[53] However in my experience, the adoption of a new standard does not require that all equipment installed in compliance with the standards in effect at the time that equipment was installed must be replaced. Yet it appears the Company is attempting to do just that—bring all of its underground primary cable into compliance with the new standard—by increasing its underground cable replacement budget. Further, the Company has completed no analyses indicating that the reliability improvement value to customers of replacing direct-buried cable with cable in conduit

[51] Exh. AG-13-17, Att. AG-13-17.
[52] Exh. AG-5-46, Att. AG-5-46.
[53] Exhs. AG-6-4(5); AG-6-4(4).

exceeds the cost of the program.[54] Yet, the Company has proposed a PIM encouraging it to replace as much direct-buried primary cable with cable in conduit as possible.

In perhaps the most telling evidence, there appears to be no increase in primary cable failures in recent years, and thus no need for large budget increases whatsoever. Though about one-third of the Company's primary underground cable is direct-buried and more than 30 years old, the primary cable failure rate has remained constant in recent years. Figure 8, below, presents the failure data.[55]

Figure 9. Primary UG Cable Failures Resulting in Service Interruptions, 2018–2022.



[54] Exh. AG-6-4(14).
[55] Exh. AG-5-34.

Q. Based on these examples, your recommendation to the Department is to hold Asset Condition budgets flat relative to historical spending, while adjusting for inflation?

A. Correct. Assuming inflation rates of 6 percent in 2023, 5 percent in 2024, 4 percent in 2025, and 3 percent thereafter, I calculate that an appropriate Asset Condition capital budget, based on the average spending from 2018–2022 of $89 million annually, is $546 million from 2025–2029. My recommendation thus reduces National Grid's proposed CPIP spending in this category by $200 million.

Q. What are your recommendations for reduction to the proposed CPIP regarding System Capacity and Performance?

A. The Company proposes to increase System Capacity and Performance spending for 2025–2029 ($921 million) by a factor of 4.3 over 2020–2024 ($213.5 million). Multiple examples can illustrate why increasing spending in this category by a factor of 4.3 is inappropriate. I recommend the Department reduce the System Capacity and Performance capital spending plan 2025–2029 to historical spending levels plus inflation. I will use multiple examples to support this recommendation, including System Capacity; FLISR; inadequate reliability improvement projections, and overhead hardening.

Q. Please explain your System Capacity example.

A. The Company proposes to increase Load Relief (capacity) spending 2025–2029 ($309.1 million)[56] by a factor of 3.2 over 2020–2024 ($95.6 million).[57] Although some might argue capacity increases are needed to accommodate future demand from building and vehicle electrification, these types of demand increases are not included in this budget, which is for Core system spending. The Company proposes an additional $1.775 billion in "Network Upgrades" to expand capacity for EV and heat pump demand in its ESMP for 2025–2029.

The Company may argue that "pockets" of load growth within its service territory require load relief projects even while overall growth in system peak is relatively flat. While I agree, such arguments do not justify a CPIP budget that is more than triple historical levels. For example, from 2020–2024, the Company's system peak grew at a compound annual growth rate of 2.5 percent,[58] and during this time $95.6 million in Load Relief capital spending was adequate to accommodate pockets of load growth. From 2025–2029, the Company projects system peak to grow at a compound annual growth rate of just 1.5 percent.[59] If $95.6 million in Load Relief spending was adequate to cover pockets of load growth during a five-year period of 2.5 percent growth, a similar amount (after adjusting

[56] Exh. AG-5-12, Att. AG-5-12-1.
[57] Exh. AG 5-12, Att. AG-5-12-3.
[58] *Id*.
[59] Exh. AG-5-15.

for inflation) should be sufficient to cover pockets of load growth during a five-year period of 1.5 percent growth.

