STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 23-039

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Distribution Service Rate Case
Regulatory Issues

DIRECT TESTIMONY

OF

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April 28, 2023

Liberty™

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I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is Erica L. Menard. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. On whose behalf are you submitting this testimony?

A. I am submitting testimony on behalf of Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty ("Liberty" or "the Company").

Q. Please describe your educational and professional background.

A. I joined Liberty Utilities Service Corp. ("LUSC") in March 2022. Prior to joining LUSC, I held various positions at Eversource Energy from 2003 to 2022 with my last position being the Manager of Revenue Requirements for New Hampshire responsible for the rate and regulatory filings presented to the New Hampshire Public Utilities Commission (the "Commission"). I also held various positions at Eversource responsible for financial planning and analysis of operational and capital expenditures, business planning functions, sales forecasting, and performance management. Prior to my employment at Eversource, I was employed by ICF Consulting in Fairfax, Virginia, from 1997 to 2003 with responsibilities for implementing load profiling and load settlement software for various utilities worldwide. I hold a Bachelor of Arts in Economics and Business Administration from the University of Maine and a Master of Business Administration from the University of New Hampshire.

Q. Please describe your duties at Liberty.

A. I am employed by LUSC as the Senior Director of Rates and Regulatory Affairs. LUSC provides local utility management, shared services, and support to Liberty and the other regulated water, wastewater, natural gas, and electric utilities commonly owned and operated by Liberty Utilities, Co. as affiliates of the Company. In my position, I am responsible for providing rate-related services to the Company.

Q. Have you previously testified in regulatory proceedings before this Commission?

A. Yes, I have testified on numerous occasions before this Commission.

II. <u>PURPOSE OF TESTIMONY AND EXECUTIVE SUMMARY</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss at a high level the Company's performance-based ratemaking ("PBR") framework to establish distribution rates over a multi-year period with an incentive structure that provides benefits to Liberty, our customers, and our regulatory stakeholders. I will also discuss Liberty's proposal to streamline the review of rate changes through the introduction of a new reconciling rate mechanism and address changes to the tariff intended to simplify administration of the tariff.

Q. Why is Liberty proposing a PBR pilot?

A. Liberty's last rate case, Docket No. DE 19-064, was resolved through a settlement agreement approved by the Commission in Order No. 26,376 (the "Settlement Agreement"). The Settlement Agreement included a determination that it is in the public interest for Liberty to explore transitioning away from the strict application of traditional cost-of-service ("COS") ratemaking principles in favor of a PBR approach.

Q. Please define PBR.

A. The Settlement Agreement defined PBR as a process of defining regulatory goals, specifying outcomes toward the achievement of those goals, applying performance metrics that measure such achievement, and establishing 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.[1]

Q. Is Liberty's PBR pilot consistent with that definition?

A. Yes, the Company's proposal is consistent with the definition of PBR included in the settlement agreement.

Q. Does Liberty believe that the Commission has the authority to implement a PBR pilot?

A. Yes. Implementation of a PBR pilot was specifically contemplated by the Settlement Agreement approved by the Commission. In addition, RSA 374:3-a provides the Department of Energy and the Public Utilities Commission with the authority to approve alternative forms of regulation other than the traditional methods which are based upon cost of service, rate base, and rate of return where any such alternative results in just and

[1] Settlement Agreement, § II(C).

reasonable rates and provides the utility the opportunity to realize a reasonable return on its investment.

Q. Were there any other stipulations agreed to in the Settlement Agreement with respect to the PBR?

A. Yes. The Settlement Agreement included three step adjustments to allow the Company to recover the costs associated with certain capital additions placed into service during 2019, 2020, and 2021.[2] As a prerequisite to obtaining approval of the third step increase, the Company was required to: (1) present proposals to the Department of Energy ("DOE") (previously Commission Staff), the Office of the Consumer Advocate ("OCA"), and New Hampshire Department of Environmental Services ("NHDES") for PBR mechanism(s) for inclusion in the Company's next distribution rate case through meetings or technical sessions commenced at least nine months prior to the April 6, 2022, step adjustment filing; and (2) in good faith consider the comments of DOE and the OCA in determining the details of the PBR mechanisms before finalizing and proposing a PBR mechanism in the next distribution rate filing.

Additionally, in the Settlement Agreement Liberty agreed to develop an Advanced Rate Design Road Map, including (1) an explanation of how Liberty plans to leverage the functionality of its existing and planned investments, particularly meters, to maximize ratepayer benefits, and (2) Liberty's plans for the future of rates for each customer class, including the extent to which the utility plans to rely on innovative rate design techniques

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[2] Settlement Agreement, § II(B).

such as time-of-use rates, critical peak pricing, etc.[3] Liberty agreed to submit the Advanced Rate Design Roadmap to DOE, OCA, the City of Lebanon, Clean Energy New Hampshire ("CENH"), and NHDES by April 6, 2022, and to include the plan in the next filed Least-Cost Integrated Resource plan or Integrated Distribution Plan filed and the Company's next rate case, as appropriate. This testimony is submitted in support of that next distribution rate filing.

Q. What efforts did the Company make with respect to these stipulations?

A. The Company met with stakeholders on several occasions beginning in the fall of 2021. Initial meetings focused on PBR education and general discussions. In September 2021, Liberty met with stakeholders regarding the contexts within which PBR has been applied in other jurisdictions and to discuss benefits associated with PBR plans and mechanisms. Liberty presented several types of performance metrics that could support a PBR regimen and sought stakeholders' feedback to inform the Company's development of more specific, actionable proposals.

In April 2022, the Company presented a PBR framework and Advanced Rate Design Roadmap. The PBR framework further defined a PBR pilot proposal with key elements of the proposal including a multi-year rate plan ("MYRP"), an earning sharing mechanism ("ESM"), and performance incentive mechanisms ("PIMs"). Additionally, an advanced rate design framework was presented to outline a phased approach to advanced rate design including a foundational investment in Automated Metering Infrastructure

[3] Settlement Agreement, § II(F)(1).

("AMI") within the multi-year rate plan to allow for more advanced rate design capabilities. The Company received stakeholder feedback at the April 2022 meeting regarding the development of the PBR pilot and the phased Advanced Rate Design approach.

In May 2022, the Company hosted a stakeholder meeting to receive input on PIMs. The Company spent the next several months engaging an outside advisor to educate and assist the Company with developing the PBR framework including the MYRP, ESM, and PIMs. In December 2022, the Company hosted an educational meeting with stakeholders on PBR and presented the Company's proposal for the PBR pilot.

In January and February 2023, the Company and stakeholders met to further discuss the Company's proposed PBR pilot and PIMs. The PBR plan presented in this docket incorporates the feedback and suggestions from those stakeholder engagement meetings. This PBR Plan proposal is discussed in more detail in the testimony of Company witnesses DeCourcey and Therrien; the PBR Plan is further supported by the testimony of Company witness Hanser.

Q. Please explain why a PBR framework as an alternative to traditional COS regulation is reasonable and beneficial to the regulatory process, the Company, and its customers.

A. As discussed in Mr. Hanser's testimony, traditional ratemaking is no longer adequate as utilities generally shift from larger and more infrequent investments (*e.g.*, building large-scale power plants) to smaller, more frequent investments (*e.g.*, grid improvement and distributed energy resource investments). An MYRP improves regulatory efficiency by reducing the frequency of rate proceedings, provides timely rate recognition, and better aligns utility revenues and performance with customer and policy goals. Mr. Hanser addresses the reasonableness of the PBR framework as an alternative to traditional COS regulation and the benefits it can provide to the regulatory process, customers, and Liberty.

