COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

DIRECT TESTIMONY OF

NICHOLAS A. CROWLEY

ON BEHALF OF

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

d/b/a UNITIL

(ELECTRIC AND GAS DIVISIONS)

D.P.U. 23-80 AND D.P.U. 23-81

EXHIBIT UNITIL-RBH-1

AUGUST 17, 2023

Table of Contents

1. INTRODUCTION

Q1. Mr. Crowley, please state your full name and business address.

A.1 My name is Mr. Nicholas A. Crowley. My business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin, 53705.

Q2. Mr. Crowley, by whom are you employed and in what capacity?

A.2 I am a Senior Economist with Christensen Associates.

Q3. Would you please summarize your educational background and business experience?

A.3 I have a Bachelor of Science degree in economics, as well as a Master of Science degree in economics from the University of Wisconsin-Madison. I began working at Christensen Associates in 2016. Prior to joining this firm, I was an economist in the Department of Pipeline Regulation at the Federal Energy Regulatory Commission ("FERC"), where I assisted with energy industry benchmarking, the incentive regulation of oil pipelines,[1] and the review and evaluation of natural gas pipeline rate cases. In these roles, I have worked extensively with FERC data, and other federal data, for the development of cost benchmarks for power systems, in measuring industry total factor productivity, and the development of marginal cost models filed before regulatory authorities in the United States and Canada. I recently co-authored an article with Dr.

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

Meitzen on the impact of price-cap regulation on Canadian electricity distribution utilities.[2] My curriculum vitae is attached as Exhibit Unitil-NAC-2.

Q4. Mr. Crowley, have you previously testified before the Department or other state regulatory commission?

A.4 Yes. I recently testified with Dr. Mark Meitzen on behalf of NSTAR Electric Company d/b/a Eversource Energy ("NSTAR Electric") in its second generation Performance-Based Regulation ("PBR") framework proceeding, conducted by the Department of Public Utilities ("Department") in D.P.U. 22-22 (2022).[3] I also testified with Dr. Meitzen on behalf of Boston Gas Company and the former Colonial Gas Company each d/b/a National Grid, in the base-rate proceeding conducted in D.P.U. 20-120 (2021).[4] I have also testified in Alberta, Canada, on issues related to PBR on behalf of EPCOR Distribution and Transmission, Inc.[5] In addition, I assisted in the calculation of total factor productivity measures for the electricity sector and developed indexes for use in the PBR proceeding conducted by the Department for Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, in D.P.U. 18-150 (2019)[6] and on behalf of NSTAR Electric in D.P.U. 17-05 (2017).[7] I also assisted in the

---

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

[3] Direct Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 22-22, January 14, 2022; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 22-22, June 10, 2022.

[4] Direct Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, November 13, 2020; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, April 23, 2021.

[5] Determination of the Third-Generation X Factor for the AUC Price Cap Plan, Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, January 20, 2023.

[6] Direct Testimony of Mark E. Meitzen, Ph.D., D.P.U. 18-150, November 15, 2018; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., D.P.U. 18-150, April 22, 2019.

[7] Direct Testimony of Mark E. Meitzen, Ph.D., D.P.U. 17-05, January 17, 2017; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., Dennis L. Weisman, Ph.D., and Carl G. Degen, D.P.U. 17-05, May 19, 2017.

allocated cost-of-service study performed by Christensen Associates for NSTAR Electric in D.P.U. 22-22.[8]

Q5. What is the purpose of your testimony?

A.5 My testimony is submitted on behalf of Fitchburg Gas & Electric Light Company d/b/a Unitil ("FG&E" or the "Company") Electric and Gas Divisions. The Company has asked me to provide testimony to support its proposed PBR framework by: (1) providing an explanation of the economic principles underlying PBR from a theoretical proposition; (2) discussing the regulatory context of PBR in Massachusetts; (3) presenting the industry total factor productivity ("TFP") and X factor calculations in the context of FG&E's proposed PBR plan; (4) performing a cost benchmarking study for FG&E; (5) recommending a consumer dividend; and (6) discussing other elements of the proposed PBR framework.

Q6. Please provide a summary of your testimony.

A.6 In this testimony, I describe the elements of FG&E's proposed PBR framework, how these elements work together, and why FG&E's PBR plan is expected to provide benefits in the form of strong efficiency incentives. I begin with an overview of the economic principles underlying PBR and its application to electric utilities, incorporating research from contemporary utility PBR plans across North America. I then draw upon this background in a review of FG&E's proposed PBR framework. The central feature of FG&E's PBR framework is a revenue cap, which adjusts the Company's allowed revenues each year by operation of a revenue adjustment mechanism that takes the form of an "I-X" formula. This formula adjusts the proposed

---

[8] Direct Testimony of Bruce Chapman, *Allocated Cost-of-Service Study*, D.P.U. 22-22, January 14, 2022.

revenue cap by the rate of economy-wide inflation ("I") minus a productivity offset ("X"), derived through a total factor productivity study (the "TFP Study").

My testimony further provides evidence from prior proceedings demonstrating that the X factor for electric and gas distribution has trended negative in recent years and explaining the drivers of those trends. Although FG&E is not proposing to implement the negative X factor that I have derived through the TFP Study, FG&E is proposing to implement a PBR Plan using other elements comprising a PBR framework. My testimony also explains the mechanics of a proposed capital supplement known as K-bar, which was recently approved by the Department for NSTAR Electric. The K-bar mechanism is currently in use by all of the major distribution utilities operating in Alberta, Canada. The discussion I have provided in this testimony includes a description of how K-bar interacts with the I-X formula, as well as discussion of other proposed PBR elements, including the proposed exogenous factor, an earnings sharing mechanism ("ESM"), and discussion of the Company's proposed rationale for the consumer dividend. Specifically, my testimony provides cost-benchmarking support for the proposed implicit consumer dividend of 1.45% for the electric division and 1.30% for the gas division, which takes into consideration that the Company is not proposing to implement the negative X factor, although the TFP Study indicates that the cost trend for electric utilities continues to be negative given the operating environment. The testimony concludes with a summary of the key findings of my review of FG&E's proposed PBR Plan.

2. ECONOMIC THEORY AND PRACTICE OF PBR

Q7. What is Performance-Based Regulation?

A.7 In the utility industry, performance-based regulation, or "PBR," is a term that refers to a range of tools that may be employed to improve incentives for firms in a way that benefits the firm, the regulator and consumers. One of the flagship tools aimed at improving utility cost efficiency is multi-year rate plans ("MRPs"), which can take the form of price and revenue caps that adjust prices (or revenues) annually by a pre-defined mechanism, typically based on the rate of inflation. Price caps have a long history in rate regulation among network industries, including telecommunications, railroads, oil pipelines, the U.S. Postal Service, electric utilities, and gas utilities. Although the details of the indexed cap differ between industries, the basic incentive principle applies broadly, which is that: indexed caps provide firms with the basis to conduct operations, while pushing for greater and greater cost efficiency. Cost-efficiency gains ultimately benefit consumers in the form of lower prices relative to the traditional cost-of-service form of regulation.

Many forms of regulation fall under the umbrella of PBR or incentive regulation, ranging from largely traditional cost-of-service ("COS") regulation with added incentives to indexed cap formulas.[9] Given the multitude of regulatory schemes that fall under the general category of PBR, I will define PBR for purposes of this testimony to mean indexed cap formulas, such as price caps, revenue caps, or revenue per customer caps.

---

[9] "Incentive regulation can be defined as the implementation of rules that encourage a regulated firm to achieve desired goals by granting some, but not complete, discretion to the firm." David E. M. Sappington, "Designing Incentive Regulation," *Review of Industrial Organization*, Volume. 9, 1994, at 246.

Q8. In general, why is PBR viewed as a superior form of economic regulation relative to COS regulation?

A.8 PBR, in the form of price caps or revenue caps, is an approach to regulation that provides the regulated firm with stronger incentives for efficiency than traditional COS regulation. Under PBR, the profit maximizing utility has an enhanced incentive to find ways to reduce costs through the elimination of inefficiencies that might have otherwise persisted if the utility had continued operating in the status quo regulatory environment. PBR also offers greater efficiency in the operation of the regulatory process by lengthening the period of time between costly and administratively burdensome rate cases. A utility under PBR might have two rate applications over a ten-year period, while a comparable utility could have as many as five over the same time period, depending on the jurisdictional ratemaking process. In principle, these incentives and a longer time period between regulatory proceedings than under COS regulation, can be expected to lead to more efficient firm behavior, efficiency in the regulatory process, and benefits for all stakeholders, including customers of the regulated firm.

One of the fundamental principles of PBR is that customers share in the benefits of incentive regulation. These benefits may occur contemporaneously during the operation of the plan (i.e., *ex ante* benefits) or after the fact (i.e., *ex post* benefits). *Ex ante* benefits would include slower rate escalation and stability of rates as compared to alternative COS-based forms of regulation. *Ex post* benefits would include consumers realizing the fruits of more efficient firm behavior and efficiencies in the regulatory process through earnings sharing and the rebasing of rates at the time the plan is reviewed.[10] In

[10] Typically, incentive regulation plans such as price cap plans are subject to a comprehensive review after a pre-determined number of years of operation—e.g., five years.

addition, the firm may have an incentive to invest more efficiently under incentive regulation as compared to COS and these investments may generate further efficiencies that flow through to customers and may also result in higher quality of services.

Q9. What is the source of the stronger incentives provided by PBR?

A.9 Under PBR in the electric utility industry, the utility is provided with a level of annual revenues to meet operational requirements, combined with the flexibility and motivation to pursue cost reduction initiatives to meet the stay-out requirements of the multi-year rate plan. Under the PBR framework, utilities are allowed to keep the benefit of those reductions until rates are reset in the future, whereas under traditional forms of COS regulation, the expectation is that more frequent rate-setting processes will occur as the utility is free to petition for a rate change when it determines that rates need to be realigned with costs to improve the utility's standing in relation to the authorized return. Although it is generally recognized that regulatory lag provides some incentive for efficient behavior under COS regulation because utilities will always strive to improve their earned rate of return, the prospect of rate relief is a readily available option under COS, as compared to a rate plan where the utility has committed to avoid the COS proceeding for a longer period of time. The longer the period of time over which the firm is required to adhere to the revenue adjustment mechanism (and, conversely, that the utility can retain its cost savings), the stronger the incentives for efficient behavior, holding all other factors constant. PBR in the form of MRPs leverages the dynamic of regulatory lag, but institutes a framework wherein the lag may be extended due to the support of a revenue adjustment mechanism.

However, the strength of the PBR incentives depend on the form of PBR and to what extent the PBR Plan supports the utility's ability to conduct operations while the search for efficiency progresses. For example, the revenue adjustment mechanism included in a PBR framework needs to be calibrated to support the utility's operations given the prevailing cost trends without diminishing the motivation to search for efficiency. Similarly, under an ESM, the firm is allowed to retain earnings above the authorized return on equity ("ROE") up to a certain point—e.g., 200 basis points above authorized ROE—after which, excess earnings are refunded to customers. Consequently, the firm has a strong profit motive to become more efficient up to the full sharing point. Above that point, the PBR plan offers incentives akin to traditional COS regulation. On the other hand, a cap or ceiling type of incentive regulation, such as price caps or revenue caps, generally provides stronger incentives for efficient behavior because there is no upper limit on the profit incentive for cost efficiency, at least in the short term. In the purest form, these types of incentive regulation mechanisms set a cap or ceiling on prices or revenues with no constraint on earnings or requirements for sharing, giving the firm the strongest incentive to reduce costs and increase profits.[11]

Q10. Is there any evidence that indexed caps work to reduce price escalation for consumers?

A.10 Yes. In a recent paper published in *Utilities Policy,* I found (in collaboration with my colleague Dr. Mark Meitzen) that electric distribution utility customers in Alberta and Ontario, where firms operate under price caps, experienced slower rate escalation than

[11] However, in most cases, even the pure form of cap regulation requires that cast-off rates be just and reasonable and that rates be trued up to costs at the time of plan reviews (typically a five-year period).

comparable utilities.[12] In a recent publication in *The Electricity Journal*, Ken Costello stated that "for a utility with normal operating efficiency, our model finds that long-run cost performance on average improves 0.51 percent more rapidly each year in an MRP with a five-year term and no earnings sharing than it does under traditional regulation when rate cases occur every three years."[13] In addition, extensive economics research in the telecommunications industry indicate productivity improvements among firms operating under price caps during the 1990s. The National Regulatory Research Institute found increased productivity among telecommunications companies operating under incentive regulation.[14] Lastly, the benchmarking analysis presented in Appendix II indicates that the two electric distribution companies currently operating under revenue caps in the CA Energy Consulting TFP sample, NSTAR Electric and Mass. Electric, have performed favorably in terms of total cost growth over recent years. In particular, NSTAR Electric ranks first among Northeastern utilities, while Mass. Electric ranks seventh out of 18 companies (see Table A.2.7). Focusing strictly on O&M costs, both NSTAR Electric and Mass. Electric have experienced lower O&M costs per customer than the national and Northeast samples during the PBR period between 2017 and 2021.

---

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

[13] Kenneth W. Costello, "Multi-year rate plans are better than traditional ratemaking: Not so fast," *The Electricity Journal*, 36, (2023).

[14] Jaison R. Abel, "The Performance of the State Telecommunications Industry Under Price-Cap Regulation: An Assessment of the Empirical Evidence," NRRI 00-14, The National Regulatory Research Institute, September 2000.

Q11. What are key challenges associated with designing a well-functioning PBR framework?

A.11 A well-functioning PBR framework provides benefits to customers, the utility, and the regulator, which often means balancing efficiency incentives with the financial needs of the utility, such that it is able to meet its obligation to serve. For example, a utility facing lumpy capital expenditures necessary to sustain service to customers may not be able to function under an extended PBR plan without additional capital supplements. On the other hand, certain forms of supplemental revenue mechanisms may detract from the efficiency goals of PBR. This means that properly designed PBR plans require thoughtful consideration of the balance between efficiency improvements and revenue adjustments to address operating costs and the need for capital investment. To achieve this balance, PBR plans contain additional elements beyond the revenue cap, including exogenous factors and capital supplements. I explain these in further detail in Section IV of my testimony.

Q12. How do the utility's risks change under PBR as compared to traditional COS regulation?

A.12 The risks associated with PBR depend on the structure of the PBR mechanism. Utilities face greater risks under PBR in circumstances where earnings are allowed to fall substantially below the authorized rate of return and, subject to the particular rules of the regulatory plan, the firm has no recourse to obtain or appeal for relief through a rate application over the PBR term. Under a form of earnings sharing with larger incentives for cost control, there is typically a lower bound on earnings—e.g., 200 basis points—

that the firm must live with before obtaining rate relief or triggering a rate re-opener.[15] With a pure cap form of regulation, just as there is no constraint on earnings above the authorized rate of return, absent conditions that allow for a rate-case re-opener in extreme circumstances, there is no automatic relief available to the firm for earnings less than the authorized rate of return. In one respect, these risks can be thought of in terms of an added incentive to the firm to perform well because it is effectively "operating without a net."

Q13. How does a revenue cap work?

A.13 A revenue cap limits the annual increase in allowed revenue for a firm using a predefined mechanism. Generally, this mechanism takes the form of a formula that involves the rate of inflation and a productivity offset. This formula is called "I-X", where I is a measure of inflation and X is a measure of expected productivity growth over the PBR term that is external to the regulated firm and is typically representative of some industry average. Under a simple revenue cap, revenues over the PBR term are set based on the following formula:

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

Where $Revenue_t$ represents current year allowed revenues and $Revenue_{t-1}$ represents the prior year's allowed revenues. This is a recursive formula, requiring an initial year determination of revenues. The initial revenue requirement is typically set in a traditional revenue requirement application, after which the formula adjusts revenues

[15] Other forms of earnings sharing taper the amount of earning above authorized ROE that the firm must refund (or the amount of rate relief for earnings below authorized ROE). For example, regarding refunds for earnings above authorized ROE, the firm may keep all earnings for 200 basis points above authorized ROE, refund 50 percent of earnings between 200 to 300 basis points above authorized ROE, and refund all earnings greater than 300 basis points above authorized ROE.

each year for the duration of the PBR term. Note that this formula relies on prior year inflation rates, which means that the revenue cap incorporates regulatory lag and that the utility does not recover increased costs contemporaneously with increased inflation. Also note that the productivity growth rate is typically fixed over the course of the plan.

Q14. How is the I-X formula derived?

A.14 The I-X formula was originally derived to apply to price-cap regulation. Economic theory states that marginal revenues equal marginal costs in competitive markets, which means that changes in price are a function of changes in input prices, input quantities, and output quantities. The derivation demonstrates how the I-X formula mimics competitive market conditions for firms operating in a monopoly environment by setting allowed price changes equal to the change in input prices and the change in TFP. By setting a price cap according to this formula, utilities experience enhanced efficiency incentives like those observed in competitive markets. This is because prices are allowed to increase at the rate of inflation, adjusted for industry productivity, which is how prices adjust in a competitive market in which prices equal marginal costs. Much of the economic logic underlying price caps also applies to revenue per customer caps and revenue caps. In Appendix 1, I provide a mathematical derivation of this formula.

Q15. How does this formula affect the behavior of the regulated firm?

A.15 As discussed above, the PBR formula incents the firm to behave more efficiently through the profit motive. The Department has provided a good intuitive description of the economic logic of indexed caps and how the regulated firm is incented to behave more efficiently under this formula:

> For a particular company, the indices serve as proxies for the growth in per-unit costs that the company should have experienced during the

> specified period, if it were an average-performing company. A company that achieved lower-than-average growth in per-unit costs during this period would be rewarded under a price-cap regulation, i.e., it would have the opportunity to earn additional profits. Conversely, a company whose growth in per-unit costs exceeded the average might realize lower-than-anticipated profits.[16]

Q16. How is the productivity adjustment, X, determined?

A.16 As described below, the specification of the X factor depends on the I factor approach. However, in either case, the X factor specification will contain a common element; namely, a measure of the expected rate of change in industry productivity.[17] The calculation of an X factor is described in greater detail below.

