COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan.	**))))))))**	**D.P.U. 23-150**

Direct Testimony of

Melissa Whited

On Behalf of

The Department of Energy Resources

March 29, 2024

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Melissa Whited. I am a Vice President at Synapse Energy Economics (Synapse), located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 35 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have 13 years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models and rate design. I have been an invited speaker in numerous industry conferences, including as a panelist for the

National Association of Regulatory Utility Commissioners (NARUC) Subcommittee on Rate Design at the 2021 Winter Policy Summit and the 2018 Annual Meeting. In 2023, I was a panelist at the New England Electricity Restructuring Roundtable on Electrification, Rate Design, and Equity where I presented case studies for supporting electrification in a manner that reduces grid costs and promotes equity.

I have sponsored testimony before the Massachusetts Department of Public Utilities (Department or DPU), the Illinois Commerce Commission, the New Hampshire Public Utilities Commission, the Georgia Public Service Commission, the Rhode Island Public Utilities Commission, the Maine Public Utilities Commission, the California Public Utilities Commission, the Hawaii Public Utilities Commission, the Public Service Commission of Utah, the Public Utility Commission of Texas, the Virginia State Corporation Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, and the Federal Energy Regulatory Commission. I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. My resume is attached as Exhibit DOER-MDW-2.

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

A. I am testifying on behalf of the Massachusetts Department of Energy Resources (DOER).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the electrification pricing proposal, performance incentive mechanisms (PIMs), and Infrastructure, Safety, Reliability & Electrification (ISRE) cost recovery mechanism proposed by National Grid (or the Company).

Summary of Conclusions and Recommendations

Q. Do you support the Company's proposed Electrification Pricing proposal, Investment Performance Incentive Mechanisms (IPIMs), or ISRE?

A. No, I do not. Briefly, and as discussed in more detail below, I cannot support the Company's proposed Electrification Pricing proposal because it:

- Fails to provide efficient price signals;
- Would increase inefficient electricity consumption and undermine the Commonwealth's emissions goals;
- Would likely result in higher costs to ratepayers through driving additional infrastructure investments;
- Would cause customer confusion around future adoption of more granular pricing structures; and
- Is inequitable by providing no benefits to low-income ratepayers while requiring that those ratepayers shoulder a portion of the costs.

I also oppose many of the Company's proposed PIMs because:

- National Grid's IPIMs are all related to maintaining or improving reliability, which is a core obligation of the utility. Where a utility fails to meet this core obligation, penalties may be appropriate, but rewards for delivering on a core obligation should be avoided.
- Two of the four IPIMs – Fault Location, Isolation, and Service Restoration (FLISR) and overhead hardening – would reward investments, rather than actual, measurable outcomes. In general, PIMs should be outcome-based, rather than only measuring an input.
- National Grid fails to explain why an additional financial incentive is required for utility grid upgrades or investments in charging infrastructure to support electrification of its vehicle fleet, particularly when the utility already recovers the cost of reliability investments with a return on its investment and little or no regulatory lag.
- PIMs should be implemented carefully with an eye to maintaining rates at affordable levels. Where PIMs have not been adequately justified, the Department should reject them to avoid undue increases in electricity rates.

Regarding the Company's proposed Infrastructure, Safety, Reliability & Electrification recovery mechanism, I find that recovery of such costs through the ISRE Factor would dilute the effect of rate design modifications that only apply to base distribution rates. Further, the Company's proposal for a more traditional cost tracker weakens cost containment incentives relative to recovery of costs through the performance-based ratemaking (PBR) plan.

Q. Please summarize your recommendations.

A. I recommend that the Department:

1. Reject the Company's proposed Electrification Pricing proposal.
2. Direct the Company to adopt one of the alternative beneficial electrification rates that I describe in my testimony.
3. Reject the Company's proposed IPIMs and Fleet Electrification PIM as proposed by the Company.
4. Implement the FLISR, Underground Residential Development (URD) replacement, and overhead hardening IPIMs on a scorecard-only basis.
5. Adopt a penalty-only structure for SAIDI and SAIFI performance.
6. Require the Company to recover ISRE costs through the PBR plan.
7. Ensure that the rate design applicable to base distribution costs also applies to ISRE-related costs.

II. NATIONAL GRID'S ELECTRIFICATION PRICING PROPOSAL

Q. Please describe the Company's Electrification Pricing Proposal.

A. National Grid proposes to introduce an optional rate for customers on its standard residential tariff (Rate R-1) called "Electrification Pricing." This rate would replace the volumetric base distribution charge with an additional fixed monthly charge of $38.15, for a total fixed charge of $49.15 per month with the standard customer charge.[1]

Q. How was the fixed charge for the Electrification Pricing proposal determined?

A. The total fixed charge of $49.15 is based on the average base distribution revenue requirement per residential customer.[2] This structure would result in every customer taking service on the Electrification Pricing tariff paying the same amount for base distribution costs, regardless of how much energy they consume. Customers who use less than average electricity would pay more under this proposal than on a volumetric rate, while customers who use more than average would pay less. Thus, it would benefit all customers with higher-than-average usage to take service on this pricing option.

