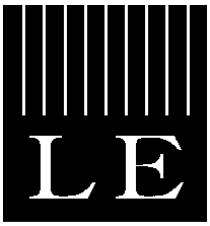
DIRECT WRITTEN TESTIMONY OF

Julia Frayer

Powering Connecticut's Future
Performance Based Ratemaking

Exhibit CLP-PBR-1



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DIRECT WRITTEN TESTIMONY OF JULIA FRAYER

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Julia Frayer. I am one of the partners and a Managing Director of London Economics International LLC ("LEI"), a Massachusetts-based consulting firm specializing in the energy, water, and other infrastructure industries. My business address is 717 Atlantic Avenue, Suite 1A, Boston, MA 02111.

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

A. LEI was retained by Eversource Energy Services Company ("Eversource") on behalf of its operating subsidiary, The Connecticut Light and Power Company ("CL&P" or "the Company") to provide expert technical analysis for its Performance-Based Multi-Year Rate Plan ("PBMRP"). I am presenting the results of an industry total factor productivity ("TFP") study and the cost benchmarking study. As described elsewhere in this testimony and the Company's filing, the Company is proposing to implement an "I-X" revenue adjustment mechanism ("RAM") as a revenue cap over a 4-year term as part of a PBR plan proposal in this proceeding.

Q. Please summarize your relevant professional background.

A. As Managing Director of LEI, I supervise and manage many of LEI's engagements involving regulatory services for the electricity sector, including advisory on regulation and rate design, as well as data analysis related to commercial aspects of utility operations and policy impacts. In addition, I also work extensively on issues pertaining to competitive wholesale markets, RTO operations, and market design. I have worked across the United States, as well as in Canada, Asia, and Europe.

Over the last 25+ years, I have studied and advised on various forms of regulation of electric utilities, including performance based ratemaking ("PBR"). I have extensively studied successful and challenging outcomes emerging from various regulatory models. I have advised utilities, regulators, and investors on best practices with respect to the design of PBR formula and maximizing the incentive structure of such a regime. In some of my work, I have guided regulators and stakeholders on implementation of innovative rate designs, while in other engagements, I have focused on empirical analysis to support proper calibration of the key parameters of a PBR rate framework. Such engagements have occurred in North America (U.S. and Canada), Europe (Austria, Germany, the Netherlands, and the United Kingdom), Asia (Malaysia), and South America (Argentina). I have

also conducted workshops for regulators and industry stakeholders on PBR.

I am very familiar with the evaluation of productivity trends and the development of TFP studies. I have examined TFP trends in electric transmission, distribution, and generation sectors, gas distribution, as well as water and wastewater networks. My work in PBR ranges across varying regulatory models. I have advised on the formulaic approach of an "I-X" revenue or price cap, as well as multi-year rate plans that use forecast of revenue requirements, which is commonly referred to as the "building-blocks" approach in the United Kingdom and Australia, where it was first applied approximately three decades ago.[1,2,3] In 2024, I prepared a TFP study for the U.S. gas distribution industry in a regulatory case before the

[1] A "building blocks" approach is a framework where revenue requirements are "built up" based on the utilities' future estimated efficient costs and return of and return on an efficient asset base.

[2] *See*, for example, the history of regulation ("RPI-X") in the UK: Ofgem. *Regulating Energy Networks for the Future: RPI-X@20; History of Energy Network Regulation*. Ref: 13b/09. Web. February 27, 2009. <https://www.ofgem.gov.uk/sites/default/files/docs/2009/02/supporting-paper---history-of-energy-network-regulation-final.pdf>

[3] The building blocks approach was implemented in Australia in the first electricity price controls, which took place in the mid- to late-1990s across the country. *See*: Farrier Swier Consulting. *Comparison of Building Blocks and Index-Based Approaches*. Prepared for Utility Regulators Forum. Web. June 2002. p. 12-13. <https://www.accc.gov.au/system/files/June%202002%20-%20Comparison%20of%20Building%20Blocks%20and%20Index-Based%20Approaches.pdf>

Connecticut Public Utilities Regulatory Authority ("PURA"). I also prepared a TFP study for the U.S. gas distribution industry in a regulatory case before the Massachusetts Department of Public Utilities.[4] For the electric distribution sector, I have previously testified in Alberta and Ontario (Canada). In 2016-2017, I headed a team that assisted the largest Southeast Asian utility, Tenaga Nasional Berhad ("TNB"), in the preparation of their first comprehensive PBR application. More recently, I submitted independent expert reports related to the calibration of the inflation factor, productivity (X) factor, and stretch factor for Ontario Power Generation's regulated hydroelectric fleet. These various PBR-related engagements are detailed in my curriculum vitae, which is provided as Attachment A to Exhibit CLP-PBR-1, and included with this written testimony.

Q. Have you previously testified before PURA?

A. Yes. In 2024, I prepared and submitted independent expert analysis on TFP trends for the U.S. gas distribution industry in conjunction with Yankee Gas's rate application (Docket 24-12-01). I have also contributed to PURA's uncontested proceeding related to the development of a PBR framework in

[4] The Massachusetts regulator ultimately adopted the X Factor I derived from the TFP study to set the PBR regime for NSTAR Gas, an affiliate of CL&P.

Connecticut for the electricity distribution sector, specifically providing independent expert advice on behalf of CL&P, in various proceeding (e.g., Docket No. 21-05-15 as well as its reopener dockets, especially Docket No. 21-05-15RE01 and Docket No. 21-05-15RE02). As part of these proceedings, I had co-authored a number of written submissions and expert technical statements and presented at several virtual and in-person technical meetings. Furthermore, I testified at PURA on the market power consequences of proposed merger of NU-NSTAR in 2012 (PURA Docket No. 12-01-07).

Q. Do you have other experience relevant to this project?

A. Yes, I have participated in several other engagements relevant to the expertise required for this project. I am knowledgeable about electric distribution companies ("EDCs") across North America, and I am familiar with Connecticut energy policies as well as ongoing discussions and considerations amongst the electric distribution utilities, docket participants, and the regulator on a potential PBR framework for Connecticut's EDCs.

In addition to testifying before PURA, I have also consulted and appeared before other Connecticut state agencies, including the Department of Public

Utility Control ("DPUC," the predecessor to PURA) and the Connecticut Siting Council ("CSC"). I testified before the DPUC several times regarding the competitiveness of transitional standard offer solicitations (for example, see Docket No. 03-07-18PH02). I also designed and oversaw the RFP process for new capacity, aimed at reducing Connecticut consumers' Federally Mandated Congestion Charges and recommended selection of winners and award of contracts (Docket No. 05-07-14PH2).

Lastly, I have testified on a variety of issues before U.S. state and Canadian provincial regulators, as well as the Federal Energy Regulatory Commission ("FERC") in the U.S. I have also served as an expert in litigation and arbitration proceedings.

Q. Are you sponsoring any exhibits in conjunction with your testimony?

A. Yes. Attachment A to Exhibit CLP-PBR-1 presents my curriculum vitae. Exhibit CLP-PBR-2 and Exhibit CLP-PBR-3 present LEI's Industry TFP Study and LEI's Benchmarking Report, respectively. Exhibit CLP-PBR-2a, CLP-PBR-3a, and CLP-PBR-3b are the workpapers for the Industry TFP Study, Unit Cost Benchmarking, and Econometrics Study, respectively.

Q. How is your testimony organized?

A. This testimony is organized into five sections. In this section, I briefly review my expertise and experience relevant to this engagement and the purpose of this testimony. The next section (Section 2) provides an introduction to PBR, including the benefits of PBR for customers and the regulated utility. In the third section, I present a summary of the findings from LEI's Industry TFP Study. In Section 4, I present the results of LEI's cost benchmarking study. Finally, in Section 5, I review CL&P's proposal PBR plan and discuss its merits vis-à-vis our experience broadly and the Industry TFP Study and Benchmarking Study, specifically.

II. PRIMER ON PBR

Q. What is PBR?

A. PBR is a form of utility regulation that mimics the forces that would have been in play if there was competition, where firms compete to provide the best service at the lowest cost through efficient operations. Under PBR, a formula is used to set the trajectory for the "price" of the service being provided by the utility by reference to inflationary pressures (which the utility typically has no control over) and industry productivity trends over time.

There are two broad forms for setting the formula—it can be done by reference to a forecast of future annual revenue requirements with some indexing to inflation or it can be done using a formulaic Revenue Adjustment Mechanism ("RAM")[5] that is a function of a pre-determined productivity target (known as "X Factor") and selected inflation index (referred to as "I Factor"). The regulator and the firm also agree to a "stay out" provision or term for the PBR, over which the formulaic RAM and associated conditions – if any – for the firm to seek a rate change before the

[5] Docket No. 21-05-15RE01 (PURA Investigation into Revenue Adjustment Mechanisms for a Performance-Based Regulation Framework) concerns the design of RAM under Connecticut's proposed PBR framework. As of the date of this testimony, PURA has not yet issued a Final Decision in the proceeding.

end of that term would apply. PBR is typically implemented as an alternative to frequent traditional cost of service ("COS") rate proceedings, where rates change based on a utility's cost of service. Under PBR, COS principles are not ignored – indeed, the cast-off rates to a PBR plan must be set consistent with COS in order to the PBR Plan to have a solid foundation over the arc of a PBR term.

Q. Why would a regulator pursue PBR?

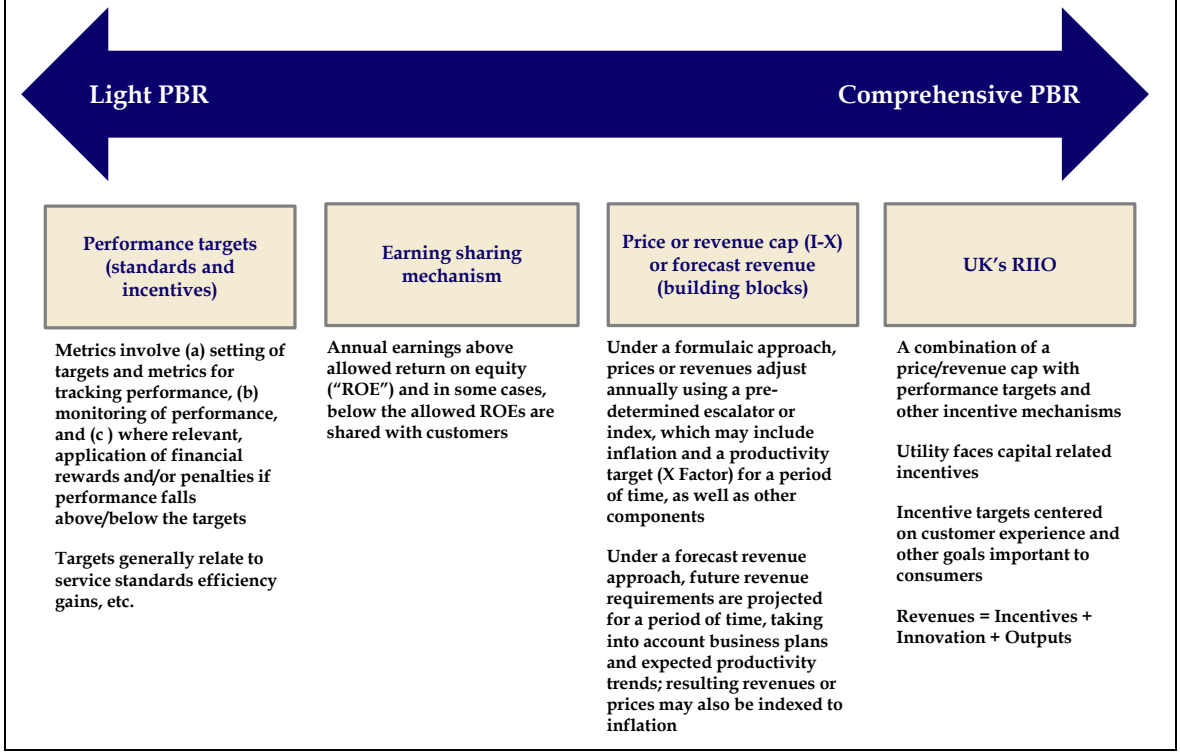
A. The primary objective of PBR is to strengthen the financial incentive for the regulated firm to lower costs and improve efficiency. PBR creates strong incentives for the utility to seek out and implement efficiencies in operations and capital investment because the price it is able to receive for its services is set pursuant to a pre-determined budget or formulaic RAM and independent of its actual annual costs of service, for the entire term of the PBR.