Q. Please explain your Fault Location, Isolation, and Service Restoration (FLISR) example.

A. FLISR is one of the Company's top spending priorities, amounting to $233 million in capital spending 2025–2029. The Company also proposes a PIM to encourage FLISR deployment acceleration and states a goal that 80 percent of its "FLISR-eligible" circuits be so-equipped.[60]

The Company justifies its FLISR capital spending with reliability improvements secured by FLISR to date.[61] However, I find that both the benefits from FLISR and the costs to install FLISR vary dramatically by FLISR scheme. As a result, one cannot justify the Company's goal to add FLISR to 80 percent of its circuits simply by extrapolating results to date. Specifically, benefits vary by customer counts, customer types, and service interruption history of the circuits involved in a FLISR scheme, and costs vary widely due to circuit tie construction that may be required to implement a FLISR scheme.

To examine the reliability improvements attributable to FLISR, I analyzed two FLISR schemes installed in 2020. I chose FLISR schemes installed in 2020 because three years of

[60] Exh. AG-13-14.
[61] Attachment Exh. AG-6-3, Att. AG-6-3, Tab "Question 5."

reliability data post-installation are now available for comparison to pre-installation reliability data for the same circuits. For one of the FLISR schemes, average interruption duration increased 77 minutes on the two circuits involved; this FLISR deployment was clearly not cost-effective. For the other FLISR scheme, average interruption duration fell 448 minutes on the circuits involved. Using the United States Department of Energy's Interruption Cost Estimator, I found the value to customers of the reliability improvements from this FLISR scheme exceeded the scheme's deployment costs. This validates my contention that the benefits of FLISR schemes are highly variable, and circuit-dependent.

Additionally, the cost to install a FLISR scheme varies dramatically by scheme. FLISR requires tie lines between circuits of adequate capacity to accommodate the transfer of customer loads from one circuit to another in the event of a service interruption. These tie lines are extremely costly to construct. To date, the Company's FLISR installations have focused on circuits that have not required tie line construction. This indicates an artificially low average cost has been assumed, because installations to date have largely avoided tie construction costs.

The Company reports it spent $20.7 million to install 43 FLISR schemes to date for an average cost of $481,000 per scheme.[62] Yet in 2024, the Company proposes to install a

[62] Exh. AG-5-58, Att. AG-5-58, tab "Question 3."

single FLISR scheme that will cost $8.9 million.[63] The reason this particular FLISR scheme will be so expensive is because it requires ten miles of tie line reconductoring. FLISR thus exemplifies the law of diminishing returns described earlier in this testimony. More FLISR schemes are not necessarily better, nor is FLISR the most cost-effective way to improve reliability. A better approach would be to identify the 20 percent of circuits which are likely to deliver 80 percent of system-wide FLISR benefit potential (as an example, per the "80/20" rule, also known as the Pareto Principle).[64]

Finally, FLISR is not as effective in instances of widespread storm damage as it is on blue-sky days, as there are fewer intact circuits available to which customer loads can be transferred. Thus, FLISR is not the best strategy for reducing long-duration service interruptions due to widespread storm damage. Long duration service interruptions should be top priority in a future dependent on electric heat, in which customers could be left without a heating source during dangerously cold temperatures. Improving storm response preparedness, and more aggressively trimming trees, are the strategies more likely to deliver better long-duration interruption improvement at less cost than FLISR capital spending.

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[63] *Id.*, tab "Question 7."
[64] *See, e.g.*, Rosie Dunford, Quanrong Su, Ekraj Tamang, and Abigail Wintour, *The Pareto Principle*, 7 The Plymouth Student Scientist, at 140–148 (2014).

To summarize, simply because FLISR is cost effective on some circuits does not mean it will be cost effective on 80 percent of the Company's circuits. The Company's FLISR goal and PIM are ill-advised, and FLISR is an excellent example of why the Department should dramatically cut the Company's System Capacity and Performance Spending budget. FLISR is also an excellent example of why cost-benefit analyses should be performed for all discretionary spending, including on a circuit-specific basis as indicated for specific technologies or programs.

Q. Please explain why inadequate reliability improvement estimates constitute an example of excessive growth in System Capacity and Performance spending in the CPIP.