Q17. Would you please describe the measure of expected changes in industry productivity used in determining the X factor for a revenue cap?

A.17 Yes. As shown in Appendix 1, economic theory can be used to derive the productivity offset to inflation for use in a price cap. The derivation is more straightforward for a price cap because the underlying economic theory assumes prices equal marginal cost, but the economic logic of price caps also applies to revenue caps. In particular, the productivity offset equals the growth rate of industry total factor productivity ("TFP"), which is generally defined as the ratio of total output to total input:

$$TFP = Total\ Output/Total\ Input \tag{2}$$

Productivity changes are measured as the percentage change in TFP, which is computed as the percentage change in total output less the percentage change in total input:

---

[16] D.T.E. 03-40, October 31, 2003, p. 474.

[17] The use of the expected rate of productivity change across the industry in setting the *X* factor provides incentives for productivity gains by the regulated firm. In contrast, if the *X* factor were to be based repeatedly on actual changes in the regulated firm's productivity, price cap regulation would function in similar fashion to cost of service regulation. See Jeffrey I. Bernstein and David E.M. Sappington, "Setting the X Factor in Price-Cap Regulation Plans," *Journal of Regulatory Economics*, Vol. 16, 1999, at 9.

$$\%\Delta TFP = \%\Delta Total\ Output - \%\Delta Total\ Input \qquad (3)$$

For example, if TFP growth is equal to 2.0%, this means that the same output can be produced with 2.0% fewer inputs, or the same quantity of inputs will yield 2.0% more output. On the other hand, if TFP growth is equal to -2.0%, this means that the same output is produced with 2.0% greater inputs, or the same quantity of inputs will yield 2.0% less output.

Q18. What are the relevant inputs that should be used to calibrate an indexed cap TFP measure?

A.18 Total input includes all resources used by the unit of production in providing services to customers. Typically, TFP studies divide total input into three categories: capital, labor, and materials. TFP is widely recognized as a comprehensive measure of productive efficiency because, unlike measures of partial productivity, such as labor productivity, TFP provides a measure of the contribution of all inputs used in the production of total output.

Q19. What are the relevant output measures that should be used to calibrate an indexed cap TFP measure?

A.19 When TFP is used to set a price cap X factor, total output consists of the services that are billed to customers produced by the relevant unit of production (e.g., a firm or an industry). In other words, TFP for this purpose would equal the ratio of billed output to total input. These billed output measures may include number of customers, system peak demand, or billed volumes sold (in Megawatt Hours). Defining this measure of TFP as *price cap TFP* (PC TFP = TFP^P):[18]

$$TFP^P = Billed\ Output/Total\ Input \tag{4}$$

As demonstrated in Appendix 1, when TFP is used in the X factor offset to inflation to calibrate a revenue-per-customer cap, total output is represented by the total number of customers served by the utility. When the revenue cap does not contain any accommodation for customer growth, the X factor includes an implicit stretch factor such that the company is required to manage the costs associated with customer growth without additional support.

Q20. Could you please expand on the revenue cap issue regarding customer growth?

A.20 Yes. Consider the difference in revenue recovery between a price cap and a revenue cap when the firm grows over time. In the case of a price cap, customer and volume growth will translate into higher revenues, assuming rates include both fixed and volumetric charges. In the case of a revenue cap, customer and volume growth does not result in higher revenues, even as the firm's total costs increase as a result of customer and volume growth. For this reason, under a revenue cap with no growth factor, the cap includes an implicit stretch factor equal to the cost growth associated with growth in customers.

Q21. What is the revenue cap formula when the I factor is based on GDP-PI?

[18] As described below, another difference between the efficiency and PC measure of TFP is how the various elements of output are weighted together to construct the relevant output index. Also, as discussed below, billed output is likely to be a proper subset of total output as customers are not billed for all of the outputs produced by the utility. Moreover, this difference has likely been increasing over recent years.

A.21 If the I factor is represented by the rate of change in economy-wide output inflation as in the GDP-PI, the revenue cap X factor is the combination of TFP and input price differentials between the electric distribution industry and the overall economy. The TFP differential between the electric distribution industry ($\%\Delta\ TFP^{R}_{I}$) and the overall economy ($\%\Delta TFP_{E}$) is given by:

$$(\%\Delta\ TFP^{R}_{I} - \%\Delta TFP_{E}) \qquad (5)$$

The input price differential between the overall economy ($\%\Delta W_{E}$) and the electric distribution industry ($\%\Delta W_{I}$) is given by:

$$(\%\Delta W_{E} - \%\Delta W_{I}) \qquad (8)$$

Combining the TFP differential and the input price differential produces the *X* factor when the GDP-PI is used as the measure of the *I* factor:

$$X = [(\%\Delta\ TFP^{R}_{I} - \%\Delta TFP_{E}) + (\%\Delta W_{E} - \%\Delta W_{I})] \qquad (6)$$

Thus, the revenue cap formula when the I factor is the GDP-PI is given by:

$$\%\Delta R = GDP\text{-}PI - [(\%\Delta\ TFP^{R}_{I} - \%\Delta TFP_{E}) + (\%\Delta W_{E} - \%\Delta W_{I})] \qquad (7)$$

Q22. You stated that output in a TFP study to calibrate a price cap consists of the services that are billed to customers. Would you please explain?

A.22 The correct specification of output for a TFP study depends on the purpose of the study, i.e., the output measure will differ depending on whether the purpose is to assess efficiency or to calibrate an indexed PBR cap. When the purpose of TFP measurement is for use in calibrating the *X* factor for a price cap (i.e., PC TFP), the output measure should reflect the elements of output associated with customer prices or revenue generation—i.e., billed output—because those are the elements of output whose prices are being constrained by the cap.[19] In general, these are not the same elements of the output that would be used in an efficiency measure of TFP since the billed output measure would include only those aspects of output produced by the firm or industry that are explicitly related to customer prices or revenue generation subject to the cap. In most cases, billed output would be a proper subset of the total output produced. For example, as described in a recent article in *The Electricity Journal*:

> [P]roviding security in today's environment means protecting against cyber threats and drone attacks. This contrasts sharply with yesteryear's security that may have required only a night watchman and a chain-link fence. Distributed generation requires costly infrastructure investments to allow wind/solar generators to interconnect with the distribution system. Similarly, other "grid mod" investments for which there are no explicit charges to consumers, such as vehicle charging investments, contribute to the imbalance between input and output growth. All these activities require more intensive use of inputs without generating any corresponding increase in billable outputs for the electric distribution companies. [20]

Q23. TFP is typically thought of as a measure of efficiency. Does that apply to the revenue or price cap TFP?

A.23 Not in the same sense as an efficiency measure of TFP. There are two primary differences between an efficiency measure and indexed cap TFP. First, as noted, the efficiency measure would likely contain a more comprehensive set of the outputs produced by the firm or industry. Second, the weighting of the various elements of

---

[19] For example, see Laurits R. Christensen, Philip E. Schoech, and Mark E. Meitzen, "Total Factor Productivity in the Telecommunications Industry," in *International Handbook on Telecommunications Economics*, G. Madden and S. Savage, eds., 2003.

[20] Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal,* 31 (2018), at 43. To the extent elements of investment are not associated with billed output, their costs must be recovered from the elements of billed output.

output into a total output index differ between an efficiency measure of TFP and PC TFP used in a price cap.[21] Only in cases where all elements of output are billed to customers and price equals marginal cost for all elements of output will the total output measure be the same for the efficiency and indexed cap measures of TFP. This is typically not the case for the electric distribution industry.[22]

Q24. Is it also true that the output measure for the version of TFP that is used in a revenue per customer or revenue cap will differ from the output measure in an efficiency measure of TFP?

A.24 Yes. As I demonstrate in Appendix 1, the proper measure of output when TFP is used in a revenue per customer is customer growth, which also differs from the measure of output in an efficiency measure of TFP. Thus, alternative measures of output, such as kWh or peak load are not appropriate for a revenue-per-customer cap.[23]

Q25. How does a revenue cap differ from a revenue-per-customer cap?

A.25 Most utilities experience an increase in customers over time. For example, FG&E has experienced approximately 0.5 percent growth in electric customers each year since 2007. Customer growth places cost pressure on the utility as the system expands to connect new homes and businesses, as well as to meet increasing demand on the system. Revenue-per-customer caps provide an additional growth factor in the I-X formula to account for growing customers and their associated costs. In contrast, revenue caps with no growth factor limit revenues regardless of the increases in system-wide costs

---

[21] The efficiency measure of TFP uses marginal cost weights and an indexed cap TFP uses revenue weights to combine individual measures of output into an index of total output (or billed output).

[22] Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal*, 31 (2018), at 43.

[23] If revenues are capped without including a customer growth factor, and the output measure chosen is customer growth, the company must manage with incrementally more constrained revenues than under a revenue per customer cap. This effectively amounts to a stretch factor equal to the percentage of customer growth.

attributable to a growing customer base and other factors. For this reason, revenue caps contain an implicit "stretch factor" equal to the forgone revenue growth required to meet the needs of new customers.

Q26. Where else are revenue caps currently in place?

A.26 Revenue caps are the predominant form of PBR for utilities in North America, Australia, New Zealand, and Great Britain. National Grid and Eversource (both gas and electric) operate under a revenue cap, as do the Hawaiian Electric Companies in Hawaii. In British Columbia, FortisBC operates under a revenue cap, as did Hydro Québec TransÉnergie in Quebec until the end of 2022. Some distribution utilities in Ontario operate under a revenue cap, although most operate under price caps. The electric distribution utilities in Alberta operate under a price cap, but the gas utilities operate under a revenue cap. Taking a further step back, PBR is currently expanding across North America, taking different forms beyond price and revenue caps. Utilities in California and New York operate under MRPs, while utilities in Minnesota and Illinois have adopted performance incentive mechanisms ("PIMs"). Duke Energy Progress in North Carolina has recently filed its first generation PBR plan, and exploratory dockets are currently open to investigate PBR in Nevada, Washington, Wisconsin, and Connecticut.

Q27. What are some lessons learned from revenue caps in other jurisdictions?

A.27 One of the fundamental challenges for utilities operating under a revenue cap (or a price cap) is that the rate stay-out period of five or more years leaves the company to operate without a safety net even as the company must continue to make costly, sometimes lumpy investments. This phenomenon casts into relief the issue of balancing utility incentives under PBR with the opportunity to recover prudently incurred costs. Two prominent examples illustrate the consequences of implementing PBR plans that do not manage to weigh these factors properly. First, Central Maine Power ("CMP") operated under a very restrictive price cap for five years between 2009-2013, but ultimately had to abandon PBR in an environment of persistent, significant revenue deficiencies.[24] Second, Hydro-Québec TransÉnergie ("HQT") began operating under a revenue cap in 2020, with a positive X factor set arbitrarily, rather than a negative X factor based on industry TFP. HQT abandoned PBR at the end of 2022, also with substantial revenue deficiencies.[25] The takeaway from these two examples is that parties cannot assume that a multi-year rate plan will automatically work under restrictive caps—the plan must be designed with serious consideration of the balance between incentives and achievability. The components of the plan should be based on methodologically robust theory and empirical evidence, not merely political convenience.[26]

Q28. What perspectives should be considered in evaluating FG&E's PBR framework?

A.28 A well-designed PBR framework should incorporate economic theory, lessons learned from the successes and failures of other PBR frameworks, and the particular features of the utility itself. Economic theory serves as a guide for navigating the question of how to maximize the value of incentives, but theory by itself may fall short of providing a

---

[24] CMP operated under a price cap with a +1.00 percent X factor. By the end of the PBR term, CMP requested an 18.2 percent rate increase and ended up leaving PBR. *See* the Maine Commission Staff "Order Approving Stipulation," Docket 2013-00168, August 25, 2014.

[25] HQT operated under a revenue cap with a +0.57 percent X factor between 2019 and 2022 but has returned to cost-of-service regulation for an interim before its next MRP in order to recover necessary costs. See D-2019-060, R-4058-2018, May 16, 2019.

[26] In a recent article in *The Electricity Journal*, Kenneth Costello voiced this concern: "Political considerations are a contributing factor to preventing MRPs from operating at the highest effectiveness; such politicization of MRPs can dilute their potential benefits, especially as they relate to cost efficiency." (Costello, 2023)

viable path for any particular utility. Past PBR frameworks have demonstrated that the initial vision engineered by economic theory may prove unworkable in the face of the realities of running a utility with particular operating constraints.

For example, in its first-generation revenue cap, FortisBC electric ("FBC") adjusted its total revenue requirement using an I-X formula, in line with the theory of maximizing the utility's economic incentives. In establishing the second generation PBR plan, FBC demonstrated that the formula could not sustainably provide revenue recovery for prudently incurred capital costs over the five-year PBR term. Consequently, the British Columbia Utilities Commission determined that FBC could remove capital expenditures from the revenue cap, instead recovering all capital expenditures on a forecasted basis. After assessing past experience and analyzing the unique qualities of FBC, the company's current PBR framework better balances the incentive goals of the regulator with the company's ability to function in a prolonged rate stay-out period. This example demonstrates the value of evaluating PBR from multiple perspectives and actively promoting an evolution in the construction of PBR to ensure each framework continues to be workable.

In addition, Department precedent and the experience of PBR in Massachusetts should be considered when evaluating FG&E's PBR proposal.

3. DEPARTMENT PRECEDENT AND REGULATORY OBJECTIVES

Q29. What is the precedent in Massachusetts for utilities to operate under PBR?

A.29 The Department has decades of experience shaping policy to enhance efficiency incentives for utilities. The foundational proceeding on incentive regulation in Massachusetts was D.P.U. 94-158, which investigated the theory and implementation of incentive regulation for electric and gas utilities. Since that time, numerous docketed proceedings have taken place at the Department related to PBR, providing a sound foundation for FG&E's current PBR filing. These proceedings included relevant decisions on revenue decoupling and grid modernization.[27] In addition, the Department has issued five decisions since 2017 that have determined the PBR frameworks of the electric and gas businesses of the two largest distribution utilities in the state.

Q30. What was investigated in D.P.U. 94-158?

A.30 The impetus for D.P.U. 94-158 was to investigate alternatives to traditional cost of service regulation, which the Department recognized as deficient:

> "…the defects of traditional COS/ROR regulation are well known. The "cost plus" approach under COS/ROR regulation contributes to (1) lack of incentive for cost control, through its inherent bias favoring expenditures which can be passed through to customers; (2) inflexible and less than efficient pricing; (3) persistent cross-subsidies among service classifications; (4) inefficient allocation of resources; (5) poor asset performance; (6) risk-averse management; and (7) disincentives for innovation. COS/ROR is also a costly method of regulation, and is characterized by long lags both in reflecting and controlling actual utility operations and their costs."[28]

In that proceeding, the Department examined the criteria by which PBR proposals for electric and gas distribution companies would be evaluated. The Department found that, because incentive regulation acts as an alternative to traditional cost of service regulation, incentive proposals would be subject to the standard of review process, which requires that rates be just and reasonable.[29] Further, the Department determined that a petitioner seeking approval of an incentive regulation proposal like PBR is

---

[27] See, D.P.U. 07-50-A; D.P.U. 12-76-B; D.P.U. 15-120; D.P.U. 15-121; and D.P.U. 15-122.

[28] D.P.U. 94-158, p. 9.

[29] D.P.U. 94-158, at 52.

required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation.[30] Lastly, a well-designed incentive mechanism should provide utilities with greater incentives to reduce costs than currently exist under traditional cost of service regulation and should result in benefits to customers that are greater than would be present under current regulation.[31]

Q31. Please describe the key findings from D.P.U. 94-158.

A.31 The department found that "incentive regulation has the potential to bring real efficiency gains and reduced rates to consumers."[32] In addition, the Department established a number of factors it would weigh in evaluating incentive proposals.[33] These factors provide that a well-designed incentive proposal should: (1) comply with Department regulations, unless accompanied by a request for a specific waiver; (2) be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services; (3) not result in reductions of safety, service reliability, or existing standards of customer service; (4) not focus excessively on cost recovery issues; (5) focus on comprehensive results; (6) be designed to achieve specific, measurable results; and (7) provide a more efficient regulatory approach, thus reducing regulatory

---

[30] D.P.U. 94-158, at 57.

[31] D.P.U. 94-158, at 57.

[32] D.P.U. 94-158, p. 41.

[33] D.P.U. 94-158, at 57.

and administrative costs. These objectives mesh with the guiding principles of PBR established in other jurisdictions.[34]

Q32. What are the expected benefits associated with PBR outlined in the Department's D.P.U. 94-158 decision?

A.32 In D.P.U. 94-158, the Department described five different benefits that PBR might provide, as follows.[35]

- Improved X-efficiency: the degree to which a firm maximizes the production of goods and services that are produced with any given combination of inputs. If a firm does not operate with maximum X-efficiency, the firm and society lose the potential benefits of increased output at no additional cost.
- Allocative efficiency: the ability to provide service using the optimal combination of inputs, thereby minimizing total cost.
- Dynamic efficiency: improved ability of firms to create value with given resources, resulting from innovation, including making cost-reducing investments in areas such as research, reorganization and capital equipment that result in the provision of service at the lowest possible cost over time.
- Facilitation of new services: incentive regulation should create a positive incentive to deliver service to customers at lower prices and encourage innovative services, thereby benefiting customers and firms alike.
- Reduced administrative and regulatory costs: cost reductions can be achieved through longer ratemaking cycles and lower litigation costs.

---

[34] See, for example, Alberta Utilities Commission, "Regulated Rate Initiative – PBR Principles," AUC Bulletin 2010-20, July 15, 2010. Also see, British Columbia Utility Commission, *Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024*, Decision and Orders G-165-20 and G-166-20, June 22, 2020, p. 168.

[35] D.P.U. 94-158, p. 53.

Q33. Has the Department's criteria for evaluating PBR frameworks changed since issuing its D.P.U. 94-158 decision?