There are also other benefits of PBR. Many regulators around the world have learned that cost cutting incentives need to be balanced with performance mandates. It is common to have PIMs included as part of a PBR plan that would further motivate the utility to achieve certain performance goals. This allows the PBR regime to be harmonized and

aligned with policy priorities and other non-price/non-cost related objectives important to customers.

The concept of PBR includes a variety of mechanisms that could be used in varying combinations to motivate the regulated firm to seek out efficiency improvements, cost cutting, and other performance improvements, where appropriate. As such, PBR is best conceptualized as a continuum, ranging from "light" to "comprehensive" mechanisms, rather than a single type of regulatory regime. Figure 1 shows a diagram of this continuum.

Figure 1. Continuum on PBR regulation from "light" to "comprehensive" key mechanisms



"Light" mechanisms include relatively minor adaptations to a traditional COS framework, such as inclusion of performance targets, and an earnings sharing mechanism ("ESMs"). For example, Connecticut's regulatory environment for EDCs already includes an ESM. A price or revenue cap and outcomes-based PBR are examples of more "comprehensive" forms of PBR.

There are several U.S. states with some form of multi-year rate plan ("MRP") in place that is equivalent to having a revenue or price cap. In addition to Connecticut, states with some form of established MRPs include California, Colorado, the District of Columbia, Florida, Georgia, Hawaii, Idaho, Illinois, Louisiana, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, New York, Ohio, Rhode Island, South Carolina, Utah, Vermont, and Washington.[6,7] A formulaic RAM has been and continues to

[6] Note that the list of MRP states may vary by source. NARUC. *Performance-Based Regulation State Tracking Map* (updated July 31, 2024). < https://www.naruc.org/core-sectors/energy-resources-and-the-environment/valuation-and-ratemaking/performance-based-regulation-state-tracking-map/>; Data from S&P Global Market Intelligence database as of June 2026.

[7] PBR implementation is currently underway in Oregon through an active rulemaking process to establish the state's multi-year rate plan and performance-based regulation framework. Nevada has statutory authority to approve multi-year rate plans and other alternative ratemaking mechanisms, although its experience implementing MRPs has been more limited than that of jurisdictions with long-established MRP framework. Sources: Oregon Public Utility Commission, "Rulemakings, accessed July 4, 2026, listing AR 676, Rulemaking to Establish Multi-Year Rate Plan Framework (HB 3179 & SB 688 Implementation), < https://www.oregon.gov/puc/about-us/Pages/Rulemakings.aspx> and Public Utilities Commission of Nevada, "Alternative or

be used in the MRPs in Massachusetts, Alberta, and Ontario for many years.[8]

Q. Does adoption of PBR require or involve modification of core ratemaking principles?

A. No. Under PBR, just as under traditional cost of service ratemaking, fundamental ratemaking principles continue to apply. In *Principles of Public Utility Rates*, James C. Bonbright explains that cost-of-service is the "basic standard of reasonableness" and that the ability of the utility to earn a "fair return" maximizes the public interest.[9] The resulting core criteria for sound rate design include: (1) recovery of total costs of service; (2) pursuit of economic efficiency; and (3) fair and equitable allocation of costs. Although commonly considered an innovative form of regulation, PBR remains a method of regulation. Therefore, the basic concept of fair return for services

Performance-Based Ratemaking," accessed July 4, 2026 < https://puc.nv.gov/Utilities/Electric/AlternativeRateMaking/>

[8] *See*, for example, Massachusetts D.P.U. 17-05 and D.P.U. 22-22 for electric distribution and D.P.U. 19-120 and D.P.U. 20-120 for gas distribution, and AUC Decision 2012-237, Decision 20414-D01-2016 (Errata), and Decision 27388-D01-2023. In Ontario, PBR has been implemented since 2000. *See*: Ontario Energy Board. "Performance-Based Regulation (PBR) Second Generation." Web. Accessed October 28, 2024. <https://www.oeb.ca/industry/policy-initiatives-and-consultations/performance-based-regulation-pbr-second-generation#:~:text=In%202000%2C%20the%20OEB%20implemented,March%2014%2C%202003%20letter%20below.>

[9] Bonbright, James C. *Principles of Public Utility Rates*. 1961. <https://www.raponline.org/wp-content/uploads/2016/05/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf>

rendered, implementation of cost causation-based rates that motivate the efficient consumption of energy by customers, as well as cost-reflective and non-discriminatory rates will still apply to PBR.

Q. What is the difference between a forecast revenue requirement (building blocks) approach versus a formulaic RAM approach?

A. The difference between a forecast revenue requirement (building blocks) approach versus a formulaic RAM approach is primarily related to the implementation. In the building blocks approach, a utility's required revenue is set for each year of the multi-year regulatory term. As implied by the name, the revenue requirement is "built up" using a forecast of total costs (i.e., operating expenses, return on investment, depreciation expense, taxes, etc.). While the forecast approach can be structured to consider industry trends and benchmarking, at its most basic form, the approach relies on the utility's projections of its forecast of costs and investment needs for the PBR term. It is common to hear that this approach presents informational asymmetry between the regulator and the regulated firm. Although this perception can be overcome with regulatory mechanisms that align the incentives of the utility around accurate forecasts and information disclosure, the process of approving utility business plans and

forecasts is nonetheless information intensive, and may become complex and contentious.

In contrast, under the formula approach, there is no need for the regulator to review forecasts of future costs of service. The RAM formula, if properly calibrated, will dynamically respond to changes in macroeconomic conditions in a way that mimics the incentives dominant in a competitive industry that creates incentive for seeking out efficiency improvements. A formula approach does require upfront effort to accurately set the formula parameters for the RAM (the I Factor and X Factor) and any additional regulatory accommodations (such as an incremental capital funding mechanism) that will be required to meet regulatory and policy goals. However, the techniques to select and set the I Factor and X Factor are well-established.

Notably, under both approaches, once the utility is given its budget – either by determination of forecasted revenue requirement or selection of parameters for a formulaic RAM – the incentives are similar.

Q. Must an I-X RAM apply to all components of a utility's revenue requirement?

A. No. An I-X RAM need not apply to all components of a utility's revenue requirement. Some PBR plans apply the I-X mechanism only to selected categories of costs, most commonly OM&A, while capital-related costs are recovered through separate mechanisms. These hybrid approaches recognize that operating costs and capital costs have different economic characteristics and therefore may warrant different regulatory treatment.

Q. What is a hybrid or partial price cap?

A. A hybrid or partial price cap is a form of PBR in which the formulaic RAM applies only to a portion of the utility's costs, while other cost categories continue to be recovered through separate regulatory mechanisms. For example, a RAM may apply only to OM&A costs, while capital investments are addressed through a separate capital funding mechanism or tracker. This approach allows the EDC to focus on the costs that it needs to improve productivity, while ensuring that utilities continue to make prudent investments necessary to provide safe and reliable service.

Q. Are hybrid or partial price cap plans consistent with sound principles of performance-based regulation?

A. Yes. The primary objective of PBR is to strengthen incentives for utilities to improve efficiency while maintaining safe and reliable service. That objective does not require every category of costs to be subject to the same regulatory mechanism. Rather, a well-designed PBR framework should align the incentive mechanism with the nature of the underlying costs. Applying a formulaic productivity adjustment to OM&A costs while addressing capital expenditures through a separate capital funding mechanism can achieve that objective by preserving incentives for operating efficiency without discouraging prudent long-term infrastructure investment.

Q. Does a hybrid price cap reduce incentives for utilities to control costs?

A. No. A hybrid framework continues to provide meaningful incentives for cost control, although those incentives may differ across cost categories. The utility remains responsible for managing operating costs efficiently under the formulaic revenue adjustment mechanism. At the same time, capital funding mechanisms are typically subject to prudence review, investment caps, reporting requirements, reconciliation mechanisms, or

other safeguards that encourage efficient capital planning while ensuring customers pay only for prudent investments.

Q. Have other jurisdictions adopted hybrid or partial price cap frameworks?

A. Yes. While the specific design varies by jurisdiction, regulators have increasingly adopted performance-based regulation frameworks that apply different regulatory mechanisms to different categories of costs. For example, in its recent electric rate proceeding, National Grid proposed an OM&A-only revenue cap under which the I-X adjustment mechanism applies only to operating costs, while capital investments are recovered separately through a Capital Recovery Mechanism.[10] In Ontario, the Ontario Energy Board's Custom Incentive Rate-setting ("Custom IR") framework allows distributors to combine formula-based annual rate adjustments with utility-specific capital funding plans.[11] Under this framework, many large electricity distributors forecast capital expenditures separately while applying incentive mechanisms to other components of

[10] Massachusetts Department of Public Utilities. *Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for Approval of a General Increase in Base Distribution Rates for Electric Service, a Performance-Based Ratemaking Plan, and a Capital Recovery Mechanism*, D.P.U. 23-150, Final Order, September 30, 2024. < https://media.wbur.org/wp/2024/10/D.P.U.-23-150-National-Grid-Rate-Case-Final-Order-9.30.24.pdf>

[11] Ontario Energy Board. *Rate Handbook (Renewed Regulatory Framework for Electricity Distributors), describing the Price Cap IR, Annual IR Index, and Custom Incentive Rate-setting ("Custom IR") options*. < https://www.oeb.ca/oeb/_Documents/Regulatory/OEB_Rate_Handbook.pdf>

revenue requirement, reflecting a hybrid approach rather than a traditional comprehensive price cap.

Q. Are there any pre-requisite conditions to ensure a successful PBR in the real world?

A. Yes, in my opinion, there are three prerequisites for a successful PBR: (1) stay consistent with the theory and a valid methodological approach; (2) ensure the various elements of the PBR regime are harmonized; and (3) make sure that basic principles of ratemaking are followed.

PBR attempts to mimic the outcomes facing a firm in a competitive market, where utilities are incentivized to maximize productivity to achieve lower unit costs compared to the rest of the industry. In an I-X framework, the price a utility can charge is a function of inflation and industry productivity. As such, I–X regulation imposes pressure on utilities by constraining prices (rates for service) to track the level of estimated efficient costs for the industry after accounting for externally derived inflationary pressures (that all firms in the industry face) and industry productivity trends. Over the term of the plan, utilities are essentially required to operate within the revenue envelope that is indexed to those inflationary and productivity trends. This results in strong incentives for the utility to contain costs and improve efficiency. Similar to a competitive industry where a firm cannot

keep pace with industry productivity (and then its marginal cost will increase and will no longer be competitive and may lose customers and market share), a regulated utility that cannot keep up with productivity trends and inflation, will suffer financial consequences (such as lower returns).[12] This means that a utility meeting the RAM formula that has been properly calibrated to inflation and productivity trends should provide the utility with an opportunity to earn a commercially reasonable return on equity, and attract investors to the business in order to fund necessary capital investment.