Q. What is the purpose of National Grid's proposed Electrification Pricing rate?

A. The Company states that "the purpose of the Electrification Pricing proposal is to encourage adoption and use of heat electrification technologies by making it more economical to do so, in support of the Commonwealth's electrification goals."[3] Further, the Company states that it "believes this price offering will support electrification in its service territory, will provide customers with options for affordability and bill stability,

[1] Exhibit NG-PP-1 at 25, Exhibit NG-PP-5 at 1.
[2] The Company explains that "the proposed fixed distribution charge is based on a simple conversion of the target residential base distribution revenue target from dollars per kWh to dollars per bill." Exhibit NG-CP-1 at 55.
[3] Exhibit NG-CP-1 at 59.

and will serve as a first step toward more cost-reflective rate design by providing rates that reflect the fact that its costs do not vary with usage."[4]

Q. Do you support the Company's proposed Electrification Pricing rate?

A. No. While I support the Company's stated intent of providing rate options that encourage the adoption of beneficial electrification technologies in pursuit of the Commonwealth's emissions limits and sublimits, I cannot support the Company's Electrification Pricing proposal for several reasons, summarized here and described below:

1. The Company's Electrification Pricing proposal fails to provide efficient price signals, in contradiction of the Department's long-standing rate design objectives.

2. By not limiting the Company's proposed Electrification Pricing to customers who adopt beneficial electrification technologies, the rate would encourage less efficient and wasteful usage, thereby hindering the achievement of the Commonwealth's emissions reductions goals and increasing costs to ratepayers.

3. The Company's Electrification Pricing proposal would cause customer confusion around the future adoption of time-varying rates.

[4] Exhibit NG-PP-1 at 26.

4. The Company's proposal would not be offered to low-income customers, thereby raising equity concerns, particularly since these customers would see their bills increase as a result of the Company's proposal.

National Grid's Electrification Pricing proposal fails to provide efficient price signals

Q. In what way is the Company's proposal contrary to the Department's rate design goals?

A. The Department's five long-standing goals for utility rate structures are efficiency, simplicity, continuity, fairness, and earnings stability.[5] However, these goals are not of equal importance. The Department has determined that efficiency is a "particularly important" goal,[6] and that "meeting the goal of efficiency should involve rate structures that provide strong signals to consumers to decrease excess energy consumption in consideration of price and non-price social, resource, and environmental factors."[7]

Q. Why do you claim that the Company's Electrification Pricing does not provide efficient price signals?

A. The Company's Electrification Pricing proposal replaces the volumetric rate with a fixed charge. Thus, no matter how much energy a customer uses, the base distribution portion

[5] D.P.U. 95-104 at 15.
[6] D.P.U. 09-39 at 404.
[7] D.P.U. 15-155 at 383-384.

of the customer's bill would remain fixed at $49.15 per month. This conveys a signal to customers that the marginal cost of consuming additional electricity is zero.

Q. What is marginal cost?

A. Marginal cost is defined as the change in total cost with respect to a small change in output. In a perfectly competitive market, the price of a good equals its marginal cost. Economic theory holds that marginal cost pricing results in efficient consumption of the good, as it provides consumers with a price signal that conveys the cost of producing additional goods. As Dr. Alfred E. Kahn explained,

> The reason is that the demand for all goods and services is in some degree, at some point, responsive to price. Then, if consumers are to decide intelligently whether to take somewhat more or somewhat less of any particular item, the price they have to pay for it (and the prices of all other goods and services with which they compare it) must reflect the cost of supplying somewhat more or somewhat less – in short, marginal opportunity cost.[8]

Notably, marginal costs convey the *future* costs of producing more of a good, rather than historical (embedded) costs.[9] Further, it is important that rates reflect marginal costs over a relatively long horizon as short-run marginal costs can be extremely volatile. Public utility ratemaking is a cumbersome and sometimes lengthy process, and it is infeasible to modify rates rapidly enough to reflect short-run changes in costs. Moreover, customer

[8] Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, vol. Volume I (Cambridge, MA: MIT Press, 1988) at 66.
[9] *Id*. at 73.

investments in electrical equipment tend to be long-lived, and thus some degree of rate stability is appropriate. For this reason, it is appropriate to look out to the future at least several years when using marginal costs to design rates.

Q. Is the marginal cost of electricity consumption zero for the distribution system?

A. No. The marginal cost of electricity consumption on the distribution system depends on the timing of that consumption. In some hours, there is ample distribution capacity that can absorb additional electricity consumption with little to no additional cost. This is particularly true in the winter season, as National Grid's system is expected to remain summer peaking through 2035.[10]

In other hours, particularly hot summer days, distribution equipment may be approaching its capacity limit, and increased electricity consumption causes greater wear and tear on the equipment and drives the need for capacity upgrades.

Q. Does a volumetric rate send a more efficient price signal than a fixed charge?

A. Yes. Although a flat volumetric rate does not account for the timing of electricity consumption, it does convey to customers that there is a cost to greater electricity usage.[11] In contrast, a fixed charge sends a signal to customers that electricity consumption

[10] Exhibit DPU 7-6, Attachment DPU 7-6 at 6.
[11] Time-varying distribution rates can convey an even better price signal regarding the cost to serve additional load, but widespread implementation of residential time-varying rates will not be available for National Grid customers until the roll-out of advanced metering infrastructure.

imposes no cost on the distribution system at all. The Company's proposed Electrification Pricing essentially eliminates all price signals for distribution costs and presents customers with the equivalent of "all you can eat" buffet pricing in contravention to the Department's core rate design objectives.

