BEFORE THE
STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET **DE 23-039**

IN THE MATTER OF: Liberty Utilities (Granite State Electric) Corp.
d/b/a Liberty
Request for Change in Distribution Rates

DIRECT TESTIMONY

OF

Nicholas A. Crowley

December 13, 2023

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1. Introduction

Q. Please state your full name.

A. My name is Mr. Nicholas Allen Crowley.

Q. By whom are you employed and what is your business address?

A. I am a Senior Economist with Christensen Associates Energy Consulting LLC ("CA Energy Consulting"). My business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin, 53705.

Q. Please summarize your education and professional work experience.

A. I have been with CA Energy Consulting since 2016. During this time, I have testified on incentive regulation issues in both the United States and Canada. I have also conducted research related to incentive regulation, recently co-authoring an article with Dr. Mark Meitzen on the impact of performance-based regulation ("PBR") on Canadian electricity distribution utilities.[1] Prior to joining this firm, I was an economist in the Office of Energy Market Regulation at the Federal Energy Regulatory Commission ("FERC"), where I assisted with energy industry benchmarking, the incentive regulation of oil pipelines,[2] and the review and evaluation of natural gas pipeline rate cases. In these roles, I have worked extensively with FERC and other federal data for the development of cost benchmarks for power systems, in measuring industry total factor productivity, and the development of PBR frameworks filed before regulatory authorities across North America. I have a Bachelor of Science degree in economics, as well as a Master of Science degree in economics from the University of Wisconsin-Madison. My curriculum vitae is attached as Exhibit DOE-NC-1.

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1 Nick Crowley and Mark Meitzen, "Measuring the Price Impact of Price-Cap Regulation Among Canadian Electricity Distribution Utilities," *Utilities Policy*, 72 (2021).

2 Five-Year Review of the Oil Pipeline Index. Issued: December 17, 2015. 153 FERC ¶ 61,312.

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

A. This testimony reviews the proposed PBR framework filed by Liberty Utilities (Granite State Electric) Corp. d/b/a/ Liberty ("Liberty" or "the Company"). The purpose of the review is to assess the incentives that the Company will face under its proposed Multi-Year Rate Plan ("MYRP"), including the capital reconciliation model, the annual reconciliation filings, the revenue decoupling mechanism, the re-opener, the Earnings Sharing Mechanism ("ESM"), and the Performance Incentive Mechanisms ("PIMs"). The assessment will consider the PBR proposal in light of the Company's previous Settlement Agreement, which stipulated that Liberty would begin exploring PBR and away from traditional cost-of-service ratemaking.[3] I am testifying on behalf of the New Hampshire Department of Energy ("the Department").

Q. How is your testimony organized?

A. Section 3 provides an overview of the Company's proposed PBR plan and the context of its exploration of PBR. Section 4 assesses the proposed MYRP and the elements included in the plan. Section 5 reviews the proposed PIMs. Section 6 presents a summary and conclusions.

3. Overview of the Company Plan and Regulatory Context

Q. Please describe the key components of the Company's proposed PBR framework.

A. The Company has proposed a three-year rate plan that establishes a revenue recovery trajectory, with new rates set at the start of each year of the MYRP term. The Company's proposed revenue requirement has been forecast for each year of the MYRP term and would be adjusted in each year under the plan, to account for the following items:

- Variances from the approved capital spending plan and their impact on rate base,

[3] "Stipulation and Settlement Agreement Regarding Permanent Rates," Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities, State of New Hampshire, Public Utilities Commission, Docket No. DE 19-064.

- Net Operating Income ("NOI") and earned return, which form the basis of the Company's ESM,
- Reconciliation of operating expenses for cybersecurity, vegetation management, and pension and Other Post Employment Benefits ("OPEBs"),
- Achievement of PIMs and the penalty or rewards that will be applied from it.

The plan also contains a re-opener, which is a mechanism by which the MYRP can be terminated as a result of unforeseen circumstances during the term of the plan that would threaten the financial integrity of the company or harm service to customers.

Q. Why is the Company proposing changes to the structure of its regulatory regime?

A. The Company cites two reasons for proposing a change to its status quo regulatory regime. First, the Company states that Liberty believes implementing PBR in New Hampshire will create value.[4] Second, the Company refers to the Settlement Agreement that determined rates after the previous rate application. This Settlement Agreement stipulated that Liberty would begin exploring PBR and away from traditional cost-of-service ratemaking.

Q. What does the Settlement Agreement state regarding the Company's exploration of PBR?

A. The Settlement Agreement states, "the Settling Parties stipulate and agree that it is in the public interest for Liberty to explore transitioning away from the strict application of traditional cost-of-service ratemaking principles in favor of a performance-based ratemaking."[5] The agreement defines PBR as a means of defining regulatory goals, specifying outcomes toward the achievement of those goals, and establishing revenue adjustment mechanisms that support safe and reliable utility service, while rewarding utility

[4] Direct Testimony of Matthew DeCourcey and Gregg Therrien, p. 8.
[5] Stipulation and Settlement Agreement Regarding Permanent Rates, p. 6.

shareholders for the achievement of performance metric benchmarks and penalizing them for failing to achieve such benchmarks.

Q. Is the definition of PBR that is provided in the Settlement Agreement universally recognized across jurisdictions under PBR?

A. No. The Settlement Agreement's definition of PBR captures certain aspects of PBR as it is implemented elsewhere, but it emphasizes performance metrics without discussing cost efficiency. In this way, the Settlement Agreement definition differs from the definition of PBR in other jurisdictions. For example, the Department of Public Utilities in Massachusetts ("Massachusetts D.P.U.") has framed PBR in terms of efficiency incentives, having determined that PBR should, "be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services," and "provide a more efficient regulatory approach."[6] In Canada, the focus is almost entirely on cost efficiency. For example, the Alberta Utilities Commission has defined the first principle of PBR to be that "a PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality."[7] The Ontario Energy Board has stated that PBR "provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies."[8] The definition of PBR in the Settlement Agreement does not contain language pertaining to cost efficiency, and therefore omits one of the more widely acknowledged principles of PBR.

[6] Massachusetts D.P.U. 94-158, pp. 58-64.
[7] AUC Decision 2012-237, September 12, 2012, p. 7.
[8] OEB, RP-1999-0034 Decision with Reasons, January 18, 2000, p. 13.