Based on experience from other jurisdictions around the world, it is important that a PBR regime create strong incentives for the utility to reduce its costs by financially rewarding the utility with higher profits in the near term. It is therefore important for regulators to avoid weakening

[12] The concept of an I-X approach was first introduced by Stephen Littlechild in his paper proposing incentive-based regulation for the British telecommunication monopoly. In this paper, Littlechild demonstrates how the RPI-X approach (where RPI stands for the retail price index, a measure of inflation) can be used as a method to mimic the factors that drive the behavior of firms and derive prices in a competitive industry, including rivalry for customers, exogenous cost trends for key inputs, and productivity changes over time. Exogenous factors that affect the price of key inputs for the firms in the industry will affect all the firms in the industry and therefore the competitive price of the product. In addition, in order for firms to be able to sell their products to customers, firms will need to keep up with industry productivity trends. If a firm cannot keep up with industry productivity, that firm's product will become more expensive to produce than the product of competitors, and they will not be able to compete for customers. Source: Littlechild, Stephen C. "Regulation of British Telecommunications' Profitability." *Department of Industry* (February 1983).

these objectives with other features that would claw back or marginalize the opportunity for higher profits in the near term. Sometimes, it may not be apparent that different elements of a PBR plan may dilute incentives for the utility. Therefore, it is important to explicitly check for alignment or harmonization of elements of a PBR plan. When utilities are provided with appropriate signals and incentives, price-cap and revenue-cap regimes can encourage utilities to pursue efficiency improvements. For example, in its evaluation of Alberta's PBR framework, the Alberta Utilities Commission found that "under both PBR plans, which incented and continue to incent the utilities to lower their costs, customers experienced lower rates under PBR than would be expected under COS regulation."[13] Likewise, the UK's RPI-X model was found to result in lower prices for customers—reducing costs by 50% between 1990 and 2010—while also enabling increased investment, improvements in reliability, and lower cost of capital.[14] Another empirical study also confirmed positive directional results for cost

[13] Alberta Utilities Commission. *Evaluation of Performance-Based Regulation in Alberta*. June 30, 2021. Pp. 19-20.

[14] Ofgem. *RIIO – a new way to regulate energy networks*. Factsheet 93. Web. October 4, 2010. <https://www.ofgem.gov.uk/sites/default/files/docs/2010/10/re-wiringbritainfs.pdf>; Buchanan, Alistair. *Ofgem's "RPI at 20" Project*. Speech at SBGI. Web. March 6, 2008. <https://www.ofgem.gov.uk/sites/default/files/docs/2008/03/ab-march-08.pdf>. Also mentioned in: Crowley, Nick and Mark Meitzen. "Measuring the price impact of price-cap regulation among Canadian electricity distribution utilities." *Utilities Policy* 72 (October 2021).

containment under price cap-regulated utilities in Alberta and Ontario, concluding "firms under price caps are *associated* with lower price escalation than a traditional regulatory framework."[15]

Although PBR departs from COS ratemaking during the term of the plan, it does not abandon basic regulatory principles. In order for a PBR plan to be successful, the starting point needs to be calibrated using COS considerations. For example, cast-off rates (also known as "going in rates") for the first year of a formulaic, index-based PBR plan should be set based on COS concepts. This is necessary in order to ensure that the utility will have an opportunity to recover the costs it incurs to serve its customers reliably.

In addition, a formulaic RAM is most likely to be successful when the parameters (I Factor and X Factor) are set based on empirical data. More specifically, the economic theory behind PBR requires that the value of the X Factor reflects observed productivity trends in the industry. In addition, the X Factor has to be harmonized with the selected I Factor.

[15] Crowley, Nick and Mark Meitzen. "Measuring the price impact of price-cap regulation among Canadian electricity distribution utilities." *Utilities Policy* 72 (October 2021). p. 8.

If the I Factor is based on an inflation index that measures changes in the prices of the inputs used by the electric distribution industry, then the X Factor can be based directly on the industry's TFP trend estimated in the TFP analysis. However, if the selected I Factor is a broad, economy-wide output price index, such as the GDP Implicit Price Deflator for Final Sales to Domestic Purchasers ("GDP-FSDP"), which measures changes in the prices of goods and services purchased by domestic users,[16] additional adjustments are necessary. Specifically, the X Factor must account for the difference between economy-wide price inflation and utility-specific input price inflation, in addition to the differences in the economy-wide total factor productivity trends and the industry's productivity trend. This approach is consistent with the economic foundation of price cap regulation, under which the I-X formula is designed to approximate the growth in the utility industry's efficient input costs rather than changes in general price levels. As a result, the X Factor serves not only as a measure of industry productivity growth but also as a mechanism for reconciling a

[16] The Bureau of Economic Analysis defines GDP-FSDP as "GDP less net exports of goods and services, less the change in private inventories, less government consumption expenditures and gross investment. Final sales to private domestic purchasers is also the sum of consumer spending and gross private fixed investment." [Source: U.S. Bureau of Economic Analysis. *GDP Release: Additional Information*. <https://www.bea.gov/news/gdp-release-additional-information>

broad economy-wide inflation index with the cost structure of the EDC industry.

Absent a rigorously developed I-X formula, the resulting revenue adjustment mechanism may not accurately reflect the utility's expected cost trajectory. Consequently, the mechanism may fail to achieve key regulatory principles, including providing strong incentives for efficiency and/or providing the utility with a reasonable opportunity to recover its prudently incurred costs and earn a fair return on its capital. [17]

Lastly, since the X Factor is based on TFP studies that evaluate historical trends, the underlying assumption is that the utility is expected to be operating in a steady-state environment, where the historical conditions for the industry are a reasonable indicator of future conditions. When future conditions differ from those observed historically, however, a simple I-X escalation mechanism may not produce an appropriate revenue trajectory. For example, if the utility is expected to undertake capital investments at a pace significantly greater than historical levels, or if future customer, load, or output growth differs substantially from historical experience, the

[17] Bonbright, James C. *Principles of Public Utility Rates*. 1961. <https://www.raponline.org/wp-content/uploads/2016/05/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf>

assumptions underlying the historical TFP analysis may no longer hold. In these circumstances, a price-cap or revenue-cap framework relying solely on an I-X adjustment may not provide a commercially sustainable regulatory framework or an adequate opportunity for the utility to recover its prudently incurred costs. Recognizing these limitations, several jurisdictions have supplemented the I-X mechanism with separate capital funding mechanisms or other adjustment mechanisms to address significant capital investment needs.[18]

The overarching lesson from both economic theory and regulatory experience is that the individual components of a RAM should be empirically calibrated and designed to work together as an integrated framework. More broadly, all elements of the PBR should be evaluated to ensure they are internally consistent and aligned with the underlying regulatory objectives. In addition, the design of the PBR framework should take into account the utility's expected operating environment over the plan period so that it remains appropriate under anticipated future circumstances.

[18] Examples of these jurisdictions include Alberta (K-Bar), Hawaii (Major Project Interim Recovery), Massachusetts (K-bar Capital Supplement), and Ontario (Incremental Capital Module and Advanced Capital Module).

III. SUMMARY OF INDUSTRY TFP STUDY RESULTS

Q. What is an Industry TFP study?

A. An Industry TFP study is used to measure the productive efficiency of an industry by assessing the total **quantity** of outputs that the firms in the industry produce relative to the **quantity** of inputs employed across all of those firms. The TFP calculus should include consideration of all relevant physical inputs to production, such as labor, materials (and services), and capital. The output(s) typically reflected in a TFP analysis represent the volume of the product or service sold by firms in the industry, which may be proxied by the number of customers served by EDCs.

For purposes of PBR, the focal point of a TFP analysis is to determine the changes in TFP levels over time for the industry, rather than the level of productivity at a given point in time. The historical productivity growth trends of the industry will inform and guide the choice of an explicit productivity target or X Factor under an I-X RAM.

Q. What methodology did you use for calculating the trend in TFP for the EDC industry?

A. I relied on the index method, as discussed in Section 2.3 of Exhibit CLP-PBR-2. Broadly, there are three methods employed by practitioners for estimating TFP growth. I chose to use an index method because it is a

relatively straightforward numerical method and is easy to explain to a diverse audience. The index method also requires significantly fewer observations to estimate trends in TFP, as compared to other quantitative techniques. And from experience, regulators have preferred using/relying on index-based studies of industry TFP trends for purposes of setting an X Factor for a PBR formula.[19]

It is important to note that the index method, because it is a numerical technique as opposed to a statistical technique, does not lend itself to statistical analyses (confidence levels or forecast error measures). Therefore, interpreting differences in estimated TFP growth rates arising from these index values necessarily involves studying differences in inputs and data, and if necessary evaluating consequences of specific methodological choices.

I used the chained Fischer Ideal index for calculating the trends in the TFP Study for the EDC industry.[20] There are a number of alternate index

[19] Examples of U.S. states and Canadian provinces that have used index-based TFP studies include Alberta (Canada), British Columbia (Canada), Hawaii, Massachusetts, New Hampshire, and Ontario (Canada).

[20] Indexes are chained by comparing data for each year to the data from the year immediately preceding it (with the exception of the base year). This method provides a more accurate portrayal of year over year growth.

number formulations that have been used by practitioners for purposes of TFP analysis, including the Laspeyres index, Paasche index, and the Törnqvist index.[21] However, other studies have proven that the Fischer Ideal index possesses the maximum number of desirable properties for an index number method and therefore is theoretically preferred over other index number formulations.[22] Moreover, government statistical agencies frequently use the Fischer Ideal index in their work.[23] That said, based on our experience, the results of the Industry TFP study are not overly sensitive to the selected index, particularly since we are focused on estimating an average trend over a 20-year timeframe rather than an average spanning just a few years.[24]

[21] Note that the Fischer Ideal index is a geometric average of the Laspeyres and the Paasche indices.

[22] Diewert, Walter and Alice Nakamura. *Concepts and Measures of Productivity: An Introduction.* 2005.