<u>The Company's proposal would undermine the Commonwealth's emissions goals and increase costs for ratepayers</u>

Q. What eligibility requirements does the Company propose for the Electrification Pricing option?

A. The Electrification Pricing option is proposed to be available to all Rate R-1 customers.[12] Moreover, the Company proposes this as a technology-neutral pricing option such that the option would be available to residential customers regardless of end-use, including the use of electric resistance heating.[13]

Q. Why is it problematic that the Company has not proposed to limit its electrification rate to customers who have adopted beneficial electrification technologies?

A. It is important to remember that increased electricity consumption by itself is not the objective. Instead, the goal of an electrification rate should be the adoption of *beneficial* electrification technologies, because beneficial electrification replaces less efficient technologies or more polluting fuels. By not distinguishing between customers who have high usage due to beneficial electrification and those who have high usage for other

[12] Exhibit NG-PP-1 at 26.
[13] Exhibit LI-NG-1-8(f).

reasons, the Company's proposal would undermine the ability to achieve the Commonwealth's 2050 Net-Zero emissions targets and the limits and sub-limits outlined in the Massachusetts Clean Energy and Climate Plan for 2050 (CECP 2050)[14] and would unnecessarily increase the need for additional utility investments.

Q. How would the Company's proposal undermine the achievement of the Commonwealth's emissions goals?

A. The Company's proposed Electrification Pricing proposal would recover all base distribution costs through a fixed charge, rather than a volumetric rate. Replacing the volumetric rate with a fixed charge would lower the effective electricity price for high usage customers.[15] Customers generally respond to prices by consuming more when the price is low, or curtailing consumption at high prices. By lowering the effective price of electricity at higher usage levels, National Grid's proposal would encourage greater electricity consumption. While increasing electricity consumption is desirable for customers who invest in beneficial electrification technologies as a means to switch off fossil-fuel equipment, it is undesirable with respect to wasteful usage or when it reduces the incentive for customers to invest in more efficient technologies.

[14] Executive Office of Environmental Affairs, Clean Energy and Climate Plan for 2050 (Dec. 2022), available at https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download (CECP 2050).

[15] The "effective electricity price" is the customer's bill divided by the customer's usage, expressed in $/kWh.

Q. Can you provide an example of how customers might respond inefficiently to the Company's proposed Electrification Pricing?

A. Yes. A lower effective electricity rate makes it less expensive for customers to heat with electric resistance heating, which is highly inefficient. National Grid's Electrification Pricing proposal would reduce the incentive for these customers to convert to more efficient heat pumps for heating. Continued reliance on electric resistance heating leads to higher electricity consumption and increased greenhouse gas emissions, hindering the achievement of the Commonwealth's emissions reduction goals.

Q. How would limiting the rate applicability to customers with beneficial electrification technologies help to address this problem?

A. A rate that is limited to beneficial electrification technologies provides an even stronger incentive for customers with electric resistance heating to adopt efficient electric heat pumps, as the heat pump would both significantly reduce their electricity consumption and allow them to pay less per kilowatt-hour of electricity, thereby improving the economic return on their investment. This helps to achieve Massachusetts' climate goals through reducing inefficient electricity consumption that contributes to electric sector emissions.

Q. How would the Company's Electrification Pricing proposal increase costs to ratepayers?

A. The Company's proposal would increase costs to ratepayers in several ways. As discussed above, the proposal would promote increased electricity consumption, regardless of whether that consumption is related to beneficial electrification or simply wasteful or inefficient usage. Depending on the timing of the increased electricity consumption and whether it is displacing less efficient technologies, it could increase National Grid's revenue requirements. It could also increase the cost of procuring energy through the wholesale market. This is especially true if the incremental electricity use drives costly capacity upgrades at the distribution, transmission, or wholesale generation level; or if it occurs during the hours with the highest locational marginal prices.

In addition, the Company's proposal would cause a rate increase for the majority of residential customers due to shifting revenue recovery away from the minority of high-usage customers (approximately 37 percent) onto the remaining majority of customers (63 percent). The Company projects that this could raise electricity rates for the majority of residential customers by more than 4 percent.[16] This increase in electricity bills for lower-usage customers would occur while providing minimal incentive for customers to adopt beneficial electrification technologies.[17]

Q. What reasons does the Company provide for not limiting the rate design to customers who have adopted beneficial electrification technologies?

A. The Company offers multiple reasons for not limiting its proposed rate to customers with beneficial electrification technologies. First, the Company states that technology-specific rates would represent movement away from more cost-reflective rate design "because

[16] Exhibit NG-CP-1 at 59.
[17] As discussed above, the Company's proposal would be open to any R-1 customer, including customers with electric resistance heating.

utility system costs do not vary by customer end use technology."[18] However, many utility system costs (particularly capacity upgrades) *are* driven by the magnitude and timing of customer load, and customer load profiles can be correlated with specific technologies. For example, the Massachusetts Residential Building Use and Equipment Characterization Study prepared for the electric and gas program administrators contains typical and peak day load shapes for a variety of household appliances.[19] Thus, it *is* possible to design technology-specific rates that are more reflective of the costs imposed on the system by those customers. More egregious, however, is the Company's implicit argument that its proposed rate design is more cost-reflective than a technology-specific rate. As discussed above, the Company's rate design – a fully fixed charge – completely severs the causal relationship between electricity consumption and base distribution costs. I cannot think of a rate structure that is further removed from reflecting cost causation.