A.33 Since the Department's decision under docket D.P.U. 94-158, PBR has expanded across North America, providing opportunities to gain insight into the mechanics and potential pitfalls of price and revenue caps. Furthermore, the Department has gained substantial firsthand experience regulating utilities under PBR. The Department has not changed its criteria for evaluating PBR proposals, as outlined above, nor has the Department altered its expectations for the benefits that PBR might provide; however, the Department has since explicitly recognized the need for certain specific plan components to be included in PBR frameworks in order for the plans to be successful. For example, the Department has found that exogenous factors are necessary to protect the regulated utility from large, unexpected costs that are outside of management's control. In addition, the Department has found that separate cost recovery mechanisms may be necessary, outside of the PBR formula, to ensure that the utility is able to recover the costs of capital investment in an environment where clean energy policy is calling on the electric distribution utilities to reinforce their systems to accommodate clean energy technology. These decisions align with decisions made by regulatory authorities in other jurisdictions.[36]

Q34. What are the characteristics of the PBR frameworks recently approved by the Department for other utilities in Massachusetts?

A.34 Since 2017, the Department has approved utility PBR frameworks in five proceedings, as follows:

[36] For example, in Hawaii, utilities operating under the revenue cap have the opportunity to recover project costs through an "Exceptional Projects Recovery Mechanism." In Alberta and Ontario, distribution utilities can file for cost tracker treatment for certain eligible projects. In British Columbia, FortisBC is permitted to file for Z factor treatment of storm costs.

- NSTAR Electric d/b/a Eversource Energy (D.P.U. 17-05)
- Massachusetts Electric Company and Nantucket Electric Company d/b/a/ National Grid (D.P.U. 18-150)
- NSTAR Gas Company d/b/a Eversource Energy (D.P.U. 19-120)
- Boston Gas Company d/b/a National Grid (D.P.U. 20-120)
- NSTAR Electric d/b/a Eversource Energy (D.P.U. 22-22)

Each of these proceedings set revenue caps that adjust allowed revenues using an I-X formula through the existing revenue decoupling mechanism. As part of these decisions, the Department also approved additional PBR components for each framework, including exogenous factors, ESM, and consumer dividends. Table 1 below summarizes the key outcomes of each decision by the Department.

Table 1: Summary of Recent Massachusetts PBR Frameworks

Decision	Distribution Service	Term (Years)	Exogenous Factors	Consumer Dividend (bps)	ESM (Cust/Firm/Dead)*
D.P.U. 17-05	Electricity	5	Yes	25	75/25/200
D.P.U. 18-150	Electricity	5	Yes	40	75/25/200
D.P.U. 19-120	Natural Gas	10	Yes	15	75/25/100
D.P.U. 20-120	Natural Gas	5	Yes	30	75/25/200
D.P.U. 22-22	Electricity	5	Yes	25	75/25/100

*The first two numbers presented in this column represent the profit split between customers and the firm, while the third number represents the deadband, or ROE threshold, over which the company must share. Note that NSTAR Gas (D.P.U. 19-120) has a tiered ESM for its 10-year plan, in which profits 150 bps above the allowed ROE are shared 50/50, and profits 200 bps above the allowed ROE are shared 75/25.

Q35. Did the Department make any other important decisions in approving these PBR frameworks?

A.35 Yes. One of the current challenges for Massachusetts utilities, as well as for utilities across the continent, is the need to replace aging capital with substantial investments in new plant. For electric distribution utilities in today's operating environment, capital replacements often take the form of grid modernization programs. The Department has found PBR frameworks must consider accommodation for these investments. For example, in D.P.U. 22-22, the Department stated that:

> "[Eversource] will need significant capital investments to develop a dynamic and modern distribution network. The Department anticipates that the Company may identify several capital projects to achieve these objectives during the development of its electric sector modernization plans pursuant to G.L. c. 164, D.P.U. 22-22 Page 61§ 92B. The Department recognizes that required investments will go beyond the Company's grid modernization proposals approved in Second Grid Modernization Plans."

In recognizing this revenue deficiency, the Department approved a capital recovery mechanism called K-bar, which adjusts allowed revenues beyond the I-X formula. Additional capital recovery programs also exist for gas utilities in Massachusetts. A pipeline replacement program referred to the Gas Safety Enhancement Program ("GSEP") has allowed distributors to recover costs outside of the revenue requirement as adjusted by the I-X formula. These Department decisions demonstrate an understanding that the I-X formula is not a cost recovery program for particular major projects, but rather a revenue adjustment mechanism to adjust base revenues over the extended rate stay-out period of the PBR term.

Q36. Please summarize your understanding of the Department precedent on PBR since D.P.U. 94-158.

A.36 Through the five decisions summarized in Table 1, the Department has demonstrated an understanding that in order for a PBR framework to properly balance incentives with achievability, a PBR framework must be tailored to the particular regulated utility. The Department has shown that just as no two utilities are identical, PBR frameworks differ from utility to utility. This aligns with the perspective of regulators across North America. For example, the Alberta Utilities Commission listed as one of its guiding principles of PBR that "a PBR plan should recognize the unique circumstances of each regulated firm."[37] In Ontario, where dozens of electric distribution utilities operate under PBR, each firm can elect one of several options from a menu of different PBR approaches, allowing each firm to determine its own unique plan.[38] Recognition by the Department that PBR is not a one-size-fits-all regulatory solution is important as it considers the first-generation plan for a small utility that differs substantially in size and system density from National Grid and Eversource.

In addition, the Department appears to have recognized that PBR frameworks should evolve as business conditions change over time. Once the term for an established PBR plan ends, stakeholders should once again engage the question of how best to continue under PBR, or whether PBR should continue. The Department's recent decision under D.P.U. 22-22 provides an example of how it has re-evaluated the components of a utility's plan between PBR generations. Specifically, the Department deviated from prior decisions by allowing NSTAR Electric to implement a formulaic capital supplement known as K-bar so that it could manage to continue operating under an extended rate stay-out period, while meeting the substantial capital investment requirements of the system. This decision demonstrates an understanding that a PBR framework is not immutable—rather, it can be adjusted and improved over time. Again, this idea aligns with the practice of PBR in other jurisdictions. PBR frameworks in British Columbia, Alberta, and Ontario have evolved substantially over time as the

[37] AUC Decision 2012-237, September 12, 2012, at 7.

[38] "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," *Ontario Energy Board*, October 18, 2012, at 13.

industry has changed and as stakeholders learned which incentive mechanisms work well and which do not.

Ultimately, the lynchpin of any PBR framework should be a concerted effort to improve upon traditional regulation with achievable incentives that benefit consumers, the regulator, and the utility. The Department explicitly stated this goal in D.P.U. 94-158 and has since worked to advance this effort.

4. ELEMENTS OF THE PBR FRAMEWORK

4.1. Overview of the Company's PBR Proposal

Q37. Please provide an overview of the elements of FG&E's PBR proposal.

A.37 Similar to the National Grid and Eversource gas and electric utility affiliates currently operating under PBR in Massachusetts, FG&E proposes to be regulated under a revenue cap with a five-year rate stay-out period beginning July 1, 2024. The proposed revenue cap will adjust allowed revenues each year for the Electric and Gas Divisions by the prior year's rate of inflation, minus a productivity offset. For the Electric Division only, the Company proposes to collect additional revenues for capital investments using a capital supplement known as K-bar, which is currently approved for NSTAR Electric.

In addition, the Company proposes a substantial implicit consumer dividend, which provides immediate financial benefits to customers in the form of a downward adjustment to the allowed revenue requirement each year. Other elements of FG&E's PBR framework include exogenous factors that allow revenue recovery for costs beyond the control of the utility and an ESM that returns a portion of revenues to consumers if earnings exceed a certain threshold. Table 2, below, summarizes FG&E's proposed PBR framework, noting the differences between the revenue cap structure for FG&E's

Electric and Gas Divisions. These elements of the PBR framework are addressed in greater detail in each respective section below.

Table 2: Summary of FG&E's PBR Proposal

PBR Component	FG&E Electric Division	FG&E Gas Division
Indexed Cap	Revenue Cap	Revenue-per-Customer Cap
Inflation Measure	GDP-PI	GDP-PI
X Factor	0.00%	0.00%
Capital Supplement	K-Bar	(None)
Z factor	Yes	Yes
Earnings-Sharing Mechanism	Yes	Yes
Re-Opener	ROE Below 6.50% in 1yr; Or, Below 7.00% in 2 consecutive years	ROE Below 6.50% in 1yr; Or, Below 7.00% in 2 consecutive years
Implicit Consumer Dividend	1.45%	1.30%
PBR Term	5 years	5 years

4.2. Revenue Cap

Q38. Would you please describe the generic revenue cap PBR formula?

A.38 In a revenue cap, allowed revenue growth is capped by the PBR index:

$$\%\Delta R_t = (I_t - X) \quad (6)$$

The measurement of X is based on a measure of TFP as described below. Each year under a revenue cap, the firm is permitted to adjust its revenue requirement according to this formula. As with other PBR cap formulas, the revenue cap provides the firm with strong incentives for more efficient behavior.

Q39. How does the revenue cap coordinate with revenue decoupling?

A.39 From an administrative perspective, revenue caps work well for companies that operate under revenue decoupling because revenue-decoupling mechanisms provide a built-in way to adjust revenues each year, consistent with the purpose of the revenue cap. Companies with revenue decoupling that operate under a revenue cap simply adjust the allowed revenue for a given year by the revenue cap formula, as defined by the PBR framework.

Q40. What is the design of FG&E's proposed revenue cap for the electric distribution portion of the business?

A.40 As described above, a revenue cap limits the annual increase in allowed revenue for a firm using a pre-defined mechanism. FG&E proposes to employ an I-X formula to set its revenue cap, where I is a measure of inflation and X is a measure of expected productivity growth. In addition, FG&E proposes to include a Z factor (Z_t), which recovers exogenous costs beyond the control of the company's management. FG&E also proposes to include a formulaic capital supplement (K_t), also known as K-bar, which is calculated using the company's historical trend of capital expenditures. Lastly, depending on the company's achieved ROE in a given year, FG&E's proposed revenue cap will adjust its revenue requirement according to the design of its ESM (ESM_t). Thus, FG&E's proposed revenue cap for the electric distribution portion of the business is described by the following formula:

$$Revenue_t = \left(Revenue_{t-1} * (1 + I_t - X - CD)\right) + Z_t + K_t + ESM_t \qquad (7)$$

Where $Revenue_t$ represents current year allowed revenues and $Revenue_{t-1}$ represents the prior year's allowed revenues. I describe the details of each component of this formula below.

Q41. What is the design of FG&E's proposed revenue cap for the Gas Division?

A.41 FG&E's proposed revenue cap for the Gas Division aligns closely with the proposed formula for the Electric Division described above, with two differences. First, the Company is not requesting a K-bar capital supplement for the Gas Division. Second, I understand that the proposed gas revenue cap contains a decoupling mechanism that allows for revenue growth associated with new customers, making it a revenue-per-customer cap. Thus, the gas utility revenue cap is described by the following formula:

$$\frac{Revenue_t}{Customer_t} = \left(\frac{Revenue_{t-1}}{Customer_{t-1}} * (1 + I_t - X - CD)\right) + Z_t + ESM_t \qquad (8)$$

The details of these components are described below.

4.3. Inflation

Q42. What are the options available for determining the I factor?

A.42 The I factor is intended to be a measure of inflation that is external to the firm. There are two basic approaches to its determination. The first approach uses some measure of industry input inflation as the I factor. This approach was used in the U.S. railroad industry but is not very common in utility incentive regulation plans in the United States. The second approach is to use a measure of economy-wide output inflation, such as the Gross Domestic Product Price Index ("GDP-PI"). This approach is the most common in U.S. incentive regulation plans, including the telecommunication and utilities industries, and has been used in previous incentive regulation plans in Massachusetts.[39] GDP-PI is the widest measure of economy-wide output inflation published by the U.S. government. FG&E proposes to use GDP-PI to adjust revenues for both gas and electric operations.

4.4. Productivity Offset (X Factor)

Q43. What is the purpose of the productivity offset, or X factor?

A.43 Along with inflation, the X factor adjusts an indexed cap on an annual basis so that the firm is allowed to set prices in a way that mimics a competitive market. If the indexed

---

[39] For example, <u>see</u>, D.P.U. 96-50 (Phase I), November 29, 1996, p. 273; D.T.E. 01-56, January 31, 2002, p. 20; D.T.E. 03-40, October 31, 2003, p. 473; and D.T.E. 05-27, November 30, 2005, p. 384.

cap was set equal to the rate of inflation with no X factor, the firm would be adjusting prices according to the change in input prices, with no consideration for the change in input *quantities* or output quantities. If input quantities increase, for example because of major, necessary capital projects, while the input prices associated with installing that capital remain flat, the indexed cap plan would not allow for rate adjustments needed to cover the increased inputs put in place by the firm. This is particularly applicable to electric distribution utilities, which have faced growing input quantity needs in recent years. The mathematical derivation of the X factor is provided in detail in Appendix 1.

Q44. What is the X factor derived for an electric distribution utility operating under a revenue cap?

A.44 In 2022, with my colleague Dr. Mark Meitzen, I submitted an electric distribution TFP study as a component of joint testimony on behalf of NSTAR Electric before the Department, in D.P.U. 22-22.[40] The electric distribution TFP and input price average in this study spanned fifteen years, from 2006 to 2020. This electric distribution study found that the empirical X factor for a revenue cap was equal to -<u>1.45 percent</u>. The findings from this study provide a reasonable approximation for the appropriate X factor for an electric distribution utility today.

Q45. What is the recommended X factor for a gas distribution utility operating under a revenue cap?

A.45 In 2020, with my colleague Dr. Mark Meitzen, I submitted a gas distribution TFP study as a component of joint testimony on behalf of National Grid before the Department, in

[40] Direct Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 22-22, January 14, 2022; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 22-22, June 10, 2022.

D.P.U. 20-120.[41] The gas distribution TFP and input price average in this study spanned fifteen years, from 2004 to 2018. This gas distribution study found that the empirical X factor for a revenue cap was equal to -1.30 percent. The findings from this study provide a reasonable approximation for the appropriate X factor for an electric distribution utility today.

Q46. Why do these studies indicate a negative X factor?

A.46 Productivity growth for the purpose of calibrating an indexed cap has declined in both the electric and gas distribution utilities in recent years. This has occurred because billable output growth measure for the purpose of calibrating an indexed cap has slowed even as the growth in inputs has increased. Inputs in the form of capital replacement, cybersecurity, and system complexity do not yield higher outputs in the form of more customers served. As long as billable output growth remains slower than input growth, TFP will be negative.

Furthermore, input *prices* for distribution utilities have grown faster than the rate of input prices in the broader economy. For example, the Handy Whitman ("HW") Index of plant input costs indicates a dramatic increase in distribution utility input prices in recent years. Between January 2022 and January 2023, distribution utility input prices increased at a rate of between 27 and 32 percent.[42] Given that distribution industry input prices are increasing faster than economy-wide prices, and that distribution industry TFP growth rates are slower than the economy as a whole, the X factor is negative.

---

[41] Direct Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, November 13, 2020; and Rebuttal Testimony of Mark E. Meitzen, Ph.D., and Nicholas A. Crowley, D.P.U. 20-120, April 23, 2021.

[42] This number can be corroborated using the Bureau of Labor Statistics publication of PPI industry group data for Electric power generation, transmission, and distribution, which increased 23.8 percent between January 2022 to 2023.

Another way to look at this phenomenon is to say: company revenues must increase faster than the rate of inflation because input costs are going up faster than billable outputs. I expect this trend may continue in the near term as inputs continue to grow with electrification.

Q47. Would you explain in more detail why input growth has exceeded output growth in recent years?

A.47 Yes. First, gas and electric distribution utility input growth has increased in recent years across the industry largely because of necessary capital investments related to replacement and grid modernization. Utilities across the United States built large portions of present-day distribution networks during the 1960s and 1970s using plant currently aging out of service. As a result, today's utilities are in the process of undertaking major capital projects to replace retired plant. At the same time, new technology aimed at improving grid efficiencies, such as Advanced Metering Infrastructure ("AMI"), have required significant investment dollars. These replacement and modernization investments have been deemed necessary by both utilities and regulators, but they do not correspond to increased *outputs* sold by the utilities. As a result, input growth has exceeded billed output growth, resulting in negative price or revenue-cap TFP growth. Specifically, the data indicates that capital inputs comprise 58 percent of TFP input growth for electric distribution utilities and 40 percent of TFP input growth for gas distribution utilities. The negative TFP growth value merely reflects the reality that utilities across the industry currently face costs that must be recovered through rates. In the past, industry TFP growth has been more positive, and may again become more positive after this current period of replacement and modernization ends.

Q48. Does negative TFP growth occur in other industries?

A.48 Yes. According to BLS data on TFP growth, capital intensive industries like air and truck transportation have both faced negative TFP growth over the past fifteen years.[43] Additionally, Statistics Canada data indicates that Canadian utility TFP growth has been substantially negative over the most recent fifteen-year period, with an average growth rate of -1.1 percent.[44] These trends occur periodically but may reverse as capital cycles ramp down.

Q49. Is customer growth always the appropriate output measure for measuring TFP growth?

A.49 No. Customer growth serves as the appropriate output measure when the X factor calibrates a revenue-per-customer cap, as is the case in this PBR proposal, but other measures of TFP growth also exist. For example, price cap X factors should rely on TFP growth rates that use output variables reflecting the prices faced by customers. This is because, under a price cap, the utility collects revenue based on all billed outputs. These outputs include volumes (kWh for electric companies, therms for gas utilities) and demand values (kW, for example). When estimating pure efficiency measures of TFP growth, all existing utility outputs—not just billed outputs—would be included in the TFP growth rate calculation. However, pure efficiency measures of TFP are not useful for setting indexed caps.

---

[43] See here: https://www.bls.gov/productivity/tables/

[44] See here: https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3610020801

Q50. Do you expect the X factor to remain negative in future years?

A.50 Although it is difficult to predict how long current input and output growth trends will prevail, it is likely that the recent period of capital replacement and modernization will eventually slow. Concurrently, if electrification forecasts prove accurate, electric utility sales volumes will increase, perhaps dramatically – a direct function of the capital investment that will be put into the systems to support electrification. All else equal, under a price cap framework, the combination of slowing input growth and increasing output growth would lead to positive TFP growth, and therefore -- a positive X factor. This would mean that customer rates would grow more slowly than inflation under a PBR framework based on empirical TFP analysis.