A. The Company proposes to more than quintuple reliability spending 2025–2029 ($612 million)[65] over 2020–2024 ($118 million).[66] Note that these figures do not include increases in Asset Condition spending, which are also intended to improve reliability.

National Grid's proposed Service Quality PIM can be employed as a stand-in for the Company's reliability improvement expectation. Unfortunately, as reported earlier, the value to customers of system-wide reliability improvements expected from Asset Condition and System Capacity and Performance spending do not exceed the costs to

[65] Exh. AG-5-12, Att. AG-5-12-1.
[66] Exh. AG-5-12, Att. AG-5-12-3.

customers (via rate increases). This is an indication that the Company may be spending past the point of diminishing return on reliability and serves as another example of why the Department should reduce the Company's proposed System Capacity and Performance capital spending budget.

Q. Please explain your overhead hardening program example.

A. The Company's definition of overhead circuit hardening is to replace bare conductor with covered (insulated) conductor, also known as tree wire.[67] Replacing bare conductor with tree wire also involves installing new, stronger poles (due to the increased weight of covered conductor). When tree branches touch bare conductor, faults and service interruptions generally result; when tree branches touch tree wire, no faults or service interruptions generally result. But while the Company touts circuit hardening as an activity to improve grid resilience to storms, in my experience, a falling tree will bring down either bare or covered conductor, and often some of the poles supporting either type of conductor.

Historically, National Grid capital spending to "storm harden" overhead circuits has averaged over $1 million annually. Since 2015, the Company has hardened 8 circuits at a cost of $10.3 million.[68] By 2029, the Company's CPIP proposes to increase overhead

[67] Exh. NG-CPIP-1,145:7.
[68] Exh. AG-13-22, Att. AG-13-22.

circuit hardening capital spending to $43 million annually[69] — a 33-fold increase. The Company has also proposed a performance incentive mechanism (PIM) that encourages it to complete as much overhead hardening as possible.

Rebuilding circuits with tree wire is a very costly way to improve reliability, at approximately $1.8 million per mile.[70] The Company has tentatively selected 43 miles of 21 circuits for hardening in its CPIP at a projected cost of $79 million; these circuits serve 32,595 customers.[71] This concerns me for two reasons. First, the cost averages $2,427 per customer, making cost-effectiveness a challenge, to say the least, Second, the $79 million will be enough to harden just one-third of one percent (0.0032) of the 13,400 miles of overhead primary circuits the Company operates.[72] At these costs per mile and per customer, overhead hardening would have to be extremely effective at improving reliability if the value of benefits delivered are to exceed costs.

Incredibly, despite the high cost of overhead hardening and the dramatic size of the proposed increase, the Company has not estimated the reliability benefits of overhead hardening,[73] nor compared the customer value of reliability benefits to overhead hardening

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[69] Exh. AG-5-12, Att. AG-5-12-1, line 121.
[70] Exh. AG-6-6-2.
[71] Exh. AG-6-6, Att. AG-6-6.
[72] Exh. AG-5-32, Att. AG-5-32. 43 divided by 13,400 is 0.0032.
[73] Exh. AG-6-6(4).

costs.[74] However, I completed my own assessment of overhead hardening's value. Of the eight circuits on which the Company completed overhead hardening 2015–2023, I selected those for which at least three years of post-hardening reliability data was available. This left me with seven circuits to analyze.[75] For these seven circuits, I compared the average reliability over the three years preceding each circuit's hardening project to the average reliability since each circuit's hardening was completed.

I found that the count of interruptions fell slightly, by about 9 percent, on these seven circuits post-hardening. But I also found that interruption duration increased 46 percent on these seven circuits post-hardening. Of the seven circuits, overall reliability (as measured by customer average interruption duration) improved significantly on one circuit, deteriorated significantly on five circuits, and was essentially unchanged on one circuit. Given the high cost per mile and per customer, such mediocre results do not justify a 33-fold increase in overhead hardening capital spending. Such overhead hardening is not a cost-effective way to improve reliability, and there is no reason why the Department should approve a PIM that encourages overhead hardening.