The Company also argues that "technology-specific rates are complex and costly to implement, requiring verification of eligible technologies and submetering of appliances."[20] This, too, is wholly inaccurate. Verification of technologies is

[18] Exhibit LI-NG-1-8(d).
[19] Guidehouse, Massachusetts Residential Building Use and Equipment Characterization Study, Phase 7 (Dec. 22, 2023), available at https://ma-eeac.org/wp-content/uploads/Residential-Building-Use-and-Equipment-Characterization-Study-Comprehensive-Report-2023-12-22.pdf.
[20] Exhibit LI-NG-1-8(d).

unnecessary; instead, self-attestation is common for determining eligibility for many utility tariffs designed for customers adopting specific technologies. For example:

- To enroll in Southern California Edison's TOU-D-PRIME tariff, a customer must simply attest that they have an electric vehicle, battery, or electric heat pump.[21]
- Central Maine Power's Seasonal Heat Pump rate requires customers to affirm that they have a heat pump through a web form but does not require verification.[22]
- In its open rate case, Unitil has proposed a technology-specific rate offering to incentivize heating electrification, requiring self-attestation of heat pump installation at the service location.[23]

Further, no submetering of appliances is necessary for whole-home rates, so there would be no additional metering or submetering costs or associated back-office costs. For example, Unitil's proposed heat pump rate offering (described above) does not require submetering as the rate applies to the customer's entire load.[24]

[21] Southern California Edison, Rate Options for Clean Energy Technology, Go Electric with a Great Plan (2024), available at https://www.sce.com/residential/rates/electric-vehicle-plans.
[22] Central Maine Power, NEW Delivery Rate Options (2024), available at https://www.cmpco.com/account/understandyourbill/newseasonalheatpumprate.
[23] D.P.U. 23-80, Exhibit DPU 2-04.
[24] *Id*.

In short, the Company's claims that a tariff limited to customers who adopt beneficial electrification technologies is infeasible, costly, or less cost-reflective is simply false.

<u>**The Company's proposal would hinder the future adoption of time-varying rates**</u>

Q. How would the Company's proposal impact the future adoption of more granular rate structures, particularly time-varying rates?

A. The Company states that its "long-term rate design strategy seeks to move toward more cost-reflective, equitable, and grid beneficial rate designs," which will include time-varying rates enabled by advanced metering infrastructure.[25] In the near-term, the Company's rate designs should be setting the stage for more granular pricing structures for distribution cost recovery so that customers can more readily transition to these advanced rates in the future. The Company's Electrification Pricing proposal fails to do this. Instead, it eliminates all price signals for base distribution costs, which will be confusing to customers when they are asked to understand and adopt more granular rates in the future.

National Grid's proposal to switch from volumetric rates to a flat fee before implementing more granular pricing in the future will only lead to customer confusion and frustration. This is equivalent to a cafeteria that currently charges customers based on the weight of the food, but proposes to switch to "all you can eat" buffet pricing in the short-term before implementing pricing that reflects both the weight and type of food a

[25] Exhibit NG-CP-1 at 56.

customer selects in a few years. In other words, it makes no sense to take a step backward in terms of pricing sophistication now, when the Commonwealth needs to be laying the groundwork for the adoption of more sophisticated time-varying rates and full use of AMI technology in a few years.

<u>The Company's Electrification Pricing proposal is inequitable</u>

Q. What are your concerns regarding the equity of the Company's Electrification Pricing proposal?

A. I am concerned that the Company's proposal would not benefit low-income customers, but these customers would be saddled with the costs of the Electrification Pricing proposal. To access the Company's Electrification Pricing option, a customer on the low-income discount rate would have to forfeit their discount and transfer onto the standard residential rate. The loss of the low-income discount would outweigh the benefit of the Electrification Pricing proposal, so there is no way for a low-income customer to benefit from the rate.

Q. How would low-income customers bear the costs of the Electrification Pricing proposal?

A. Currently, higher-usage customers pay higher bills than low-usage customers. Under the Company's proposal, customers with higher-than-average usage would pay the same amount in base distribution costs as an average usage customer, leading to a revenue shortfall. This revenue shortfall would then be recovered from all other customers, including low-income customers.

Q. How much would other customers' rates increase due to the Electrification Pricing proposal?

A. The Company estimates that about 37 percent of all residential customers would benefit from its Electrification Pricing proposal.[26] If all of those customers enrolled in this pricing option, it would increase rates for a residential customer with average monthly usage by 4.1 percent, or $108 annually.[27]

III. ALTERNATIVE ELECTRIFICATION RATES

Q. Are there any electrification rates for utilities that lack advanced metering infrastructure (AMI) that would avoid the problems you describe above?

A. Yes. Advanced metering infrastructure is a precursor to implementing time-varying rates more broadly for residential customers, but AMI will not be fully rolled out for National Grid's residential customers for several more years. However, this does not mean that rates cannot be modified to be more cost-reflective and provide incentives for electrification in the near-term. Below I describe two options that could be implemented prior to the full roll-out of AMI:

1) A seasonal rate, whereby distribution costs are recovered based on the seasonality of future peak loads on various distribution system components; and

[26] Exhibit NG-CP-1 at 59.
[27] *Id*.

2) An explicit rate discount for customers adopting beneficial electrification technologies.

Q. Please explain how a seasonal rate could be designed to promote greater adoption of beneficial electrification technologies.