Q51. Does the fact that the X factor is negative undermine the incentives for the regulated firm to behave efficiently?

A.51 No. Incentive regulation provides the utility the flexibility to pursue cost-reduction initiatives and to keep the benefit of those reductions until rates are reset in the future. This is true regardless of whether the *X* factor is positive or negative as the efficiency incentives derive from breaking the linkage between revenues and costs. In other words, what is critical is that the *X* factor be invariant (exogenous) to the individual firm's actual performance. For example, although target revenues are determined under a revenue cap, the firm still has the incentive to minimize its costs—<u>i.e.</u>, the profit motive is fully operative—and this incentive is not dependent on the magnitude or sign of the *X* factor.[45] The *X* factor simply reflects the competitive benchmark that is expected to

[45] For example, suppose there is an economy-wide shock (e.g., an oil price hike) that results in a contraction of the supply curve in a competitive market, ceteris paribus. The interaction of supply and demand will cause prices in a competitive market to rise, which is the competitive market counterpart to a negative *X* factor in a regulated setting. The incentives for each individual competitive firm to minimize costs and be as efficient as possible are not altered by the fact that prices in this given period have increased rather than decreased.

prevail over the term of the PBR plan. In the case of a negative *X* factor, the cap that the firm faces will be higher over time, all other factors held constant.

The measure of TFP for the purpose of calibrating a revenue cap X factor is not equivalent to a pure efficiency measure of TFP. This salient fact and the fact that this measure of TFP can legitimately be negative were addressed in a recent article in *The Electricity Journal*:

> There is no theorem in economics that states that productivity growth for an industry must be positive. In fact, many industries exhibit negative productivity growth over prolonged periods. Whether TFP growth or the X factor is positive or negative is not a theoretical matter, but an empirical one. The fact that electric distribution industry TFP growth has turned negative in more recent time periods is not dispositive of the industry becoming less efficient. Two features of measured TFP for electric distribution industry – how output is specified for an indexed PBR plan and the relationship between measured output growth and capital input growth – provide reasons why negative TFP growth does not necessarily imply that any individual utility or the industry is becoming less productive. …
>
> The correct specification of output growth for a TFP study depends on the purpose of the study: the output measure will differ depending on whether the purpose is to assess efficiency or to calibrate a price or revenue cap. When the purpose of TFP measurement is for use in calibrating the X factor for a price or revenue cap, the output measure should reflect the elements of output associated with price or revenue generation – i.e., billed output. This is likely not the output that would be used in an efficiency measure of TFP since it would include only those aspects of output produced by the firm or industry that are explicitly related to price or revenue generation subject to the cap. In most cases, billed output would be a proper subset of the total output produced. … In addition, the weighting of the various elements of output into a total output index differ between an efficiency measure of TFP and TFP used in a price or revenue cap. …
>
> In our previous work, we have found negative electric distribution industry TFP growth is largely due to the relatively recent combination of high capital input growth (the largest component of electric distribution total input) and slowing billed output growth. This finding is not unique to our analyses. … Moreover, the conditions under which service is provided today differ markedly from historical benchmarks, exacerbating the divergence between investment growth and billable

> output growth. This is the case because the environment in which the utilities provide service is far more challenging today than it was historically. For example, providing security in today's environment means protecting against cyber threats and drone attacks. This contrasts sharply with yesteryear's security that may have required only a night watchman and a chain-link fence. Distributed generation requires costly infrastructure investments to allow wind/solar generators to interconnect with the distribution system. Similarly, other "grid mod" investments for which there are no explicit charges to consumers, such as vehicle charging investments, contribute to the imbalance between input and output growth. All these activities require more intensive use of inputs without generating any corresponding increase in billable outputs for the electric distribution companies. This certainly does not imply that utilities are becoming less efficient.[46]

Q52. Why is it reasonable to expect that the X factor found in each of these prior proceedings remains relevant for FG&E in its current proposal?

A.52 There is one more year of data available since the TFP study filed on behalf of NSTAR Electric in D.P.U. 22-22, and three more years are available since the TFP study filed on behalf of National Grid (gas), D.P.U. 20-120. Because these studies used a 15-year average, the addition of one year or three years of data is unlikely to substantially change the TFP and input price averages. For example, the TFP study filed on behalf of NSTAR Gas Company in D.P.U. 19-120 determined an X factor of -1.18 percent.[47] The following year, the TFP study filed on behalf of National Grid (gas) determined an X factor value that was more negative, but only by 12 basis points.[48] Furthermore, a TFP study filed on behalf of Enbridge Gas Distribution in December 2022 recommended an X factor of -1.35 percent, only five basis points off the -1.30 percent recommended on

---

[46] Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal,* 31 (2018), p. 44.

[47] D.P.U. 19-120, at 84.

[48] D.P.U. 20-120, at 83.

behalf of National Grid (gas) in 2020.[49] Averaging growth rates over fifteen years provides a buffer that smooths any one-year anomalies.

Q53. What are the consequences if the X factor does not match the empirical findings of a TFP study?

A.53 For a firm operating under a revenue cap, if the X factor is set too low (for example, too negative), revenues may be allowed to increase at a faster rate than is needed to provide a reasonable opportunity to recover operating costs. In other words, customers will pay more through rates than is needed by the firm to meet its cost to serve. If the X factor is set too high (in this case, a zero or positive X factor would be considered "too high"), the firm will not have a reasonable opportunity to recover its prudently incurred operating costs. This could have implications for service quality and financial stability in the form of increased credit risk, ultimately leading to a higher cost of capital for the firm. In extreme cases, a X factor set too high could force the company to exit the revenue cap altogether. For this reason, in cases where it is politically convenient to eschew an empirical X factor for a more restrictive indexed cap, the utility will likely require additional supplements to meet its costs, or PBR will not serve as a workable regulatory framework under the current operating environment.

Q54. Is FG&E's proposed X factor of zero reasonable?

A.54 FG&E is proposing an X factor of zero, in line with the X factor recently proposed by Eversource in D.P.U. 22-22, to be implemented in conjunction with the K-bar. Set at zero, the Company's proposed X factor is between 130 basis points and 145 basis points more positive than the empirical evidence suggests, which means that FG&E will be

[49] Incentive Rate-Setting Mechanism, Exhibit 10, EB-2022-0200, filed October 10, 2022.

taking on higher risk of revenue shortfalls under the proposed PBR framework. However, the reasonableness and feasibility of a proposed X factor needs to be considered in light of FG&E's entire proposed PBR framework. Other aspects of the plan, such as the K-bar mechanism and an explicit Consumer Dividend of 0.00 percent will contribute to the possibility that this X factor may be workable for the Company, despite being significantly more restrictive than industry trends suggest.

4.5. Capital Supplement (K-Bar)/Electric Division

Q55. What is the company's proposed capital supplement for the Electric Division?

A.55 FG&E proposes to recover supplemental revenue for the electric distribution portion of the business through a capital recovery mechanism by the name of "K-bar." Under the mechanism, supplemental K-bar revenues equal the difference between historical trend capital expenditures and the actual revenues obtained under the I-X formula. FG&E does not propose to include a K-bar capital supplement for the gas portion of its business.

Q56. What is the history of the K-bar mechanism?

A.56 K-bar originated in Alberta, where distribution utilities operate under a price cap. The initial idea behind K-bar came from a paper that proposed a forecasted capital approach, under which utilities would forecast their capital spending over the five-year PBR term, and then recover the difference between the forecast and actual revenues obtained under the I-X formula.[50] The AUC adjusted this proposed approach by setting revenue recovery with the historically driven formula now known as K-bar, rather than relying

[50] "Sappington, David and Weisman, Dennis, Assessing the Treatment of Capital Expenditures in Performance-Based Regulation Plans," September 1, 2015.

on a forecast from each utility. The Alberta distributors began using this revenue adjustment mechanism in the second generation PBR framework, after a capital tracker approach in the first generation generated an excessive regulatory burden for both the companies and the Alberta Utilities Commission ("AUC").[51] The goal of K-bar was to apply a formulaic approach to supplemental capital in order to simplify the capital recovery process relative to capital trackers.[52] In 2022, the Department approved Eversource's proposed K-bar mechanism.[53]

Q57. Why does the Company need a capital supplement as a component of its PBR framework for the Electric Division?

A.57 FG&E proposes to operate under a five-year revenue cap adjusted by an I-X formula, with an X factor equal to zero. As described above, previously accepted industry TFP studies indicate that the empirical X factor equals -1.45 percent and -1.30 percent for electric distribution and gas distribution, respectively. These negative X factors reflect input growth in both industries, which give rise to revenue needs that are expected to grow faster than the rate of economy-wide inflation. Based on these studies, a revenue cap with a zero X factor, as proposed by FG&E, would not be expected to provide the company with sufficient revenue support to make the PBR work over an extended time period for the stay-out. The Company has also outlined significant capital investment needs that will exceed the rate of GDP-PI inflation over the five-year PBR term.[54]

Q58. How is K-bar calculated?

[51] AUC 20414-D01-2016, December 16, 2016, at 7.

[52] Capital tracking mechanisms require a "mini rate case" each year in order to justify costs.

[53] D.P.U. 22-22, at 66.

[54] See Exhibit RBH-1, Testimony of Robert Hevert.

A.58 K-bar is calculated as follows:

i. Step 1: Calculate the revenue requirement that is recovered in the base rates under the I-X mechanism for the first year of the PBR term.

ii. Step 2: Calculate the notional revenue requirement for capital expenditures in the first year of the PBR term.

- The utility obtains capital additions for each of the past five years.
- Inflate each of the capital additions to current dollars using the approved I-X formula, with the approved I factor for each year and the approved X factor for the prior generation PBR plan.
- Using the inflated capital additions, calculate the average K-bar capital additions over the historical five-year period.
- Inflate the average K-bar capital additions to the current year using the new approved I-X formula.
- Calculate the amount of K-bar capital cost incurred for the current year, based on the current year capital additions from the prior sub-step.

iii. Step 3: Calculate the base K-bar.

- Calculate the difference between the current year K-bar capital-related revenue requirement required on a projected basis (from Step 2) and the current year K-bar capital-related revenue requirement recovered in the base rates (from Step 1). The result is the capital funding shortfall or surplus amount for the current year.

Q59. How does K-bar fit into the broader PBR framework?

A.59 As shown in equation (4), K-bar is an element of the formula used to obtain annual revenues under FG&E's revenue cap. After calculating the K-bar revenues for a given year, the value obtained will be added to the total revenue requirement reported in FG&E's annual filing. Mechanically, this will work in the same way that exogenous factors or ESM adjustments are added to the revenue requirement for a given year.

Q60. Does K-bar align with the Department's regulatory objectives and regulatory precedent?

A.60 Yes. K-bar complies with Department regulations and precedent, as it will be implemented in the same manner as Eversource's current implementation. This mechanism is designed to provide incentives to FG&E that will improve the provision of monopoly services and will not result in reductions of safety, service reliability, or existing standards of customer service. On the contrary, for capital cost recovery, FG&E will be better able to provide service to customers both over the PBR term and in the long run as it makes necessary capital investments. Because K-bar takes a formulaic approach to capital recovery, FG&E's revenues under the mechanism will not focus excessively on cost recovery—instead, the mechanism will enable FG&E to recover revenues in a streamlined regulatory environment that will reduce administrative costs relative to the cost-of-service alternative. K-bar provides a simple addition to FG&E's annual recovery adjustment, as shown in equation (4).

4.6. Exogenous Factors (Z Factor)

Q61. What is a Z factor?

A.61 A Z factor is ordinarily included in a PBR plan to provide for exogenous events. The Z factor allows for an adjustment to a company's rates to account for a significant financial impact (either positive or negative) of an event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula.

Q62. What is the Department precedent for including exogenous factors in a utility's PBR framework?

A.62 The Department has recognized that there may be exogenous costs, both positive and negative, that are beyond the control of a company and, because the company is subject to a stay-out provision, they may be appropriate to recover (or return) through the PBR mechanism.[55] The Department has defined exogenous costs as positive or negative cost changes that are beyond a company's control and are not reflected in the GDP-PI.[56] The Department has listed examples of Z factors, including incremental costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry.[57] Z factors often include a materiality threshold, under which the company must absorb the costs with no recourse. In Massachusetts, this value equals the product of 0.001253 and the Company's total operating revenues in the test year.

Q63. Does FG&E's Z factor proposal align with Department precedent?

A.63 Yes. The Company has proposed a Z factor in line with Z factors approved by the Department in prior PBR framework decisions.[58] FG&E proposes to recover exogenous costs that exceed a threshold value of $110,000 for the electric division and $60,000 for the gas division in 2024, as discussed in the testimony of Company Witness Robert Hevert. This value exceeds the minimum threshold value described above. After 2024, the materiality threshold will be updated by the change in the inflation factor.

4.7. Earnings Sharing Mechanism ("ESM")

Q64. What is an ESM?

A.64 An ESM provides a means for the utility to share in the over- and under-recovery of revenues over the course of the PBR term. For example, under an ESM, the company

---

[55] D.P.U. 94-158, at 62.

[56] D.P.U. 94-50, at 172-173.

[57] D.P.U. 96-50 (Phase I) at 291; D.P.U. 94-50, at 173.

[58] See, for example, Boston Gas Company d/b/a National Grid, D.P.U. 20-120, at 96, fn.60 13 (2021).

will return a portion of its revenues to customers in the event that the company exceeds its allowed rate of return by a certain amount, known as a deadband. Likewise, if the company fails to achieve its allowed rate of return below a predetermined deadband, the company is allowed to collect a portion of its revenue shortfall from customers. An ESM can be designed to have different deadband thresholds and different sharing proportions. Massachusetts utilities currently operate with an ESM that returns to customers 75 percent of revenues above the deadband, while the company keeps 25 percent.

Q65. Please describe FG&E's proposed ESM.

A.65 FG&E proposes an ESM consistent with the Department's prior decisions, with the following parameters: sharing with customers 75.00 percent of earnings above a 100-basis point threshold above the authorized Return on Equity, allowing the Company to retain 25.00 percent of those surplus earnings. The proposed ESM does not incorporate earnings deficits, which means FG&E's customers do not face any price risk if FG&E falls below its target return.

Q66. Does this align with the Department's regulatory objectives and regulatory precedent?

A.66 The ESM proposed by FG&E aligns with Department precedent. Table 1 demonstrates that utilities currently operating in Massachusetts have the same ESM structure. There is some controversy over whether ESMs align with the broader efficiency goals of PBR because ESMs provide companies with an incentive to operate within the deadband, possibly detracting from efforts to fully realize efficiency gains. For this reason, an ESM with a wide deadband would have stronger efficiency properties than an ESM with a small deadband, as the company would have a greater incentive to achieve efficiency improvements.

4.8. Re-Opener

Q67. Could you please explain the term re-opener, and why it is used in PBR frameworks?

A.67 PBR plans are typically characterized by a longer period of time between traditional revenue requirement applications for the utility under the plan. This time between "rebasing" results in a prolonged separation of costs and revenues, providing the utility with enhanced efficiency incentives but also enhanced risk. The I-X formula provides some attrition relief for utilities over the rate-stay-out period, but because costs and revenues are separated over the PBR term by design, sufficient cost recovery only persists if the utility experiences stable cost escalation in line with the formula. Since the automatic nature of the I-X formula does not adjust annual revenues for sustained changes in utility costs in the comprehensive manner that rate applications adjust revenues, a utility operating under PBR could potentially experience earnings that are dramatically higher or lower than the amount provided under the I-X formula. This is particularly true if no earnings-sharing mechanism is in place because ESMs share the results of a deviation from the utility's allowed rate of return. To protect against an untenable divergence of costs and collected revenues, PBR plans include "re-openers," or mechanisms that allow for review of the regulated entity's PBR plan during the PBR term and potential relief in the form of adjustments to the PBR plan or exiting the plan completely in the event certain predefined conditions occur. The process varies slightly by jurisdiction but generally begins with a triggering event, followed by a regulatory proceeding to determine whether the PBR plan requires changes. A triggering event typically takes the form of a deviation of actual return on equity ("ROE") from allowed ROE. The review that follows from a re-opener triggering event may or may not lead to changes to the PBR framework.

Q68. What other jurisdictions use re-openers as a component of utility PBR frameworks?

A.68 All jurisdictions in North America that have utilities operating under revenue caps or price caps, outside of Massachusetts, incorporate some form of re-opener into the established PBR framework. This includes Hawaii, British Columbia, Alberta, and Ontario. The triggering thresholds in each of these jurisdictions differs, but generally corresponds to a deviation of realized ROE and authorized ROE of a predetermined magnitude, stated in basis points. The thresholds vary from 150 basis points to 500 basis points above or below the allowed ROE.

Q69. What are the parameters of FG&E's proposed re-opener?

A.69 FG&E proposes a re-opener provision in its PBR framework that will trigger a review of its PBR plan if realized ROE falls below 6.50 percent in any single calendar year beginning with 2025 or below 7.00 percent for two consecutive calendar years. The re-opener trigger will be assessed as part of FG&E's annual PBR filing, much like the ESM test. This provision will initiate a proceeding to determine whether aspects of the PBR plan must be adjusted. This proposal is reasonable and aligns with re-opener provisions in every other jurisdiction operating under indexed cap regulation.

4.9. PBR Term

Q70. What is FG&E's proposed revenue cap term, and how does this align with Massachusetts precedent?

A.70 FG&E proposes a revenue cap term of five years. In prior proceedings, the Department has found that a well-designed PBR should be of sufficient duration to give the plan enough time to achieve its goals and to provide utilities with the appropriate economic incentives and certainty to follow through with medium- and long-term strategic business decisions.[59] In addition, the Department has stated that one benefit of incentive regulation is a reduction in regulatory and administrative costs.[60]

4.10. Consumer Dividend

Q71. What is a consumer dividend in the context of a revenue cap?