Q. Given that the definition is not universally recognized, is there a problem with applying PBR as defined in the Settlement Agreement?

A. Not necessarily, but it depends on the goals of the regulator. If the regulatory objective is to incent the utility to achieve or exceed certain performance benchmarks, like improved reliability, the definition provided in the Settlement Agreement may provide a workable basis for designing a MYRP. If the regulator aims to improve cost efficiency incentives for the utility relative to cost-of-service regulation, this definition is unlikely to match that objective, as it does not mention costs or efficiency.

4. Assessment of the proposed Multi-Year Rate Plan

Q. How does the Company's proposed MYRP work?

A. The Company has proposed a forecasted revenue requirement for each year over a three-year period. This forecasted revenue will serve as the basis of rates over the term of the MYRP. However, the proposed total revenue requirement for the Company in a given year will adjust for a number of factors. First, the Company proposes to adjust its rate base according to actual expenditures on capital projects placed into service in the prior year. Second, revenues will contain reconciliations for certain specific operation and maintenance ("O&M") expenses. Third, the Company proposes to adjust revenues using an ESM if the actual return on equity ("ROE") is above or below the deadband relative to the allowed ROE. Fourth, the company proposes to adjust revenues on the basis of achieving certain PIMs. Fifth, total revenues will adjust according to a revenue decoupling mechanism. At the end of the MYRP, the Commission will "review the effectiveness of the program" and "determine whether to allow the Company to recover the costs of significant deviations from its approved capital plan, if any such deviations exist."[9]

[9] Direct Testimony of Matthew DeCourcey and Gregg Therrien, p. 5.

Q. Please describe the Company's proposed rate base reconciliation.

A. Part of the Company's proposed annual reconciliation adjusts for differences in utility plant in service ("UPIS") that occur over the plan term. The Company states that this rate base adjustment "prevents the company from either under- or over-earning because of variations in the cost of capital projects that lie outside management's control."[10] This reconciliation will adjust UPIS for projects that were planned but not undertaken, as well as variations between approved costs and actual costs for projects. Upward adjustments to rate base have a cap of 20% on a project-specific basis, and 10% for the total change in UPIS. Projects with costs lower than the approved amount will reduce UPIS "without limit."[11]

Q. What are the incentive implications of the proposed rate base reconciliation?

A. The proposed rate base reconciliation mechanism provides an incentive for the company to stick to its proposed capital plan, but it is in the Company's interest to spend more than the forecasted cost on specific projects, up until total changes to UPIS equal 10%. The Company has this incentive because if the rate base reconciliation approach is approved as proposed, the Company is able to adjust its rate base up to 10% of the forecasted cost of UPIS placed into service in a given year without the need to justify this increase in capital spending. Furthermore, the company has no incentive to find cost savings that allow the company to spend less than the forecasted capital spending, since all underspending on capital will reduce rate base, without limit or threshold.

[10] Direct Testimony of Matthew DeCourcey and Gregg Therrien, pp. 16-17.
[11] Direct Testimony of Matthew DeCourcey and Gregg Therrien, p. 21.

Q. What is your assessment of the proposed rate base reconciliation mechanism?

A. The rate base reconciliation mechanism provides the company with an incentive, generally, to stick to its capital plan. However, the mechanism does not promote cost efficiency relative to cost-of-service regulation.

Q. What is an alternative approach to capital under PBR that provides the least change to the Company's proposal?

A. There are several alternative approaches that provide enhanced cost efficiency incentives. One alternative approach with the least change to the Company's plan would be to remove the rate base reconciliation mechanism but allow the company to retain cost overruns in a deferral account to be scrutinized at the end of the MYRP. If the cost overruns are deemed prudent, they can be added to rate base as part of the next revenue requirement application, after the MYRP term. This approach has the cost incentive advantage that the Company could not place any cost overruns into rate base beyond the forecasted amount until and unless the costs are deemed prudent. This would also maintain a reduced administrative burden because the company would not have to request changes to the forecasted revenue requirement until the end of the MYRP term. Rate base would be set according to the forecast until the next rate application.

Q. Are there other alternative approaches to capital under PBR with enhanced efficiency incentives?

A. Yes. One approach with even higher incentives would be to require the company to stick to its proposed capital spending with no rate base adjustments, meaning that the company could not defer the cost overruns to the end of the MYRP term. This approach is used by at least one utility, FortisBC, Inc., which has a three-year capital forecast as part of its MYRP, with any variances between the forecast and actual amount subject to an ESM.[12] Another approach would be to forgo the forecast approach and operate under an I-X revenue cap, which would set allowed revenues according to the growth of inflation and industry productivity indexes. This would decouple the company's costs from revenues during the MYRP, instead relying on industry cost trends to determine revenues. Revenue caps and price caps expose the utility to cost pressures that mimic competitive markets.

Q. Why are ESMs included in PBR frameworks?

A. ESMs can serve as guardrails to protect consumers and the utility in the event of dramatic deviations from the utility's allowed ROE. An oft-cited reason for including an ESM in a PBR plan is to provide customers with benefits if the Company exceeds its authorized ROE beyond some threshold. However, for reasons explained further below, customers may in fact not be better off under an ESM, because the Company has a dulled incentive to seek cost efficiencies if part of the gains from those efficiencies are immediately taken away.

Q. What are the incentive properties of ESMs, generally?

A. Although ESMs are a common feature of PBR frameworks, they induce the opposite cost efficiency incentives that PBR aims to generate. If the objective of PBR is to introduce cost efficiency pressure on the utility, ESMs reduce this pressure by allowing the utility to collect additional revenues if it is unable to achieve the level of efficiency assumed in its revenue forecast, and, conversely, forces the utility to give back a portion of the gains from efficiency improvements relative to the forecast. For this reason, the utility does not have a strong incentive to improve its productivity under an ESM, particularly as the deadband shrinks. As Witness Hanser writes, an ESM with no deadband "effectively removes any incentive for performance improvement."[13] To the extent that consumers obtain any shared

[12] British Columbia Utilities Commission, Decision and Orders G-165-20 and G-166-20, p. 130. Also see, David E.M. Sappington and Dennis L. Weisman, "Assessing the Treatment of Capital Expenditures in Performance-Based Regulation Plans," September 1, 2015, p. 32.
[13] Direct Testimony of Philip Q. Hanser, p. 11.

earnings through the ESM, this benefit is likely to be a larger slice of a smaller pie. In many cases, consumers do not see any benefits from ESMs because the Company never exceeds the ROE deadband.