A. A seasonal rate should account for the seasonality of marginal costs associated with meeting peak load on the distribution system. Specifically, the cost of future growth-related capacity needs should be determined and assigned to the season in which peak loads are most likely to occur, taking into account projected heat pump and other distributed energy resource load profiles.

Historically, National Grid's substations have primarily peaked in the summer months,[28] and National Grid expects its system to remain summer peaking through the year 2035.[29] Thus, a seasonal rate would recover most shared distribution capacity costs in the summer months, rather than the winter months, resulting in a much lower winter rate. This would benefit customers who adopt electric heat pumps, as they tend to increase winter electricity consumption significantly.

Q. Can you provide an example of a seasonal rate designed to promote heat pumps?

A. Yes. Central Maine Power (CMP) is piloting a Seasonal Heat Pump rate. The Seasonal Heat Pump Rate consists of a higher fixed charge and a seasonal volumetric charge,

[28] D.P.U. 15-155, Exhibits NECEC-02-002 and VS-02-012.
[29] Exhibit DPU 7-6, Attachment DPU 7-6 at 6.

which are both set based on the Company's marginal cost of service study. The seasonal volumetric rate recovers all distribution and transmission costs during the summer season (May through October) because CMP's distribution system is overwhelmingly summer-peaking and is projected to remain so for at least the next several years, even with the adoption of heat pumps and other distributed energy resources.[30] All other charges (such as energy efficiency, low income, and stranded costs) are recovered in all months. This results in the following distribution rates:[31]

Table 1. Central Maine Power Seasonal Heat Pump Rate

Service Fee	$/month	$37.71
May – October	$/kWh	$0.137508
November – April	$/kWh	$0.004317

[30] CMP's rate design filing notes that "[c]urrently the two summer months concentrate almost 100 percent of the system-wide distribution probability of peak. … The probability of winter peak would increase for the coldest winter months from less than 1 percent as of 2021 to about 9.4 percent in 2026 as a result of changes brought by DERs and electrification, however July and August will continue to have the highest likelihood of carrying the annual peak at the distribution system level relative to winter months in the next five years, due to the grid´s lower carrying capability in high temperatures. All other months in the year (shoulder season) will have significant lower loads, meaning that load increases in those months due to electrification or other factors will impose little or zero marginal distribution cost at the distribution substation level." Docket No. 2022-00152, Exhibit AN-3 (Aug. 2022) at 6.

[31] CMP, Rate A-Seasonal, Residential Service (effective Jan. 2024), available at https://www.cmpco.com/documents/40117/115962041/a-seasonal+02.28.24.pdf/13c3d872-e9d9-48f3-030d-f261ba6b8456?t=1709126369895; CMP Recommendations Resulting from the CMP Rate Design Collaborative Stakeholder Process, Docket No. 2022-00152 (Dec. 1, 2023), available at https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={35A1E320-E2D8-4977-B7D6-450D4A2E9D6D}&DocExt=pdf&DocName={35A1E320-E2D8-4977-B7D6-450D4A2E9D6D}.pdf.

Q. What are the advantages of a seasonal rate?

A. A seasonal rate is much more cost-reflective than a rate without seasonal differentiation (*e.g.,* National Grid's current flat rate or its Electrification Pricing proposal), while also potentially providing a substantial rate discount to customers who use most of their electricity in the winter (such as customers who adopt heat pumps). It also does not undermine the price signal for energy efficiency or conservation, as it maintains a largely volumetric rate structure. Because the rate is cost-reflective, there is no need to limit it to customers who adopt beneficial electrification technologies.

Q. How would an explicit rate discount function?

A. A rate discount could be designed similarly to an economic development rate or load attraction rate. Historically, economic development rates or load attraction rates have been used by utilities to attract new businesses to locate in the utility's service territory by providing temporary rate discounts. The theory is that by attracting additional load, the fixed costs of providing electricity will be spread over greater electricity sales, resulting in lower rates for all customers. Similarly, beneficial electrification rates could provide a discount for some period of time to encourage the addition of new, beneficial load on the system, beyond the level that would occur under existing rate structures. As long as rates are set above the marginal cost of providing electricity, utility customers as a whole will be better off with the addition of new load. Over time, the rates are generally increased to reflect total embedded costs, rather than only covering marginal costs.

Q. Is the marginal distribution cost associated with heat pump usage high?

A. No. The marginal costs on the distribution system associated with winter heat pump usage are generally expected to be low for the next decade, as National Grid's system is expected to remain summer peaking.[32] Further, the system can accommodate greater thermal loads during the winter, further reducing the impact of heat pumps on the system. Thus, significant heat pump adoption can occur within existing system headroom at very low marginal cost.

Q. Have any other utilities proposed a discounted rate for heat pumps?

A. Yes. This approach to a beneficial electrification rate is similar to the heat pump rate recently proposed by Fitchburg Gas and Electric Company d/b/a Unitil in D.P.U. 23-80. Unitil's heat pump rate (HP-RES) features a discounted winter rate relative to the standard residential rate, with all other rate components remaining the same as the standard rate.[33] The discount was designed to be revenue neutral with usage levels prior to adopting heat pumps. In other words, based on the Company's expectations for increased kilowatt-hour usage, the rate would still recover the same level of total fixed

[32] On some circuits, heat pump adoption may cause distribution upgrades sooner than 2035, but most of National Grid's substations and feeders have historically been summer peaking, suggesting that this is likely to uncommon in the near-term.