[74] Exh. AG-6-6(7).
[75] Exh. AG-13-22, Att. AG-13-22.

Q. So, based on these examples, you recommend the Department hold the Company's System Capacity and Performance budget flat, though adjusting for inflation?

A. That is correct. Assuming inflation rates of 4 percent in 2025 and 3 percent thereafter, I calculate that an appropriate System Capacity and Performance budget, based on the average spending 2020–2024 of $42.7 million annually, to be $237 million 2025–2029. My proposed System Capacity and Performance budget therefore recommends a $685 million reduction from National Grid's CPIP.

Q. Can you please summarize your budget recommendations for Customer and Public Requirements, Asset Condition, and System Capacity and Performance?

A. To summarize, I recommend that the Department order a $1.092 billion reduction in National Grid's CPIP core capital spending plans 2025–2029, from $3.949 billion to $2.857 billion. I note that the reduced plan spending I recommend is still more than double the core capital the Company spent from 2018-2022 ($1.413 billion).[76] Specifically:

- The Customer and Public Requirements budget should be $1.32 billion, constituting a $207 million reduction;
- The Asset Condition budget should be limited to its historical average plus inflation, or $546 million, constituting a $200 million reduction;
- The System Capacity and Performance should be limited to its historical average plus inflation, or $237 million, constituting a $685 million reduction.

[76] Exh. NG-CPIP-1, at 61, Table 4.

V. COST DISALLOWANCE RECOMMENDATIONS (STEPHENS)

Q. Please introduce this section of testimony.

A. In the previous section of this testimony, I presented my concerns about the Company's approach to authorizing capital for "discretionary" project and program spending; namely, that the Company completes no quantified estimation of customer benefits relative to customer costs for these items, and that decisions to approve discretionary projects are not data driven. As these deficiencies appear to have been in place for some time, it should come as no surprise that in my review of National Grid's additions to plant-in-service submitted for cost recovery in this case, I identified multiple examples of unjustified capital spending. Almost all of the disallowances consist of discretionary projects. No comparisons of customer benefits to customer costs were completed for any of these projects, and my investigations indicate none are likely to deliver benefits to customers in excess of costs. I recommend cost disallowances of $124.2 million on these projects as summarized below.

Project/Program	Disallowance Amount [77]
Lynn Substation Replacement	$ 30.7 million
Recloser Replacement Programs	4.6 million
Hendersonville Substation	22.2 million
Revere to Winthrop 23kV Underground Cable Replacement	23.7 million
Melrose Substation Replacement	9.4 million
Gloucester Substation Replacement	33.7 million
Total	$124.2 million

Q. Please explain your recommendation to disallow the $30.7 million cost of replacing the Lynn 4kV Substation Replacement.

A. This project replaced the Lynn 4kV substation. The project was primarily justified by subjectively assessed Asset Condition issues at the substation.[78]

My evaluation of the Asset Condition issues reported on the substation identified none that could be addressed only by rebuilding the substation;[79] asset condition issues identified for specific items can be addressed through repair or replacements of individual items much less expensively. All the equipment in the substation had passed its most recent routine,

[77] All disallowance amounts consist of plant placed into service, and associated costs of removal, from January 1, 2020, through March 31, 2023, per Exh. NG-BJM-3 for each project.
[78] *See* Exh. NG-BJM-6A, Book 1, at USSC-149 to USSC-265.
[79] Exh. AG-8-4, Att. AG-8-4.

objective functional and diagnostic tests,[80] and the book value of the equipment at the substation is $12.3 million.[81] These data points indicate to me that while the substation itself may have been old, the substation's critical equipment was not all that old, and, more importantly, was functioning properly.

Although these observations are illustrative, the most critical issues are substation reliability and safety. Here too, I find no justification for replacing the substation. There have been zero equipment failures resulting in service interruptions in the past five years[82] and zero OSHA-recordable injuries at the substation in the past ten years, at the Lynn 4kV substation.[83]

National Grid's approval of this project demonstrated inadequate capital spending governance. I recommend the Department disallow the Company's request to recover $30.7 million in project costs from customers.