Q. Do all ESM designs have the same incentive properties?

A. No. ESMs may be designed to be symmetrical or asymmetrical, have deadbands of different sizes, and share earnings in different proportions depending on the deviation of earnings from the authorized rate of return. Calibrating these parameters changes the incentive structure of the ESM. For example, economist Dr. Dennis Weisman proposed a "high-powered" ESM in Alberta during the 2023 proceeding, which was designed to operate the same way as the standard ESM for returns within and below the deadband. The difference arises for returns above the upper bound on earnings above the deadband. The first one-hundred basis points of returns above the upper bound on the deadband accrue largely to consumers. The second one-hundred basis points above the upper bound on the deadband accrue largely to the regulated firm.[14] This provides the Company with continued incentive to seek efficiencies even after it crosses the sharing threshold.

Q. Please describe the Company's proposed ESM.

A. The Company proposes a symmetric ESM with a deadband of 100 basis points (bps). If the Company's earned ROE exceeds the allowed ROE by more than 100 bps but less than 200 bps, 50% of the excess earnings will be shared with customers. If earned ROE exceeds allowed ROE by more than 200 bps, 75% of excess earnings are shared with customers.

[14] "Economic Tradeoffs in the Design of the Third-Generation PBR Regime," Dennis L. Weisman, PhD., January 27, 2023. Alberta Utilities Commission, Proceeding 27388.

Q. What is your assessment of the Company's proposed ESM?

A. The Company has proposed a standard ESM as part of its PBR framework. Whether to include such a mechanism depends on whether the priority of the PBR framework is to provide incentives for productivity improvements in the form of cost efficiency, or to minimize risk. If the goal of the plan is to minimize risk over a long MYRP term, an ESM may be an appropriate element to include. However, the proposed MYRP has a low risk profile even without an ESM, for the following reasons. First, the Company's MYRP would span only three years. Second, the proposed revenue trajectory would be based on the Company's own forecasts of its revenue needs, as opposed to exogenous index values. Third, deviations from the forecast would be trued-up for certain cost categories, including vegetation management, cybersecurity, pensions, and capital projects. Given that the proposed MYRP is already fairly low risk, the risk reducing benefits of an ESM are not worth the dampening effect on efficiency incentives. On the other hand, if certain aspects of the plan are not accepted, such as the re-opener, or the proposed approach to revenue recovery for vegetation management, cybersecurity, pensions, and capital projects, the risk reducing benefits of an ESM may make more sense.

Q. What are the reasons that a utility needs funding for vegetation management programs?

A. Vegetation management is critical for both safety and grid reliability. Without adequate funding for the maintenance of overhead lines, a distribution utility runs the risk of increased outages and wildfires. The lack of proper vegetation management was a central issue in the litigation proceedings in the wake of wildfires in California and Washington, and appear to be an issue in the wake of wildfires on the island of Maui.[15] Any utility running electrical lines through forested areas must budget for the control of vegetation.

[15] See, for example, https://www.npr.org/2022/04/12/1092259419/california-wildfires-pacific-gas-electric-55-million; https://www.opb.org/article/2023/12/06/pacificorp-labor-day-archie-creek-fire-settlement/.

Q. What is the Company's proposed cost recovery approach to vegetation management?

A. The Company has proposed no limit on the reconciliation of vegetation management expenses over the three-year MYRP. Witnesses DeCourcey and Therrien stated that this approach is necessary because the Company "can neither reasonably predict nor manage the cost of the vegetation management VMP,"[16] arguing that contractor availability and cost is uncertain or unknown. The Company proposes to "include reconciliation of its actual VMP spending to the budget approved in this proceeding," along with "narrative descriptions of the procurement processes it utilized to ensure that it incurred costs competitively,"[17] which will allow the Commission to observe whether costs are prudently incurred.

Q. How have the Company's vegetation management costs varied in recent years?

A. Relying on the Federal Energy Regulatory Commission's ("FERC") Form 1 sheet "Operation and Maintenance", Line 149 (Account 593), which records expenses for "Maintenance of Overhead Lines," we can observe that such costs were approximately $2.9 million in 2020, $4.6 million in 2021, and $5.4 million in 2022.[18] Across the distribution utility industry in the United States, Maintenance of Overhead Lines costs increased an average of 13.5% annually in the five years between 2017 and 2021.[19] Across the same time period, according to FERC Form 1 data, the Company's Maintenance of Overhead Lines costs increased an average of 27.0% annually. This data indicates that these costs have risen substantially in recent years across the industry, but the Company's costs have increased even more than the industry average.

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[16] Direct Testimony of Matthew DeCourcey and Gregg Therrien, p. 44.
[17] Direct Testimony of Matthew DeCourcey and Gregg Therrien, p. 45.
[18] FERC Form 1 data can be obtained here: https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-1-f-3-q-electric-historical-vfp-data
[19] Based on FERC Form 1 data, Electric Operation and Maintenance, Page 320, Line 149.

Q. Please address the incentives associated with the Company's proposed approach to recovering costs associated with vegetation management.

A. The data and industry experience indicates some justification for a vegetation management reconciliation mechanism as proposed. For safety and reliability reasons, the Company cannot ignore the need for vegetation management, even as the cost of such maintenance rises. This approach is not without drawbacks, however. First, an unlimited true-up of spending does not provide any incentive for cost control on the part of the utility. Second, the need to devote Commission staff to scrutinizing the Company's vegetation management costs on an annual basis creates regulatory burden relative to a more hands-off approach. Third, as discussed below, if vegetation management costs can be fully reconciled without limit, the Company effectively has no barrier to spending, and subsequently recovering, whatever it takes to meet its proposed Reliability PIM.

Q. What is your recommendation regarding the proposed approach to vegetation management?

A. Please refer to direct testimony from Witnesses Eliabeth Nixon and Jacqueline Trottier for the Department's recommendation regarding the proposed vegetation management cost recovery mechanism. To the extent that the Company is permitted to spend beyond its forecast with regard to vegetation management, I recommend rejecting the Reliability PIM. With acknowledgement that some differences may arise from Company-specific factors, such as service territory and environment, I also recommend that the Company investigates methods to align its Maintenance of Overhead Lines cost growth more closely with the growth rate of the broader industry.