Q. Please explain the guiding principles Liberty considered in designing the PBR pilot presented.

A. Liberty's design of the PBR pilot considered a framework that balances customer interests, regulatory and administrative efficiency to the utility, stakeholders, and customers, and supports maintaining the utility's financial health while facilitating state policy goals. With the proposed framework, the Company is still able to meet its core obligation to provide safe, reliable electric service to all customers at reasonable rates while maintaining a reasonable opportunity to recover the costs necessary to do so. This plan provides Liberty a reasonable opportunity to earn a fair rate of return through the prudent deployment of capital while also working toward achieving New Hampshire's ten-year state energy policy goals and objectives.

This PBR pilot does not change the applicable regulatory standards and protections that New Hampshire has in place with respect to regulatory oversight and ratemaking principles.

Q. Please define the period covered by Liberty's PBR pilot.

A. Liberty's PBR plan consists of a three-year period based on a historical test year for the 12-month period ended December 31, 2022, a bridge period from January 1, 2023, through June 20, 2023, and forward-looking rate years beginning July 1, 2023, July 1, 2024, and July 1, 2025 (the "Rate Years"). The Rate Years are discussed further in the Direct Testimony of Company Witnesses Matthew DeCourcey and Gregg Therrien.

Q. Please provide a high-level summary of the ESM being proposed by the Company as part of the PBR pilot.

A. The MYRP includes a symmetrical ESM that shares an earnings surplus or deficit with customers if the Company's adjusted earnings exceed or fall below a certain level, also known as a deadband. Within the deadband, there is no sharing mechanism with customers. Outside of the deadband, sharing occurs. The specifics associated with the MYRP and ESM including the timing of review, how earnings are calculated and what earnings are eligible for sharing and the mechanism for sharing the excess with customers are described in more detail in the Direct Testimony of Messrs. DeCourcey and Therrien.

III. <u>PERFORMANCE INCENTIVE MECHANISMS</u>

Q. Please summarize this section of your testimony.

A. In this section, I summarize the Company's proposal to create three PIMs that create financial incentives for Liberty to achieve high levels of reliability, promote the adoption of time of use ("TOU") rates that have the potential to save customers' money, and to reduce the time required to evaluate and approve applications for distributed generation.

For each PIM, I describe the parameters, explain why the Company believes that its approval will create benefits for customers, and discuss how the approach proposed by the Company is consistent with industry best practices in jurisdictions that regulate electric utilities via PBR. In addition, I also propose one PIM that requires the Company to regularly collect and report performance data and explain the basis for that proposal.

Q. What are PIMs?

A. PIMs are ratemaking tools that create incentives for certain outcomes that are deemed to be beneficial or desirable. Mechanics vary and incentives can be applied in different ways. Some PIMs create a financial reward for a utility's strong performance and/or a penalty for poor performance. Others create an incentive for beneficial behavior by allowing a utility to share the economic benefits its performance creates with customers. And some PIMs may not include financial incentives at all but instead require the collection and reporting of performance data, one goal of which is to incent the utility to operate effectively by enhancing transparency and accountability.

Q. Is the Company proposing each of those types of PIMs?

A. Yes. As described below, the Company is proposing PIMs that utilize each of the financial incentive mechanisms and one reporting-only PIM. The Company's proposed PIMs are summarized in Table 1 below.

Table 1. Summary of Proposed PIMs

PIM	Target criteria	Incentive
Reliability	Reliability performance compared to a defined group of peer utilities	Financial reward and penalty
TOU rate adoption	Education and promoting of TOU rate program, increasing TOU rate adoption	Reward only
Interconnect times	Reduction of times required to process interconnection applications for DERs	Reward only
Performance reporting	Collection and reporting of EV penetration rates	Reporting only

Q. In his testimony, Mr. Hanser identifies four key components that are recognized as underlying industry best practices in the specification of PIMs in a PBR setting. Does the Company's proposal align with these principles?

A. Yes, the proposed PIMs are designed to reflect the principles that Mr. Hanser explains in his testimony[4].

Q. Did any other overarching principles guide the Company's development of its proposal?

A. Yes. Generally speaking, the Company's proposed PIMs are intentionally conservative first steps in the sense that they are unlikely to lead to dramatic results. The Commission's acceptance of Liberty's proposal will create new, meaningful incentives for the Company to innovate, to seek efficiencies, and to generally perform at a high level for its customers and we are excited about the opportunities that framework will create.

[4] Direct Testimony of Philip Q. Hanser at p. 19.

At the same time, Liberty is cognizant that PBR is a new concept in New Hampshire and so this element of our proposal reflects an incrementalist perspective. In the future, we expect that our experience with PBR, perhaps with the experiences of other New Hampshire utilities, will help to inform the development of PIMs that may be broader, better targeted, or more impactful. In the meantime, the Company believes that the PIMs described below strike an appropriate balance between incenting performance that creates value for customers while minimizing the potential for unintended consequences.

Q. Did the Company seek input from any experts to develop these PIMs?

A. Yes. The Company engaged its advisors at The Brattle Group, Mr. Bill Zarakas and Mr. Philip Hanser in particular, and also solicited input from key external stakeholders including the DOE, OCA, the City of Lebanon, Clean Energy New Hampshire, and NHDES. As described previously, the PBR Working Group met five times to educate parties on PBR, learn which elements of a PBR were important to stakeholders, discuss incentive mechanism proposals, and narrow down the list of possible incentive metrics. Ultimately, most of our proposed PIMs were either discussed at length with the Working Group or were proposed by one of the parties.

A. <u>Reliability PIM</u>

Q. Please summarize Liberty's reliability PIM proposal.

A. Liberty proposes to compare its reliability performance to a group of other electric utilities in New Hampshire, Maine, and Massachusetts on an annual basis. If Liberty's performance is among the top performers in the group, the Company will be eligible for an incentive payment. If Liberty's performance is among the worst performers, the Company will be assessed a penalty.

Q. On what basis will the reliability performance of this group be measured?

A. Reliability performance will be measured using two widely utilized metrics. The first is the System Average Interruption Frequency Index ("SAIFI"), which measures the frequency with which customers experience outages and is calculated as the number of customers affected by an outage over some period divided by the number of customers on a system. The second is the System Average Interruption Duration Index ("SAIDI"), which measures the length of outages and is calculated by customers' aggregate outage times divided by the number of customers on a system[5]. Mr. Strabone's Direct Testimony discusses SAIFI and SAIDI and their relevance in detail.

Q. Has the Company shared its plan to utilize SAIFI and SAIDI for this purpose with its key stakeholders?

A. Yes, the topic was discussed at meetings of the PBR Working Group and the use of these metrics for a PIM focused on reliability performance appears to have general support.

Q. Where will the SAIFI and SAIDI data come from?

A. Each year, the Energy Information Administration ("EIA") publishes data collected via Form 861, otherwise known as the *Annual Electric Power Industry Report* ("Form 861"). SAIFI and SAIDI are included among the data that can be accessed through the EIA's

[5] Customers' aggregate outage times can be thought of as the average duration of outages multiplied by the number customers who experienced an outage.

website[6]. Unless otherwise noted, the SAIFI and SAIDI measures reported in the remainder of this section of my testimony are the metrics that exclude Major Event Days ("MEDs"), which are periods of extreme weather. Using data that exclude MEDs is typical for purposes similar to one proposed by the Company.

Q. To which utilities will the Company compare its performance?

A. The Company will compare its performance to certain utilities that operate in New Hampshire or the states adjacent to New Hampshire. The identified utilities are Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource") and Unitil Energy Systems ("UES") in New Hampshire; Fitchburg Gas & Electric Light Company d/b/a Unitil ("FG&E") and NSTAR Electric Company d/b/a Eversource Energy ("NSTAR") in Massachusetts; and Central Maine Power Co. ("CMP") and Versant Power ("Versant") in Maine.

Q. Have any of those utilities changed names recently?

A. Yes, NSTAR is part of Eversource Energy and does business in Massachusetts under the Eversource brand name, as does its New Hampshire affiliate. For purposes of clarity in my testimony, references to Eversource are to the utility that operates in New Hampshire while NSTAR refers to the Massachusetts electric utility. Similarly, Versant used to be called Emera Maine. For simplicity, all references to Versant below include the period in which the company was called Emera Maine.