Q. Please explain your recommendation that the $22.2 million cost to build the Hendersonville Substation should be disallowed.

A. This project constructed a new substation in Everett. The project was primarily justified by Asset Condition issues at three substations serving the area, including Everett,

[80] Exh. AG-8-4(1)(i).
[81] Exh. AG-8-4(1)(ii).
[82] Exh. AG-8-4(2)(i).
[83] Exh. AG-8-4(2)(ii).

Thorndike, and Wellington. Secondary considerations included increased load growth expected in the area over the long term, as well as arc flash safety issues due to the three substations' proximity to the Mystic Generating Station. The new Hendersonville substation was designed to address these issues.[84]

My evaluation of the Asset Condition reports on the three substations identified no issues that could be addressed only by building a new substation;[85] asset condition issues identified for specific items can be addressed through repair or replacements of individual items much less expensively. Further, my evaluation of the reliability of the three substations over the past five years identified reliability performance significantly better than the Company average. Historical reliability data thus indicate that asset condition in these substations had not impacted service reliability. The average SAIDI and SAIFI values of the circuits served by each of the substations 2019–2023 is presented below.[86]

4kV Circuits Served by (count)	2019–2023 SAIDI (Minutes)	2019–2023 SAIFI (Interruptions)
Thorndike (3)	10	0.136
Everett (12)	51	0.478
Wellington (5)	42	0.237

[84] Discovery Conference March 18, 2024; Exh. AG-8-13, Att. AG-8-13 Confidential [hereinafter "Everett Area Study"].
[85] Everett Area Study; Att. AG-8-13 Supp. Confidential.
[86] Exh. AG-5-17, Att. AG-5-17-1.

Although growth in load in the area over the long term is possible, in my experience real estate projects always take longer to come to fruition than developers and urban planners anticipate. Further, it appears Distribution Planning Guidelines will only be violated in the instance of 1) worst-case component failures; 2) that occur during summer peak; 3) when the grid is already operating under contingency scenarios; and 4) only with the addition of the new loads that are not specifically identified at this time.[87]

Finally, Exelon Generation — the owner of the Mystic Generation Station — announced its intention to close the station on March 29, 2018.[88] Thus, the Company knew, or should have known, that the arc flash safety issue caused by the three substations' proximity to the Mystic Station was already being addressed two months before the Everett Area Study identifying arc flash as a safety risk in the three substations was completed (i.e., in May 2018).

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[87] Everett Area Study at 17.

[88] *See* Press Release, Exelon Corp., Exelon Second Quarter 2018 Results, at 5 (March 29, 2018), https://www.exeloncorp.com/company/Documents/Press%20Release-Earnings%20Tables/Q2%202018%20Press%20Release%20and%20Earnings%20Attachments%20-%20FINAL.pdf.

National Grid's approval of this project demonstrated inadequate capital spending governance. I recommend disallowing the Company's request to recover $22.2 million in project costs from customers.

Q. Please explain your recommendation to disallow $33.7 million in cost to rebuild the Gloucester Substation.

A. This project rebuilt the Gloucester Substation. The project was primarily justified by Asset Condition and animal (seagull) contact issues at the substation.[89]

My evaluation of the condition issues reported at the substation identified none that could only be addressed by rebuilding the substation;[90] asset condition issues identified for specific items can be addressed through repair or replacements of individual items much less expensively. All the equipment in the substation had passed its most recent routine, objective functional and diagnostic tests,[91] and the book value of the equipment at the substation was $3.9 million when the decision to approve its replacement was made (i.e., in 2016).[92] These data points indicate to me that while the substation itself may have been old, the substation's critical equipment was not all that old, and it was functioning properly.

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[89] Exh. BJM-6A, Book 4, at USSC-1399 to USSC-1461.
[90] Exh. AG-8-11, Att. AG-8-11, at 7–9.
[91] Exh. AG-8-11(3).
[92] Exh. AG-8-11(4).