A.71 As shown in Equation (4), a consumer dividend is an additional element of the PBR formula that adjusts the firm's allowed revenues on an annual basis. In particular, a consumer dividend is a percentage value that offsets inflation, slowing allowed revenue growth each year, thereby provide customers with immediate benefits over the PBR term. The rationale behind the consumer dividend, from the perspective of the Department, is that the consumer dividend reflects the regulated firm's expected future gains in productivity resulting from the move from cost-of-service to incentive regulation.[61] Note that, in other jurisdictions, the consumer dividend is often called a "stretch factor."

---

[59] D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 66; D.P.U. 94-50, at 272.

[60] D.P.U. 17-05, at 402; D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 64.

[61] D.P.U. 96-50 (Phase I) at 165-166, 280.

Q72. What is your proposed consumer dividend for FG&E?

A.72 The effective consumer dividend for the utility's gas operations equals 1.30 percent, which is the difference between FG&E's proposed zero X factor and the empirical X factor found in the most recent TFP growth studies of the gas distribution utility industry. Similarly, the effective consumer dividend for FG&E's electricity distribution operations is at least +1.45 percent. FG&E's electricity effective consumer dividend is in fact even larger than 1.45 percent because FG&E proposes to operate under a revenue cap with a per-customer decoupling mechanism (or a revenue-per-customer cap). Thus, the PBR formula for FG&E employs an X factor of zero that reflects a sizable consumer dividend, such that no additional consumer dividend is recommended for either the Gas or Electric Divisions.

Q73. What is the basis for this recommendation?

A.73 As in other jurisdictions, the choice of setting a consumer dividend for utilities in Massachusetts requires informed judgement. The information supporting a particular consumer dividend takes the form of regulatory precedent, cost benchmarking analysis, and an analysis of the PBR framework as a whole. I discuss each of these three pillars below.

Q74. How does Department precedent inform the recommended consumer dividend?

A.74 The Department has found that a consumer dividend represents a tangible ratepayer benefit within PBR frameworks.[62] FG&E's effective consumer dividend meets the broadly recognized PBR objective to share efficiency gains between the company and its customers. As shown in Table 1, the Department has accepted five PBR frameworks

---

[62] D.P.U. 18-150, at 60-61; D.P.U. 17-05, at 395.

since 2017 with consumer dividends ranging from 0.15 to 0.40. Many of these consumer dividends correspond to revenue caps with empirical, negative X factors, which means that the revenue cap adjustment upward in most past proceedings was significantly larger—as many as 145 basis points larger—than the revenue cap proposed by FG&E. Thus, FG&E's *additional* consumer dividend of 0.00 percent, coupled with a zero X factor, is among the highest consumer dividends proposed in Massachusetts in recent years.

In addition, in accordance with Department precedent, I conducted a benchmarking analysis to support the consumer dividend recommendation.

Q75. What information does a benchmarking study provide that is relevant to setting the consumer dividend?

A.75 A cost benchmarking study provides a means of understanding a particular company's cost experience by comparing the costs of its operations to the costs experienced by other utilities in the same industry. This information is valuable in the context of designing a PBR framework because it can inform assumptions about what efficiency improvements might be expected under a more high-powered regulatory construct. If a utility under cost-of-service exhibits less efficient cost control relative to its peers, the regulator may assume that the company has the ability to find some efficiency gains upon switching to PBR. A consumer dividend gives these cost efficiency gains to customers in the form of a more restrictive revenue cap. Conversely, a company that demonstrates superior cost efficiency relative to its peers would be unlikely to find a substantial means of reducing costs, as it already operates at a low cost. Thus, the regulator would assign a lower consumer dividend to a cost-efficient firm. In other words, a "less cost efficient" company would face a higher consumer dividend than a "more cost efficient" company, where the cost efficiency is obtained through a benchmarking analysis.

Q76. What methods did you use to benchmark FG&E's unit costs against peer companies?

A.76 I have performed separate cost benchmarking analyses of FG&E's electric and gas operations. For data reasons, time periods covered by the benchmarking studies differ between electric and gas operations. This is because gas data is not freely available in an aggregated format for natural gas distribution companies in the United States.[63] Nevertheless, I used the same methodological approach for benchmarking both the gas and electric operations with the data that was available. I have performed a "unit cost" benchmarking approach akin to those filed in prior PBR proceedings. This involves comparing FG&E's unit costs against a national sample, a regional sample, and a specifically selected sample of peer companies. I also performed an additional econometric analysis to try to better control for the factors driving cost differences between FG&E and the distribution industry. A full benchmarking study report is provided in Appendix 2. The accompanying workpapers are provided in Exhibit Unitil-NAC-3.

Q77. What are the findings of the unit cost benchmarking analysis for FG&E's electric operations?

A.77 The benchmarking analysis for FG&E's electric operations produces mixed results. Under the unit-cost benchmarking approach in 2021, FG&E experiences higher costs than 63 electricity distributors out of 70 electric distributors nationally; higher costs than 16 out of 17 in the Northeast region; and higher costs than 3 out of 5 among a set of

---

[63] Aggregated gas data cannot be obtained without an expensive subscription to S&P Global Market Intelligence.

similar peers. These findings suggest that FG&E faces higher costs than most companies, though similar costs compared to other small companies.

It is important to recognize that this kind of analysis has major limitations. A comparison approach to benchmarking does not control for any of the drivers that give rise to these cost differences. For example, until I added additional companies to our database for this analysis, FG&E was a much smaller utility than any other company in our data sample. FG&E served 30,460 electricity distribution customers in 2021, whereas the next smallest company in the sample served more than four times as many customers (Otter Tail Corporation, 133,943 customers) and the national average was 37 times larger (1.15 million customers). To the extent that electric distribution companies face economies of scale, FG&E's small size disadvantage will reduce its cost efficiency relative to its larger peers. The addition of five similarly sized peer companies mitigates this problem slightly, but a unit cost approach also does not account for other differences between utilities, of which there are many. These differences may include system density, terrain, climate, soil type, customer mix, tree cover, and the company's stage in capital replacement cycle, among others.

Q78. What are the findings of the econometric cost benchmarking analysis for FG&E's Electric Division?

A.78 Because of the limitations associated with unit cost benchmarking, I also perform an econometric benchmarking analysis. This analysis aims to control for the differences between companies using a technique called "fixed effects." Using this approach, FG&E ranks 57 out of 71 companies in the national sample and 13 out of 18 utilities in the northeast. The results indicate that FG&E's costs rose slightly faster than average over the fifteen-year sample period, but are not dramatically different from the typical company, both in the national sample and in the northeast region.

Q79. What are the findings of the unit cost benchmarking analysis for FG&E's Gas Division?

A.79 Given gas data limitations, I have used the natural gas distribution data filed in my testimony under D.P.U. 20-120 to perform the benchmarking analysis using the national and northeast sample of gas distributors. This data series ends in 2018. Although the magnitude of FG&E's cost relationships compared to the sample may vary somewhat since the 2020 filing, the truncated data series still provides benchmarking insight, as I expect the qualitative relationships to be largely unchanged in the past three years. However, to ensure some gas benchmarking results made use of data from the most recent years available, I manually collected data through 2022 for five peer companies. The unit cost benchmarking analysis indicates that FG&E experiences higher costs in 2018 than 69 out of 87 gas distributors nationally. Restricting the sample to the northeast, FG&E experiences unit costs slightly lower than the median, higher than only 13 out of 29 in the northeast region. Among a set of similar peers, FG&E has higher costs than 3 out of 5 peers. As shown in Appendix 2, FG&E's cost relationship with the group of five peer companies varies from year to year but has not changed dramatically since 2016. This unit cost approach has the same limitations with gas distribution analysis as with electricity distribution.

Q80. What are the findings of the econometric cost benchmarking analysis for FG&E's Gas Division?

A.80 The econometric approach to benchmarking FG&E's natural gas cost trends shows that FG&E ranks 44 out of 71 companies in the national sample and 9 out of 30 companies in the northeast sample. These results show that despite having higher level gas distribution costs, as recognized by the unit cost benchmarking approach, FG&E's cost growth over time aligns closely with the industry average, and somewhat better compared to companies in the northeast. In fact, FG&E's actual cost growth was 0.14 percent slower than the cost growth predicted by regression model over the fifteen-year study period.

Q81. Do the unit cost benchmarking results provided in this testimony represent management's ability to control costs?

A.81 No. The unit cost benchmarking study presented in Appendix II is not a cost efficiency study, nor is it calibrated to study a utility's opportunities for greater efficiency. The unit cost benchmarking study works off of an estimation of unit costs to provide insight into the customer rate experience between utilities in the sample. This experience does not control for factors that may explain cost differences between utilities. For various reasons, cost differences will exist between utilities even if those utilities are run (individually) with 100 percent efficiency. As a result, the unit cost benchmarking study has only minimal relevance in terms of assessing management's cost control efforts. The econometric portion of the study does control for some of the utility's cost drivers. However, even this study does not control for differences in capital growth rates across companies, which is a material factor in the unit cost benchmarking result. Capital is a substantial driver of costs for all utilities, which means that systems requiring persistent (and growing) capital investment will have lower benchmarking scores than systems that happen to reside in a less capital-intensive environment or are in a less intensive phase of the capital replacement cycle.

Q82. Do the cost benchmarking results reveal differences between utilities in the Northeast relative to utilities in other parts of the United States?

A.82 Yes. The results indicate that utilities in the Northeast region face higher costs than utilities elsewhere. In the electric econometric study, only 3 of 71 companies score in the top half of U.S. electric distribution utilities. In the gas econometric study, only 5 out of 86 companies score in the top half of U.S. gas distribution utilities. This indicates that systematic differences exist for utilities in the Northeast. These differences may relate to any number of factors, including age of capital, changing policy initiatives, and, in the case of gas distribution, the mix of pipeline assets in the ground. Indeed, when the cost growth study removes capital costs and focuses only on O&M costs, companies in the Northeast region fare better relative to the nation-wide sample. However, regional cost differences will be present even in relation to the O&M perspective due to the higher costs associated with operating in the Northeast region.

Q83. How do the other aspects of FG&E's PBR plan inform the consumer dividend recommendation?

A.83 As described above, FG&E has proposed an X factor of 0.00 percent. Given that the empirically determined X factor is substantially negative, the concession to operate under a zero X factor for both gas and utility operations means that FG&E will be operating under a highly constrained revenue cap plan. Revenues will be allowed to increase substantially slower than industry cost growth. This PBR proposal also contains no factor accommodating customer growth for FG&E's Electric Division. As a result, an *additional* implicit consumer dividend will equal the rate of electricity customer growth faced by the utility each year. Lastly, FG&E is a small utility, which may make it more difficult to find efficiency gains through economies of scale. This suggests a lower consumer dividend than what might be expected of a larger company.

Q84. How does your professional judgement inform the recommended consumer dividend?

A.84 Department precedent provides a starting point for assessing FG&E's consumer dividend, and the cost benchmarking analysis offers additional insight into potential cost efficiency improvements that might be available to FG&E under PBR. However, the PBR framework must be assessed wholistically, rather than with a narrow focus on what has been accepted in the past or how the company currently performs according to benchmarking analysis. Given all of the plan details described above, I would expect an appropriate consumer dividend for FG&E to be smaller than the proposed +1.45 to +1.30 effective consumer dividends reflected in the difference between the proposed zero X factor and the empirical X factor based on industry data. In the interest of adhering to the Department's precedent of non-negative consumer dividends, I recommend for FG&E an additional consumer dividend, beyond the proposed effective consumer dividend, of 0.00 percent.

5. FG&E'S PBR FRAMEWORK ALIGNS WITH THE DEPARTMENT'S REGULATORY OBEJCTIVES

Q85. Does FG&E's PBR proposal meet the Department's criteria for a well-designed PBR framework?

A.85 Yes. FG&E's PBR framework will comply with Department regulations, as its plan aligns with already existing PBR plans in Massachusetts. As described above, using a revenue cap set with the I-X formula, the plan has been designed to serve as a vehicle to a more competitive environment and to improve the provision of utility services. The plan will provide the necessary revenues to support the current gas and electric distribution systems, and will therefore not result in reductions of safety, service reliability, or existing standards of customer service. Because the revenue cap is set exogenously with national data, the PBR framework will not focus excessively on cost recovery issues. By adhering to a simple revenue adjustment approach that covers the firm's total revenue requirement, FG&E's proposal focuses on comprehensive results and, along with its proposed scorecard, is designed to achieve specific, measurable results. Lastly, the five-year rate stay-out period provides a more efficient regulatory approach, thus reducing regulatory and administrative costs.

Q86. Is it reasonable to expect that FG&E's proposal will achieve the benefits outlined in D.P.U. 94-158?

A.86 Yes. FG&E's PBR framework provides an incentive for the company to generate the five benefits associated with PBR, as outlined by the Department (improved X-efficiency; Allocative efficiency; Dynamic efficiency; Facilitation of new services; and Reduced Administrative and Regulatory costs).

Q87. Please explain how FG&E's proposed PBR framework promotes improved X-efficiency.

A.87 The Department defines X efficiency as the degree to which a firm maximizes the production of goods and services that are produced with any given combination of inputs. The cornerstone of FG&E's proposed PBR framework is a revenue cap formula using a measure of inflation and industry productivity, both of which are external to the Company's own costs and operations. After FG&E sets its initial rates, this formula is intended to break the direct link between the Company's costs and its allowed revenues under the PBR Plan. This will provide the Company with a profit incentive to improve its cost efficiency, which can ultimately translate into price and/or revenue reductions relative to the status quo.

Q88. Please explain how FG&E's proposed PBR framework promotes allocative efficiency.

A.88 The Department defines allocative efficiency as the ability to provide service using the optimal combination of inputs, thereby minimizing total cost. A revenue cap plan like the one proposed by FG&E introduces quasi-competitive pressures through the I-X cap, which incent the regulated utility to find cost-minimizing solutions when allocating funds to either capital or operating and maintenance costs over the PBR term. Therefore, the incentives provided by the proposed plan promote allocative efficiency that is at least as good as, if not better than, traditional cost-of-service regulation.

Q89. Please explain how FG&E's proposed PBR framework promotes dynamic efficiency.

A.89 The Department defines dynamic efficiency as the improved ability of firms to create value with given resources, resulting from innovation, including making cost-reducing investments in areas such as research, reorganization and capital equipment that result in the provision of service at the lowest possible cost over time. The proposed PBR framework promotes dynamic efficiency primarily through the extended rate-stay-out period of five years. A longer period between rate applications will allow FG&E staff to find ways to innovate, research, and reorganize, during time that would otherwise be spent focusing on regulatory filings and administrative work.

Q90. Does the proposed plan facilitate new services and reduced administrative and regulatory costs?

A.90 Yes. Under PBR, a company may have greater flexibility to provide new services to customers, since the company does not need to justify every cost as part of a revenue requirement application once it is operating under the revenue cap. The five-year rate stay-out period will also reduce administrative and regulatory costs, as staff will spend less time assembling regulatory filings.

Q91. Does FG&E's proposal differ substantially from existing PBR frameworks?

A.91 No. FG&E's proposed PBR framework aligns closely with other PBR frameworks currently operating in Massachusetts. As with most other PBR plans in Massachusetts, FG&E has proposed a five-year revenue cap that includes some common additional factors. The exogenous factor (Z factor) aligns with Department precedent in its scope and materiality threshold. The ESM matches what is currently in use by Eversource and National Grid. FG&E proposes to calculate its capital supplement, K-bar, using the same approach as Eversource. The revenue-per-customer cap applied to gas distribution services aligns with revenue cap plans in place across Canada. Considered as a whole, FG&E's proposed PBR framework will function similarly to the other Massachusetts utilities operating under PBR.

6. SUMMARY OF FINDINGS

Q92. Please summarize your testimony and analysis.

A.92 In reviewing FG&E's proposed PBR framework, I have found that the Company has developed a plan that adheres to the Department's precedent and meets the regulatory objectives of PBR. The proposed plan will provide benefits to customers in both the short term and the long term through efficiency gains by the company as it operates under a revenue cap with a consumer dividend and an ESM. For this reason, FG&E's proposed PBR framework is in the public interest and should be approved by the Department.

Q93. Does this conclude your testimony?

A.93 Yes it does.

7. APPENDIX 1: DERIVATION OF THE I-X FORMULA

The I-X formula was originally derived for use in price cap regulation. Under price cap regulation, the prices that can be charged by the regulated firm are governed by a formula that effectively limits changes in prices to some measure of inflation, adjusted for the regulated industry's ability to offset inflation with gains in productivity—i.e., the "I – X" formula sets a ceiling on price changes for services that are subject to the price cap. The price cap approach to regulation is based on the proposition that in competitive markets the prices charged for a product or service are determined by the prices of the inputs used to produce the product or service, adjusted for any productivity gains exhibited in combining those inputs to produce the product or service. This formula essentially mimics the change in average industry unit costs[64] and, thus, price changes are capped by the expected change in average industry unit costs.

The price cap formula has the general form:[65]

$$\%\Delta P = (I - X) \qquad \text{(A.1.1)}$$

Where

$\%\Delta P$ = allowed change in capped price (or index of prices)
I = inflation growth rate
X = productivity growth rate

[64] As noted above, X is a measure of expected productivity growth over the PBR terms that is external to the regulated firm and is typically representative of some industry average.

The formula is derived as follows. As demonstrated here, it is simply industry input price growth less industry TFP growth. Under competitive conditions, the growth in the revenue of the industry ($\%\Delta R_I$) is equal to the growth in its cost ($\%\Delta C_I$):

$$\%\Delta R_I = \%\Delta C_I \tag{A.1.2}$$

Because revenue equals output price times output quantity, the rate of revenue change can be decomposed into the rate of output price change ($\%\Delta P_I$) plus the rate of output quantity change ($\%\Delta Y_I$):

$$\%\Delta R_I = \%\Delta P_I + \%\Delta Y_I \tag{A.1.3}$$

Similarly, because cost equals input price times input quantity, the rate of cost change can be decomposed into the rate of input price change ($\%\Delta W_I$) plus the rate of input quantity change ($\%\Delta Q_I$):

$$\%\Delta C_I = \%\Delta W_I + \%\Delta Q_I \tag{A.1.4}$$

Combining equations (A.1.2) through (A.1.4) implies that, under competitive conditions, output prices will increase at a rate equal to input price inflation minus the rate of total factor productivity growth (defined as the change in the quantity of total output less the change in the quantity of total input, i.e., $\%\Delta Y_I$ - $\%\Delta Q_I$):

$$\%\Delta P_I = \%\Delta W_I - (\%\Delta Y_I - \%\Delta Q_I) = \%\Delta W_I - \%\Delta TFP_I \tag{A.1.5}$$

where $\%\Delta TFP_I$ represents the rate of industry total factor productivity growth. Equation (A.1.5) is simply the "I – X" cap formula where I = $\%\Delta W_I$ and X = $\%\Delta TFP_I$.