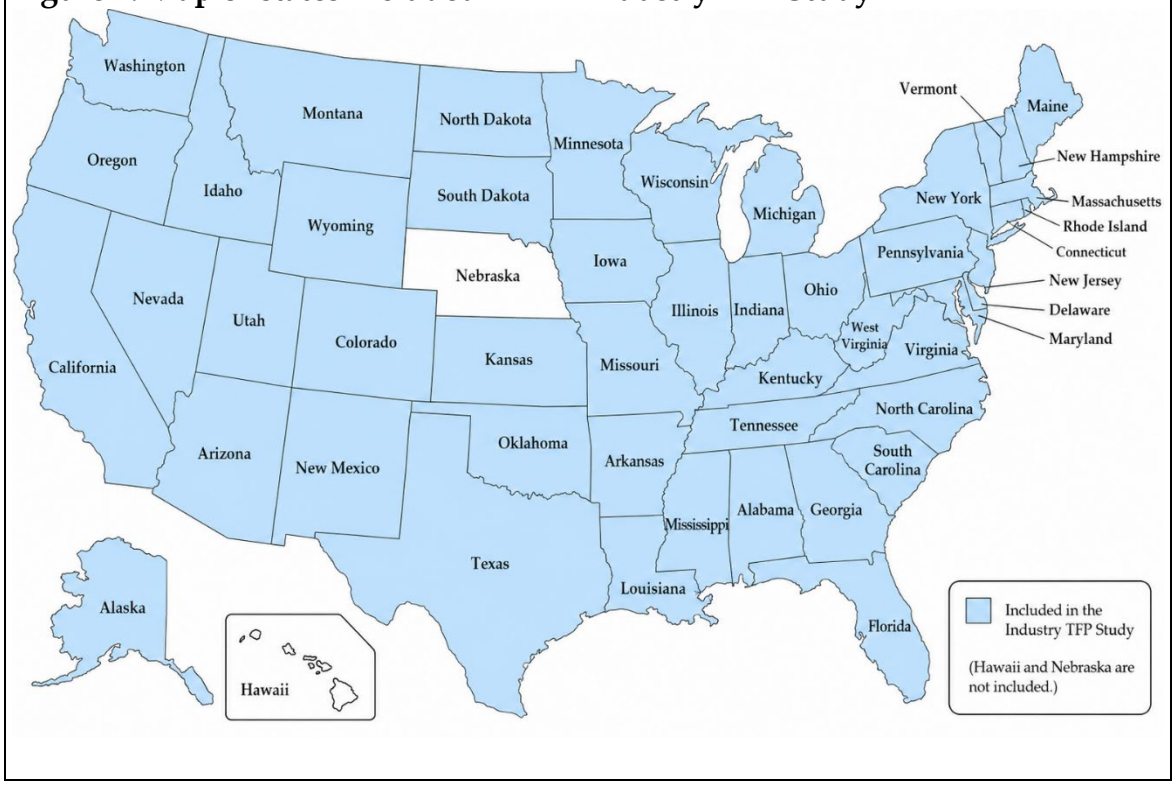
[23] For example, the U.S. Bureau of Economic Analysis uses the Fisher Indices in its national income and product accounts. Source: Bureau of Economic Analysis. Glossary. < https://www.bea.gov/help/glossary/chained-type-index>

[24] In general, the Fisher Ideal index produces very similar results to other index formulations such as the Laspeyres index, Paasche index, and Törnqvist index. The differences are more pronounced over a short timeframe, where the weighting scheme reflected in the Fischer Ideal can produce numerically different values.

Q. Which firms did you include in your industry group?

A. The Industry TFP Study was constructed based on the aggregation of data from 88 U.S. EDCs.[25] These 88 EDCs are located across 48 states[26] and the District of Columbia, and represent approximately 90% of electric customers served by investor owned utilities across the U.S. in 2024. I refer to these 88 EDCs as the "LEI Industry TFP Study." Figure 2 shows a map of the states covered in the LEI Industry TFP Study.

Figure 2. Map of states included in LEI Industry TFP Study



[25] *See* Appendix A of Exhibit CLP-PBR-2 for the list of these EDCs.

[26] The two states that are not represented in the TFP Study include Hawaii, and Nebraska.

The 88 EDCs encompass both small and large utilities, ranging from a utility that had only 77,523 customers in 2024 to one that had almost 6 million customers (for reference, CL&P had approximately 1.3 million customers as of 2024). For an industry TFP to be useful for PBR formula design purposes, it should capture the trends in productivity across all EDCs, not just the historical productivity trends of the utility applying for PBR treatment. Notwithstanding the fact that the LEI Industry TFP Study does not capture 100% of all EDCs in the U.S. (because of data limitations), the analysis is comprehensive, and consistent with other EDC TFP studies submitted in recent years to regulators across North America.[27]

In addition to the Industry TFP Study encompassing the 88 EDCs across the U.S., I performed a number of sensitivities. I evaluated industry TFP trends for the EDCs that are in the Northeast Region[28] as well as sensitivities on using sales as an output, different timeframes, and alternative depreciation approach. Industry TFP trends for the Northeast Region are discussed in

[27] For example, the TFP studies prepared for NSTAR Electric (Massachusetts D.P.U. 22-22), and Public Service Company of New Hampshire (DE 24-070) included national samples of 65 and 87 U.S. electric distribution companies ("EDCs"), respectively. Similarly, in its most recent rate application, EPCOR Distribution & Transmission Ltd. in Alberta relied on a sample of 65 U.S. EDCs, while FortisBC Inc. used a sample of 82 U.S. utilities in its TFP study.

[28] The Bureau of Labor Statistics ("BLS") defines the Northeast Region to include the nine states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

Section 5 of Exhibit CLP-PBR-2 while results for the other sensitivities are discussed in Appendices B and C of the same Exhibit.

Q. You mentioned that the LEI Industry TFP Study does not capture 100% of all EDCs in the U.S. because of data limitations. Would you explain this further?

A. Yes. The goal was always to include as many U.S. EDCs as possible, but one needs to also recognize that the analysis required consistent, reliable, long-term data for each EDC. The primary source for the data relied upon was FERC Form 1, supplemented by other public sources such as the U.S. Bureau of Economic Analysis ("BEA"), BLS, Federal Reserve Economic Data ("FRED"), Moody's, Treasury, S&P Capital IQ, and Internal Revenue Service ("IRS") data. My team and I began with 144 investor-owned EDCs operating in the U.S. as of 2024, but only included companies with sufficiently complete and reliable data from 1988 through 2024. Although the TFP trend itself is measured over the last 20 years (2005–2024), historical data back to 1988 was needed to construct the capital input quantity. Applying rigorous data-quality criteria resulted in a final sample of 88 EDCs across 48 states, representing approximately 90% of total customers served by U.S. investor-owned utilities ("IOUs") as of 2024.

Q. Over what timeframe is the TFP growth rate calculated, and is this a valid timeframe for purposes of ratemaking?

A. The Industry TFP Study presented an average TFP trend over a 20-year timeframe (covering the period of 2005 to 2024).[29] In addition to the 20-year average growth rate in industry TFP, the study included trends covering the most recent 15 and 10 year timeframes for purposes of sensitivity testing.

The primary purpose of conducting an Industry TFP Study for ratemaking purposes is to estimate an average rate of change in productivity, which is naturally going to span multiple years. Looking over many years of data will reduce the bias that can be caused by numerical outliers or one-off events that affect productivity in any single set of consecutive years. At the same time, one must be careful not to include outdated information about productivity that is not going to be representative of current operating dynamics and future possibilities, especially as the historical TFP growth trends are intended to inform future rates.

[29] The most recent complete set of financial and performance data available as of June 2026, when LEI completed its analysis, was for calendar year 2024. By starting with 2005, LEI has estimated a 20-year annual average growth rate in the EDC industry TFP.

Given data availability and quality (*see* Section 2.6 of Exhibit CLP-PBR-2 for further details) and best practices for TFP analysis, a 20-year timeframe is not only appropriate but also results in the most conservative (e.g., highest) estimate of TFP growth for the industry. Shorter-term estimates of TFP growth (10 years and 15 years) were more negative, as discussed in Section 4.3 of LEI's Industry TFP Study.[30]

On the other hand, a longer term (e.g., more than 20 years) would also not capture significant changes in the industry such as widespread AMI deployment, distributed energy resources ("DERs"), increased cybersecurity requirements, resilience and climate adaptation investments, and modern vegetation management practices. Furthermore, over very long periods, structural changes may occur because of changes in technology or changes in regulation. When structural breaks exist, older observations become less informative for measuring industry productivity for purposes of forward-looking rate setting.

[30] *See* Figure 22 of Exhibit CLP-PBR-2 for the 20-, 15-, and 10-year TFP averages, which are -1.41%, -1.48%, and -1.99% respectively.

Q. What inputs did LEI examine in its TFP Industry Study?

A. LEI constructed a two-input model consisting of quantities of capital and quantities of non-capital inputs (based on deflated OM&A costs).

Capital quantities were based on an estimation of the real capital stock (capital additions and retirements) and weighted by the implicit rental price of capital, developed in a seminal paper by Christensen and Jorgenson (1969).[31] (*see* Section 3.3.5 of Exhibit CLP-PBR-2).

Non-capital quantities are based on various OM&A expenses, such as customer accounts, customer service, sales, and administrative and general ("A&G") expenses.[32] As discussed in Section 3.2 of the LEI Industry TFP Study (Exhibit CLP-PBR-2), Account 908 (Customer Assistance Expenses) was excluded from the Industry TFP Study because these expenditures primarily reflect customer assistance and public policy programs that are driven by legislative and regulatory requirements, rather than the utility's efficiency in providing electric distribution service. Including these costs would introduce policy-driven differences across jurisdictions and could distort measured productivity trends, particularly as customer assistance

[31] Christensen, L.R. and D.W. Jorgenson. "The Measurement of Real Capital Input, 1929 – 1967." *Review of Income and Wealth* 15. 4 (December 1969): 293-320.

[32] As discussed in Section 3.2 of the LEI Industry TFP Study (Exhibit CLP-PBR-2), only a portion of A&G expenses based on the share of the distribution assets relative to the total plant.

programs have expanded over time. This data was taken directly from utility filings (*see* Section 3.2 of Exhibit CLP-PBR-2 for a description of the data that LEI relied on to calculate the OM&A and capital inputs).

Q: Why are you referring to quantities of inputs in your description of TFP trends?

A. For purposes of calibrating the X Factor, the Industry TFP Study must be designed to capture the trend in physical productivity for EDCs. Because this is not a financial or accounting study, raw financial data should not be used. Instead, my team converted raw financial data from monetary values to physical unit proxies. Price deflators were used to convert nominal monetary values into "real" dollar-denominated quantities.

Q. What output metric did LEI use in its Industry TFP Study?

A. I used the total number of customers served by each EDC in each year as the output metric. The use of customer counts as an output measure is common in TFP studies of the electric distribution industry, as well as other network industries. An important advantage of this measure is that customer counts are objective, consistently defined, and readily available across EDCs, allowing for meaningful comparisons over time and across utilities.

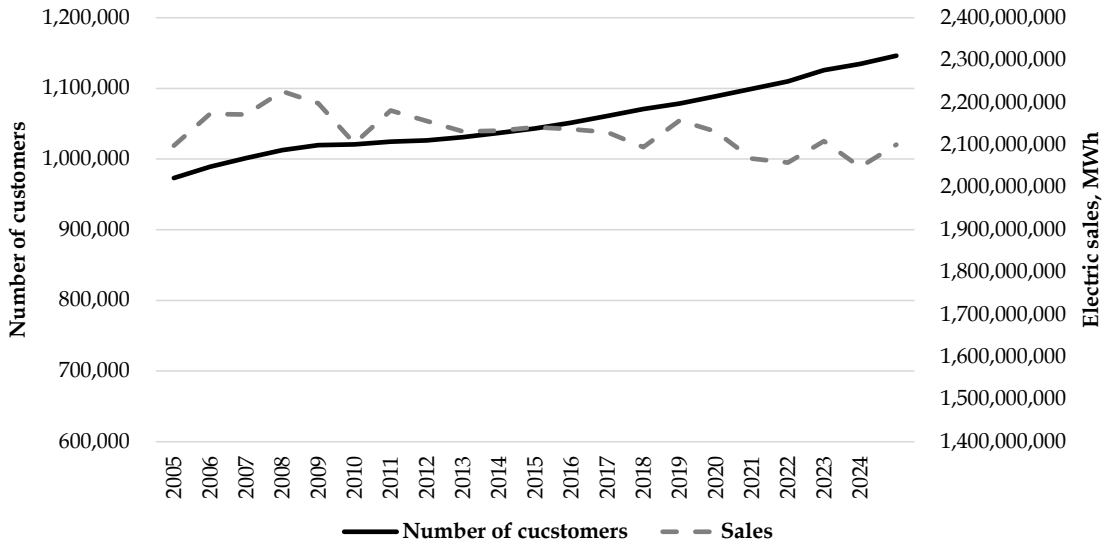
I also considered annual electricity sales as a potential output measure. However, unlike customer counts, electricity sales are affected by numerous factors that are largely outside the utility's control, including weather conditions, macroeconomic activity, customer growth, electrification trends, and, in some regions, the addition of large loads such as data centers. These factors can materially influence annual electricity consumption without reflecting any change in the utility's underlying productivity.[33] For example, unusually hot or cold weather may increase electricity sales even though the utility's workforce, distribution assets, and operating practices remain largely unchanged. As a result, changes in annual electricity sales do not necessarily represent changes in the efficiency with which an EDC provides distribution service.