Q. What is the Company's proposed approach to recovering costs associated with cybersecurity?

A. The Company has proposed no limit on the reconciliation of operating expenses associated with cybersecurity, arguing that the "cybersecurity space is characterized by rapid, unpredictable change and spending is mostly beyond management's control."[20] The company proposes an allowable adjustment to rate base of 25% for any cybersecurity capital project.

Q. Please assess the Company's proposed approach to recovering costs associated with cybersecurity.

A. While Witnesses DeCourcey and Therrien note that "OpEx associated with cybersecurity programs are even less predictable than capital spending,"[21] they defer to Witness Shawn Eck for justifying the need for a limitless cybersecurity reconciliation mechanism. Witness Eck states that he is not confident in the spending outlook for cybersecurity set forth by the company and asserts that there is no alternative to the proposed reconciliation mechanism to deal with deviations from the cybersecurity spending forecast.[22] Beyond this assertion, the claim that cybersecurity costs cannot be reasonably forecast over a three-year period is not well-supported in the Company's evidence. Furthermore, contrary to the testimony of Witness Eck, other approaches to handling cost variances in MYRPs do exist. For example, the Company could record deviations in a variance account which could be reviewed for prudence at the end of the MYRP term. Another option could be a Z factor, which captures unexpected costs that are outside of the control of the Company and can be recovered on an annual basis. These options provide superior cost containment incentives while protecting the company from unforeseen costs that arise for the maintenance of critical security. Please

[20] Direct Testimony of Matthew DeCourcey and Gregg Therrien, p. 39.
[21] Direct Testimony of Matthew DeCourcey and Gregg Therrien, p. 41.
[22] Direct Testimony of Shawn Eck, p. 19.

refer to Witnesses Eliabeth Nixon and Jacqueline Trottier for the Department's recommendation regarding cybersecurity costs.

Q. How would the Company incorporate a Z factor into its MYRP?

A. A Z factor is ordinarily included in a PBR plan to provide for one-time exogenous events that exceed a size threshold. One commonly cited example of a Z factor could be an unexpected, one-time increase in tax rates during the PBR term. Another example of a Z factor could be construction projects required by the state, like the movement of utility plant to make way for a road. Z factors are defined with a minimum threshold, such that only substantive cost changes merit recovery through the mechanism. The threshold could be calibrated in relation to the utility's operating costs or annual revenues. For example, in Massachusetts, the Z factor threshold value equals the product of 0.001253 and the Company's total operating revenues in the test year.[23] It is reasonable for Liberty to adopt this same methodology for determining the Z factor threshold. If the Company experiences an event that surpasses the cost threshold and meets the definition of a Z factor, it can file for recovery of related costs either upon incurring the costs or through an annual review filing.

Q. Please address the Company's proposed approach to recovering costs associated with pensions.

A. The Company has proposed that it be allowed to reconcile all expenses related to pensions and Other Post-Employment Benefits. Because interest costs and return on plant assets are driven by factors outside of the Company's control, the company has no control over these expenses. If service costs, or the pension benefits earned by employees, are also uncontrollable, then reconciliation of pension expenses is reasonable. If the Company were operating under an I-X revenue cap, the formula would, in theory, capture these cost changes. However, the X factor is often set using historical data that would not capture

[23] Massachusetts D.P.U. 22-22, Final Order, November 30, 2022.

annual fluctuations in interest rates over the term of the PBR plan. As such, many PBR plans exclude pension costs from the revenue or price cap because of the widely acknowledged variation in costs that are exogenous to the regulated firm. For further discussion of the Departments recommendation regarding the handling of Liberty's pension costs, please refer to Witnesses Eliabeth Nixon and Jacqueline Trottier.

Q. How does the Company's Revenue Decoupling Mechanism ("RDM") currently work?

A. My understanding is that the RDM allows Liberty to recover the difference between allowed and actual revenues via a $/kWh adder (or rebate) applied to usage in the subsequent year. Total allowed revenue scales with the number of customers served. That is, it is a revenue per customer decoupling mechanism, in which the allowed revenue per customer is set in the rate case (and updated whenever the revenue requirement is updated) and the total allowed revenue is equal to the number of customers currently served multiplied by the allowed revenue per customer. The number of customers served is calculated using an "equivalent bill" method, in which customer charge revenue is divided by the customer charge amount to determine the number of customers. This method prevents the customer count from being overstated due to partial billing months. The total revenue shortfall or surplus is allocated to customer classes using pre-defined class shares. A 3.0% cap is applied to annual rate increases and decreases, with any excess above the cap returned to the deferral account, where it earns interest at the prime rate.

Q. How will the RDM adjust with the revenue requirements of the proposed MYRP?

A. When the revenue requirement changes under the MYRP, the RDM's allowed revenue per customer values will change in the same proportion. For example, a 10 percent increase in the revenue requirement would lead to a 10 percent increase in allowed revenue per customer. Note that total allowed revenues may change by a different amount depending on the number of customers Liberty serves.[24]

Q. Is the Company's proposed MYRP reasonable with respect to its revenue decoupling mechanism?

A. Not entirely. As explained above, the Company's current approach to revenue decoupling provides for revenue growth as the Company's customer base grows. At the same time, the Company's proposed MYRP forecasts a revenue requirement for three years over the MYRP term, factoring in growth as a component of the revenue escalation each year.[25] This amounts to counting growth twice, which means the current revenue decoupling mechanism is incompatible with the proposed MYRP. This does not mean that revenue decoupling as a concept is incompatible with the MYRP. Rather, it means that the revenue decoupling mechanism must be modified to operate within the context of the MYRP.

Q. What is your recommendation regarding the incompatibility between the Company's revenue decoupling mechanism and the proposed MYRP?

A. A simple fix to removing the issue of double counting in the Company's proposed MYRP is to alter the current revenue decoupling mechanism such that the Company applies decoupling to total revenues, rather than revenue-per-customer. This means that annual revenue growth would occur through the MYRP forecast, as proposed, without further revenue increases from customer growth through the decoupling mechanism. I recommend making this adjustment to the decoupling mechanism, rather than attempting to extricate the growth element from the MYRP revenue forecast, as this adjustment is straightforward and simple to implement.