[6] https://www.eia.gov/electricity/data/eia861/

Q. Why are these appropriate utilities to use for comparison?

A. These utilities were selected primarily because they are all Investor-Owned Utilities ("IOUs") that do business in or around New Hampshire. The Form 861 data include all three IOUs in New Hampshire and the two in Maine. The data for Massachusetts includes the companies listed above as well as two utilities owned by National Grid that were excluded because they report SAIFI and SAIDI using a different standard; the same was true for Green Mountain Power, the only IOU in Vermont.[7]

Q. Did Liberty consider using data for utilities located farther away?

A. Yes, Liberty considered using data for utilities located farther away and ultimately decided to utilize data for the selected states because they may be more likely to reflect the regional conditions that affect reliability and because they are less likely to be impacted by exogenous seasonal weather affects, which could influence the results of the comparisons.

Q. Have you collected recent SAIFI and SAIDI data from the Form 861s?

A. Yes. Annual data for the period 2017–2021 are shown below.

[7] The EIA reports SAIFI and SAIDI using a standard established by the Institute of Electrical and Electronics Engineers ("IEEE") as well as the same metrics that were measured using other standards, as applicable. Most utilities use the IEEE standard; however, National Grid in Massachusetts and Green Mountain Power in Vermont do not use the IEEE standard. Exclusion of the non-IEEE standard data is intended to better facilitate comparisons on an equivalent basis.

Table 2. SAIFI Without MEDs, 2017–2021 (interruptions per customer)

		2017	2018	2019	2020	2021
NH	Liberty	1.3	1.0	0.9	1.0	0.9
	Eversource	1.1	1.1	0.7	0.8	0.8
	UES	1.3	1.2	0.8	1.6	1.0
MA	FG&E	1.3	1.6	1.2	1.3	1.3
	NSTAR[8]		0.8	0.7	0.7	0.7
ME	CMP	1.8	1.9	1.5	2.0	2.0
	Versant	2.2	2.5	2.0	2.4	2.0

Table 3. SAIDI Without MEDs, 2017–2021 (total outage duration per customer)

		2017	2018	2019	2020	2021
NH	Liberty	157.1	158.1	115.7	100.9	108.7
	Eversource	118.6	119.9	82.6	95.8	96.8
	UES	112.7	115.8	82.5	120.0	102.8
MA	FG&E	74.8	108.0	83.6	64.9	77.1
	NSTAR	74.3	85.0	70.3	65.0	75.8
ME	CMP	202.2	235.8	189.8	220.8	219.6
	Versant	368.0	397.0	302.0	319.0	218.0

Q. With reference to these data, what performance improvements is the Company seeking to incent with the Reliability PIM?

A. Compared to other utilities in this group, Liberty's SAIFI was lower (better) than most over this period, but its SAIDI compares less favorably. The Reliability PIM is thus designed to create an incentive for the Company to maintain its strong SAIFI score relative to this group, while continuing to improve its SAIDI score.

[8] SAIFI data for NSTAR was not reported for 2017.

Q. How would the PIM work?

A. Following the end of each rate year ("RY"), beginning with RY2, the Company will compare its SAIDI and SAIFI scores reported by EIA to those of the other utilities shown above. If it has achieved either the lowest or second lowest (best) scores in both categories, it will collect an incentive reward. If its SAIFI and SAIDI are both either the highest or second highest (worst) among this group, it will be assessed a penalty. For all other outcomes, no incentive or penalty would apply.

Q. When will that comparison be made?

A. Following each rate year, Liberty will submit the reconciliation filing that is described in the Direct Testimony of Messrs. DeCourcey and Therrien. The comparison of the performance and the calculation of the penalty or incentive payment will be included in that reconciliation filing.

Q. Will the comparison be made based on a previous rate year?

A. No. For simplicity, the Company proposes to compare SAIFI and SAIDI based on the previous Calendar Year ("CY").

Q. Why is the Company proposing a Calendar Year comparison?

A. The Company is proposing to perform the comparison on a CY because this is consistent with how the EIA reports the Form 861 data. Each October, data for the previous year are published. For example, the most recent data released were for CY 2021 and were made available in October 2022. The Company could combine multiple years' data to synthesize a period that could better match the rate year periods proposed elsewhere in this proceeding but doing so would be complex and subject to uncertainties as to whether any of the data that are reported for a CY are consistent throughout that year. Such adjustments also serve no specific purpose in terms of supporting the Company's incentive to perform.

Q. Will the use of CY data for this purpose make the Reliability PIM any less effective?

A. No, there is no reason to think that it would. Accounting for the exclusion of a reconciliation following RY1, which I describe below, the Commission's acceptance of the recommended PIM would create a financial incentive for reliability performance throughout the period for which rates will be set in this proceeding.

Q. Why is the Company proposing to exclude the PIM from the reconciliation of RY1?

A. The Company is proposing to begin measuring the reliability PIM in the reconciliation filing for RY2. This delay will allow the Company time to align the incentives created by the penalty/reward structure in the PIM, the Company's ability to respond to those incentives, and the timing of the release of the relevant data by the EIA. The Company is proposing that RY1 end in June 2024. The next release of the Form 861 data would be the following October and include data for CY 2023. Since 2023 is already well underway and will be nearly or fully complete by the time this case is completed and the PIMs are established, a new penalty/reward structure for 2023 applied at that time cannot create a meaningful incentive for the Company to improve performance. For that reason, Liberty proposes that the Reliability PIM first be applied following the end of RY2 using SAIFI and SAIDI data reported for CY 2024, which will be available at that time.

Q. Please describe the proposed incentive and penalty.

A. The proposed mechanism is symmetrical in the sense that the incentive and the penalty are the same size. For both, the Company proposes that the incentive be equal to the value of a 25 basis points ("bps") return on Liberty's rate base for the year most recently ended. The incentive or penalty would be calculated based on the rate base established after all the adjustments and reconciliations described in the Direct Testimony of Messrs. DeCourcey and Therrien. The incentive or penalty would subsequently be recovered or refunded, respectively, via the Electric Reconciliation Adjustment Mechanism ("ERAM"), which I describe in Section IV of my testimony.

Q. Is a reliability PIM necessary when the Commission already oversees the reliability of the service that Liberty provides its customers?

A. The intent of the PIM, and PBR in general, is to create incentives that will result in utility behaviors that benefit customers. In this case, the Company believes that there are currently few incentives for a utility to outperform industry standards or not underperform industry standards. Outperforming industry standards occurs when the Company achieves SAIFI and SAIDI scores higher than similar utilities. Put another way, there is currently no incentive for a utility to improve performance where it is meeting industry standards. However, meeting industry standards may not translate to customer satisfaction. The PIM, therefore, is designed to bridge the gap between the incentives that are provided for within the current framework (i.e., incentives to meet the industry standard) and create better outcomes for customers.

Q. Is that why Liberty is proposing a PIM that focuses on reliability even when other witnesses testifying on its behalf assert that its reliability performance is already strong?

A. Yes, in large part. The Company also sought input from participants in the Working Group who generally support the concept of new PIMs indexed to SAIFI and SAIDI. Additionally, Liberty's core mission is to provide customers with safe, reliable electric service and that, as such, it was important in this proceeding to directly tie its financial outcomes from implementing PBR to the level of reliability performance it can deliver.

Q. Is the Reliability PIM consistent with how PBR is implemented across the electric industry?

A. In his Direct Testimony, Mr. Hanser explains that it is. There, Mr. Hanser concludes that the proposed mechanism, the use of a two-way incentive/penalty mechanism, and the size of the financial component are all consistent with industry best practices and are thus likely to create benefits for customers[9].