Moreover, EDCs invest in and maintain distribution infrastructure to provide customers with safe and reliable access to electricity and sufficient capacity to meet peak demand, rather than to deliver a specific volume of electricity over the course of a year. Accordingly, the number of customers served is the more appropriate output measure for evaluating productivity in the electric distribution industry because it more closely reflects the

[33] U.S. Energy Information Administration. *Annual Energy Outlook 2026*. April 8, 2026. < https://www.eia.gov/outlooks/aeo/>

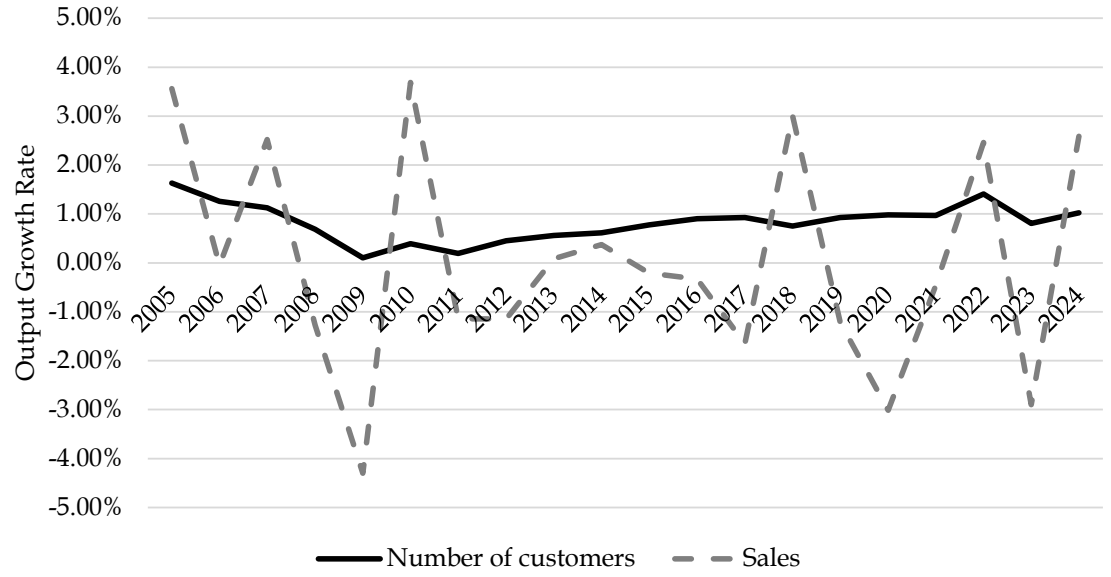
primary function of an EDC and provides a more stable and comparable basis for measuring productivity over time, as shown in Figure 3 and Figure 4 below.

Figure 3. Total number of customers served vs. electric sales (reflecting all 88 EDCs studied)



Source: Energy Information Administration ("EIA") 861 for customer data and FERC Form 1 for sales data

Figure 4. Growth rate trends of the number of customers served vs. electric sales (reflecting the 88 EDCs studied)



Source: EIA 861 and FERC Form 1 for sales data

Q. What were the key results in LEI's Industry TFP Study?

A. The U.S. EDC industry TFP grew by -1.41% per annum on average over the 2005-2024 timeframe, as seen in the last column of Figure 5 below.[34] Notably, the average TFP growth rate is more negative if we look over the last 15 years or the last 10 years.

Figure 5. LEI's Industry TFP results (2005-2024)

Year	Output	Inputs			Productivity		
	Customers [A]	Capital [B]	OM&A [C]	Total [D]	Capital [A-B]	OM&A [A-C]	TFP [A-D]
2005-2006	1.25%	2.01%	-0.74%	0.50%	-0.76%	1.99%	0.75%
2006-2007	1.12%	2.11%	6.91%	4.74%	-0.99%	-5.79%	-3.62%
2007-2008	0.68%	2.40%	-0.38%	0.89%	-1.72%	1.06%	-0.21%
2008-2009	0.10%	2.99%	1.62%	2.25%	-2.88%	-1.52%	-2.15%
2009-2010	0.39%	1.86%	0.93%	1.35%	-1.47%	-0.54%	-0.96%
2010-2011	0.19%	2.34%	1.91%	2.11%	-2.15%	-1.72%	-1.92%
2011-2012	0.45%	3.09%	-0.11%	1.38%	-2.64%	0.56%	-0.93%
2012-2013	0.56%	3.18%	-4.08%	-0.59%	-2.62%	4.63%	1.15%
2013-2014	0.61%	3.53%	0.59%	2.04%	-2.92%	0.02%	-1.43%
2014-2015	0.78%	3.87%	-3.12%	0.41%	-3.10%	3.89%	0.37%
2015-2016	0.90%	4.23%	1.69%	2.99%	-3.33%	-0.79%	-2.09%
2016-2017	0.92%	4.27%	1.09%	2.75%	-3.35%	-0.17%	-1.82%
2017-2018	0.75%	4.23%	-2.01%	1.27%	-3.48%	2.76%	-0.53%
2018-2019	0.92%	4.49%	1.41%	3.04%	-3.57%	-0.49%	-2.12%
2019-2020	0.98%	4.89%	13.70%	9.12%	-3.91%	-12.72%	-8.14%
2020-2021	0.97%	3.39%	-6.24%	-0.97%	-2.42%	7.21%	1.94%
2021-2022	1.40%	3.27%	6.23%	4.49%	-1.88%	-4.83%	-3.09%
2022-2023	0.80%	4.42%	-1.03%	2.20%	-3.62%	1.84%	-1.39%
2023-2024	1.02%	4.90%	-3.02%	1.69%	-3.88%	4.04%	-0.67%
Average 2004-2024	**0.78%**	**3.44%**	**0.81%**	**2.19%**	**-2.67%**	**-0.03%**	**-1.41%**
Average 2009-2024	**0.80%**	**3.86%**	**0.50%**	**2.28%**	**-3.06%**	**0.30%**	**-1.48%**
Average 2014-2024	**0.96%**	**4.23%**	**1.31%**	**2.95%**	**-3.27%**	**-0.35%**	**-1.99%**

[34] The TFP results are described in greater detail in Section 4 of Exhibit CLP-PBR-2.

Output (number of customers) grew on average by 0.78% per annum over the 20-year timeframe (see column A in the figure above).

The 20-year average growth rate in total input quantities amounted to 2.19% per annum (see column D in the figure above). This positive trend in total inputs is primarily driven by strong and consistent growth in capital. Growth in the quantity of capital inputs has been driven by a combination of aging infrastructure replacement, investments to improve reliability and resilience, grid modernization, and the expansion of distribution infrastructure to accommodate evolving system needs. These trends are well documented in the industry. In a recent report examining utility infrastructure investment, the Department of Energy's EIA found that distribution-related capital expenditures have been the largest contributor to the increase in utility infrastructure spending over the past two decades.[35] Specifically, the EIA reported that capital expenditures on distribution infrastructure increased by $31.4 billion (approximately 160%).[36] According to the EIA, this growth reflects utilities' investments to replace and upgrade aging distribution equipment, construct new

[35] U.S. EIA. *Grid infrastructure investments drive increase in utility spending over last two decades*. 2024. <https://www.eia.gov/todayinenergy/detail.php?id=63724>

[36] Ibid.

distribution lines, transformers, and substations, strengthen systems against storms and wildfire risk, integrate renewable energy and other distributed energy resources, and deploy advanced grid technologies such as smart meters, sensors, and distribution automation equipment. [37]

Q. Can the Industry TFP trend be disaggregated into capital and non-capital productivity trend?

A. Yes. LEI's industry TFP study measures productivity growth using both capital and OM&A inputs, consistent with the objective of evaluating overall industry productivity. Because the underlying TFP framework separately measures the productivity associated with capital and OM&A inputs, the study also produces partial factor productivity ("PFP") measures for each input category. PFP measures the rate of change of a single input versus the rate of change of the output.

Over the past 20 years (2005-2024) the average annual capital PFP for EDCs in the U.S. is -2.67% while the average annual OM&A PFP for EDCs in the U.S. is -0.03%, as shown in Figure 6. These results are consistent with the different trends observed for capital input versus OM&A input over time, as presented in Figure 5 (Columns B and C, respectively).

[37] Ibid.

Figure 6. LEI's Industry Annual Capital and O&M PFP 2005-2024

Year	Productivity	
	Capital	OM&A
2005-2006	-0.76%	1.99%
2006-2007	-0.99%	-5.79%
2007-2008	-1.72%	1.06%
2008-2009	-2.88%	-1.52%
2009-2010	-1.47%	-0.54%
2010-2011	-2.15%	-1.72%
2011-2012	-2.64%	0.56%
2012-2013	-2.62%	4.63%
2013-2014	-2.92%	0.02%
2014-2015	-3.10%	3.89%
2015-2016	-3.33%	-0.79%
2016-2017	-3.35%	-0.17%
2017-2018	-3.48%	2.76%
2018-2019	-3.57%	-0.49%
2019-2020	-3.91%	-12.72%
2020-2021	-2.42%	7.21%
2021-2022	-1.88%	-4.83%
2022-2023	-3.62%	1.84%
2023-2024	-3.88%	4.04%
Average 2005-2024	-2.67%	-0.03%

Q. How should the observed industry TFP and PFP trends be used in CL&P's rate proposal?

A. LEI understands that CL&P is proposing a four-year revenue cap plan that includes an annual I-X RAM, consumer dividend, an ESM, and a capital funding mechanism.

With respect to the annual revenue adjustment mechanism, CL&P proposes to apply the X Factor only to OM&A costs, while capital costs will be adjusted based on actual capital placed-in service, subject to a cap set at the level of projected capital investments needed over the PBR term, as presented in this case. The capital adjustment will be subject to an annual review process. Consistent with this approach, CL&P proposes using the 20-year average OM&A PFP trend of -0.03%, as estimated in LEI's Industry TFP Study, as the X Factor applicable to the OM&A component of its cost of service established in this proceeding.

Because the proposed X Factor measures productivity only for OM&A inputs, the corresponding I Factor should likewise reflect changes in OM&A input prices. Accordingly, CL&P proposes to use a composite OM&A input price index consisting of the Employment Cost Index ("ECI") for utility labor costs and an economy-wide inflation such as a GDP-FSDP for non-labor operating costs, weighted to reflect the historical industry OM&A labor/non-labor cost structure.