[24] Request No. DOE 7-28.
[25] Direct Testimony of Anthony Strabone, p. 25.

Q. What is the company's re-opener proposal?

A. The company defines its proposed re-opener as "a mechanism by which the MYRP can be terminated"[26] if circumstances arise that threaten either the financial integrity of the company or the realization of benefits for customers. The Company does not propose any specific trigger, but states that any party could petition for a re-opener at any time during the MYRP term.

Q. How are re-openers typically defined in other jurisdictions?

A. In other jurisdictions, the term re-opener refers to a mechanism that triggers the reassessment of a PBR framework during the PBR term. However, this does not necessarily mean that the re-opener will terminate the PBR plan. For example, in Alberta, the Alberta Utilities Commission ("AUC") defines a re-opener as "intended to provide an opportunity to investigate and modify a particular component in the operation or design of the PBR plan,"[27] in contrast to the term "off-ramp," which specifically refers to the termination of a PBR plan. The Company's choice to define the term differently does not present a problem, but it is worth noting that this definition is not universal.

Q. How are re-openers typically implemented in other jurisdictions?

A. The Company's proposal to have no triggering mechanism for the re-opener sets it apart from other jurisdictions. Elsewhere, re-openers are usually triggered by a deviation between the company's authorized ROE and its earned ROE. For example, in British Columbia, FortisBC, Inc. has a re-opener that is triggered if the company's earned ROE exceeds or falls below its authorized ROE by 150 basis points. This does not mean that the PBR plan is automatically terminated if the re-opener is triggered, but rather that components of the plan are re-examined to inform next steps. This approach is used roughly the same way in

[26] Direct Testimony of Matthew DeCourcey and Gregg Therrien, p. 54.
[27] AUC Decision 2012-237, September 12, 2012, p. 156.

Alberta and Ontario.[28] The Hawaiian utilities that operate under PBR have a set of re-opener triggers that include an ROE trigger like those in Canada.[29] In Massachusetts, the companies operate with no re-opener provision.[30]

Q. Is the Company's proposed re-opener reasonable and appropriate?

A. The Company's proposed re-opener provision allows any party to file for a re-opener at any time. This reduces cost efficiency incentives for the company since it can petition to leave the plan if its actual costs deviate from its forecast to any degree. This approach also has the potential to increase regulatory burden, because any party that is displeased with the trajectory of the Company during the MYRP can petition the Commission to end the plan, requiring the Commission to review the petition and make a determination. The Company's proposed MYRP already contains significant guardrails, as follows: (1) its revenue trajectory over the MYRP term is set by its own cost forecast rather than an index approach, (2) the MYRP term is only three years, (3) deviation of certain costs from the forecast can be fully recovered, and (4) the MYRP contains an ESM. For these reasons, a re-opener appears unnecessary in the context of the proposed plan. However, if the Company were to make modifications to its plan and have a re-opener, including an ROE trigger would improve the cost efficiency incentives of the plan and reduce the potential for frivolous requests to terminate the plan. Furthermore, the re-opener should be defined such that the trigger opens a discussion into whether the PBR plan should be modified or abandoned, and not defined such that the trigger automatically results in abandonment of the plan.

[28] AUC Decision 27388-D01-2023, October 4, 2023.
[29] Hawaii Public Utilities Commission, Docket No. 2018-0088, Decision and Order No. 37507.
[30] See, for example, Massachusetts D.P.U. 22-22, D.P.U. 20-120, D.P.U. 19-120, D.P.U. 18-150, D.P.U. 17-05.

Q. Please provide conclusions regarding the Company's proposed MYRP.

A. Evidence suggests that MYRPs slow utility cost growth through strengthening incentives.[31] However, MYRPs are not a panacea for improved regulation, and they can perform worse than traditional forms of regulation if they are poorly designed.[32] For this reason, it is important to consider each element of the plan in the context of the whole design and consider whether it improves upon the status quo. As explained above, the Company's proposed plan lacks cost efficiency incentives. In addition, the plan does not appear to reduce meaningfully the regulatory burden relative to the status quo. Finally, the proposed revenue requirement provides for customer-related growth that is already accounted for in the RDM. For these reasons, I recommend the Commission does not approve the MYRP plan as filed. However, certain adjustments could be made that would make the plan more reasonable, as explained below.

Q. If the Company's proposed MYRP were approved as filed, what other components of the rate application would be affected?

A. If the proposed MYRP were accepted as filed, with all of the proposed risk mitigating components, the allowed rate of return on capital should be adjusted to account for the reduced risk of the company under this plan. The MYRP proposal includes cost reconciliation provisions, an ESM, a decoupling mechanism that includes customer growth, and an open-ended re-opener provision. Each of these elements reduces the Company's risk, which will reduce the cost of equity capital for the Company. An adjustment to the allowed rate of return may not be needed if the proposed alternatives outlined in Table 1 are accepted instead.

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[31] See, "Measuring the Price Impact of Price-Cap Regulation Among Canadian Electricity Distribution Utilities," Nick Crowley and Mark Meitzen, *Utilities Policy,* 72 (2021). Also see, "Impact of multiyear rate plans on power distributor productivity: Evidence from Alberta." Mark Newton Lowry, David A. Hovde, Rebecca Kavan, Matthew Makos, *The Electricity Journal.* July 2023.
[32] "Multi-year rate plans are better than traditional ratemaking: Not so fast," Kenneth W. Costello, *The Electricity Journal,* April 2023.

Q. Can the proposed three-year MYRP be modified to provide improved cost efficiency incentives?

A. Yes. The proposed plan can be modified readily to incorporate improved cost efficiency incentives. First, the proposed MYRP contains rate base reconciliations that reduce cost efficiency incentives. Rather than allowing for an automatic 10% upward adjustment to the forecasted rate base, a higher-powered incentive MYRP would hold the Company to its forecast revenue requirement with no adjustments. Deviations from the forecast revenue requirement may be allowed for vegetation management and pension costs, but not for cybersecurity, which should be reasonably within the forecasting capabilities of the company. To protect the company against unforeseen events, the plan could include a Z factor for unexpected exogenous costs. With a Z factor, if an event occurs that unexpectedly causes costs outside of the Company's control, the Company may request cost recovery through a filing. Second, a higher-powered MYRP would not include an ESM, or, it would include a "high-powered" ESM as described above. Third, the Company's re-opener would have an ROE trigger, rather than allowing the plan to be re-opened at any time during the three-year term. Table 1 below summarizes the recommendations described above regarding the Company's proposed MYRP. Note that this alternative approach maintains the same three-year PBR term and sets the revenue requirement each year using the Company's forecast.