Regarding reliability, the Company reported just seven service interruptions related to equipment failure and animal contact issues over the last ten years. The longest of these service interruptions lasted just 1.8 minutes.[93]

Interestingly, the Company rebuilt the 4kV components of the substation using 15kV equipment (that it currently operates at 4kV). The substation was thus rebuilt in anticipation of a potential future conversion to 15kV as load growth (for example, from EV or heat pumps) might require.[94] Although this decision requires slightly more capital in the short run, it could reduce capital spending in the long run, as it avoids rebuilding the substation twice. However, the Company is not employing this approach broadly,[95] as indicated by multiple 4kV substation construction projects I report on in this section of testimony. The fact that National Grid is not considering the Gloucester substation approach more frequently as it rebuilds 4kV substations does not instill confidence that it is appropriately governing, or trying to minimize, capital spending.

My recommendation is that the Company should not replace equipment or substations based on subjective assessments of condition stands. The fact that the Company often replaces 4kV substations based on subjective assessments of asset condition, and uses 4kV

[93] Exh. AG-8-11(2).
[94] Exh. AG-8-11(7).
[95] Exh. AG-8-11(11).

equipment when it does so, should be of particular concern to the Department. Such replacements appear to ignore the fact that future load growth due to EV and heat pumps could cause this equipment to be replaced again with higher voltage equipment (with higher load-carrying capacity) in the not-so-distant future. This asset "churn" is not in customers' best interest. In the long run, it would be better to continue operating 4kV equipment that passes its tests than to replace it based on subjective condition assessments with 4kV equipment, and then to replace it again in a decade or two with 15kV equipment once such replacement is justified by load growth.

National Grid's approval of this project demonstrated inadequate capital spending governance. I recommend disallowing the Company's request to recover $33.7 million in project costs from customers for this project be disallowed.

Q. Please explain your recommendation to disallow $23.7 million in cost to replace the 23kV underground cable between the Revere and Winthrop substations.

A. This project replaced just four miles of direct-buried 23kV underground cable between two substations, Revere and Winthrop. The justification for the project is listed as Asset Condition, with a secondary concern of reliability. Though the cable is old, two sets of

supply lines connect the substations, meaning that both cables would have to fail simultaneously for a service interruption to occur.[96]

The project was originally approved in 2018. At the time, the project cost was estimated at $13.5 million. Additional capital to complete the project was authorized in 2021, bringing the total project cost to $49.6 million, *almost four times the original cost estimate*. The Company is seeking recovery of $23.7 million in capital placed into service in this rate case.[97]

In the past five years, only one cable failure has occurred (on April 21, 2018). The service to one customer was interrupted for 54 minutes.[98]

National Grid's initial approval of this project demonstrated a lack of capital spending governance, as historical reliability performance did not justify a $13.5 million project. Inadequate capital spending governance was further demonstrated as project costs ballooned to almost four times the original estimate. I recommend disallowing the Company's request to recover $23.7 million in project costs from customers.

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[96] Exh. BJM-6, Book 1,Part 4, at SPFC-222 to SPFC-264.
[97] The difference between the $49.6 million project cost estimate and $23.7 million cost sought for recovery consists of project components yet to be placed into service.
[98] Exh. AG-8-21.

Q. Please explain your recommendation to disallow $9.4 million in cost to decommission the Melrose Substation.

A. The project was prompted by Asset Condition issues, and to a lesser extent reliability and safety issues.[99] Another project justification cited is the risk of high fault current failures on the substation's oil-fused cutouts.

However, in the past five years the Company reports no service interruptions from substation equipment failures.[100] The Company reports no OSHA-reportable injuries in the substation in the past ten years.[101] The Company also reports no high fault current failures on the substation's oil-fused cutouts in the past five years.[102]

The Company reports five equipment failures on circuits served by the substation in the past five years, but these would not have been avoided by decommissioning this substation. In fact, the Company admits "historical or projected reliability performance is not directly tied to the driver of this asset condition project."[103]

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[99] Exh. BJM-6A, Book 4, at USSC-1540.
[100] Exh. AG-8-15(3).
[101] Exh. AG-8-15(4).
[102] Exh. AG-8-15(5).
[103] Exh. AG-8-15(1).