B. TOU Rate Adoption PIM

Q. Please summarize the proposed the TOU Rate Adoption PIM.

A. In the testimony of Company Witness Gregory Tillman, the Company is proposing to offer new, opt-in TOU rates to its Residential (Class D) and Small Commercial (Class G-3) customers.[10] Mr. Tillman's testimony describes the parameters of the new rates, the

[9] Hanser Direct Testimony, p. 22
[10] As Mr. Tillman explains in his testimony, there are a small number of residential customers who already have access to TOU rates under Rate Class D-10. Those customers will have the option of moving to the new residential TOU rate or to returning to non-TOU residential service.

bill guarantee that the Company will be offering customers who switch to TOU rates, and the way that benefits are likely to accrue to all of Liberty's customers, including the ones who choose not to switch to a TOU rate. Among those are lower bills, including for those customers who do not opt for TOU service. Liberty is proposing a PIM centered around customer adoption of TOU rates. The TOU Rate Adoption PIM will allow Liberty to earn an incentive as more customers sign up for TOU rates, which will create an incentive for the Company to promote the program.

Q. How will the implementation of TOU rates create savings opportunities for Liberty's customers?

A. As Mr. Tillman explains in his testimony, time-of-use rates (sometimes referred to as time-varying rates) create incentives for customers to switch their usage from high-priced periods to lower-priced periods. By doing so, the Company's peak demand is lowered, reducing the amount of capacity and transmission that must be purchased from the wholesale market, and allowing energy purchases to be transacted at a lower price[11].

Q. Who benefits from the cost reductions associated with reducing peak demand?

A. All of Liberty's customers can benefit from a reduction in peak demand. Customers that opt-in to the TOU rates benefit directly by shifting their energy consumption to lower-priced periods. All customers, including customers that do not opt-in to TOU rates, also benefit from reductions in the charges for capacity and transmission which result from the lower system peaks caused by the TOU customers[12]. Additionally, more efficient

[11] Tillman Direct at p. 7
[12] *Id.* at p. 7

consumption reduces emissions, which creates societal benefits and potentially avoiding the need for a future capital investment in the system.

Q. How can Liberty encourage its customers to switch to TOU rates?

A. Mr. Tillman's testimony describes Liberty's two-part customer outreach plan, which includes efforts to educate our customers regarding TOU rates and its benefits generally, and a subsequent, targeted initiative to recruit program participants[13].

Q. Does the Company believe that its TOU Rate Adoption PIM creates a meaningful incentive for the Company to enroll more customers into TOU rates?

A. Yes, it does as it encourages the Company through an incentive to use multiple channels to educate customers on what time-of-use rates are and how customers can potentially save money by enrolling in TOU rates.

Q. Does the TOU Rate Adoption PIM create financial risks or burdens for any of Liberty's customers?

A. No. The only financial reward the Company will be able to receive will be an incentive if a certain percentage of customers sign up for the TOU rate. And since TOU rates are intended to shift consumption to off-peak periods, lowering costs to the customers and creating potential benefits to the system, the Company's proposal represents a "win-win" for it and its customers.

[13] Tillman Direct Testimony, p. 13-14

Q. Is there precedent in New Hampshire for the creation of a financial reward designed to incent utility support for the penetration of a program that will create customer savings?

A. Yes. The New Hampshire Triennial Energy Efficiency Plan contains performance incentives ("PI") that promote the achievement of New Hampshire's Energy Efficiency Resource Standard ("EERS") goals and contain metrics designed to encourage income-eligible participation in energy efficiency programs and to encourage peak load reductions. At a high level, the performance incentives contain three to five metrics with an incentive weighting, a minimum threshold, a maximum performance incentive level, and a method of verification. The underlying principles of the PI framework are[14]:

- It uses metrics that are transparent – e.g., performance is incentivized within separate key metric areas that are clear and well-defined, and aligned with EERS goals.
- It is administratively expedient – e.g., provides an easy-to-use one-page template based on the existing data compilation methods used by the utilities.
- It increases focus on targets and promotes various policy objectives by applying incentives to each performance component separately - e.g., peak demand.
- It establishes minimum thresholds for each performance indicator to encourage performance on each of the targets.

[14] New Hampshire Energy Efficiency Calculation of Performance Incentive Beginning in 2020 Report Issued by the NH Performance Incentive Working Group (July 31, 2019) - https://www.puc.nh.gov/EESE%20Board/EERS_WG/20190913-EERS-WG-PI-FINAL-REPORT.pdf

- It preserves effective elements of the existing minimum PI requirements - e.g., baseline target and cap, BCR, actual savings, etc.
- It uses a portfolio approach, which provides the utilities with greater flexibility in terms of program implementation and innovation and increasing low-income participation through fuel-neutral measures.

Q. Have other utilities had success utilizing PIMs in a manner similar to the one proposed by Liberty?

A. Yes. Witness Hanser notes that,

> the State of Illinois has a variety of so-called "smart grid" metrics for its utilities related to customer participation in various forms of time-varying pricing programs. Similarly, Xcel Minnesota proposed a PIM for the percentage of E.V. owners enrolled in managed charging rates and another PIM for the percentage of E.V. charging taking place during off-peak hours (compared to total E.V. charging).[15]

C. Interconnect PIM

Q. Please describe Liberty's third proposed PIM, the Interconnect PIM.

A. Liberty proposes to create an incentive-only PIM that will create a financial reward if Liberty can reduce processing times for interconnection applications for certain types of Distributed Energy Resources ("DERs").

[15]Hanser Direct Testimony at p. 25.

Q. What currently establishes the required processing times for interconnection applications?

A. Section 52 of the Company's Electric Delivery Service Tariff (the "Tariff") sets the interconnection standards for inverter-based facilities sized up to 100 kilovolts-ampere ("kVA"), including interconnection timelines.

Q. How long does the Tariff provide for the Company to evaluate interconnect applications for those types of resources?

A. There are two separate application processes, which are summarized on page 48 of the Tariff. For resources that are 10 kVA or less, and which meet certain other screening criteria, the maximum application processing time is 20 days. For resources that are greater than 10 kVA (but less than 100 kVA), or which otherwise do not meet the screening criteria, a Supplemental Review of the application is required, the primary purpose of which is to evaluate whether modifications to the distribution system would be required and, if so, what the costs of those modifications would be. The Tariff requires that a Supplemental Review be completed within 40 days. In all instances related to interconnection processing, timelines refer to business days under normal Company operating conditions.[16]

Q. Which timeline would the Interconnect PIM seek to improve?

A. The Interconnect PIM would incentivize the Company to shorten the existing 40-day time required to complete Supplemental Reviews.

[16] Tariff at p. 42.

Q. What is the Company's proposal?

A. The Company is proposing to earn an incentive payment for any year in which the average time to process Supplemental Reviews is 25 days or less. The incentive payment, if earned, would be equal to the value of 10 bps of the rate base of the rate year that is subject to the reconciliation filing. The incentive payment will be recovered through the ERAM in the same manner as any incentive payment earned pursuant to the Reliability PIM. If the average time spent in the queue is greater, no reward will be recovered.

Q. Why has the Company chosen to target a reduction in the time to process interconnect applications for projects greater than 10 kVA?