Q. How does LEI's Industry TFP Study compare with the TFP studies accepted in other I-X PBR plans for EDCs?

A. LEI's TFP trend is reasonable and aligned with findings from several recent TFPs for the EDC sector. TFP studies performed by other consultants have produced negative TFP results. For example, in the 2024 industry TFP study submitted to the New Hampshire regulator as part of the rate application of Public Service Company of New Hampshire, the average TFP for the 2000-2022 timeframe was -0.26% per year.[38] A 2023 study conducted for EPCOR Distribution and Transmission, Inc. in Alberta showed an average TFP growth rate of -1.08% per year for the U.S. EDC industry over the 2007-2021 timeframe.[39] A 2018 study National Grid (Massachusetts Electric Company and Nantucket Electric Company) reported average TFP growth of -0.30% per year for the U.S. EDC industry over the 2002 to 2016

[38] Kolesar, Mark B. *Total Factor Productivity and the X-Factor for use in Public Service Company of New Hampshire)PBR Plan*. June 11, 2024.

[39] Meitzen, Mark E., Ph. D. And Nicholas A. Crowley. *Determination of the Third-Generation X Factor for the AUC Price Cap Plan*. January 27, 2023.

timeframe.[40] Industry TFP studies for gas local distribution companies in recent years have also tended to be negative.[41]

Q. Does a negative TFP trend imply the industry (or utility) is becoming inefficient?

A. No, that is not the correct interpretation. A negative TFP trend does not, in itself, indicate that an industry or utility is becoming inefficient. Rather, it indicates that, over the period examined, measured inputs have grown more rapidly than measured outputs. In the electric distribution industry, this outcome can arise even when utilities are operating prudently and efficiently. EDCs are increasingly required to invest in grid modernization, system hardening, cybersecurity, wildfire mitigation, resilience, aging infrastructure replacement, and compliance with evolving reliability and public policy requirements. Many of these investments improve the quality, resilience, and reliability of service but are not fully reflected in traditional output measures such as the number of customers served or

[40] Meitzen, Mark E and Lawrence R. Kaufmann. *National Grid - Investigation as to the Proprietary of Proposed Tariff Changes.* November 15, 2018.

[41] London Economics International LLC. *Empirical Analysis of Total Factor Productivity Trends in the U.S. Gas Distribution Industry (for Yankee Gas Services Company)*. November 8, 2024. National Grid. *Direct Testimony of Mark E. Meitzen and Nicholas Crowley*. November 13, 2020. Black & Veatch. *Total Factor Productivity, Benchmarking, and Recommended Inflation and X Factor for Enbridge Gas Inc. Inventive Rate Setting Mechanism*. Docket 2022-10-31, EB-2022-0200. October 2022.

electricity delivered. Consequently, input growth may exceed measured output growth, resulting in a negative observed TFP trend even though customers are receiving a higher quality and more resilient electric system. Indeed, regulators in several jurisdictions have recognized that negative TFP trends may be appropriate where the industry is experiencing sustained capital investment, changing service obligations, or slower output growth. TFP studies for electric utilities in Hawaii, Massachusetts, and Alberta have all observed negative industry productivity trends during periods characterized by significant capital investment and evolving utility obligations. For example, the TFP study submitted in Hawaii's PBR proceeding concluded that slower productivity growth reflected slower demand growth together with substantial investments in pollution controls, renewable energy integration, and grid modernization.[42] Similarly, testimony submitted in Massachusetts explained that capital inputs were growing more rapidly than traditional output measures because of aging infrastructure, technological change, increasing system

[42] Pacific Economics Group Research LLC. *Exhibit D2: Total Factor Productivity Research in Support of Annual Revenue Adjustment Mechanism*, submitted in Hawaii Public Utilities Commission, Docket No. 2018-0088, Instituting a Proceeding to Investigate Performance-Based Regulation (August 14, 2019).

requirements, and other cost drivers beyond customer growth.[43] These examples demonstrate that a negative TFP trend is not evidence of inefficiency; rather, it reflects the economic realities facing a modern electric distribution industry undergoing substantial investment and transformation.

Q. Would the X Factor in an I-X RAM take on the value of the average industry TFP trend?

A. No, not necessarily. As previously discussed in Section 0, if an economy-wide, output-based inflation index is selected for the I Factor, additional adjustments are needed to convert the TFP growth rate into an appropriate X Factor. Specifically, the difference in inflation trends for the inputs used by the EDC industry versus inflation trends reflected in the selected inflation index must be accounted for. An economic-wide, output-based inflation index will also inherently capture some level of productivity improvement over time (the conversion of inputs to final goods and services (i.e., outputs)); therefore, there needs to be adjustment for TFP differences between the industry and the economy. For example, over a 20-year timeframe, under the assumption of a revenue cap that uses the

[43] Meitzen, Mark E. D*irect Testimony of Dr. Mark E. Meitzen on Behalf of NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource Energy*, D.P.U. 17-05 (2017).

industry TFP trends and an I Factor based on GDP-FSDP, the recommended X Factor would be -2.05% per year, as discussed in Section 6 of Exhibit CLP-PBR 2.

However, if the RAM applies only to OM&A costs, rather than total costs, the appropriate productivity measure is OM&A PFP, not industry TFP, as discussed earlier. In that case, provided that the I Factor is based on a utility input-price index that reflects the inflation experienced by OM&A inputs, no further adjustments are required to the OM&A PFP when determining the X Factor. This is because the inflation index already captures changes in the prices of the utility's OM&A inputs and does not embed economy-wide productivity effects. This eliminates the need for separate input-price or productivity differential adjustments. Accordingly, for a RAM such as the one proposed by CL&P, where the X Factor applies only to OM&A costs, the OM&A PFP itself represents the appropriate X Factor. This approach is also consistent with regulatory-approved PBR plans by utilities such as National Grid in Massachusetts and FortisBC in British Columbia, Canada, where regulators concluded that an OM&A-only revenue cap should be

paired with a utility input-price inflation index, and no additional adjustments to the OM&A PFP are necessary to establish the X Factor.[44]

[44] Mark E. Meitzen and Nicholas A. Crowley. *Pre-Filed Direct Testimony of Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, M.S., on behalf of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid*, D.P.U. 23-150. pp. 14–19 and App. I; Lawrence Kaufmann. *Evidence on Multi-Year Ratemaking Plan Design, submitted on behalf of FortisBC Inc., British Columbia Utilities Commission, Application for Approval of a Multi-Year Ratemaking Plan for the Years 2020 through 2024* (Apr. 26, 2019). pp. 19–29.

IV. SUMMARY OF COST BENCHMARKING STUDY

Q. Please describe the unit cost benchmarking analysis you performed.

A. LEI's Cost Benchmarking Study evaluated CL&P's cost performance relative to other EDCs in North America over the last 10 years, using the same formulation of costs as estimated for the LEI Industry TFP Study.

The study benchmarked three measures of cost:

1. OM&A costs;
2. capital-related costs; and
3. total costs, which is the sum of OM&A and capital costs.

The study also presented two complementary benchmarking approaches. The first approach used unit cost benchmarking, which compared CL&P's costs to other peers on a per-customer basis. The second approach employed econometric benchmarking techniques, which explained costs using a number of business drivers, including the price of key inputs (such as wages), scale of operations, network density, and economies of scope related to the distribution function.

In summary, the unit cost benchmarking provides an intuitive assessment of relative efficiency, while the econometric benchmarking refines the analysis to more accurately inform on CL&P's relative cost performance.

Q. Why did LEI perform both unit cost benchmarking and econometric benchmarking?

A. The two approaches answer slightly different questions and therefore complement one another.

Unit cost benchmarking provides a transparent comparison of cost per customer across utilities and time, and is widely used in North American utility regulation because it is easy to understand and interpret. While informative, it does not address critical questions around why a certain EDC may have lower or higher unit costs – for example due to economies of scale or scope, or whether certain business drivers have a material influence over costs, as such as input prices, network configuration and customer mix.

Econometric benchmarking builds upon the unit cost benchmarking analysis by applying the economic concept of a cost function and controlling for differences in business drivers that may affect costs; some of these business drivers are outside management's control to change immediately and therefore must be accounted for when evaluating a utility's efficiency levels.

Using both approaches provides greater confidence in the conclusions because they rely on different methodologies while evaluating the same underlying question of relative cost performance.

Q. What data did you use in the unit cost benchmarking analysis?

A. The unit cost benchmarking analysis uses the same dataset that underlies LEI's Industry TFP Study such as the capital costs, OM&A costs, and customer counts.[45] Specifically, the benchmarking study includes data for 88 EDCs across the United States and covers the most recent ten years, 2015 through 2024.

Q. Why did LEI conduct unit benchmarking analysis over 10 years?

A. Benchmarking is intended to provide an assessment of the utility's current cost performance; however, looking over a multi-year period of time allows for (a) more rigorous analysis (especially under the econometrics), and (b) identification of any time-based patterns that the regulator may want to consider in its use of this empirical analysis in rate setting.

[45] *See* Sections 3.1 and 4.3 of the LEI Cost Benchmarking Report (Exhibit CLP-PBR-3).

Q. What were the findings from the unit cost benchmarking analysis?

A. LEI's unit cost benchmarking analysis shows that CL&P ranks 47th out of 88 utilities nationally on total cost per customer over 2005–2024, near the midpoint of the national sample—ranking more favorably on capital cost (32nd) but less favorably on OM&A cost (69th).[46, 47] Within its Northeast Region peer group, CL&P performs comparatively better, ranking 8th out of 22 EDCS on both total cost and capital cost per customer (in the first quartile), while ranking 11th out of 22 EDCs on OM&A cost (aligned with median). Overall, CL&P's total and capital cost performance stand out as comparatively strong within the Northeast Region, while its OM&A spending remains higher than about half of the regional peers and many national peers.

In addition, the Unit Cost Benchmarking analysis indicates that CL&P's capital-related costs and total costs on a per-customer basis have consistently remained below the industry average, whereas its OM&A costs per customer have generally exceeded the industry average, as discussed

[46] A lower rank number (e.g., 1st) indicates comparatively lower cost and thus stronger relative performance, while a higher rank number (e.g., 88th) indicates comparatively higher cost relative to the peer group.

[47] *See* Section 3.3 of the LEI Cost Benchmarking Report (Exhibit CLP-PBR-3).

in Section 3.5 of the LEI Cost Benchmarking Report (Exhibit CLP-PBR-3). These results indicate that, relative to the utilities included in the benchmarking sample, CL&P has generally incurred lower capital and total costs per customer, but higher OM&A costs per customer on average. Figure 7 below shows CL&P's actual unit costs relative to industry average unit costs – a negative value implies below average costs for CL&P, while a positive value implies above average costs for CL&P.

Figure 7. CL&P's actual unit costs relative to industry average unit costs, 2015-2024 (%)

Year	OM&A Cost	Capital Cost	Total Cost
2015	21.0%	-8.0%	1.0%
2016	22.0%	-9.0%	1.0%
2017	21.0%	-7.0%	2.0%
2018	10.0%	-9.0%	-3.0%
2019	20.0%	-9.0%	0.0%
2020	11.0%	-11.0%	-4.0%
2021	27.0%	-12.0%	-3.0%
2022	17.0%	-17.0%	-9.0%
2023	41.0%	-19.0%	-6.0%
2024	39.0%	-16.0%	-4.0%
10-year average	**22.9%**	**-11.7%**	**-2.6%**
4-year average	**31.0%**	**-15.9%**	**-5.6%**

Note: A positive value indicates that CL&P's costs are above the benchmark, while a negative value indicates that CL&P's costs are below the benchmark. Accordingly, negative values indicate relatively more favorable cost performance, as they reflect lower costs than the benchmark.