National Grid demonstrated a lack of capital spending governance by approving this project. I recommend disallowing the Company's request to recover $9.4 million in costs from customers for this project be disallowed.

Q. Please explain your recommendation to disallow $4.5 million in recloser replacement program costs.

A. Reclosers are a type of circuit breaker on a distribution line. When a fault occurs downstream, the recloser opens like a circuit breaker, avoiding a service interruption for upstream customers until the cause of the fault can be addressed.[104] Reclosers automatically close into the fault, on the chance that the fault was transient, not permanent. (A common cause of transient faults is a tree branch that temporarily grazes a conductor.) If the fault were transient, the recloser remains closed, restoring power to downstream customers after just a few moments. If the fault is permanent, the recloser opens again, the service interruption is sustained for downstream customers, and a crew is dispatched to address the cause of the fault. Reclosers thus improve reliability, as service interruptions caused by transient faults may be quickly ended.

[104] Note that avoiding service interruptions upstream of a recloser is one of the benefits National Grid touts for its FLISR deployment. Traditional reclosers that are not part of a FLISR scheme can provide the same benefit to customers upstream of a recloser that a FLISR scheme offers. Reclosers can therefore provide a significant amount of the benefits a typical FLISR scheme offers without the high cost of tie construction.

The Company is currently operating two recloser replacement programs. One such program appears to be required for reliable service due to a manufacturing defect, but it inappropriately capitalizes associated O&M costs. The other program does not appear to deliver benefits in excess of costs.

The Company's decision to replace Viper reclosers due to a manufacturing defect appears sound, and the manufacturer is honoring its warranty. However, the Company is capitalizing O&M costs associated with the device replacement program, including device removal costs; shipping and handling costs; and reinstallation costs.[105] As a result, the Company is earning profits from ratepayers on its decision to install a type of recloser that turned out to be faulty.

These capitalized replacement costs should not be borne by customers. Although the manufacturing defect is neither the fault of the Company nor its customers, the Company is provided an opportunity to earn an authorized rate of return to compensate for its business risks. Manufacturing defects in installed equipment is a business risk for which the Company is compensated via the Company's opportunity to earn a return on its capital investments. As a result, I recommend denying the Company's request to recover $2 million in costs from this program.

[105] Exh. AG-8-6(2).

Separate from the Viper recloser replacement program, the Company's Cooper recloser replacement program is not required for safe and reliable service. The Cooper reclosers are not part of a manufacturer's recall program. Further, the Company reports no safety incidents, no Cooper recloser failures, and no associated service interruptions.[106] As a result, I recommend denying the Company's request to recover $2.5 million in costs from this program.

VI. REVIEW AND SUMMARY OF RECOMMENDATIONS

Q. Please summarize your testimony and recommendations.

A. This testimony began by providing context and perspective for the Department's consideration, starting with the massive scale of the Company's CPIP. If the Company deploys all Plan components as proposed, annual capital spending will more than sextuple from 2019 to 2029, and we estimated that distribution rates will almost double from 2023 to 2029. We expressed concern that doubled rates will slow EV and heat pump adoption by National Grid customers — precisely the opposite of the outcome intended by the Commonwealth's clean energy policies. We also compared the growth in electricity use expected by one Massachusetts EDC in its ESMP 2023–2047 and found it to be no greater than the growth experienced in the United States from 1920–1944, or from 1945–1970.

[106] Exh. AG-8-7.

We explained the impact of capital bias on EDC capital planning, using "grid readiness" and reliability/resilience capital planning as examples, employing consumer new product adoption and law of diminishing return curves to illustrate. We also explained the rate increase mitigation value of delaying grid readiness spending until sales volume begins to grow from EV and heat pump adoption (only to the extent such deferrals are possible, of course).