A. Stakeholders expressed concerns during the PBR Working Group sessions regarding the time required to process applications for projects greater than 10 KVA. These concerns have also been raised regularly in discussions that Company staff has with customers and other stakeholders in its normal course of business. One reason the issue is of particular concern is that many residential Photovoltaic ("PV") systems require Supplemental Review before they can be connected. The increasing popularity of such installations creates an impetus to improve Liberty's responsiveness to customers in this area, if possible. This appears to be an industry-wide concern. In his testimony, Mr. Hanser explains that regulators in other jurisdictions are creating new mechanisms to incent faster processing times of interconnect applications for similar reasons.[17]

[17] Hanser Direct Testimony, p. 24

Q. Why is a PIM an appropriate tool to reduce interconnect application processing times?

A. The Company is currently in compliance with its Tariff regarding interconnection application timelines. This makes it difficult for the Company to support a request to the Commission for an increase in its cost of service to devote more resources to improvement despite reasonable concerns from stakeholders and customers. Liberty believes that the issue is thus an ideal target for a PIM and is consistent with the descriptions of the goals for PBR outlined in the Settlement Agreement. In particular, the Settlement Agreement identified PBRs that "reward[] utility shareholders for the achievement of performance metric benchmarks" that support policy objectives.[18] Facilitating interconnection is consistent with policy objectives related to the diversity of resources and the Interconnect PIM will facilitate this objective. Application of the PIM will also create additional data that can be used to evaluate the effectiveness of performance incentive metrics for subsequent rate proceedings for Liberty and for other utilities in New Hampshire.

Q. Why is the Company proposing an incentive-only mechanism instead of one that includes a penalty as well?

A. The Company is not proposing a corresponding penalty because the Company's interconnection application performance is governed by tariff and the Company should not be penalized if its performance complies with the Tariff. In addition, the Commission

[18] DE 19-064 Settlement Agreement, Bates 006

is already authorized to impose sanctions for tariff violations and thus any penalty associated with this PIM would be duplicative.

Q. How will the Company report changes in application processing times?

A. In the same annual reconciliation filing in which it will report data related to earnings and the other PIMs, Liberty will report for the average time required to complete Supplemental Reviews for the previous calendar year. The Company will also provide relevant supporting documentation, if any, and indicate the change to the ERAM required to collect the incentive payment, if applicable.

D. <u>Reporting PIMs</u>

Q. What are reporting PIMs?

A. Reporting-only PIMs create requirements for a utility to collect and report new data on an ongoing basis. As part of its PBR proposal, the Company is recommending one PIM that will require new reporting designed to enhance transparency and accountability, provide insights that may be useful to the Commission and our customers, and potentially support the development of PIMs or other policy-oriented mechanisms in future proceedings. Reporting PIMs do not include performance rewards or penalties.

Q. Are reporting PIMs typical in the electric industry?

A. Yes, as discussed in Mr. Hanser's testimony, reporting PIMs are typical, particularly in jurisdictions that are in the early stages of implementing PBR.[19]

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[19] Hanser Direct Testimony at p. 25-26.

Q. How did the Company select the reporting PIM that it is recommending?

A. The reporting PIM was primarily based on feedback received during the stakeholder sessions that I describe above. In particular, during the meeting held on February 2, 2023, participants presented their own PIMs recommendations. Attached as Attachment ELM-1 is a summary prepared by the OCA and its advisor setting forth its recommendations presented to the Working Group. The Working Group discussed the proposed PIMs in detail, but ultimately did not select any PIMs on the list for inclusion in the proposed PBR pilot and PIM Plan.

Q. Is the Company recommending all the PIMs listed in Attachment ELM-1?

A. No. Some of the PIMs listed in Attachment ELM-1 would be duplicative in the sense that they would collect data that is already reported elsewhere. Others are not relevant for this case or would require data that the Company does not currently have access to. Additional discussion on the basis for the selection of the Reporting PIM follows later in this section of my testimony.

Q. If the Commission orders the implementation of the proposed reporting PIM, how will the Company report the relevant information?

A. The Company will report on the results of PIM performance as a separate addendum to the annual PBR reconciliation filing. This addendum would provide a written summary of the numerical results along with required descriptions and clarifications. Where necessary and appropriate, the Company would also provide related documentation, calculation, workpapers, and other relevant supporting materials.

Q. Is the Company requesting that the Commission order the implementation of the reporting PIM precisely as it is described below?

A. No. The Company proposes that the Commission accept the recommended PIM. The Company would then engage with stakeholders to reach a consensus about how the PIM will be implemented. Following this engagement, the Company would make a compliance filing that proposes the appropriate details and reflect the Commission's relevant findings in this case.

Q. Why is that additional stakeholder process necessary?

A. An additional process is necessary because a number of important details remain unresolved, and the Company believes that continuing the collaborative approach begun by the Working Group before this proceeding would be most effective. During those sessions, the parties made good progress identifying areas of significant interest, as reflected in the list of proposed PIMs that follows. The Company thinks the Working Group is well positioned to finalize the relevant details and that this collaborative process will enable efficient future review of the resulting data.

Q. How many reporting PIMs is the Company recommending?

A. The Company is recommending one reporting PIM related to EVs at this time.

Q. Please summarize the reporting PIM related to EVs proposed by the OCA.

A. The OCA recommends that Liberty 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 managing charging program whereby the charging of EVs is managed to reduce unnecessary burden on the grid.[20]

Q. Does the Company agree?

A. Yes, subject to confirmation of data availability and subject to the additional Working Group process described above to reach an agreement on the acceptability of the data. The Company is not currently proposing any managing charging programs; therefore the Company expects that this PIM will report only off-peak charging for customers on TOU rates.

Q. Why is the Company not proposing to apply a financial incentive or penalty to the reporting PIM for EVs?

A. At this time, the Company has very limited EV TOU rate data and is proposing changes to EV TOU rates. For this reason, the Company would expect to track consumption data in order to develop a target in the future.

Q. Regarding the PIMs proposed in Attachment ELM-1 that the Company is not proposing to adopt, can you please explain why not?

A. Yes. The Company considered all proposed PIMs. However, Attachment ELM-1 includes several proposed PIMs related to the Company's planned AMI investment and customer engagement. Because of the timing of Liberty's AMI investment, which is discussed in the Direct Testimony of Company Witnesses Dmitry Balashov and Anthony

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[20] Attachment ELM-1 includes a reference to Xcel Energy that the Company believes is a typographical error. It has assumed, for purposes of this discussion, that that reference is to Liberty.

Strabone, Liberty does not expect this data to be available until the end of the period for which rates will be established in this proceeding, if at all. For this reason, the Company determined that establishing reporting for these metrics is more appropriate in a future rate case. Similarly, the Company is not specifically proposing any Non-Wires Alternatives ("NWAs") at this time and therefore does not agree that it should adopt the proposed PIM related to savings from NWA metrics. Insofar as the evaluation of NWAs is currently a focus of the Least Cost Integrated Resource Planning ("LCIRP") plans that New Hampshire utilities are required to make at regular intervals, the Company believes that it would be appropriate and efficient to leave the evaluation and reporting of the benefits of NWAs to those proceedings.

Q. Are there any PIMs proposed in Attachment ELM-1 that focus on data that the Company is already collecting and reporting elsewhere?

A. Yes. Attachment ELM-1 includes proposals for PIMs to track customer complaint totals, the amount of demand reduction capacity installed on the Company's system, customer arrearage amounts, customer outage data and response times and other information that is already reported elsewhere. Liberty is generally supportive of incorporating these and other reporting requirements into the PBR framework; however, without Commission orders that obviate the need to report these data in other contexts, creating new reporting PIMs would only create redundancy and unnecessarily increase administrative burdens.

IV. ELECTRIC RECONCILIATION ADJUSTMENT MECHANISM

Q. Why is the Company proposing a new reconciling mechanism?

A. The Company currently has seven reconciling mechanisms in place to recover various categories of costs. The Company is required to submit, and the Commission must review, petitions for each of these adjustments on at least an annual basis. The Company is also proposing new mechanisms that will reconcile costs associated with several of the Company's proposals outlined in this proceeding (e.g., fee free, MYRP earnings sharing mechanism, etc.). By creating one comprehensive reconciling mechanism that includes all these components, a single, consolidated review of rate adjustments can be performed by the Commission and stakeholders resulting in administrative efficiencies.