Q. Why did LEI also perform an econometric benchmarking analysis?

A. Although unit cost benchmarking provides useful information, it compares utilities using a single measure such as cost per customer and therefore cannot explain what is driving costs, nor can it account for legitimate differences in operating conditions that cause an EDC to have lower or higher unit costs than peers.

Econometric benchmarking provides a more robust assessment because it accounts for the impact of various business drivers that are shown to have a statistically significant impact on utility costs. It therefore allows for a more nuanced comparison of CL&P's actual costs against the costs expected for a utility with similar business drivers and operating characteristics, rather than against a simple industry average.

Q. What data did LEI use in its econometric benchmarking analysis?

A. Similar to the unit cost benchmarking analysis, the econometric benchmarking dataset was developed using cost data from LEI's Industry TFP study. In addition, it also uses a number of explanatory variables describing utility operating conditions, such as the price of inputs, operating scale, network density, and distribution business share in the regression analysis. The econometric benchmarking analysis uses a

balanced panel regression of costs of 88 EDCs over the 2015 through 2024 period, resulting in 880 utility-year observations. Section 4.3 of Exhibit-CLP-PBR-3 provides a more detailed discussion on this.

Q. What did the econometric benchmarking analysis show?

A. The econometric benchmarking results show the relative impact of various business drivers on total costs for EDCs. For example, in the OM&A model, the benchmarking allowed us to consider the prevailing wages over time and by state, as well as the scale of operations. Furthermore, the econometric analysis allowed for the development of a more accurate benchmark CL&P's historical performance given the presence of various business drivers. CL&P was found to have actual capital and total costs that were below the benchmark over the last 10 years, while OM&A costs were somewhat above the benchmark, as shown Figure 8:

- OM&A costs averaged approximately **12% above** the model-predicted benchmark;
- Capital costs averaged approximately **14% below** the benchmark; and
- Total costs averaged approximately **2% below** the benchmark.

After controlling for differences in business drivers, the econometric benchmarking results indicate that CL&P's cost performance in terms of total costs and OM&A costs are stronger than suggested by the unit cost benchmarking analysis, as discussed in Section 4.5 of the LEI Cost Benchmarking Report (Exhibit CLP-PBR-3).

Figure 8. CL&P's cost performance compared to the model-predicted benchmark, 2015-2024 (%)

Year	Total Cost	Capital Cost	OM&A Cost
2015	-1.4%	-9.7%	5.4%
2016	3.3%	-7.3%	13.5%
2017	-0.4%	-6.0%	4.1%
2018	-7.9%	-14.6%	-1.4%
2019	-3.6%	-13.7%	5.9%
2020	-6.1%	-13.7%	1.0%
2021	-2.0%	-12.6%	14.7%
2022	-7.6%	-19.1%	12.6%
2023	0.1%	-20.7%	31.9%
2024	2.2%	-18.1%	31.5%
10-year average	**-2.3%**	**-13.5%**	**11.9%**

Note :The reported values represent CL&P's average percentage deviation from the applicable benchmark over the 2015–2024 period. A positive value indicates that CL&P's costs are above the benchmark, while a negative value indicates that CL&P's costs are below the benchmark. Accordingly, negative values indicate relatively more favorable cost performance, as they reflect lower costs than the benchmark.

Q. How reliable is the econometric benchmarking analysis?

A. The econometric results are reasonable from both an economic and statistical perspective. The estimated relationships generally align with the principal cost drivers that economic theory would predict for electric

distribution utilities. For example, utility size, labor costs, and customer density each exhibit relationships with costs that are generally consistent with the expected economics of utility operations. The models also explain a substantial portion of the variation in utility costs. The R-squared values range from approximately 89% for the OM&A model to approximately 95% for the total cost model, indicating strong explanatory power.

Q. How should PURA use the results of your benchmarking study?

A. The Benchmarking Study should be viewed together with LEI's Industry TFP Study. The Industry TFP Study estimates the industry's long-run rate of productivity improvement and informs the industry productivity component of the X Factor.

The Benchmarking Study addresses a different question by evaluating CL&P's current level of cost efficiency relative to its peers in the industry. The benchmarking results indicate that CL&P's capital costs and total costs are below the average costs of other peers and below the benchmark constructed in the econometric models. While CL&P's OM&A costs remain above both the industry average under the unit cost benchmarking analysis and the model-predicted benchmark under the econometric benchmarking analysis, these results do not necessarily indicate that the Company is

inefficient. Rather, they suggest that, relative to its peers, CL&P has historically relied more heavily on OM&A expenditures than capital-related expenditures in providing electric distribution service. Nevertheless, there may remain some opportunity for CL&P to improve its OM&A cost efficiency.

It is important to emphasize, however, that benchmarking results should not be translated directly into a Consumer Dividend or S Factor. The difference between a utility's actual costs and its benchmarked costs represents an estimate of relative cost performance at a point in time; it does not indicate the extent to which those differences can reasonably or sustainably be eliminated over the term of a PBR plan. Benchmarking thus identifies relative efficiency and the potential for further improvement, but does not itself establish the annual rate at which such gains can be achieved. The results discussed above and in the LEI Cost Benchmarking Report (Exhibit CLP-PBR-3) provide empirical support for a modest Consumer Dividend that recognizes continued efficiency opportunities while acknowledging the Company's strong overall cost performance. In my opinion, the Company's proposed Consumer Dividend of 0.30% is reasonable in light of these results. In addition, approved Consumer Dividends in other North American jurisdictions generally range from

0.15% to 0.60%, as shown in Figure 12 in the LEI Cost Benchmarking Report (Exhibit CLP-PBR-3). CL&P's proposed 0.30% falls within this range and is consistent with the stretch factors approved in jurisdictions such as Alberta, British Columbia, Massachusetts, and Ontario.

V. REVIEW OF CL&P's PROPOSED PBR PLAN

Q. Have you reviewed CL&P's proposed Performance-Based Multi-Year Rate Plan ("PBMRP")?

A. Yes. I have reviewed the Company's proposed PBMRP, including its proposed revenue adjustment mechanism, Consumer Dividend (or Stretch Factor), earnings sharing mechanism, capital funding mechanism, performance metrics, and the proposed four-year plan term. My review was conducted from the perspective of PBR design and draws upon my experience advising utilities and regulators on the design, implementation, and evaluation of PBR plans in numerous jurisdictions. My opinions are based on established economic principles governing incentive regulation and on my review of the Company's proposal.

Q. Please provide an overview of CL&P's proposed PBMRP .

A. CL&P proposes a PBMRP that combines several mechanisms: a formulaic revenue adjustment mechanism based on an I-X framework; a Consumer Dividend; an ESM; performance metrics with financial incentives; an

exogenous cost mechanism; and a capital funding mechanism. In my opinion, this overall structure is generally consistent with the framework discussed in Docket No. 21-05-15RE01 (PURA Investigation into Revenue Adjustment Mechanisms for a Performance-Based Regulation Framework), where these types of mechanisms were identified and evaluated as potential components of a PBR framework for Connecticut. I acknowledge, however, that while PURA has conducted extensive stakeholder discussions and issued straw proposals in that proceeding, it has not yet issued a final decision adopting a PBR framework.

Q. In Section II above, you have discussed the characteristics of a well-designed PBR plan. In your opinion, is CL&P's proposed PBMRP generally consistent with these principles?

A. Yes. In my opinion, the Company's proposed PBMRP incorporates the principal components commonly found in well-designed PBR frameworks. Specifically, the proposal includes a formulaic revenue adjustment mechanism; a Consumer Dividend that shares efficiency gains with customers; a further guardrail in the form of an ESM that allows customers to share in financial gains if the Company earns returns above an established threshold; and performance metrics with financial consequences that help ensure cost efficiencies are not achieved at the

expense of service quality while encouraging continuous improvement in areas that customers value; an exogenous cost mechanism that addresses cost changes outside the Company's control; and a capital funding mechanism that provides a structured process for funding qualifying capital investments needed to maintain and modernize the electric system in support of safe, reliable, and resilient service. In addition, the Company is proposing a suite of performance metrics, including with financial penalties and incentives tied to its performance in key areas over the course of the PBMRP. Each of these components serves a distinct purpose, and together they create a balanced framework that promotes efficiency, maintains appropriate incentives for the Company, and provides important benefits and protection for customers.

Furthermore, these proposed PBR components are generally consistent with the framework discussed in Docket RE21-05-RE01.

Q. Please comment on CL&P's proposed PBR term.

A. CL&P's proposed four-year PBMRP term is reasonable. A multi-year term is important because it gives the utility a defined period in which it can retain a portion of efficiency gains, thereby strengthening incentives to manage costs between rate cases. At the same time, a four-year term is not

so long that it materially weakens regulatory oversight. This is consistent with discussions under Docket RE21-05-RE01.

Q. What is the I Factor that CL&P is proposing?

A. The Company intends to use an OM&A PFP measure as the basis for the X Factor, and as such, the corresponding I Factor should reflect the price inflation of OM&A inputs such as labor and non-labor operating expenses because those are the inputs whose productivity is being measured. CL&P is proposing to use a composite OM&A input price index where the labor cost inflation will be represented by the ECI while the non-labor cost inflation will be represented by the GDP-FSDP with the two indices weighted based on the EDC sector labor/non-labor share.

Q. What is the X Factor that CL&P is proposing?

A. The Company is proposing to use an OM&A PFP measure as the basis for the X Factor. LEI's Industry TFP Study measures productivity growth using both capital and OM&A inputs. Because the underlying TFP framework separately measures the productivity associated with capital and OM&A inputs, the study also produces PFP measures for each input category. Since CL&P's proposed RAM applies only to OM&A costs, and capital costs are addressed separately through the proposed capital funding mechanism, the

relevant measure of industry productivity is the OM&A PFP. Accordingly, the OM&A PFP serves as the basis for the proposed X Factor.

This approach also avoids the need for the additional adjustments that are commonly required when an X Factor is derived from an economy-wide TFP study. Under a traditional I-X framework that relies on a broad economy-wide inflation index, the measured industry TFP must typically be adjusted to reflect differences between economy-wide productivity growth and utility productivity growth, as well as differences between economy-wide input price inflation and the input price inflation actually experienced by utilities. In contrast, CL&P's proposed I Factor is specifically designed to reflect the Company's OM&A cost structure by using a composite input price index consisting of a utility labor cost index ECI) and a non-labor price index (GDP-FSDP), weighted using the industry's labor and non-labor OM&A cost shares. Because the inflation component is calibrated to reflect the composition of utility OM&A costs, and because the X Factor is based directly on the corresponding industry OM&A productivity measure, there is no need to further convert the OM&A PFP into an X Factor through additional TFP differential adjustments.

Based on LEI's Industry TFP Study, the average OM&A PFP growth rate for 2015-2024 is negative 0.03% (or -0.03%), which is the proposed X Factor.

Q. What are your independent views of CL&P's proposed Consumer Dividend?

A. CL&P's proposed Consumer Dividend starts with a baseline level of annual "sharing" of benefits with its customers and then allows for that "sharing": to adjust over time, indexed to changes in controllable O&M costs per customer against an inflation-adjusted benchmark. If the Company outperforms that benchmark, customers receive an increased "dividend" funded through a reduction on the revenue that would otherwise be collected under the PBMRP. Importantly, the Consumer Dividend has a floor of 0.3%, meaning it can only reduce customer rates and cannot become a surcharge. In my view, this novel approach benefits the customers because it provides them with an immediate share of the expected efficiency gains during the PBR term, rather than requiring them to wait until the next rate case, where regulators and the utility would identify efficiency gains and their impact on costs of service through re-basing process.