[33] D.P.U. 23-80, Exhibit Unitil-JDT-1 at 24-25; D.P.U. 23-80, Exhibit Unitil-JDT-6 at 1.

costs from customers as it did prior to the adoption of a heat pump.[34] However, due to the amount of revenue recovered through reconciling mechanisms rather through base distribution rates for Massachusetts utilities, this approach would still result in a relatively modest rate discount for heat pump customers, since it would only apply to base distribution rates. A more effective approach would be to apply the discount more broadly across various cost recovery mechanisms as proposed by DOER in its Initial Brief in D.P.U. 23-80/23-81.[35]

Q. What are your recommendations regarding National Grid's Electrification Pricing proposal?

A. I recommend that the Department reject National Grid's Electrification Pricing proposal and direct the Company to implement an alternative rate structure, such as seasonal pricing or a rate discount for customers that have attested to having beneficial electrification technologies. This alternative rate option should be available to low-income customers as well to promote equity. In this case, the low-income rate discount would be applied to the new alternative rate so that it is commensurate with the current discount.

[34] D.P.U. 23-80, Exhibit Unitil-JDT-1 at 24-25; Exhibit Unitil-JDT-6 at 1; Tr. Vol. 3 at 210.
[35] D.P.U. 23-80, D.P.U. 23-81, DOER Initial Brief at 8-14.

IV. PERFORMANCE INCENTIVE MECHANISMS

Q. What is a performance incentive mechanism?

A. A PIM is a performance metric with a target and associated financial reward or penalty for meeting or failing to meet a target. PIMs can serve as a useful regulatory mechanism to positively influence utility behavior to advance energy policy goals that are not directly aligned with a distribution company's public service obligations or existing financial incentives. Tracking metrics and scorecards are used to collect and monitor data for the purpose of measuring and reporting utility performance and for establishing future performance metrics.

Q. What PIMs has National Grid proposed?

A. The Company proposes two categories of PIMs: investment-related PIMs (IPIMs) and operating-based PIMs. Within the IPIM category, the company proposes four PIMs related to: (1) FLISR project deployment; (2) URD direct buried cable replacement; (3) overhead hardening; and (4) reliability. In addition, the Company is proposing the following five operating-based PIMs: (1) Increased Enrollment in the Low-Income Discount Program; (2) Fleet Electrification; (3) Digital Customer Engagement; (4) First Call Resolution; and (5) Megawatts of Distributed Energy Resources Interconnected.[36]

[36] Exhibit NG-CPIP-1 at 167.

The combined maximum potential reward or penalty over the period 2025-2029 is $70.6 million, as shown in the table below.[37]

Table 2. National Grid's Proposed PIM Maximum Reward/Penalty (Millions)

	2025	**2026**	**2027**	**2028**	**2029**	**Total 2025-2028**
IPIMs	$4.00	$4.40	$4.80	$15.40	$26.00	$54.60
PIMs	$3.09	$3.15	$3.20	$3.30	$3.30	$16.04
Total	$7.09	$7.55	$8.00	$18.70	$29.30	**$70.64**

I do not address all of these PIMs in my testimony; instead I focus on the Company's IPIMs and fleet electrification proposal. My silence on other PIMs does not indicate that I agree with or support the Company's proposals.

<u>IPIMs</u>

Q. What is the maximum reward or penalty for National Grid's proposed IPIMs?

A. The combined maximum reward or penalty for National Grid's proposed IPIMs is $54.6 million, as shown in the table below.

Table 3. National Grid's Proposed IPIM Maximum Reward/Penalty (Millions)

	2025	**2026**	**2027**	**2028**	**2029**	**Total 2025-2028**
FLISR	$3.30	$3.60	$3.80	$4.20	$4.50	$19.40
URD Replacement	$0.70	$0.80	$1.00	$1.20	$1.50	$5.20
Overhead Hardening					$10.00	$10.00

[37] Exhibit NG-CPIP-1, Table 15 at 134.

Service Quality Extension				$10.00	$10.00	$20.00
Total	$4.00	$4.40	$4.80	$15.40	$26.00	**$54.60**

Q. Please describe National Grid's proposed FLISR IPIM.

A. National Grid proposes a target of installing 30 FLISR schemes each year (which includes the design and installation of multiple grid automation devices such as pole-top reclosers, feeder monitoring devices, and other devices).[38] If the Company exceeds 36 schemes, it would earn an incentive of $366,667 for each scheme, until the maximum incentive cap of $3,300,000, or 45 FLISR schemes, is reached. If the Company installs less than 24 schemes, then the Company will pay a penalty of $366,667 for each scheme below the deadband until the penalty cap of $3,300,000 is reached.[39]

Q. Please describe the URD Direct Buried Cable Replacement IPIM.

A. This PIM would measure the Company's improvement of reliability to customers experiencing four or more outages over the prior three years due to failure of their direct buried primary cable.[40] The IPIM would measure the number of annual direct buried cable faults for cables that have experienced four or more faults over the past four years (the CEMI-4 list). National Grid proposes a target of 70 percent of these cables not

[38] *Id*. at 136.
[39] *Id*. at 137.
[40] *Id*. at 139.

experiencing a fault during the year[41] relative to the baseline of 64 percent.[42] The Company would earn a reward if its performance exceeds 80 percent, and a penalty if its performance falls below 60 percent.[43]

Q. Please describe the proposed Overhead Hardening for Resiliency IPIM.

A. This PIM would measure the replacement of targeted mainline overhead wire with tree-resistant wire, targeting sections that have under-performed during major events and considering climate projection data where available. This PIM would enhance both blue-sky reliability and performance during storms. The Company has set a target to replace the wire over 50 miles by the end of the five-year rate plan.[44] The Company proposes to earn an incentive for replacing more than 60 miles of wire within five years or pay a penalty if it fails to replace at least 40 miles of wire.