Table 1: Elements of a Modified Three-Year MYRP

MYRP Element	Alternative MYRP Approach
PBR Term	Three years*
Revenue Requirement	Forecast for each year*
Cost Reconciliations	Refer to Department Witnesses
Z Factor	One-time exogenous costs
Revenue Decoupling	Remove the per-customer component
ESM	None
Re-Opener	Trigger of +/-300 basis points from allowed ROE

*Indicates no structural change from the Company's proposed MYRP.

Q. Do any utilities in North America operate under an MYRP similar to the modified three-year MYRP described in Table 1?

A. Yes. In the state of New York, utilities operate under a three-year MYRP in which each year has a forecasted revenue requirement with a decoupling mechanism.[33] Although the current MYRP for Consolidated Edison of New York contains a capital reconciliation mechanism, the reconciliation is "downward-only," which means that the company cannot collect a return on rate base for capital expenditures that would increase the rate base beyond the forecasted amount. Other three-year MYRPs also exist throughout North America with various modifications. For example, in the province of British Columbia, BC Hydro operates under a three-year MYRP, though the British Columbia Utilities Commission has directed the utility to move toward a revenue cap of at least five years by the end of 2023.[34]

[33] See, for example, "Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans with Additional Requirements," by the New York Public Service Commission, for Consolidated Edison Company of New York, Inc., July 20, 2023.
[34] "British Columbia Hydro and Power Authority Review of the Performance Based Regulation Report," British Columbia Utilities Commission, Decision and Order G-388-21, December 21, 2021.

Q. How could the MYRP be modified to provide even greater cost efficiency incentives than the alternative outlined in Table 1?

A. There are two modifications to the MYRP provided in Table 1 that would provide enhanced cost efficiency incentives. First, the MYRP term could be lengthened from three years to four or five years. A longer period of time between rate applications improves the regulated firm's incentive to find cost efficiencies and further reduces regulatory burden over time. Second, the Company could incorporate competitive market pressure into its MYRP using a price cap or revenue cap mechanism. A price cap mechanism generally allows the firm's prices to adjust each year at a rate equal to input price inflation less the industry productivity growth rate. A revenue cap operates similarly. This approach, often called "I-X" regulation,[35] adjusts rates or revenues according to industry trends, allowing the firm to retain earnings from higher levels of productivity relative to peer companies, until the next rate application. Conversely, if the firm exhibits lower productivity growth than its peers, it experiences lower earnings. Such a plan could still include guardrails to mitigate risk, like a Z factor and a re-opener provision, but the price or revenue cap adjustment mechanism would allow for a longer MYRP term and provide strong incentives to the company from which all stakeholders might benefit.

Q. Do you recommend that the Company operates under a revenue cap (or price cap), instead of its proposed approach?

A. Not at this time. Although operating under a revenue cap or price cap generally would offer superior cost efficiency incentives relative to a three-year MYRP, a transition to this kind of regulatory framework requires planning and preparation. A MYRP like the one outlined in Table 1 provides a reasonable intermediate step to operating under I-X in the future.

[35] The "I factor" represents inflation, while the "X factor" represents productivity growth.

However, I recommend that, over the duration of the three-year MYRP set by this proceeding, the Company assesses its ability to operate under an I-X revenue cap.

Q. How do you recommend that the Company assesses its ability to operate under a revenue cap?

A. Given that Liberty currently operates with revenue decoupling, a revenue cap offers the most straightforward approach. For this reason, I recommend that, while operating under its MYRP, as set in this proceeding, the Company assess how it would perform under a prototypical revenue cap. A prototypical revenue cap would give the Company the opportunity to collect information about operating under a revenue cap without making the actual transition. This prototypical revenue cap would be calculated as follows. The Company's allowed revenue requirement each year would be set by an adjustment to the Company's test year revenue requirement from the first year of the MYRP using a measure of input price inflation minus a productivity offset, plus the percentage change in customers served. In mathematical terms, the formula for the Company's allowed revenue during years two and three of its MYRP would be set with the following formula:

$$Allowed\ Revenue_t = Allowed\ Revenue_{t-1} * (1 + I_{t-1} - X + G_{t-1})$$

Where *I* is the inflation factor, *X* is the productivity offset, and *G* is percentage growth rate in customers served. At the end of the MYRP, the Company will have information from this prototypical revenue cap exercise, and from its actual spending, which can be used by the Company and stakeholders to better understand a potential transition to a revenue cap in the next iteration of PBR.

Q. For the Company's prototypical revenue cap calculation, what is your recommendation for the X factor?

A. If the Company were to operate under an actual revenue cap plan, I would recommend that the Company undertake a Total Factor Productivity ("TFP") growth study of a set of similarly situated peer utilities to set the X factor. However, because this recommended calculation will merely calibrate a prototypical revenue cap, I recommend an X factor of +0.2%, which is close to recent calculations of average regional distribution utility TFP growth, pertaining to the calibration of a revenue cap.[36]

Q. For the Company's prototypical revenue cap calculation, what is your recommendation for the inflation factor?

A. Under a revenue cap using TFP growth as the productivity offset, the inflation factor is most appropriately based on a composite of labor and non-labor input price indexes designed to match the inflation rate of the Company's annual expenditures. I recommend a regional Employee Cost Index to address labor-related input prices.[37] This is a regional labor index of wages and salaries paid to utility employees. I recommend that non-labor input price changes are addressed by a Producer Price Index for Electric Utilities (PPI-Electric Utilities).[38] These separate indexes are weighted together by the proportion of the Company's O&M associated with labor and non-labor costs, respectively. Note that if the Company were to select an output measure of inflation, like GDP-PI, the X factor would need to be adjusted for an economy-wide TFP growth rate and an economy-wide input price growth rate. Since this complicates the calculation, I recommend using input price measures of inflation.