Q. What is your view of CL&P's proposed ESM?

A. CL&P proposes to retain an ESM that is generally consistent with the current regulatory framework, under which annual earnings above the authorized return on equity ("ROE") are shared equally between customers and shareholders. Under the proposed PBMRP, however, the customers' share of any overearnings would be credited directly back to customers, rather than first being applied to reduce environmental remediation or catastrophic storm balances as under the current mechanism. The proposal does not include downside earnings sharing. Accordingly, if the Company's earned ROE falls below the authorized ROE during the PBMRP term, shareholders bear that risk and customers are not required to compensate the Company.

Although I would have preferred an ESM that includes deadbands for purposes of strengthening cost containment incentives under the plan, I recognize that an ESM is an important guardrail and serves to protect customers if achieved earnings exceed the authorized return.

Finally, having an ESM is also consistent with discussions in Docket No. 21-05-15RE01.

Q. Has CL&P proposed any PIMs or performance metrics?

A. Yes. CL&P proposes several performance metrics across three categories: service quality and reliability, customer satisfaction and engagement, and sustainability and financial efficiency. The proposed PIMs include reliability measures such as Blue Sky SAIDI, Blue Sky SAIFI, CEMI, and CELID, as well as customer-facing metrics such as DER interconnection processing, digital customer engagement, call-handle time, post-transaction surveys, and average discount-rate enrollment time. The proposal also includes reporting-only metrics for receivables, greenhouse gas emissions, and cost efficiency.

The proposal establishes an overall performance incentive framework under which the maximum financial exposure for performance metric penalties is limited to an amount equal to 0.5% of the Company's total distribution revenues. Individual PIMs, or suites of metrics, would each be assigned a portion of the overall penalty and incentive pool. Penalty allocations would collectively equal 100% of the available penalty amount, while incentive-based PIMs would collectively account for 50% of the available incentive amount. Performance would be evaluated using graduated performance bands based on statistical deadbands for reliability metrics, and performance against a composite index target for customer

service metrics, with penalties and incentives determined on a sliding scale rather than as an all-or-nothing threshold. Under this approach, financial consequences increase progressively as performance moves farther away from the targets.

In my opinion, the Company's proposed performance metrics are generally consistent with the objectives of a well-designed PBR framework. The proposed metrics focus on outcomes that are largely within the Company's management control and measure aspects of utility performance that are important to customers, including reliability, customer service, and operational efficiency. Together with the proposed Consumer Dividend and ESM, these metrics help balance the strong cost-containment incentives created by the PBMRP by encouraging the Company to maintain and improve service quality while pursuing operating efficiencies.

The use of defined performance targets, graduated performance bands, and a sliding-scale approach to financial incentives and penalties provides a more proportionate relationship between performance and financial consequences than an all-or-nothing threshold. Similarly, capping the overall financial exposure and assigning specific weightings across the various metrics helps ensure that the incentives remain meaningful without

becoming so large that they undermine the stability of the overall regulatory framework.

Q. Is there a theoretical need for a capital funding mechanism as part of CL&P's PBMRP?

A. Given that CL&P is only applying the I-X formula on OM&A portion of rates, it will be insufficient to fund all necessary costs to serve CL&P's customers. An alternative capital funding provision is necessary to ensure a sustainable PBR regime.

CL&P's proposal is based on an approved forecast of capital investment established in this proceeding, with annual reconciliation through PURA's RAM proceedings. Its proposed capital funding mechanism limits recovery to the lesser of the approved forecasted capital revenue requirement or the revenue requirement associated with actual plant placed in service, and it prevents recovery during the initial PBMRP term for capital spending above the approved forecast.

The concept of providing a separate mechanism to support capital investment within a PBR framework is not unique. Several jurisdictions have adopted capital funding mechanisms that complement, rather than replace, the basic I-X framework in order to address ongoing capital

investment needs during a multi-year rate plan. K-bar arrangements are used in PBR regimes for regulated utilities in Massachusetts and Alberta, Canada. For example, in Massachusetts (DPU 23-150), the DPU approved National Grid's I-X mechanism applicable to operating and maintenance expenses and a separate capital cost recovery mechanism for core distribution investments. In approving that framework, the DPU explained that the PBR plan was intended to encourage operating efficiencies and moderate future cost increases, while the capital recovery mechanism would provide the Company with the funding needed to complete essential investments necessary to maintain the safety and reliability of the electric distribution system, subject to cost-control and prudency measures designed to protect customers from over- or mis-investment.[48]

Similarly, British Columbia provides an example of a PBR framework that incorporates forecast capital expenditures. Under FortisBC's multi-year Rate Framework, the British Columbia Utilities Commission ("BCUC") approved a formula-based approach for controllable OM&A expenses while separately approving forecast capital expenditures for the three-year

[48] Massachusetts Department of Public Utilities, *Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of General Increases in Base Distribution Rates for Electric Service*, D.P.U. 22-22, Order (September 30, 2022). pp. 2-3, 37-56.

regulatory period. Rather than relying on historical capital spending, the approved forecast capital expenditures are incorporated prospectively into the utility's revenue requirement for the multi-year plan. The BCUC recognized that this forward-looking approach was appropriate given the utility's ongoing investment needs associated with electrification, aging infrastructure, reliability, resiliency, and evolving system requirements. [49]

Although the specific design of these capital funding mechanisms varies across jurisdictions, the underlying regulatory objective is the same: to preserve strong incentives for operating efficiency while ensuring that utilities continue to make prudent investments necessary to maintain safe, reliable, resilient, and modern electric systems. I believe CL&P's proposal appropriately reflects these principles by pairing an OM&A-focused I-X mechanism with a capital funding mechanism that includes meaningful customer protections through forecast caps, annual reconciliation, and prudence review.

Furthermore, although the proposed capital funding mechanism is based on forecasted capital investments, the four year stay-out provision

[49] British Columbia Utilities Commission. *FortisBC Energy Inc. and FortisBC Inc. 2025 to 2027 Rate Setting Framework, Decision and Order G-58-25 (March 2025), §§ 3.2.1–3.2.2.*

preserves strong incentives for capital efficiency. Because the Company generally cannot seek recovery of capital expenditures above the approved forecast during the PBMRP term through a new base rate proceeding, it bears the financial risk of capital spending that exceeds the approved forecast. As a result, the Company has a strong incentive to develop realistic capital forecasts, carefully prioritize investments, manage project costs, and execute its capital program efficiently. At the same time, the proposal's annual reconciliation process ensures that only prudent investments placed in service remain eligible for recovery in rates, up to the approved forecast and subject to prudence review. This component of the mechanism ensures that customers are not subject to rates that are based on forecasted capital investments that are not yet providing service to them.

Q. Are you concerned that a revenue cap may lead CL&P to implement unduly severe cost reductions or defer needed investments?

A. A revenue cap creates incentives to control costs, but those incentives must be balanced with performance metrics, PIMs, an ESM, and annual reporting,. CL&P's proposal includes those safeguards. In addition, because the Company's proposed capital funding mechanism includes annual reconciliation of actual plant additions and recovery is contingent upon PURA's determination that investments are prudent, used, and

useful, the proposal substantially reduces any incentive to defer necessary capital investments during the PBMRP term.

Q. How would you evaluate the proposed Z Factor?

A. I understand that CL&P is proposing a Z Factor to CL&P proposes an Exogenous Cost Factor ("Z-factor") to address significant cost changes that occur during the PBMRP term that are beyond the Company's control and are not reflected in the I Factor used in the annual revenue adjustment mechanism. The proposed Z-factor would apply to both increases and decreases in costs resulting from qualifying exogenous events, such as changes in state or federal laws, regulatory cost reassignments, or externally imposed accounting rule changes. To qualify for recovery or refund, the combined revenue impact of qualifying exogenous events must equal or exceed 0.5 percent of the Company's total distribution revenues. Qualifying ongoing cost changes would be reflected in base distribution rates, while non-recurring costs would be recovered or refunded through a separate reconciling mechanism or amortized over an appropriate period.

The Z Factor is a mechanism that allows for adjustment in revenues or rates where events occur that are beyond the reasonable control of utility management; that were neither foreseen nor foreseeable at the time the PBR

RAM formula was set; and that create incremental costs that have a significant impact on the utility's finances. A utility experiencing such a qualifying event would be able to apply for Z Factor treatment within the term of PBR and start recovery of these costs from consumers, therefore reducing the overall costs of such an event (in comparison of just a deferral account). The Z Factor could also work to give consumers the benefits of any unforeseen exchanges that reduce costs (for example, tax-related changes). Therefore, the benefit of having a Z Factor is that it serves as a guardrail for both the utility and consumers' benefit, allowing for the utility to stay out and remain for PBR even in the face of potentially disruptive events, and to minimize the cost of qualifying events through timely recovery of costs from (or granting of credits to) customers.

For example, in Alberta, the Z Factor adjustment can be negative or positive, and to qualify for Z Factor treatment, the event must meet all five of the regulator's criteria: the event must have been outside of management control; the impact must be material; the impact should not have had

material impact on the I Factor; all costs were prudently incurred; and the impact of the event was unforeseen.[50]

Similarly, in British Columbia, the regulator found the Z Factor to be a necessary component of the PBR framework because of the protection afforded to both customers and the utility.[51] Like in Alberta, these Z Factor-qualifying costs need to be material, the result of events outside of management control, unforeseen, prudently incurred, and outside of "the base upon which rates were originally derived."[52]

The Z Factor proposal put forth by CL&P aligns with the Z Factor designs tested and implemented in other jurisdictions.

Q. Based on your experience designing PBR plans, and evaluating PBR outcomes, what are the expected benefits of CL&P's proposed PBMRP?

A. The revenue cap, and specifically the I-X formula-based RAM and capital funding mechanism, will create a strong economic incentive for CL&P to manage its costs. If CL&P can reduce its costs below the OM&A cap set by

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[50] Alberta Utilities Commission, *2024–2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities, Decision 27388-D01-2023*. October 4, 2023. pp. 118–119.

[51] British Columbia Utilities Commission. Decision and Orders G-165-20 and G-166-20. June 22, 2020. <https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/item/481438/index.do#_Toc43366430>

[52] Ibid.

formula, it will be able to increase its profitability. If it does, customers will benefit as they will get a larger Consumer Dividend, and if triggered under the ESM, 50% of any earnings over the authorized level. This aspect of the PBR plan mirrors the market discipline in competitive markets, where firms focus on reducing their own costs rather than trying to influence prices charged to customers.

Furthermore, from a customer's perspective, the proposed performance metrics provide a direct mechanism for holding the Company accountable for delivering high quality customer service across a suite of metrics. Customers benefit not only from the cost containment incentives created by the PBMRP, but also from financial penalties if performance deteriorates and financial rewards only when the Company achieves measurable improvements in customer-focused outcomes. This combination helps align the Company's financial incentives with the quality of service that customers receive.

The PBR plan proposed by CL&P also provides the utility with a level of predictability as to how external factors that have the potential to derail the PBR will be addressed. This approach will allow CL&P to focus on

improving its operations and servicing its customers in light of the changing rules and regulations.

Lastly, the reduction in regulatory burden (through a predictable, annual rate adjustment thereby avoiding intensive rate case reviews) will benefit not only CL&P but also the regulator and, ultimately, customers of CL&P.

Q. Does this conclude your testimony?

A. Yes.