When the inflation measure is not industry input prices, but rather, an economy-wide output price measure of inflation, the derivation above must be altered to accommodate the difference in economy-wide prices and the industry input price. This works as follows:

Specifying equation (A.1.5) for the national economy, the rate of output price growth for the economy ($\%\Delta P_E$) is equal to the rate of input price growth for the economy ($\%\Delta W_E$), less total factor productivity growth for the economy ($\%\Delta TFP_E$):

$$\%\Delta P_E = \%\Delta W_E - \%\Delta TFP_E \tag{A.1.6}$$

Or, substituting GDP-PI for $\%\Delta P_E$:

$$GDP\text{-}PI = \%\Delta W_E - \%\Delta TFP_E \tag{A.1.7}$$

Or, equivalently:

$$GDP\text{-}PI = - \%\Delta W_E + \%\Delta TFP_E \tag{A.1.8}$$

Adding (A.1.8) to the right-hand side of equation (7) (<u>i.e.</u>, adding zero to equation (7)) and rearranging terms produces:

$$\%\Delta P_I = GDP\text{-}PI - [(\%\Delta TFP_I - \%\Delta TFP_E) + (\%\Delta W_E - \%\Delta W_I)] \tag{A.1.9}$$

Equation (9) indicates that the allowed rate of change of the price cap index is equal to the rate of general price inflation in the aggregate economy less an adjustment factor (the X factor), where the adjustment factor equals: (a) the difference between the targeted rate of industry total factor productivity growth and economy-wide total factor productivity growth (the "TFP differential"); and (b) the difference between the rate of economy-wide input price growth and industry input price growth (the "input price differential").[66] To summarize, when GDP-PI is used as the I factor in the price cap formula, the X factor is the sum of TFP and input price differentials:

$$X = [(\%\Delta TFP_I - \%\Delta TFP_E) + (\%\Delta W_E - \%\Delta W_I)] \qquad \text{(A.1.10)}$$

So far, the derivation has described price caps. Because FG&E proposes to operate under a revenue cap, rather than a price cap, it is instructive to see how the I-X formula differs from price cap formula under a revenue-per-customer cap.

To see this, assume the I factor is given by a measure of industry input inflation, and, first, decompose total revenue in the following way:

$$\%\Delta R_I = \%\Delta RPC_I + \%\Delta CUSTOMERS_i \qquad \text{(A.1.11)}$$

Rearranging (A.1.11):

$$\%\Delta RPC_I = \%\Delta R_I - \%\Delta CUSTOMERS_i \qquad \text{(A.1.12)}$$

From (A.1.4), we have that, under competitive conditions, the growth in the total revenue of the industry ($\%\Delta R_I$) is equal to the growth in its cost ($\%\Delta C_I$)—i.e., $\%\Delta R_I = \%\Delta C_I$ – and from (A.1.6) we have that the rate of cost change can be decomposed into the rate of input price

[66] When the (i) total factor productivity growth for the industry is the same as that for the general economy; and (ii) input price growth for the industry is the same as that for the general economy, the X factor is equal to zero. In this special case, the firm's prices would be allowed to change with the rate of inflation in the general economy.

change ($\%\Delta W_I$) plus the rate of input quantity change ($\%\Delta Q_I$)—i.e., $\%\Delta C_I = \%\Delta W_I + \%\Delta Q_I$. Substituting $\%\Delta C_I$ for $\%\Delta R_I$ in (A.1.12) yields:

$$\%\Delta RPC_I = \%\Delta C_I - \%\Delta CUSTOMERS_i \tag{A.1.13}$$

Substituting $\%\Delta W_I + \%\Delta Q_I$ for $\%\Delta C_I$:

$$\%\Delta RPC_I = \%\Delta W_I + \%\Delta Q_I - \%\Delta CUSTOMERS_i \tag{A.1.14}$$

Rearranging:

$$\%\Delta RPC_I = \%\Delta W_I - (\%\Delta CUSTOMERS_i - \%\Delta Q_I) \tag{A.1.15}$$

$$\%\Delta RPC_I = \%\Delta W_I - \%\Delta TFP'_I \tag{A.1.16}$$

Where $\%\Delta TFP'_I = \%\Delta CUSTOMERS_i - \%\Delta Q_I$, which is industry TFP growth with the growth in customers as the measure of output. Equation (A.1.16) represents a revenue per customer cap formula where the I factor is industry input price growth (i.e., $\%\Delta W_I$).

An important difference between a revenue per customer cap and a revenue cap is that a revenue cap does not typically allow revenue to change with customer growth. Therefore, an important feature of the FG&E electric division proposal is that, under a revenue cap, the company is absorbing additional customer growth through productivity improvements, or in other words, it is including an implicit stretch factor in its cap equal to the rate of customer growth.

8. APPENDIX II: COST BENCHMARKING STUDY

8.1. Introduction

Fitchburg Gas & Electric has requested that I perform a cost benchmarking study for the Electric Division and Gas Division, individually. The findings of this analysis inform my recommended consumer dividend.

Benchmarking studies provide unique value to distribution utilities. Distribution utilities effectively operate with limited competitive market pressures to incent a reduction in the relative use of inputs to control costs. Instead, incentives for cost control arise from regulatory pressure, coupled with the firm's profit motive. In traditional cost-of-service regulatory environments, economists assume utilities face weaker cost control incentives than companies in competitive markets, which means utilities may not be cost minimizing. Furthermore, utilities may not know without statistical research the extent to which they are cost minimizing. A cost benchmarking study provides a means of comparing the costs of a utility's operations to the costs of other utilities in the same industry in an attempt to discern how a particular firm's costs compare to similarly situated firms. Utilities may use this information to better understand how to gain efficiencies, set rates, or, in the case of PBR applications, establish a consumer dividend.

A consumer dividend provides customers with a share of the efficiency gains obtained through PBR. The magnitude of such efficiency gains depends, in part, on efficiency prior to the commencement of the PBR term. For example, if a firm is already highly efficient relative to its peers, further achievable gains may be smaller in magnitude. Benchmarking studies offer an approximation of a particular utility's cost efficiency, and thus can inform the recommended magnitude of a consumer dividend.

8.2. Methodology

There are two approaches to cost benchmarking for distribution utilities. One approach has come to be called "unit cost" benchmarking. This method compares the total cost per unit of output from one firm against a set of peer firms, where the peer firms could be a national sample, a regional sample, or a specific set of peers, selected based on criteria chosen by the analyst. A key drawback of this approach is that the results depend heavily on the sample of peer utilities, since the study itself merely compares average costs and does not control for firm characteristics beyond the selection of the peers. Nevertheless, the method has the benefit of simplicity and in some cases may be the best option in light of data limitations. Massachusetts companies operating under PBR have employed this method for unit cost benchmarking in prior proceedings.

The other general form of cost benchmarking is an econometric approach, which is an umbrella that contains several distinct techniques. Each technique under the econometric umbrella attempts to resolve, through regression analysis, the problem of reliance on peer companies that may have substantially different operating demands than the particular utility in question. One econometric technique is a cross-sectional regression model, which contains a set of relevant explanatory variables, across a large number of companies. This approach takes data from many companies and uses statistics to determine how the explanatory variables impact utility costs, on average. The theory behind the cross-sectional approach is that the choice of peer utilities matters less if a regression model can account for differences across firms using variables that explain the cost drivers at each company. Such variables as miles of distribution line, customer density, age of plant in service, and terrain can control for legitimate cost-related differences between firms. An additional benefit of this particular approach is that it can be performed on a single year of data if necessary. The results of the cross-sectional regression approach can be interpreted the same way as the unit cost benchmarking approach because it asks the same question: how do the company's costs compare with a set of peers? The difference between this approach and the simple unit cost approach is that the regression controls for explanatory variables driving those costs.

Through the inclusion of explanatory variables, an econometric approach may improve the accuracy of a benchmarking analysis. However, this regression technique can present a false sense of scientific certainty about a utility's cost efficiency. The cross-sectional approach assumes that the variables chosen for the model fully explain the utility's cost drivers. If a variable that drives cost is not included in the regression model, the company will appear to perform differently from the model's prediction because the model has an omitted variable bias. For example, suppose a distribution utility happens to operate in a climatological environment, facing frequent hurricanes. Every year, a hurricane destroys the distribution system, which means every year they incur massive storm costs. Compared to peers, this company might appear highly cost-inefficient if the model contains no explanatory variable associated with weather that accounts for these hurricanes. In reality, the company may be just as efficient as its peers, but experiences ongoing costs beyond its control that are not explained by the variables in the model. This same concept could be applied to a company operating in rocky terrain or an expensive regulatory environment. On the other hand, a less efficient company that happens to serve a utility-friendly region may seem more efficient than its peers if the model does not indicate the beneficial qualities of its environment. Any variable, if excluded from the regression model, may skew the results in this manner. This is the key limitation of cross-sectional regression benchmarking.

A second econometric technique does not directly measure unit costs, but instead estimates a cost *curve*—or trend in costs over time—and relies on company "fixed effects" to isolate different qualities unique to each company. The fixed effects model resolves a large portion of the company-specific variable problem of the cross-sectional approach by controlling for all time-invariant factors faced by the utility. For example, suppose a company has large unit costs, but its unit cost growth over time is consistent with the rest of the industry after accounting for observable factors like customer growth. Looking just at unit costs, one might conclude that the company is cost inefficient. However, by looking at the cost trend while controlling for fixed effects, the more likely conclusion is that the larger unit costs are a result of fixed factors, like terrain or climate, that it cannot control.

The fixed effects approach provides superior control for company specific cost drivers, but still faces the prospect of omitted variables along a time axis. While every company's specific cost drivers are fully explained by a company-level fixed effects model, differences occurring across time have no control under this approach. Time effect omissions can be mitigated to some degree by controlling for time varying effects that impact all companies in the sample—like a national recession or economic shock. But, some time-varying effects may exist that are specific to one company, which cannot be controlled in the model. For example, if a company experiences a hurricane just once, this would be a time-varying phenomenon specific to one particular service territory and would impact the benchmarking results for that company. Despite this risk, the technique provides insight worth consideration. I employ this approach and discuss the specifics of the regression in Section 8.3, below.

An additional drawback to each econometric approach is that they introduce more complexity. Regressions can give rise to arcane debates about the minutiae of model specifications and various statistical choices made by the analyst. For this reason, I present a parsimonious fixed effects regression model. The simple regression design provides a useful additional perspective on costs that improves on the simple unit cost approach.

8.2.1. Electric Distribution Utility Data

This study presents results from two benchmarking studies, a gas study and an electric study, as FG&E provides both gas and electric distribution services to customers. To perform the analysis, cost and output information is required for all utilities in the benchmarking sample, preferably over time.

The time series underlying these studies differ because of data availability. In particular, because the Federal Energy Regulatory ("FERC") collects and publishes electronic databases of annual electric distribution utility data, the electric distribution benchmarking study relies on data through 2021 for 65 U.S. utilities.[67] This data is used to determine the total cost associated with electric distribution operations, as follows:

$$\begin{aligned} Total\ Cost_{i,t} = {} & Distribution\ O\&M\ expenses_{i,t} + CA\&S\ expenses_{i,t} \\ & + Allocated\ A\&G\ expenses_{i,t} + IRP\ Capital_{i,t} \end{aligned} \qquad \text{(A.2.1)}$$

Where "Distribution O&M expenses" consist of all O&M costs associated with distribution operations, including salaries; "CA&S expenses" consist of customer accounts and sales expenses, including salaries; "Allocated A&G expenses" consist of administrative and general expenses, allocated by each utility's proportion of distribution plant in service relative to total

[67] Data from 2022 will not be widely available until late 2023.

plant in service, including salaries; and "IRP Capital" consists of the implicit rental price of capital.

Each of these data is described in detail below.

Distribution Labor

To measure distribution labor input, I base labor cost on the direct payroll distribution booked to electricity distribution operating and maintenance expenses found in the FERC Form 1 (see Figure A.2.1).

Distribution Materials

To measure distribution materials input, I base materials cost on operating and maintenance expense for distribution from FERC Form 1 less direct payroll distribution described above (see Figure A.2.1).

Customer Accounts and Sales Labor and Materials

The following FERC Form 1 accounts are used to determine customer accounts and sales expenses that are included in O&M expenses: The labor expense portion of customer accounts and sales expenses are line items in the FERC Form 1 (see Figure A.2.1).

Materials expenses for customer accounts and sales expenses are determined by the total O&M expenses for these accounts less the direct payroll distribution for these accounts (see Figure A.2.1).

Administrative and General Labor and Materials

Administrative and General ("A&G") expenses are comprised of joint and common costs that pertain to activities that span a utility's functional components—distribution, transmission and production—and are not dedicated to the distribution function. Capturing any additional distribution-related costs that may be contained in these accounts comes at the expense of relying on additional and uncertain assumptions, and there is simply no economically unique approach to determining distribution-related costs from the joint and common A&G expense accounts. Economic literature recognizes that there is not a unique, economically causal method to allocate joint and common costs.[68] Allocations of joint and common costs are arbitrary from an economic perspective because it cannot be determined what portion of a joint and common input designed to provide multiple products or services is properly ascribed to a single product or service. Accordingly, judgment is involved in any allocation of joint and common costs.

Conversely, from a regulatory perspective, a utility's distribution function is responsible for covering some portion of A&G costs. Therefore, this TFP study adopts a regulatory, non-economic apportionment principle for assigning A&G expenses to distribution. Specifically,

---

[68] For example, in the context of calculating a rate of return, Baumol, Koehn, and Willig illustrated the economic arbitrariness of joint and common cost allocations by allocating hypothetical railroad investment among three different commodities—lead, balsa wood, and precious metals—using three different, presumably reasonable, allocation methods—carloads, weight and value. The resulting investment allocations were wildly different depending on the method of allocation. The authors concluded that:

> Fully allocated cost figures and the corresponding rate of return numbers simply have zero economic content. They cannot pretend to constitute approximations to *anything*. The "reasonableness" of the basis of allocation selected makes absolutely no difference except to the success of the advocates of the figures in deluding others (and perhaps themselves) about the defensibility of the numbers. There just can be no excuse for continued use of such an essentially random or, rather, fully manipulable calculation process as a basis for vital economic decisions by regulators.
>
> William J. Baumol, Michael F. Koehn, and Robert D. Willig, "How Arbitrary is 'Arbitrary'?—or, Toward the Deserved Demise of Full Cost Allocation," *Public Utilities Fortnightly* Volume 120, Number 5, September 3, 1987, at 21 (emphasis in original).

.

the portion of joint and common A&G expenses allocated to the distribution function is determined by multiplying a firm's total A&G expenses for each year in the sample by the annual average across all firms in the sample of the percent of distribution plant relative to total plant.

The labor expense portion of A&G expenses are line items in the FERC Form 1 (see Figure A.2.1). Materials expenses for A&G expenses are determined by the total expenses for these accounts less the direct payroll distribution for these accounts (see Figure A.2.1).

Capital

Because capital is purchased in one period and used over a number of years, the price and quantity of capital input for a given year over the lifetime of a capital asset must be inferred.

The quantity of capital stock is determined by the perpetual inventory equation under the hyperbolic model of capital decay. The perpetual inventory equation constructs an end-of-year capital stock from the capital stock at the end of the previous year and the quantity of capital stock additions during the year, using a hyperbolic decay function to address efficiency losses over time. The hyperbolic model relies upon two fundamental assumptions. First, the model assumes that distribution plant-in-service consists of a collection of assets with differing service lives, represented by a truncated normal distribution with a mean equal to the average service life (L) of all assets together and a standard deviation of L/4. While some components of plant in service may reach retirement prior to 33 years and other components may reach retirement after 33 years, *on average* plant will retire at the peak of the bell curve, the average service life.

The hyperbolic model's second assumption is that, individually, electric distribution assets provide a slowly declining level of service (i.e., capital input) during the initial period of the asset's lifetime, followed by a more rapid efficiency decay in the later period of the asset's lifetime. The trend of efficiency decay is defined by the hyperbolic function has the following form, where assets that are retired at age N:

$$S_t = \frac{N - t}{N - \beta t}, t < N \tag{A.2.2}$$

Where S_t is the relative efficiency of an asset in year t and β serves as a parameter effecting rate of decay. For β, the BLS uses a parametric value of 0.75 for structures.[69] In my distribution capital input calculations, I use this same parameter.

The construction of capital stock under the hyperbolic model combines the two assumptions described above. The hyperbolic model assumes that individual assets will decay slowly at first, then more quickly as they approach retirement, and that these individual asset retirement ages follow a truncated normal distribution. When these assumptions are combined, the decay of distribution plan efficiency *on average* follows a backwards "S" shape. The cohort average efficiency decay trend reflects the hyperbolic model assumption that some plant efficiency exists beyond the average service life, since some subset of plant in fact retires after the class average retirement.

The study period begins in 2007. To estimate capital input for the year 2007, I need an end of year capital stock estimate for 2006. That in turn requires projections of investment back to 1941, since the hyperbolic model assumes asset retirements of a normal distribution of 65 years. Since existing data dates back to 1964, capital investment was estimated for the years prior.

---

69 Note that choosing a value for β equal to 1.0 would result in asset decay equivalent to OHS, where asset efficiency does not decay over the life of the asset. In this way, the OHS approach is a subset of the more generalized hyperbolic model.