Q. Please describe National Grid's proposed service quality extension IPIM.

A. Under this PIM, National Grid proposes to improve its System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) performance for 2028 and beyond by another one-sixth of the standard deviation of performance[45] This proposal represents a continuation of the glide path that was

[41] *Id*. at 141.
[42] Exhibit NG-CPIP-7 at 4. Performance for the period 2021-2023 ranged from 59 percent to 73 percent.
[43] Exhibit NG-CPIP-1 at 142.
[44] *Id*. at 146.
[45] *Id*. at 149.

originally established in D.P.U. 12-120-D and which is set to expire in 2027.[46] Under the Company's proposal, the penalties for SAIDI/SAIFI under-performance would continue, but the Company would also be rewarded for achieving overperformance on SAIDI, with a reward beginning at 1/3 of a standard deviation below the target (114.3 minutes per customer) and reaching its maximum at one standard deviation from the target (61.4 minutes per customer).

Q. Do you have concerns with National Grid's proposed IPIMs?

A. Yes. I outline my concerns below:

- First, National Grid's IPIMs are all related to maintaining or improving reliability, which is a core obligation of the utility. Where a utility fails to meet this core obligation, penalties may be appropriate. However, rewards for delivering on a core obligation should be avoided.

- Second, two of the four IPIMs (FLISR and overhead hardening) would reward investments, rather than actual, measurable outcomes. For example, the FLISR IPIM only addresses the number of FLISR schemes installed, rather than measurable improvements in reliability. In general, PIMs should be outcome-based, rather than only measuring an input.

[46] *Id*. at 150.

- Third, PIMs should not offer a utility more financial benefit than is necessary to align its performance with the public interest. National Grid earns a return on its capital investments and will continue to have expedited cost recovery under the Performance-Based Ratemaking (PBR) plan, and therefore has an incentive to invest in its system to improve reliability. While a PIM can be effective to counteract a disincentive that the utility faces, it is inappropriate to provide additional financial reward for the performance of a core function for which the utility is already robustly compensated. National Grid has not explained why an additional financial incentive is required for utility grid upgrades and improved reliability, particularly when the utility already recovers the cost of reliability investments with a return on its investment and little or no regulatory lag.

- Finally, PIMs should be implemented carefully with an eye to maintaining rates at affordable levels. While it is desirable to have reliable service, this aim must be balanced with the affordability of utility rates. The more that electricity rates continue to rise, the more difficult it will be to meet the Commonwealth's building and transportation electrification targets.

Q. Do other jurisdictions provide financial rewards for improvements in reliability?

A. Generally not. As discussed in an article published in the *Electricity Journal*,[47] historically most performance measures in PBR plans focused on minimum standards of performance to ensure that cost-cutting measures did not erode utility performance quality. Thus, performance metrics primarily set standards below which the electric company could be financially penalized, as opposed to rewarding utilities for improved performance.[48] This approach is consistent with the existing service quality metrics, which are penalty only.[49]

Q. What do you propose for the Company's proposed IPIMs?

A. I propose that the FLISR, URD replacement, and overhead hardening IPIMs be converted to scorecard metrics to measure the Company's progress in meeting its installation targets, but that no additional incentive be provided. I also propose that the Department continue a penalty-only PIM for SAIDI and SAIFI for 2028 and 2029, but that the reliability target be maintained at 2027 levels until the Department conducts a thorough analysis of the costs and benefits to achieving greater reliability.

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[47] Ron Davis, "Acting on Performance-Based Regulation," *The Electricity Journal* (May 2000), available at http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/Davis_Acting_on_Performance.pdf.

[48] *Id.*

[49] D.P.U. 12-120-D.

<u>Operating-Based PIMs</u>

Q. Do you have concerns regarding the Company's proposed operating-based PIMs?

A. Yes. At this time, I am only addressing the Company's proposal to electrify its fleet vehicles.[50] My silence on other PIMs does not indicate that I agree with or support the Company's proposals.

Q. Please describe the Company's proposed Fleet Electrification PIM.

A. The Company's fleet electrification PIM would track the number of electric vehicles (EVs) acquired to replace existing internal combustion vehicles on a schedule to attain 100 percent EVs by 2030.

Q. What is your concern with the Company's Fleet Electrification PIM?

A. While I encourage the Company to electrify its fleet, the Company has not justified why an incentive is required for it to electrify its fleet, particularly given that the Company has an incentive to invest in the additional charging infrastructure that would be required to achieve this PIM, as such investments are capitalized. As discussed above, PIMs should be implemented only when necessary to maintain rate affordability.

[50] Exhibit NG-CPIP-1 at 167.