Q. Please describe the reconciling cost recovery mechanisms that Liberty has in effect today.

A. Liberty has several rates that recover, on a fully reconciling basis, costs incurred by the Company for stranded costs, transmission services, default energy service costs, and distribution operating expenses. The stranded cost and transmission charges are reviewed together in a single retail rate annual reconciliation filing, although there are separate rates for each mechanism.

Q. What types of costs are recovered through each of the current reconciling mechanisms?

A. The Stranded Cost charge recovers the costs associated with the Contract Termination Charge from New England Power Company due to restructuring. The Transmission

Charge recovers costs for transmission-related services. In addition to transmission services, the Transmission Charge also includes the Regional Greenhouse Gas ("RGGI") refund as approved in Order No. 26,664 (May 9, 2014). The Transmission Charge includes the RGGI refund because, at the time this was approved, the retail rate was the only means by which Liberty could rebate the available RGGI amounts on a per kWh basis to all customers. The Transmission Charge also recovers municipal property taxes above the level established in distribution rates through the Property Tax Adjustment Mechanism ("PTAM"). The Company recovers Vegetation Management Program ("VMP") costs above the amount established in distribution rates through a separate reconciling mechanism and recovers any variance between actual and allowed distribution revenues through a Revenue Decoupling Adjustment Factor ("RDAF") reconciling mechanism, both of which are an adjustment to distribution rates. The Storm Recovery Adjustment Factor ("SRAF") reconciling mechanism collects or returns approved storm costs as a separate rate. Finally, the Energy Service ("ES") rate reconciles and recovers power supply costs for customers served through default service as well as program administration costs.

Q. How does the Company recover approved expenses related to rate cases?

A. Historically, the Company has recovered any differences between approve permanent rates and temporary rates, also known as recoupment, through its base distribution rate without any reconciliation. The Company has also been permitted to recover approved rate case expenses through base distribution rates without any reconciliation.

Q. Does the Company recommend any changes to the manner in which approved recoupment and rate case expenses are recovered?

A. Yes. The current method of increasing and decreasing base distribution rates is problematic in that it requires a temporary increase in base distribution rates followed by a similar decrease in base distribution rates once the cost is fully recovered. This approach causes the base revenue per customer used in the revenue decoupling analysis to change as the base distribution rates are adjusted. The Company's natural gas affiliate EnergyNorth recovers temporary rates through a separate recovery mechanism instead of adjusting base distribution rates. The Company is recommending moving to this recovery mechanism approach, as detailed below.

Q. Please explain the Company's proposal for a new reconciling mechanism.

A. The Company is proposing a new non-bypassable reconciling rate called the Electric Reconciliation Adjustment Mechanism ("ERAM"). The ERAM is intended to reconcile distribution-related costs that are included in base costs set in the MYRP and fall into the following criteria:

1) cannot be known with certainty or are beyond the Company's control,
2) have no earnings opportunity,
3) can be demonstrated in advance the manner (and thus the reasonableness of the manner) in which the costs will be incurred, even though the magnitude of the costs is not yet known, and

4) benefit customers and support the provision of service in the normal course of business.

Q. What are the benefits of having a mechanism like the ERAM in place?

A. There are several reasons why implementing the ERAM is appropriate. One is that utilizing a single factor to accommodate multiple rate-making matters is an efficient approach, as it reduces the need to have multiple tariffs for different policy or business purposes and creates a streamlined, predictable approach for both Company preparation and Commission review. In addition, establishing a reconciling mechanism outside of base distribution rates will allow for greater transparency in the rate-setting process for certain, discrete items that are subject to variability. The use of a single ERAM rate will also allow the distribution rate and associated revenue decoupling calculations to be undisturbed by changes to agreed-upon reconciling items related to distribution rates.

Q. Is there a precedent for this kind of mechanism?

A. Yes. Unitil has a mechanism called the External Delivery Charge and Eversource has a mechanism called the Regulatory Reconciliation Adjustment mechanism that provides for the recovery and/or reconciliation of cost items similar to what the Company is proposing.[21]

[21] See Eversource Order No. 26,433 (December 15, 2020) in Docket No. DE 19-057 and Unitil Order No. 26,655 (July 28, 2022) in Docket No. DE 22-038.

Q. What costs does the Company anticipate will be included in the ERAM?

A. The ERAM is designed as a single volumetric-based rate allocated on an equal cents per kilowatt-hour basis that will recover or refund the costs associated with multiple programs. The Company is proposing to include the following components in the ERAM:

- **Property Tax Adjustment Mechanism ("PTAM").** The PTAM is currently a component in the Transmission rate. The PTAM is designed to recover or refund any variances in property tax expenses as compared to the assumed level in base distribution rates. The Company is not requesting a change to the PTAM mechanism, rather is proposing that the PTAM be moved from the Transmission rate to the ERAM and for interest to be calculated using the current monthly prime rate.
- **RGGI Refund ("RGGI").** The RGGI Refund is currently a component in the Transmission rate. The RGGI Refund is designed to refund RGGI auction proceeds to customers. The Company is not requesting a change to the RGGI Refund mechanism, rather is proposing that the RGGI Refund be moved from the Transmission rate to the ERAM.
- **Net Metering ("NM").** The NM costs are a component of the energy service rate and are included in the annual reconciliation factor within energy service rates. The Company is proposing that the NM expense be moved from the Energy Service rate to the ERAM. This would result in NM costs being recovered from all customers on an equal cents per kilowatt hour basis by rate class.

- **Regulatory Reconciliation Adjustment ("RRA").** The RRA is a new component intended to recover (1) changes in the Commission assessment from the level in base rates, (2) the DOE and the OCA proceeding consultant expenses, and (3) other Commission-approved consultant costs the Company incurs as directed by the Commission and/or related to consultant expenses incurred to respond to Commission dockets (i.e., data platform, battery storage consultants).
- **Rate Case Expense ("RCE").** The RCE is a new component intended to recover amortized rate case expense as approved by the Commission in a general rate case proceeding. Amortized rate case expense is currently recovered through base distribution rates and is allocated according to the rate design approved in the most recent rate case.
- **Recoupment Factor ("RF").** The RF is a new component intended to recover or refund amortized recoupment revenue related to the difference between temporary and permanent distribution rates as approved in a general rate case. Amortized recoupment revenue is currently recovered through base distribution rates and is allocated according to the rate design approved in the most recent rate case.
- **Residential Assistance Factor ("RAF").** The RAF is a new component intended to recover the costs associated with the portions of past due balances forgiven as proposed in the Arrearage Management Program ("AMP") and program implementation costs.
- **Fee Free Adjustment ("FFA").** The FFA is a new component intended to reconcile the estimated Fee Free Payment Program Costs included in base rates

with the actual cost of credit card and debit card fees waived and program implementation costs.

- **Revenue Adjustment Charge ("RAC").** The RAC is a new component intended to recover or refund the ESM, incentives earned or penalties incurred via the PIMs along with the potential to recover or refund any accumulated incentive or penalty at the end of the three-year rate plan. In addition, reconciliation of OpEx for cybersecurity, vegetation management and pension and OPEBs as outlined in the Direct Testimony of Messrs. DeCourcey and Therrien[22].

A. Rate Case Expense

Q. Please describe the nature of rate case expenses.

A. The costs to be incurred for the rate case are incremental, external costs that are primarily for services such as outside consulting services and legal expenses to assist with the preparation and presentation of this rate case, including the development of studies on various matters required to establish appropriate rates for the Company's customers. The Company obtained competitive bids for these services consistent with the Puc 1900 rules. Also included will be copying expenses, the cost of legal notices, and the cost of the court reporter. A list of these outside services and their estimated costs are shown in Attachment ELM-2.

[22] DeCourcey-Therrien Direct Testimony, p. 14-15

Q. How does the Company propose to recover rate case expenses incurred in this proceeding?

A. The Company proposes to recover the total cost associated with this rate case, which is currently estimated to be $1,639,260, over a twenty-four-month period without carrying charges. As described above, the Company is proposing to recover rate case expenses through the ERAM charge assessed to all rate classes on an equal cent per kilowatt-hour basis.