Because the net book value of distribution plant is not reported in the FERC Form 1, it is estimated by taking the ratio of distribution plant in service to total electric plant in service[70], and applying it to net electric plant in service.[71] Using the variable HW to represent the Handy-Whitman index, the mathematical formula to construct the benchmark value is as follows.

$$K_{1964} = \frac{NetElectricPlantInService \cdot \left({}^{DistributionPlantInService}\!\Big/_{TotalPlantInService} \right)}{\sum_{i=1}^{20} \left[{}^{i \cdot HW_{1944+i}}\!\Big/_{\left(\sum_{i=1}^{20} i\right)} \right]} \tag{A.2.3}$$

Using this assumption and the average age and efficiency parameters described above, I can project the relative efficiency of the benchmark capital stock for the years 2007 through 2021.

Once the end-of-year capital stock is computed, the flow of capital services during a year is based on the quantity of capital stock at the end of the previous year, after accounting for the hyperbolic decay of capital inputs. To estimate the quantity of additions during the year, I divide distribution additions to plant in service by the Handy-Whitman index for distribution plant.

Price of Capital Input

The price of capital input is the implicit rental price that corresponds to the assumptions underlying the perpetual inventory equation described above. The price of capital input is based on an equilibrium relationship between the price an investor is willing to pay for an asset and

---

[70] Distribution plant in service is found in the FERC Form 1, page 205, line 75, column g. Total plant in service includes production plant in service (page 205, line 46, column g), transmission plant in service (page 205, line 58, column g), general plant in service (page 205, line 99, column g), and distribution plant in service.

[71] FERC Form 1, page 200, line 15, column c.

the after-tax expected value of services that the asset will provide over the asset's lifetime. This relationship is called the implicit rental price formula.

The implicit rental price formula under hyperbolic decay has the following mathematical representation.

$$p_t = \frac{(1-uz)}{(1-u)} \cdot \left[\sum_{i=1}^{65} \left(\frac{1+\rho}{1+r} \right)^i \delta_i \right]^{-1} HW_{t-1} \tag{A.2.4}$$

The variable u represents the corporate profits tax rate, the variable z represents the present value of tax depreciation charges on one dollar of investment in distribution plant and equipment, the variable r represents the forward-looking cost of capital, and the variable I represents the forward-looking inflation rate. The number 65 is twice the average service life, minus one, which is the range of asset lifetimes under the truncated normal distribution.

Based on tax law, we use a corporate tax rate of 35 percent for u during the years before the Tax Cuts and Jobs Act, and 21 percent for subsequent years. And we compute z using the sum-of-years digit method.

In some applications of the implicit rental price formula, the current year's cost of capital and inflation rate are used as proxies for the forward-looking rates. This can produce substantial year-to-year variation in the implicit rental price, making it difficult to determine the trend in input price growth. An alternative that has been previously employed and produces a more stable input price series is to assume that investor's forward looking real rate of return (cost of capital less the inflation rate) is constant through time.[72] We apply this alternative by computing the average cost of capital rate and the average inflation rate over the 2006-2020 period. The average cost of capital is based on the Moody's seasoned AAA bond yield, published by the Federal Reserve Bank of St. Louis.[73] The average inflation rate is based on the Consumer Price Index for All Urban Consumers.[74]

Table A.2.1, below, summarizes the data used to conduct the electric distribution study.

---

72 For example, the Australian Bureau of Statistics has employed this method in its measurement of capital. See W.E. Diewert, "Issues in the Measurement of Capital Services, Depreciation, Asset Price Changes, and Interest Rates," in C. Corrado, J. Haltiwanger, and D. Sichel, eds. *Measuring Capital in the New Economy* (University of Chicago Press, 2005), at 491.

73 FRED Economic Data, Federal Reserve Board of St. Louis (https://fred.stlouisfed.org/series/AAA)

74 Bureau of Labor Statistics, Consumer Price Index for all Urban Consumers, Series ID CUUR0000SA0 (http://www.bls.gov/cpi/)

Table A.2.1: FERC Form 1 Data by Line Number

Page 354, FERC Form 1: "Distribution of Wages and Salaries"

	Line Number
Distribution	23
Customer Accounts	24
Sales	26
Administrative and General	27

Pages 320-323, FERC Form 1: "Electric Operation and Maintenance Expenses"

	Line Number
Total Power Production Expenses	80
Total Transmission Expenses	112
Total Distribution Expenses	156
Uncollectible Accounts	162
Total Customer Account Expenses	164
Franchise Requirements	188
Maintenance of General Plant	196
Total Administrative and General Expenses	197
Total Electric Operations and Maintenance Expenses	198

Pages 204-207, FERC Form 1: "Electric Plant in Service"

	Line Number	Line Change
Total Production Plant	42	Through 2002
Total Production Plant	46	After 2002
Total Transmission Plant	53	Through 2002
Total Transmission Plant	58	After 2002
Total Distribution Plant*	69	Through 2002
Total Distribution Plant*	75	After 2002
Total General Plant	83	Through 2002
Total General Plant	90	2003
Total General Plant	99	After 2003
Total Electric Plant in Service	88	Through 2002
Total Electric Plant in Service	95	2003
Total Electric Plant in Service	104	After 2003

*Columns C and D for Additions and Retirements, respectively

8.2.2. Gas Distribution Utility Data

Gas distribution utilities do not report annual data to FERC, which means the gas benchmarking study cannot rely on a free, centralized, government publication of gas distribution data. However, each *state regulator* collects annual distribution utility data, often in PDF format. This data is compiled and made available for purchase by an organization called S&P Global Market Intelligence. In D.P.U. 20-120, I used the S&P Global Market Intelligence data to calculate a U.S. gas distribution utility industry TFP growth rate. Since the input and output data requirements of a benchmarking study overlap with the requirements of a TFP study, I use the same data in my gas analysis.

One key issue with using the data used in D.P.U. 20-120 is that the series ends in 2018 for each of the 87 companies in the sample. I perform an econometric benchmarking analysis, analogous to the approach performed for the electric distribution study, but the study has the limitation of being three years out of date. For this reason, I manually collected the data for five peer companies, obtaining data through 2022. An econometric study is not reliable with such a small sample size, but a unit cost approach can be performed, as the peer companies were specifically selected based on attributes as described in Section 8.2.1.

The formula below represents the total cost of gas distribution operations.

$$\begin{aligned} Total\ Cost_{i,t} = {} & Distribution\ O\&M\ expenses_{i,t} + CA\&S\ expenses_{i,t} \\ & + CS\&I\ expenses_{i,t} + Allocated\ A\&G\ expenses_{i,t} + IRP\ Capital_{i,t} \end{aligned} \tag{A.2.5}$$

Where "Distribution O&M expenses" consist of all O&M costs associated with distribution operations, including salaries; "CA&S expenses" consist of customer accounts and sales expenses, including salaries; "CS&I expenses" consist of customer service and information expenses, including salaries; "Allocated A&G expenses" consist of administrative and general expenses, allocated by each utility's proportion of distribution plant in service relative to total plant in service, including salaries; and "IRP Capital" consists of the implicit rental price of capital.

The data used for the gas benchmarking study are described below.

Distribution Materials

To measure distribution materials input, I base materials cost on operating and maintenance expense for distribution from S&P Global Market Intelligence, less labor compensation described above.

Components of O&M Expenses

Labor and materials inputs were derived from annual O&M expenses for each company in the sample. The O&M expenses in this model were calculated by summing the following accounts:

Table A.2.2: O&M Expense Accounts

Name of Account
Total Distribution O&M Expenses
Total Underground Storage Expenses
Total Other Storage Expenses
Customer Service & Information Expenses
Customer Accounts Expenses
Sales Expenses
Administrative & General Expenses, apportioned by Plant
less Franchise Requirements
less Maintenance of General Plant

From this summation, the following items were subtracted:[75]

Table A.2.3: Subaccounts Removed

Name of Account
Customer Accounts – Uncollectible Accounts (904)
Customer Service & Information Expenses – Customer Assistance (908)

The model incorporates CS&I, incorporates customer accounts, and sales expenses. CS&I accounts contain expenses associated with operating a gas distribution system. Conversations with utility personnel both at the Company and other distribution utilities in the United States allowed us to selectively remove subaccounts from CS&I that contained DSM expenses. For gas utilities in Massachusetts, DSM expenses were booked in Account 905. For all other utilities, DSM expenses were booked in Account 908. This permits us to include the remainder of CS&I expenses that do not contain DSM expenses.

Administrative and General Labor and Materials

Administrative and General ("A&G") expenses are comprised of joint and common costs that pertain to activities that span a utility's functional components—distribution, transmission and production—and are not dedicated to the distribution function. As with the electric A&G expenses, judgment is involved in any allocation of joint and common costs. Therefore, this benchmarking study adopts the same regulatory, non-economic apportionment principle for assigning A&G expenses to distribution that was accepted under D.P.U. 18-150, D.P.U. 19-120, D.P.U. 20-120, and D.P.U. 22-22. Specifically, the portion of joint and common A&G

[75] Account 908 was removed because this account generally contains DSM expenses among gas distribution utilities. However, in the state of Massachusetts, DSM expenses are generally booked in Account 905 (CS&I: Miscellaneous). For such companies, Account 908 was included, but Account 905 was removed.

expenses allocated to the distribution function is determined by multiplying a firm's total A&G expenses, less franchise requirements, for each year in the sample by the annual average across all firms in the sample of the percent of distribution plant relative to total plant.

The plant-apportioned A&G expenses were then included in the calculation of O&M, as described above.

Capital

As with the electric distribution benchmarking study, described above, the quantity of capital stock is determined by the perpetual inventory equation. The perpetual inventory equation constructs an end-of-year capital stock from the capital stock at the end of the previous year, the quantity of capital stock additions during the year, and the quantity of capital stock retirements during the year. In the gas study, because data was only available beginning in 1998, capital stock retirements are determined through the one hoss shay model.[76] The basic assumption underlying the one hoss shay model is that an asset provides a constant level of services (i.e., capital input) over the lifetime of the asset. In other words, an asset's efficiency or ability to provide productive services[77] does not deteriorate as the asset ages.[78]

[76] As with the electric distribution studies approved in D.P.U. 17-05, D.P.U. 18-150, D.P.U. 19-120, and D.P.U. 20-120, the one-hoss-shay efficiency decay method is appropriate for gas distribution. .

[77] A decline in an asset's efficiency or ability to provide productive services is defined as *economic depreciation.* This is not to be confused with the accounting or financial concept of depreciation which relates to the write-off or decline in financial value of an asset over its lifetime.

[78] This does not preclude increased maintenance to preserve an asset's productive services as the asset ages. However, any increased maintenance will be reflected in O&M expenses.

Using the variable K to represent the end-of-year capital stock, I the quantity of additions during the year, and R to represent the quantity of retirements during the year, the perpetual inventory equation has the form:

$$K_t = K_{t-1} + I_t - R_t \qquad \text{(A.2.6)}$$

To estimate the quantity of additions during the year, I divide distribution additions to plant in service by the Producer Price Index for construction materials. To estimate the quantity of retirements during the year, I divide distribution retirements from plant in service by an appropriately lagged value of the Producer Price Index for construction materials. I use a lag of 51 years. This lag represents the approximate average age of assets as they were retired over the course of the study period, at matches what was used in D.P.U. 19-120 and D.P.U. 20-120.

Since the perpetual inventory equation is a recursive equation, it is necessary to estimate a "benchmark value" of K for an early year. As the only information available to construct a benchmark value is the book value of plant and equipment, which is made up of assets of different vintages, one can only approximate the quantity of capital stock from the book value. To improve precision of the capital stock estimates for the years in the TFP study, it is useful to select a benchmark year that is well before the beginning of the TFP sample. The earliest year for which plant-in-service data was widely available in the S&P Global Market Intelligence database was 1998, so this is the year I used. The capital stock in 1998 is determined by dividing the gross book value of distribution plant in 1998 by an appropriate weighted average of Producer Price Index values for 1998 and previous years.

Using the variable PPI to represent the Producer Price Index, the mathematical formula to construct the benchmark value is as follows. This is a triangularized weighted average of the price index, which places more weight on construction prices in recent years.

$$K_{1998} = \frac{GrossDistributionPlantInService}{\sum_{i=1}^{51}\left[i \cdot PPI_{1947+i} \Big/ \left(\sum_{i=1}^{51} i\right)\right]} \tag{A.2.7}$$

Once the end-of-year capital stock is computed, the flow of capital services during a year is based on the quantity of capital stock at the end of the previous year.

$$KS_t = K_{t-1} \tag{A.2.8}$$

Price of Capital Input

The price of capital input is the implicit rental price that corresponds to the assumptions underlying the perpetual inventory equation described above. The price of capital input is based on an equilibrium relationship between the price an investor is willing to pay for an asset and the after-tax expected value of services that the asset will provide over the asset's lifetime. This relationship is called the implicit rental price formula.

The implicit rental price formula under hyperbolic decay has the following mathematical representation.

$$p_t = \frac{(1-uz)}{(1-u)} \cdot \left[\sum_{i=1}^{65} \left(\frac{1+\rho}{1+r}\right)^i \delta_i\right]^{-1} HW_{t-1} \tag{A.2.9}$$

The variable u represents the corporate profits tax rate, the variable z represents the present value of tax depreciation charges on one dollar of investment in distribution plant and equipment, the variable r represents the forward-looking cost of capital, and the variable I represents the forward-looking inflation rate. The number 65 is twice the average service life, minus one, which is the range of asset lifetimes under the truncated normal distribution.

Based on tax law, I use a corporate tax rate of 35 percent for u during the years before the Tax Cuts and Jobs Act, and 21 percent for subsequent years. And I compute z using the sum-of-years digit method.

In some applications of the implicit rental price formula, the current year's cost of capital and inflation rate are used as proxies for the forward-looking rates. This can produce substantial year-to-year variation in the implicit rental price, making it difficult to determine the trend in input price growth. An alternative that has been previously employed and produces a more stable input price series is to assume that investor's forward looking real rate of return (cost of capital less the inflation rate) is constant through time.[79] I apply this alternative by computing the average cost of capital rate and the average inflation rate over the 2006-2020 period. The average cost of capital is based on the Moody's seasoned AAA bond yield, published by the Federal Reserve Bank of St. Louis.[80] The average inflation rate is based on the Consumer Price Index for All Urban Consumers.[81]

---

79 For example, the Australian Bureau of Statistics has employed this method in its measurement of capital. See W.E. Diewert, "Issues in the Measurement of Capital Services, Depreciation, Asset Price Changes, and Interest Rates," in C. Corrado, J. Haltiwanger, and D. Sichel, eds. *Measuring Capital in the New Economy* (University of Chicago Press, 2005), at 491.

80 FRED Economic Data, Federal Reserve Board of St. Louis (https://fred.stlouisfed.org/series/AAA)

81 Bureau of Labor Statistics, Consumer Price Index for all Urban Consumers, Series ID CUUR0000SA0 (http://www.bls.gov/cpi/)

8.3. Results

As described in Section 8.2, I took two approaches to benchmark FG&E's costs. First, I performed the same unit cost approach that has been accepted in previous PBR applications before the Department. Second, I perform an econometric approach. I provide the details of the regression specifications in each relevant subsection below.

8.3.1. Electric Distribution Benchmarking Results

Unit Cost Results (Electricity)

The unit cost benchmarking analysis for FG&E's electric distribution system compares FG&E against a national sample of 71 companies, a regional sample of 18 companies specifically in the Northeastern United States, and a peer set of five firms similarly sized firms. The unit costs for each company is calculated by dividing Total Cost for a given year, as defined by equation A.2.2, by the average number of customers served that year. Table A.2.4 displays the average Total Cost per Customer (unit cost) among the National Sample, the Northeast Sample, and the Peer Group, as well as FG&E by itself.

Table A.2.4: Total Cost per Customer (Electricity, USD)

Sample	2019	2020	2021	Average
National Sample	578	601	621	600
Northeast Sample	611	603	618	611
Peer Group (5 companies)	660	659	690	670
Fitchburg Gas & Electric	817	750	753	773

Table A.2.5 compares the unit cost of FG&E with the average unit cost among each sample. The table demonstrates that FG&E faces costs that are approximately 22 percent above the national sample, 19 percent above the northeast sample, and 9 percent above the group of similarly sized peers.

Table A.2.5: Percentage Difference in Total Cost per Customer (Electricity)[82]

Sample	2019	2020	2021	Average
National Sample	26%	21%	18%	22%
Northeast Sample	19%	21%	18%	19%
Peer Group (5 companies)	11%	11%	6%	9%

The tables above summarize the unit cost information of the broad distribution industry, relative to FG&E. Table A.2.6 provides a full list of all companies in the sample, the total customers served by each company, the unit cost, and the rank of each company in terms of unit costs relative to the group.

[82] Note that Account 925, "Injuries and Damages," was removed for all years for Pacific Gas & Electric and Southern California Edison companies. This is because these companies incurred large legal fees associated with wildfires during the most recent years of the sample. Our benchmarking methodology conservatively removes these costs from the analysis. For this reason, the differences in FG&E's costs and the national sample average total costs are smaller than they appear in our analysis.