V. COST RECOVERY MECHANISMS

Q. Please describe the Company's proposed cost recovery mechanisms.

A. The Company is proposing a hybrid model consisting of a performance-based regulation (PBR) plan and a more traditional capital tracker for capital costs.[51] The PBR model would apply only to operating costs, which is a departure from the Company's prior PBR plan, which applied to both operation and maintenance (O&M) expense and capital investments. For capital cost recovery, the Company proposes the ISRE Mechanism, which would recover the revenue requirement associated with core capital projects and projects related to the Company's Electric Sector Modernization Plan (ESMP).[52] In addition, the Company proposes to continue its other cost recovery mechanisms, such as Grid Modernization, Electric Vehicle Infrastructure and Advanced Metering Infrastructure (AMI) mechanisms.

Q. Why is the Company proposing the ISRE mechanism rather than recovering capital costs through the PBR mechanism?

A. The Company states that "the capital investment needs for the Company's electric distribution system over the next five years are well beyond historical levels," and "cannot be sufficiently funded through traditional cost-of-service ratemaking, nor a historical-trend based PBR mechanism."[53] The Company further argues that the ISRE

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[51] *Id*. at 16.
[52] *Id*. at 17.
[53] *Id*. at 35.

mechanism will enable it to undertake its proposed level of investments by "providing timely and annual recovery of its Core Investments and ESMP Investments."[54]

Q. What is the level of spending proposed to be recovered through the ISRE mechanism?

A. The Company projects that it will require approximately $790 million per year to support its Core Investments and an additional $445 million per year for ESMP investments from FY 2025 through FY 2029.[55] For comparison, in the Company's most recent rate case (D.P.U. 18-150), the Company requested an annual capital investment cap of $249 million under the PBR plan, or $295 million if the Capital Investment Recovery Mechanism (CIRM) were continued.[56] Thus, the Company is requesting a four-fold increase in capital investment cost recovery over the term of the 2025-2029 rate plan relative to its 2018 rate case.

<u>Rate Design and Cost Recovery Mechanisms</u>

Q. How would the ISRE and other cost recovery mechanisms be reflected in rates?

A. Currently, base distribution rates do not include revenues recovered through other cost recovery mechanisms (e.g., grid modernization costs, EV infrastructure, and AMI costs). In terms of rate design, these other cost recovery mechanisms are treated separately from base distribution costs. The Company's ISRE proposal appears to function similarly, as

[54] *Id*. at 35.
[55] *Id*. at 43.
[56] *Id*. at 41.

the Company has proposed a separate ISRE Factor (ISREF) to recover the annual allowable ISRE revenues.[57]

Q. What are the implications of recovering costs through separate cost recovery mechanisms versus rolling them into base distribution rates?

A. Numerous implications arise when costs are recovered through various mechanisms, rather than through base rates. One important consideration is the price signal sent to customers through rate design. Typically changes to the rate structure (such as the adoption of seasonal rates), only apply to base distribution rates. However, base distribution rates are becoming an increasingly small portion of customers' delivery bills as more and more costs are recovered through other cost recovery mechanisms. This dilutes the effect of rate design modifications that only apply to base distribution rates. The Company's proposal to recover ISRE costs through the ISRE Factor serves to further weaken the price signals sent through rates to customers. Thus, for rate design purposes, it is important to recover as many costs as possible through base distribution rates. Alternatively, the Department should clarify that it expects changes in rate design to apply to other cost recovery mechanisms as well, as proposed by DOER in its Initial Brief in D.P.U. 23-80/23-81.[58]

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[57] M.D.P.U. No. 1532, Exhibit NG-PP-13.
[58] D.P.U. 23-80, D.P.U. 23-81, DOER Initial Brief at 8-14.

Cost Containment Incentives

Q. Do you have any other concerns regarding the Company's proposed ISRE cost recovery mechanism?

A. Yes. By proposing to recover capital costs through a separate cost tracker, rather than a PBR mechanism, the Company's incentives to control costs would be reduced because the Company would not benefit financially from achieving cost efficiencies. The efficiency incentive was recognized by the Department in its order approving the PBR mechanism in D.P.U. 18-150, in which the Department found that "PBR, as compared to a capital cost recovery mechanism, will provide it with greater incentives to reduce costs" and would result in greater benefits to customers than the prior capital investment recovery mechanism (CIRM).[59]

Moreover, unlike the CIRM, the Company's proposed ISRE mechanism is capped based on a five-year forecasted capital investment plan, rather than based on a historical trend. Cost forecasts are notoriously challenging for regulators, as it is difficult to ensure that the forecasts are reasonable due to asymmetry of information. The magnitude of National Grid's forecasted investments over the rate plan term increases the stakes for customers. Although greater levels of investment in the distribution system may be needed to support electrification, National Grid's proposal lacks the important safeguards for customers that were included in other mechanisms (particularly the CIRM and the PBR mechanism).

[59] D.P.U. 18-150 at 51.

VI. CONCLUSIONS AND SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

A. I recommend that the Department:

1. Reject the Company's proposed Electrification Pricing proposal.
2. Direct the Company to adopt one of the alternative beneficial electrification rates that I describe in my testimony.
3. Reject the Company's proposed IPIMs and Fleet Electrification PIM as proposed.
4. Implement the FLISR, URD replacement, and overhead hardening IPIMs on a scorecard-only basis.
5. Adopt a penalty-only structure for SAIDI and SAIFI improvements.
6. Require the Company to recover ISRE costs through the PBR plan.
7. Ensure that the rate design applicable to base distribution costs also applies to any ISRE-related costs.

Q. Does this conclude your testimony?

A. Yes, it does.