Q. How does the Company account for rate case expenses?

A. The Company defers for future recovery all costs associated with the case as they are incurred during the proceeding without interest charges per Puc 1907.01(f).

B. <u>Assessments and Consultant Costs</u>

Q. Provide an explanation of NHPUC assessments incurred since the last rate case.

A. Pursuant to RSA chapter 363-A, Liberty is responsible for a share of the Commission's annual expenses. In 2014, RSA chapter 363-A was amended to provide that the amounts assessed to utilities such as Liberty are recoverable through distribution rates. See RSA 363-A:6, I. In accordance with RSA 363-A:6[23], Liberty may request a rate recovery mechanism to refund or recover variances between actual annual assessment costs and amounts included in base distribution rates. Liberty does not currently have a mechanism in place to reconcile assessment costs. The level of annual assessment costs in base rates

[23] The commission shall by order establish rate recovery mechanisms for any public utility that is not either an excepted local exchange carrier, as defined in RSA 362:7, I(c), or a rural electric cooperative for which a certificate of deregulation is on file with the commission. Such rate recovery mechanisms shall adjust annually to recover any change in a utility's annual assessment.

as established in the DE 19-064 rate case is $453,765. The 2022 calendar test year amount is $651,654, which is based on the Fiscal Year 2022 quarter 3 and quarter 4 and Fiscal Year 2023 quarter 1 and quarter 2 invoice amounts. Liberty has not deferred any costs above the amount in base rates and has not requested a cost recovery mechanism between the last rate case and this rate case because the annual assessments had not been materially higher than the amount in base rates. However, the 2022 test year assessment level has increased by approximately 26 percent over the amount in base distribution rates as shown in the table below. As a result of this significant increase, Liberty is now proposing an annual rate recovery mechanism going forward.

Table 4. Commission Assessment Fees

Fiscal Year	Assessment
TY 2018 (FY 2019 July 2018 – June 2019)	$453,765
FY 2020 (July 2019 – June 2020)	$498,146
FY 2021 (July 2020 – June 2021)	$531,245
FY 2022 (July 2021 – June 2022)	$625,836
FY 2023 (July 2022 – June 2023)	$628,226

Q. Provide the total amount of the assessments and a proposed recovery of these assessments.

A. The annual assessment included in permanent distribution base rates for all rate years is $628,226 based on Fiscal Year 2023 assessment less $10,000 allocated to Energy Service. On a calendar year basis, the Company will compare actual annual assessment costs to the amount approved in base distribution rates. Any variances will be refunded or recovered from customers through the ERAM on an equal cents per kilowatt-hour basis from all rate classes with interest applied at the prime rate.

Q. Provide an explanation of Commission, DOE, and OCA expert outside services charges incurred since the last rate case.

A. As previously explained in this testimony in Section III, Regulatory Asset and Liabilities, Liberty is assessed fees related to experts employed by the Commission, DOE, and OCA. For deferred costs through December 31, 2022, the Company is proposing recovery through amortization of a regulatory asset over the three-year rate period. Effective January 1, 2023, the Company proposes an annual reconciling mechanism to recover any expert outside service costs assessed to Liberty. Examples of expert outside consultant costs include consultants hired for proceedings such as LCIRP, Net Metering, and EV Time of Use rates.

Q. Please explain what other Commission-approved costs would be recovered through the ERAM that have not been discussed.

A. The Company may incur incremental costs associated with investigations or changes to rules or laws that require the Company to incur incremental costs outside of a general distribution rate case. Examples include the online data platform, battery storage pilot program, and net metering. The Company is proposing to recover incremental costs incurred with interest at the prime rate on an annual basis through the ERAM with interest calculated on any over or under recoveries at the prime rate.

C. AMP (Arrearage Management Plan)

Q. Please explain why the AMP is being included for recovery in the ERAM as the RAF.

A. The Company is proposing to implement an AMP for eligible low-income customers. The AMP provides payment assistance for qualifying residential customers struggling with past-due utility bills. Eligible customers participating in the AMP will receive $100 in monthly arrearage forgiveness for each timely payment of their current monthly bill, unless the remaining arrearage balance is less than $100, for a total forgiveness of up to $1,200. More discussion of this proposed program can be found in the Direct Testimony of Lauren Preston.

Q. What costs related to the AMP is the Company seeking to recover?

A. The Company is seeking to recover the costs associated with the portions of the past due balance that will be forgiven (as described above) and the program implementation costs. As discussed in Ms. Preston's testimony, the Company estimates that it will cost approximately $1.1 million to implement the AMP, which includes the forgiven past due balance amounts, legal fees, IT costs, and communication costs.

Q. Please explain the Company's proposal for recovering the AMP costs.

A. The Company is seeking to recover 100 percent of the forgiven past due balance amounts for customers enrolled in the AMP through the ERAM. As part of the ERAM filing, the Company will submit the tracked costs for inclusion in the next ERAM rate adjustment. The RAF would also include an estimate of AMP costs for the next 12-month period which would be reconciled with actual costs in the following year's ERAM filing. Any variances will be refunded to or recovered from customers through the ERAM on an equal cents per kilowatt-hour bases from all rate classes with interest applied at the prime rate.

D. <u>FFA (Fee Free Adjustment)</u>

Q. Please explain why the FFA is being included for recovery in the ERAM.

A. The Company is proposing to implement a Fee Free program to eliminate convenience fees for credit and debit cards.

Q. What costs related to the FFA is the Company seeking to recover?

A. The FFA is intended to reconcile the estimated Fee Free Payment Program costs included in base rates with the actual costs of credit card, debit card, and electronic check payment fees waived. As discussed in the testimony of Ms. Preston, the Company included estimated annual waived fees of $78,538 in base rates. This amount assumes up to 7 percent of residential customers and 5 percent of commercial customers use the Fee Free Payment Program.

Q. Please explain the Company's proposal for reconciling the FFA costs.

A. The Company is seeking to recover 100 percent of the waived fees. Since the proposed base rates include an estimate of $78,538, the Company seeks to reconcile the estimate to actual costs through the ERAM. Any variances will be refunded or recovered from customers through the ERAM on an equal cents per kilowatt-hour basis from all rate classes with interest applied at the prime rate.

E. RAC (Revenue Adjustment Charge)

Q. Please explain why the RAC is being included for recovery in the ERAM.

A. As described in the Direct Testimony of Messrs. DeCourcey and Therrien, as part of PBR and MYRP the Company proposes to make an annual RAC filing within the ERAM on September 1[24]. The RAC is a new component intended to recover or refund the following items[25]:

- Vegetation management operating expense
- ESM
- PIM incentive or penalties
- Pension and OPEB
- Cybersecurity

Q. How does the Company propose the ERAM components be reviewed and approved?

A. On an annual basis, after the rate year is complete, on September 1 Liberty would file a report for each of the components identified above with supporting documentation and calculations to support the increase or decrease in base distribution rates associated with each component. The DOE, OCA, and interested parties would review the report over 60 days with an opportunity for discovery to be issued to the Company. At the end of the discovery period, if all costs were found to be prudent, then the variance between the

[24] DeCourcey-Therrien Direct Testimony, p. 49
[25] *Id.*, p. 49

amount included in the RY and the actual costs in the report would be used to establish a rate for the next 12-month period, without the need for a hearing. The rate would be a fully reconciling rate with monthly carrying charges calculated at the prime rate.

The table below provides a comparison of each component described above, the current rate recovery mechanism, and the future proposed rate recovery mechanism.