The testimony next addressed the Company's proposed PIMs. We found that every PIM the Company proposed violated one or more of the Department's threshold principles or design guidelines for PIMs, and recommended the Department reject all Company-proposed PIMs as a result. However, in the event the Department prefers to maintain some level of performance-based ratemaking, we suggested PIMs in three performance areas we deemed most critical: Affordability; Reliability/Resilience; and Clean Energy Adoption.

This testimony then turned to recommendations on the Company's $3.95 billion "core" business capital spending component of its CPIP 2025-2029 — 2.3 times greater than the five-year period ending 2024 ($1.695 billion), and with zero smart meter, grid modernization, CIP, or ESMP spending included. We described the Company's capital project review and authorization process, finding it did not include cost-benefit analyses for discretionary projects, resulting in inadequate capital spending governance. In our experience, and in multiple examples provided throughout the testimony, we believe this

omission caused the capital planning process to fund discretionary projects which will not deliver reliability, resilience, or other benefits of sufficient customer value to exceed the costs customers must pay for them. We also explained the role of regulation as a substitute for competition, and as a tool to improve capital spending governance. We presented recent Illinois Commerce Commission orders, and EDC reactions to them, as an example.

Turning to National Grid's CPIP, we presented multiple examples to support our recommendations for large reductions in the Company's core business CPIP 2025–2029, including:

- A $207 million reduction in the Customer and Public Requirements budget;
- A $200 million reduction in the Asset Condition budget;
- A $685 million reduction in the System Capacity and Performance budget.

Finally, we presented our recommended cost disallowances. We recommended that the costs of four substation projects, one underground cable replacement project, and two equipment replacement programs be disallowed, totaling $124.2 million. Almost every instance consisted of a discretionary project for which no comparison of expected benefits (reliability or other) relative to costs was completed. In general, decisions the Company made to fund these projects demonstrated the lack of capital spending governance inherent in the capital project authorization and five-year capital plan development processes the Company employs, particularly for discretionary projects and programs.

Q. Do you have concluding thoughts to share?

A. Yes. We appreciate the leading role the Commonwealth of Massachusetts is taking to decarbonize its economy. We are familiar with such efforts in many states and find Massachusetts to be among the furthest along. We also appreciate the dedication of the Department and Staff in helping to carry out the Commonwealth's policies. We sincerely hope our testimony has contributed to all parties' understanding of the challenges associated with decarbonization, and thank the Department, Staff, and intervenors for considering this testimony.

Q. Does this conclude your Direct Panel Testimony?

A. Yes.

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 Pepco's Second Multi-Year Rate Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel in Maryland PSC Case No. 9702. December 15, 2023.

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 Duke Energy's Peak-time Rebate Pilot Results. Testimony on behalf of the Attorney General in 2022-00251. November 9, 2022.

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 **t**estimony 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.

Evaluate 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.

Evaluate 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

Evaluate 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

Evaluate 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

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.

Evaluate 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.

Curriculum Vitae – Dennis Stephens

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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 Pepco's Second Multi-year Rate Plan. Panel testimony with Paul J. Alvarez on behalf of the Office of People's Counsel in Maryland PSC Case No. 9702. December 15, 2023.

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.

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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.

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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

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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.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

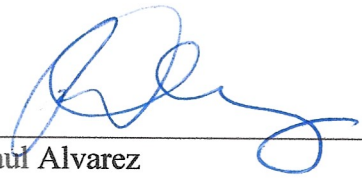
Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid	**D.P.U. 23-150**

AFFIDAVIT OF PAUL ALVAREZ

Paul Alvarez does hereby depose and say as follows:

I, Paul Alvarez, on behalf of the Massachusetts Attorney General's Office, certify that the testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury this 29th day of March, 2024.



Paul Alvarez

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DEPARTMENT OF PUBLIC UTILITIES

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AFFIDAVIT OF DENNIS STEPHENS

Dennis Stephens does hereby depose and say as follows:

I, Dennis Stephens, on behalf of the Massachusetts Attorney General's Office, certify that the testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury this 29th day of March, 2024.

Dennis Stephens