[36] Note that the measurement of TFP growth differs depending on whether one is calibrating a revenue cap or a price cap. When calibrating a revenue cap TFP growth rate, the appropriate output measure is the growth rate of customers served. When calibrating a price cap, the TFP growth rate includes all billable outputs, which in recent years would yield a much lower TFP growth rate, around -1.0%.
[37] ECI data published here: https://www.bls.gov/regions/northeast/data/xg-tables/ro1xg04.htm.
[38] PPI data published here: https://www.bls.gov/ppi/databases/.

5. Assessment of the Proposed Performance Incentive Mechanisms

Q. Does the definition of PIMs used by Liberty align with the conventional definition of PIMs?

A. No. Witness Menard states that, "some PIMs may not include financial incentives at all but instead require the collection and reporting of performance data."[39] This is not correct. Conventionally, PIMs, by definition, have financial incentives associated with them. The financial incentive is the "incentive mechanism" component of the performance incentive mechanism. For example, the Hawaii Public Utilities Commission states that a PIM is "a metric paired with a performance benchmark/target and a financial incentive by which to provide financial motivation for utilities to improve performance toward established outcomes, or to discourage underperformance."[40] Witness Hanser's testimony acknowledges this fact, stating, "PIMs include a financial incentive structure."[41] This is a semantic point, but it is important for New Hampshire to establish a lexicon for discussing regulatory concepts.

Q. Is there a problem with excluding PIMs from the ROE calculation used to determine the ESM amount?

A. No. If the Company were to include the PIM reward or penalty in the ROE calculation that determines earnings sharing, the Company would be sharing the benefits and penalties of the PIMs with customers. This would dull the incentive properties of the PIMs.

Q. Is it problematic that the company did not perform any Benefit-Cost Analysis ("BCA") in setting the rewards and penalties of its PIMs?

A. In some respects, yes. Without any analysis of the financial value of the marginal benefit of improved performance, or the marginal cost of worse performance, it is not possible to

[39] Direct Testimony of Erica L. Menard, p. 9.
[40] Hawaii Public Utilities Commission, Docket No. 2018-0088, Decision and Order No. 36326, p. 11.
[41] Direct Testimony of Philip Q. Hanser, p. 20.

assess whether the financial rewards or penalties associated with each PIM align with the value they provide. It is therefore not possible to determine empirically whether the PIMs are just and reasonable. However, the Company states that a “BCA was not required to develop our proposal nor was it requested by any stakeholder during the working sessions related to the Company's proposal held ahead of the filing of this case.”[42] If stakeholders would have agreed upon the details of these PIMs, the regulator could assume the PIMs were just and reasonable on the basis that all parties agreed to them.

Q. What are the economic forces at work under the proposed Reliability PIM?

A. Because Liberty would be able to true up its VMP costs through the vegetation management reconciliation mechanism, it would perceive a marginal cost of zero to improve its reliability. However, even though the Company does not perceive the cost, a marginal cost to providing improved reliability does exist, it is simply borne by the consumers. This mismatch of perception and reality would not present a major problem in the absence of a related PIM, because the Company would have little incentive to overspend in such a case. When paired with the Reliability PIM, however, problems arise as a result of a mismatch of perceived marginal costs and marginal benefits to reliability. Liberty already ranks first or second among its peers in terms of reliability,[43] which means it is unlikely that marginal customer benefits resulting from VMP spending are very high. And yet, because of the Reliability PIM, the company perceives a large marginal benefit to VMP spending. The Company's high perceived marginal benefit and low perceived marginal cost paired with the customer’s relatively low marginal benefits and relatively higher marginal costs give rise to an incentive for overinvestment in reliability.

[42] Request No. OCA 1-39.
[43] Direct Testimony of Erica L. Menard, p. 15.

Q. What is your recommendation for the proposed reliability PIM?

A. I recommend rejecting the Reliability PIM for two reasons. First, the company has not shown that the marginal benefit of improved reliability exceeds the marginal cost to provide it. As stated in response to DOE 7-42 ("No analysis exists."),[44] the Company did not submit any empirical analysis to make the case that the PIM is worthwhile. Second, as explained above, given the Company's proposal to annually reconcile variances between forecasted and actual costs of vegetation management, this PIM allows the Company to increase its rate of return while the costs of providing the associated reliability are flowed directly through to customers. This PIM provides an incentive for the company to spend more than the optimal amount on vegetation management, since customers bear the full cost. A reliability PIM of this sort could make more sense under a revenue cap or price cap form of PBR, where the company must contain spending growth, including vegetation management spending growth, at or below an industry benchmark in order to realize its allowed rate of return. Under such a cap, a reliability PIM would balance the Company's cost efficiency incentives with a benefit to maintaining a high degree of service quality. The proposed plan does not have this cost efficiency incentive, and therefore does not need a PIM to counteract the cost-cutting incentive.

Q. What is the Company's proposed TOU Rate Adoption PIM?

A. The Company proposes to receive a 10-basis point increase in its authorized ROE if 0.5% of residential customers adopt TOU by the third year of the MYRP.[45,46] The Company proposes to achieve higher TOU adoption through a customer outreach plan that includes education and recruitment efforts.

[44] Request No. DOE 7-42.
[45] Direct Testimony of Philip Hanser, p. 24.
[46] Request No. OCA 1-45.

Q. Do TOU rates provide value to the distribution system?

A. Yes. TOU rates provide retail customers with price signals about the value of electricity services during different times of the day. This price signal provides an incentive to shift electricity usage to lower cost times of day, reducing peak demand and reducing overall system costs.

Q. Is the Company's TOU Rate Adoption PIM a reasonable addition to its proposed PBR framework?

A. The Company's proposed TOU Rate Adoption PIM has some merit as a concept. Unlike the proposed Reliability PIM, the TOU Rate Adoption PIM does not create incentive-related conflicts with other elements of the PBR framework. In addition, this PIM would improve the Company's incentive to educate residential customers about the TOU rate. However, an empirical assessment of the value of this PIM was not performed, making a complete evaluation of the proposal difficult. Furthermore, because the Company's rollout of AMI will occur over the MYRP term,[47] the infrastructure required for TOU rates is not currently available for all customers. AMR meters will need to be installed in the interim period to support rates D-TOU and G-3-TOU.[48] To the extent that the Company deploys capital in the form of meters for the purpose of meeting the reward threshold for this PIM, and then replaces that capital in the near term with AMI, the Company's capital spending may be duplicative. Finally, Witness Hanser's testimony that Arizona utilities achieved 50% TOU rate participation over a decade does not support the proposed reward threshold of 0.5% TOU rate participation over three years.[49] For these reasons, I recommend against approving this particular proposed TOU rate adoption PIM.