Table 5. ERAM Components

Charge	Current Recovery Rate	Current Date Filed / Effective Date	Proposed Recovery Rate	Cost Review Period	Proposed Date Filed / Effective Date
PTAM	Transmission	Mar 15 / May 1	Distribution – ERAM	Apr 1 – Mar 30	Oct 1 / Dec 1
RGGI	Transmission	Mar 15 / May 1	Distribution – ERAM	Jan 1 – Dec 31	Oct 1 / Dec 1
NM	Energy Service	Jun 15 / Aug 1	Distribution – ERAM	Jan 1 – Dec 31	Oct 1 / Dec 1
RRA	N/A	N/A	Distribution – ERAM	Jan 1 – Dec 31	Oct 1 / Dec 1
RCE	Base Distribution Rates	Apr 6 / Jul 1	Distribution – ERAM	Jan 1 – Dec 31	Oct 1 / Dec 1
RF	Base Distribution Rates	Apr 6 / Jul 1	Distribution – ERAM	Jan 1 – Dec 31	Oct 1 / Dec 1 1
RAF	N/A	N/A	Distribution – ERAM	Jan 1 – Dec 31	Oct 1 / Dec 1
FFA	N/A	N/A	Distribution – ERAM	Jan 1 – Dec 31	Oct 1 / Dec 1
RAC	N/A	N/A	Distribution – ERAM	Jul 1 – Jun 30	Oct 1 / Dec 1

Q. Is the Company proposing any changes to the Revenue Decoupling Adjustment Factor?

A. No. The Revenue Decoupling Adjustment Factor ("RDAF") is a component of the distribution rate where actual revenues per customer are compared to allowed revenues per customer on an annual basis. The Company is not requesting a change to the RDAF mechanism and would continue to calculate a separate rate for the RDAF which will be included in distribution rates. The RDAF would continue to be calculated based upon a July 1 through June 30 decoupling year, a filing on September 1, and rates effective on November 1.

Q. Please explain why the Company recommends this approach to reconciling distribution costs and why it is in the best interest of customers.

A. One of the guiding principles in the performance-based ratemaking methodology Liberty has proposed in this rate case is to create administrative efficiencies. This approach achieves that by allowing for quick and efficient review through the submission of agreed-upon documentation necessary to review previously established costs and agreed-upon reconciliation methodologies allowing for expeditious review of costs that are pass-through in nature. These costs are mainly outside of the Company's control and if they were prudently incurred and supported, the review process should be efficient, allowing for the Company to implement the resulting change in rates with less administrative burden for all parties.

V. <u>TARIFF CHANGES</u>

Q. Please describe any other proposed changes to Liberty's current tariff.

A. In addition to the changes described above related to the ERAM, the Company is proposing changes to certain non-recurring charges, its line extension policy, and an overall reformatting of the tariff to allow for the more efficient administration of the tariff.

Q. Please explain the proposed changes to the line extension policy.

A. The Company is revising its line extension policy in the Company's tariff to be more in line with the other investor-owned utilities in New Hampshire. The following is a summary of the changes:

- Combined four policies (Individual Residential Customers, Residential Developments, Individual Commercial and Industrial Customers, and Commercial and Industrial Developments) into one policy based on the type of service (single-phase and three-phase). This change provides ease of administration because rate class no longer dictates policy; policy is dictated by the type of service.
- Removed the 100-foot credit per home built for residential developments.
- Applied the 300 feet without an additional charge consistently across all customer classes and removed the Contribution in Aid of Construction ("CIAC") calculation for Commercial customers.
- Added terms and conditions related to demolitions, service size upgrades, and multi-unit dwellings to clarify when the 300-foot credit applies.
- Removed the $4,500 credit per lot for commercial developments.

Q. Do these changes to policy benefit customers?

A. Yes. The policy is structured such that a customer is charged based on the type of service required, rather than rate class. All customers are treated equally by receiving up to 300 feet without an additional charge as part of basic service, regardless of the service being single phase or three phase. The DOE has noted concern in previous dockets such as DE 21-004 and DE 19-064 that the CIAC calculation relies on the customer providing expected loads in the determination of the expected contribution offset which has the potential to inflate expected revenues resulting in a lower contribution offset. If the expected loads do not materialize, it results in all other customers paying the difference in cost through distribution rates. Removing the CIAC from the line extension policy avoids this issue and brings the line extension policy in line with the other investor-owned utilities in New Hampshire. In summary, the changes to the line extension policy will make administration easier for the Company, be consistent with other investor-owned utilities in New Hampshire and allow for consistent application and cost recovery removing the potential for cost-shifting to other customers.

Q. Are there any other changes to the Company's existing tariff that the Company would like to address?

A. Yes. The Company reviewed several non-recurring charges in the Company's tariff and proposes changes to bring costs more in line with the Company's actual costs.

Q. Is the Company proposing any changes to its current miscellaneous charges?

A. Yes. Liberty proposes revisions to the following nonrecurring charges:

Table 6. Non Recurring Charges

	Current Charge	Revised Charge
Service Connection Fees – Field Visit	$35	$ 0
Service Connection Fees – No Field Visit	$20	$ 0
Reconnection Fee	$35	$50
Reconnection Fee – After Hours	$70	$80
Collection Fee	$35	$50
Meter Test Fee	$20	$50

Q. Explain why the Company is proposing to eliminate the Service Connection Fees.

A. Liberty believes that the Service Connection is already included in the base rates as a service connection is a daily business function and therefore should no longer be collected as a separate fee.

Q. What information is used to support the proposed nonrecurring charge revisions?

A. The Company calculated the nonrecurring charges based upon actual expenses incurred. The labor calculations use a fully loaded labor rate for craft labor and estimated labor hours to complete the request. The estimated completion times are based on management expertise. The estimated mileage is based on the average round trip and the most current published Internal Revenue Service business standard mileage rate.

Q. Why is the Company requesting to revise these charges?

A. It has been some time since the Company last evaluated these charges. Increases in labor wage and benefit costs, transportation costs, and material charges are not reflected in the current charges. The Company believes that the costs should be borne by the cost causer and thus should reflect as such and not be overly subsidized by base rates.

Q. Do the changes to the nonrecurring charges result in a change in the miscellaneous revenue?

A. Yes. The proposed nonrecurring charges will result in a decrease in miscellaneous revenues and a corresponding increase in rate revenue of $14,700, as illustrated in the table below.

Table 7. Miscellaneous Revenue

	Current Charge	2016-2019 Average Occurrences	Test Year Revenue	Revised Charge	Adjustment	Pro Forma
Service Connection – No Field Visit	$20	7,843	$47,580	$0	($47,580)	$0
Service Connection – Field Visit	$35	0	$0	$0	$0	$0
Reconnection	$35	589	$0	$50	$29,440	$29,440
Reconnection – After Hours	$70	43	$0	$80	$3,440	$3,440
Collection Fee	$35	0	$0	$50	$0	$0
Meter Tests	$20	0	$0	$50	$0	$0
Total			$47,580		($14,700)	$32,880

Q. Why do the number of occurrences represent the average between 2016 and 2019 and not the test year?

A. Due to the conversion to Customer First, the Company placed a halt on most nonrecurring charges in October 2022. Therefore, the Company believes the test year revenue and occurrences are understated.

Q. Why did the Company choose to use the average between 2016 and 2019?

A. Liberty chose to begin with 2016 as 2016 represents the first calendar year following Liberty's last base rate filing. The Company did not include the Years 2020 and 2021 as they are not representative of a typical year due to the COVID-19 moratorium.

Q. Please describe the Company's reformatting of the tariff.

A. The Company modified the formatting of the tariff to allow for more efficient administration. Rates for Delivery Service were moved from each individual rate schedule to a summary of rates page. A clean and redlined version of the tariff is being provided with the Company's application.

VI. <u>CONCLUSION</u>

Q. Do you believe that Liberty's proposal as outlined in your testimony will allow Liberty to continue to provide safe and reliable service?

A. Yes.

Q. Does this conclude your pre-filed Direct Testimony?

A. Yes.

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