[47] Direct Testimony of D. Balashov and A. Strabone, p. 6.
[48] Request No: DOE TS 2-50, Respondent: Greg Tillman. Also see, Direct Testimony of Greg Tillman, p. 12.
[49] Direct Testimony of Philip Q. Hanser, p. 27.

Q. Please summarize the Company's proposed Interconnect PIM.

A. Liberty has proposed an incentive-only PIM that will reward the Company if it can reduce processing times for interconnection applications for Distributed Energy Resources ("DERs") that require a Supplemental Review.[50] In particular, the Company proposes a 10-basis point increase in its rate base during the corresponding rate year if the Company can achieve an average interconnect time of 25 days or fewer.[51]

Q. What is your assessment of the Company's proposed Interconnect PIM?

A. This PIM proposal shares the same shortcoming as the other PIMs proposed by Liberty Utilities, in that it ascribes a dollar value benefit to an action by the Company without providing support that the action is worth the proposed dollar value. Beyond this shortcoming, the Interconnect PIM, as proposed, has two additional drawbacks. First, the Company has achieved the goal of this PIM with no financial reward over the past five years. Since 2018, the average amount of time the Company has used to complete its Supplemental Reviews was between 17 and 24 days.[52] For this reason, enacting this PIM would effectively provide an additional return to the Company for accomplishing a task it currently accomplishes with no financial incentive. Second, the Interconnect PIM provides an ROE reward for service to only a subset of Liberty's customers—those customers with interconnects greater than 10 kVA. This means the PIM reward amounts to a subsidization of enhanced service to large customers, which is funded by the entire customer base. If a particular subset of the Company's customers sought faster interconnection times, only this customer class should pay the incremental cost for improved service. As an aside, it is worth noting that this PIM is a reward-only PIM, while the Hawaiian interconnect PIM referenced by Witness Hanser, contains both a reward and a penalty.[53] Despite these issues, the

[50] Direct Testimony of Erica Menard, p. 23.
[51] Direct Testimony of Erica Menard, p. 25.
[52] Request No. OCA 1-40, part (c).
[53] Docket No. 2018-0088; Decision and Order No. 37787, Filed on May 17, 2021.

Company states that, "Stakeholders expressed concerns during the PBR Working Group sessions regarding the time required to process applications for projects greater than 10 KVA."[54] This PIM was designed to address these concerns.

Q. What is your recommendation regarding the Company's proposed Interconnect PIM?

A. I recommend that the Company's Interconnect PIM is not approved as proposed, for the reasons described above. An alternative approach to addressing the stakeholder concerns voiced in the PBR Working Group may be more reasonable, as follows. Instead of an upward adjustment to ROE for achieving speedy interconnections for a subset of customers, the Company could negotiate the value of this faster interconnection time with the customers themselves. This would resolve the problems with the PIM as proposed. First, it would allow customers to suggest a preferred Supplemental Review schedule. Second, it would provide customers with an opportunity to negotiate the value at which they prefer this schedule. Third, it would remove the subsidization effect of the PIM, such that customers smaller than 10 kVA do not pay for the reward. This alternative recommendation follows from the Company's statements that the PIM addresses stakeholder concerns about interconnection times. If stakeholders did not have such concerns, I would recommend rejecting this PIM for the reasons stated above.

Q. Please address the Company's "Reporting PIM."

A. The Company proposes one "Reporting PIM," which it defines to be informational, with no financial incentive associated with it. This reporting metric would "report the percentage of total EV charging during off peak hours that is undertaken by customers who are either on TOU rates or who take service under a managed charging program whereby the charging of EVs is managed to reduce unnecessary burden on the grid."[55] Reporting this information is

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[54] Direct Testimony of Erica Menard, p. 25.
[55] Direct Testimony of Erica Menard, pp. 29-30.

sensible. I recommend using the term "reported metric" to refer to this component of the Company's proposal, since there is no financial incentive associated with the metric.

Q. Please summarize your recommendations regarding the Company's proposed PIMs.

A. The problem common to all the Company's proposed PIMs is that they do not rely on empirical evidence regarding marginal costs and marginal benefits. It is virtually impossible to place a dollar value on any action that has not evaluated the marginal costs and benefits of that action. In addition, each PIM has individual issues. Table 2, below, summarizes my recommendations for each of the Company's proposed PIMs and the reported metric.

TABLE 2: Summary of Recommendations for Proposed PIMs

Proposed Element	Recommendation	Commentary
Reliability PIM	Reject	More reasonable with no vegetation management cost tracker.
TOU Rate Adoption PIM	Reject	More reasonable after AMI rollout.
Interconnect PIM	Reject	Negotiate with customer group on value of faster interconnection.
EV Charging Reporting Metric	Approve	Use the term "reported metric."

6. Summary and Conclusion

Q. Could you please summarize your testimony?

A. The Company's proposed framework attempts to apply the definition of PBR set out in the Settlement Agreement filed in 2020. In particular, the Company has defined regulatory goals, specified outcomes toward the achievement of those goals, and established revenue adjustment mechanisms that support safe and reliable utility service, while rewarding utility shareholders for the achievement of performance metric benchmarks and penalizing them for failing to achieve such benchmarks. However, the proposed plan has issues with execution of this definition. First, the regulatory goals do not contain cost efficiency incentives, and, as a result, the MYRP shifts risk from the Company to the customers without offering commensurate benefits to customers in return. Second, the revenue adjustment mechanisms of the plan that reward and penalize performance, in particular the proposed PIMs, lack definition because they do not have any underlying analysis to support the value of the rewards and penalties, in addition to other issues. For this reason, I recommend rejecting the PBR framework, including the MYRP, as proposed. I recommend adopting the alternative PBR framework set forth in Table 1, along with consideration for PBR alternatives that provide superior incentives, simplify the regulatory process, and provide clear benefits to customers.

Q. Does this conclude your testimony?

A. Yes it does.