Table A.2.6: Rank of Total Cost Per Customer (Electricity, 2021)

Company Name	Region	Customers	Unit Cost	Rank
Ohio Edison Company		1,062,269	341	1
Nevada Power Company		984,770	396	2
Cleveland Electric Illuminating Company		755,212	406	3
Dayton Power and Light Company		532,418	413	4
Florida Power & Light Company		5,214,219	420	5
El Paso Electric Company		445,647	422	6
Public Service Electric and Gas Company	NE	2,323,293	427	7
MDU Resources Group, Inc.		144,103	436	8
Gulf Power Company		477,672	438	9
Public Service Company of Colorado		1,535,755	456	10
Puget Sound Power and Light Company		1,196,851	457	11
Superior Water, Light and Power Company		15,198	472	12
Duke Energy Ohio, Inc.		735,921	472	13
Idaho Power Company		596,394	480	14
Wisconsin Electric Power Company		1,144,822	481	15
Duke Energy Kentucky, Inc.		146,513	491	16
Florida Power Corporation		1,899,991	501	17
Green Mountain Power Corporation	NE	270,677	501	18
Metropolitan Edison Company		581,453	501	19
Narragansett Electric Company	NE	501,117	510	20
Massachusetts Electric Company	NE	1,344,807	521	21
Kansas Gas and Electric Company		337,830	526	22
Tucson Electric Power Company		440,831	532	23
Kentucky Utilities Company		565,153	537	24
Pennsylvania Electric Company	NE	588,261	541	25
Southwestern Public Service Company		400,209	541	26
Jersey Central Power & Light Company	NE	1,150,247	544	27
Virginia Electric and Power Company		2,698,553	550	28
Wisconsin Public Service Corp		454,892	562	29
Kingsport Power Company		48,597	563	30
Indiana Michigan Power Company		604,531	564	31
NSTAR	NE	1,475,929	565	32
Duquesne Light Company	NE	607,350	566	33
Entergy New Orleans, Inc.		209,159	568	34
South Carolina Electric & Gas Co.		771,620	570	35
Kansas City Power & Light Company		570,014	572	36
Public Service Company of New Hampshire	NE	529,986	574	37
Madison Gas and Electric Company		160,976	575	38

Consumers Energy Company		1,871,096	591	39
Commonwealth Edison Company		4,095,262	598	40
Duke Energy Indiana, Inc.		860,972	599	41
Southwestern Electric Power Company		546,238	600	42
Carolina Power & Light Company		1,644,311	601	43
Oklahoma Gas and Electric Company		874,591	606	44
PECO Energy Company	NE	1,682,172	609	45
Appalachian Power Company		964,443	612	46
Monongahela Power Company	NE	395,061	620	47
Baltimore Gas and Electric Company		1,320,805	631	48
Arizona Public Service Company		1,317,266	633	49
New York State Electric & Gas Corp	NE	913,633	635	50
Detroit Edison Company		2,249,459	640	51
Otter Tail Corporation		133,943	647	52
Northern Indiana Public Service Co.		483,297	650	53
Niagara Mohawk Power Corporation	NE	1,706,025	653	54
Connecticut Light and Power Company	NE	1,272,008	676	55
Central Hudson Gas & Electric Corp	NE	307,825	687	56
Upper Peninsula Power Company		53,295	687	57
Southern California Edison Co.		539,709	703	58
Delmarva Power & Light Company		912,209	707	59
Portland General Electric Company		727,743	711	60
Entergy Arkansas, Inc.		149,852	741	61
Southern Indiana Gas and Electric Company, Inc.		238,799	747	62
Orange and Rockland Utilities, Inc.	NE	30,460	753	63
Fitchburg Gas and Electric Light Company	NE	1,510,098	780	64
Alabama Power Company		178,980	815	65
Empire District Electric Company		41,685	819	66
Wheeling Power Company		3,530,574	825	67
Consolidated Edison Company of New York, Inc.	NE	5,192,855	839	68
Mississippi Power Company		190,660	975	69
Pacific Gas and Electric Company		5,260	1,151	70
Mt. Carmel Public Utility Company		5,623,301	1,262	71

*indicates the company is one of the five peer companies

The electricity distribution unit cost benchmarking results show that FG&E has a higher total cost per customer relative to a national sample of electricity distributors. However, these results reflect significant analytical limitations. The comparison of FG&E's unit costs against the average cost of a group of other utilities does not control for any of the factors that drives cost differences. The selection of a regional sample and a similarly sized peer group may provide an improved cost comparison between companies, but even comparing results among these subsets does not isolate specific circumstances of each firm. System density, system size, regulatory regime, terrain, climate, peak demand, service quality, current system growth rate, and place in capital replacement cycle, among other factors, may drive cost differences. None of these differences can be reasonably captured with a simple average cost comparison. For this reason, it is difficult to reach any definitive conclusions using the unit cost approach.

Econometric Results (Electricity)

The reason for performing an econometric benchmarking study is to control for firm-specific factors that influence cost and cannot be controlled by the company. Using a regression to control for these factors, benchmarking comparisons between companies reflect differences in cost efficiency rather than differences in the economic environment which may influence the unit cost results.

The primary challenge with an econometric approach is that there are many variables to control for through the regression, and most of these variables are not observed by the econometrician. One way to circumvent this issue is to benchmark each company's rate of change in unit costs over time against its peers. This allows one to control for any variable that does not change during the sample – such as the company's terrain or system size – without needing to observe it. The remaining set of time-varying factors can be controlled for explicitly. The tradeoff of this approach is that the regression measures each company's relative *cost efficiency growth rate* over time, rather than measuring the level of the company's relative costs in a specific year.

Thus, this benchmarking method offers an alternative perspective on a company's relative performance. For instance, a company may have large unit costs. But if its unit cost growth over time is consistent with the rest of the industry after accounting for observable factors like customer growth, it's arguably the case that its large unit costs are the product of fixed factors, like terrain or climate, that it cannot control. To formalize this idea, we formulate a model that expresses unit costs as a function of total customers, company factors that are fixed over time, and annual factors like industry productivity growth and input price trends that impact all companies. The regression specification can be seen below as equation A.2.10.

$$\ln(AC_{it}) = \beta \ln(Cust_{it}) + \alpha_i + \delta_t + u_{it} \tag{A.2.10}$$

Where

- AC_{it} is company I's unit cost in year t
- β is a constant
- $Cust_{it}$ is company I's total customers in year t
- α_i is company i's fixed effect (I's time-invariant portion of unit costs)
- δ_t is the year t fixed effect (all factors that impact all companies in period t)
- u_{it} represents all other factors that impact company I's unit costs in period t

After estimating our model, we compare the change in each company's unit costs over time to the change in its predicted unit costs from the model. A company's score is equal to this difference, with positive scores denoting unit cost growth that exceeded the model's prediction.

It is important to be clear about the correct interpretation of the score variable, particularly in an empirical setting where we cannot observe all relevant time-varying factors. First, the score represents a difference between actual and predicted cost *growth rate* over the fifteen-year study period, not a difference in actual and predicted *level costs*. Second, the method eliminates the problem of omitted variables for factors that do not change over time, but it does not completely remove the possibility of omitted variables, which is inherent to all regression-based benchmarking analysis. For example, if a company's unit costs grew at 5 percent during our sample but the model predicted growth of 4 percent, then the company's score of +1 percent implies that the model was unable to explain 1 percent of the company's unit cost growth. While part of this 1 percent may be explained by below-average cost efficiency, omitted time-varying factors may explain the difference as well, such as severe weather events that impact only a subset of companies.

This regression model provides an additional perspective on how FG&E's costs compare with the larger industry. Unlike the unit cost approach, or even other econometric approaches, the company fixed effects model controls for all non-time-varying factors, like terrain, region, density, urban environment, and any other quality that might be unique to each utility and does not change significantly over the fifteen-year study period.

The results from our econometric benchmarking exercise for electricity distribution can be found below in Table A.2.7. Using this approach, FG&E ranks 58 out of the 71 total companies, with annual cost growth 0.81 percent above its predicted growth rate.

Table A.2.7: Econometric Benchmarking Scores (Electricity)

Duke Energy Ohio, Inc.	Score	Rank	Region
Duke Energy Ohio, Inc.	-2.28%	1	
Upper Peninsula Power Company	-2.25%	2	
Nevada Power Company	-1.83%	3	
Wisconsin Electric Power Company	-1.73%	4	
Entergy New Orleans, Inc.	-1.41%	5	
South Carolina Electric & Gas Co.	-1.40%	6	
Kansas Gas and Electric Company	-1.27%	7	
Kansas City Power & Light Company	-1.26%	8	
Gulf Power Company	-1.23%	9	
NSTAR	-1.19%	10	NE
Arizona Public Service Company	-1.08%	11	
Duke Energy Indiana, Inc.	-1.07%	12	
Idaho Power Company	-1.05%	13	
Mississippi Power Company	-1.05%	14	
Superior Water, Light and Power Company	-0.95%	15	
Otter Tail Corporation	-0.92%	16	
Public Service Electric and Gas Company	-0.86%	17	NE
Virginia Electric and Power Company	-0.71%	18	
Puget Sound Power and Light Company	-0.71%	19	
Indiana Michigan Power Company	-0.66%	20	
Ohio Edison Company	-0.65%	21	
Wisconsin Public Service Corp	-0.59%	22	
Southwestern Electric Power Company	-0.47%	23	
Detroit Edison Company	-0.42%	24	
Cleveland Electric Illuminating Company	-0.38%	25	
Duke Energy Kentucky, Inc.	-0.36%	26	
El Paso Electric Company	-0.35%	27	
Alabama Power Company	-0.31%	28	
Appalachian Power Company	-0.29%	29	
Entergy Arkansas, Inc.	-0.21%	30	
Niagara Mohawk Power Corporation	-0.21%	31	NE
Public Service Company of Colorado	-0.20%	32	
Madison Gas and Electric Company	-0.19%	33	
Florida Power Corporation	-0.14%	34	
Dayton Power and Light Company	-0.14%	35	
Carolina Power & Light Company	-0.06%	36	
Consolidated Edison Company of New York, Inc.	-0.03%	37	NE
Narragansett Electric Company	0.21%	38	NE
Empire District Electric Company	0.22%	39	
Northern Indiana Public Service Co.	0.24%	40	
Pennsylvania Electric Company	0.28%	41	NE
Baltimore Gas and Electric Company	0.28%	42	
Oklahoma Gas and Electric Company	0.31%	43	
Massachusetts Electric Company	0.42%	44	NE

Kingsport Power Company	0.42%	45	
Orange and Rockland Utilities, Inc.	0.45%	46	NE
Peco Energy Company	0.48%	47	NE
Florida Power & Light Company	0.50%	48	
Metropolitan Edison Company	0.51%	49	
MDU Resources Group, Inc.	0.58%	50	
Commonwealth Edison Company	0.59%	51	
Connecticut Light and Power Company	0.63%	52	NE
Tucson Electric Power Company	0.65%	53	
Public Service Company of New Hampshire	0.68%	54	NE
Southwestern Public Service Company	0.71%	55	
Monongahela Power Company	0.77%	56	NE
Consumers Energy Company	0.81%	57	
Fitchburg Gas and Electric Light Company	0.81%	58	NE
Duquesne Light Company	0.90%	59	NE
Central Hudson Gas & Electric Corp	0.96%	60	NE
Kentucky Utilities Company	0.96%	61	
Jersey Central Power & Light Company	1.06%	62	NE
New York State Electric & Gas Corp	1.06%	63	NE
Southern Indiana Gas and Electric Company, Inc.	1.30%	64	
Portland General Electric Company	1.31%	65	
Mt. Carmel Public Utility Company	1.50%	66	
Delmarva Power & Light Company	1.52%	67	
Southern California Edison Co.	1.53%	68	
Green Mountain Power Corporation	1.61%	69	NE
Wheeling Power Company	1.97%	70	
Pacific Gas and Electric Company	3.65%	71	

8.3.2. Gas Distribution Benchmarking Results

Unit Cost Results (Natural Gas)

Data limitations complicate the benchmarking work for FG&E’s natural gas distribution operations. For the reasons stated in A.2.3, our national and northeast sample data ends in 2018. I was able to manually collect data for 5 peer companies, which were selected based on comparisons of system size and proportion of total pipe that is made of cast iron. Table A.2.8 shows the total cost per customer for the national sample of 88 gas distributors, the northeast sample of 30 companies, and the set of five specifically selected peers.

Table A.2.8: Total Cost per Customer (Natural Gas, USD)

Sample	2016	2017	2018	2019	2020	2021	2022	Average
National	352	360	365					359
Northeast	484	503	512					500
Peer (five companies)	629	662	664	701	714	750	784	701
Fitchburg Gas & Electric	526	513	545	569	531	551	625	551

Despite the lack of data for the most recent years, the relative difference in unit costs does not change substantially year to year. Table A.2.9 shows that the largest percentage change across any one-year time frame, for any group, is approximately seven percentage points. The table shows that FG&E's unit costs, during the historical period, exceeded the national average by approximately 47 percent. The table also shows that FG&E's unit costs are much closer to parity with the northeast sample. This may be a result of infrastructure issues common across northeastern companies—for example, ageing plant, cast iron pipe, and urban service territory. Comparing FG&E against the peer group, differences in unit costs are negative, meaning that FG&E experiences an average of 21 percent lower total costs per customer than its similarly situated peers. This suggests a difference in the nature of operations among smaller companies like FG&E, which have more cast-iron pipe.

Table A.2.9: Percentage Difference in Total Cost per Customer (Natural Gas)

Sample	2016	2017	2018	2019	2020	2021	2022	Average
National	49%	42%	49%					47%
Northeast	9%	2%	6%					6%
Peer (five companies)	-16%	-22%	-18%	-19%	-26%	-27%	-20%	-21%

The tables above summarize the unit cost information of the broad distribution industry, relative to FG&E. Table A.2.10 provides a full list of all companies in the sample, the total customers served by each company, the unit cost, and the rank of each company in terms of unit costs relative to the group.

Table A.2.10: Rank of Total Cost Per Customer (Natural Gas, 2018)

Company Name	NE	Customers	Unit Cost	Rank
Questar Gas Company		1,046,071	202.1	1
Spire Missouri Inc.		1,171,811	212.6	2
Atlanta Gas Light Company		1,595,065	232.1	3
Northern Illinois Gas Company		2,226,874	235.1	4
Sierra Pacific Power Company		166,539	235.2	5
Ohio Gas Company		49,684	244.4	6
Illinois Gas Company		9,414	250.4	7
Wisconsin Gas Llc		632,782	254.7	8
The East Ohio Gas Company		1,205,480	259.3	9
Colonial Gas Company	NE	209,505	266.6	10
Columbia Gas Of Ohio, Inc.		1,437,349	273.2	11
Midwest Natural Gas, Inc.		17,000	274.8	12
Southern California Gas Company		5,776,786	275.2	13
Oklahoma Natural Gas Company		880,927	277.5	14
Public Service Company Of North Carolina, Incorporated		567,633	285.5	15
Wisconsin Power And Light Company		189,679	286.8	16
Pike County Light And Power Company	NE	1,230	290.6	17
Kansas Gas Service Company, Inc.		639,300	313.4	18
San Diego Gas & Electric Company		885,908	313.6	19
Black Hills Energy Arkansas, Inc.		168,402	320.4	20
Northern States Power Company – Wi		114,865	321.2	21
Pacific Gas And Electric Company		5,428,318	322.2	22
Northern Indiana Public Service Company		827,653	337.7	23
Pike Natural Gas Co		7,540	341.4	24
Indiana Gas Company, Inc.		599,365	345.3	25
Bluefield Gas Company		3,300	345.5	26
Madison Gas And Electric Company		159,640	348.5	27
Consumers Energy Company		1,775,563	350.6	28
Cascade Natural Gas Corporation		289,433	352.0	29
Louisville Gas And Electric Company		325,785	352.3	30
NSTAR Gas Company	NE	295,092	354.3	31
Midwest Natural Gas Corporation		14,467	355.0	32
Virginia Natural Gas, Inc.		297,950	360.0	33
Arkansas Oklahoma Gas Corp.		57,590	362.6	34
Avista Corporation		350,731	364.1	35
Citizens Gas Fuel Company		17,670	365.1	36
Northwest Natural Holding Company		743,371	367.8	37
Peoples Gas System		386,282	384.0	38

Duke Energy Ohio, Inc.		431,664	385.2	39
Puget Sound Energy, Inc.		830,778	386.5	40
National Fuel Gas Distribution Corporation	NE	751,327	389.7	41
Rochester Gas And Electric Corporation	NE	315,706	390.1	42
Southern Indiana Gas And Electric Company		111,934	392.1	43
Chattanooga Gas Company		66,031	392.7	44
Hope Gas, Inc.		111,459	408.6	45
Mountaineer Gas Company		215,639	415.5	46
Superior Water, Light And Power Company		12,777	423.6	47
North Shore Gas Company		162,040	424.0	48
Vermont Gas Systems, Inc.	NE	52,355	424.9	49
Niagara Mohawk Power Corporation	NE	619,966	428.4	50
DTE Gas Company		1,264,304	428.9	51
Public Service Electric And Gas Company	NE	1,846,681	431.6	52
New Jersey Natural Gas Company	NE	543,751	443.1	53
Baltimore Gas And Electric Company		678,038	448.6	54
Washington Gas Light Company		1,177,322	449.3	55
Ohio Valley Gas Corporation		24,323	452.0	56
Duke Energy Kentucky, Inc.		99,379	456.1	57
South Jersey Gas Company	NE	387,197	460.5	58
Boston Gas Company	NE	709,288	467.6	59
Columbia Gas Of Pennsylvania, Inc.	NE	433,185	468.7	60
Spire Mississippi Inc.		18,568	471.6	61
Wyoming Gas Company		6,882	478.9	62
Southern Connecticut Gas Company	NE	198,577	481.8	63
PECO Energy Co.	NE	524,510	486.7	64
Columbia Gas Of Kentucky, Incorporated		115,203	493.6	65
Columbia Gas Of Virginia, Incorporated		269,799	507.5	66
St. Joe Natural Gas Co, Inc.		2,997	509.6	67
New York State Electric & Gas Corporation	NE	267,754	533.2	68
Liberty Utilities (EnergyNorth Natural Gas) Corp.	NE	91,349	535.5	69
Fitchburg Gas And Electric Light Company	NE	16,060	544.6	70
Berkshire Gas Company	NE	40,208	552.0	71
Delta Natural Gas Company, Inc.		35,073	561.4	72
UGI Penn Natural Gas, Inc.	NE	172,039	567.8	73
Columbia Gas Of Maryland, Incorporated		33,476	575.1	74
Brooklyn Union Gas Company	NE	1,257,521	575.4	75
Fillmore Gas Company, Inc.	NE	1,256	588.2	76
Peoples Gas Light And Coke Company		859,483	612.6	77
Connecticut Natural Gas Corporation	NE	177,769	615.9	78
Philadelphia Gas Works Co.	NE	506,207	652.8	79
Corning Natural Gas Corporation	NE	15,017	655.4	80

Consolidated Edison Company Of New York, Inc.	NE	1,083,064	659.1	81
Yankee Gas Services Company	NE	233,803	695.9	82
Central Hudson Gas & Electric Corporation	NE	82,461	736.4	83
Orange And Rockland Utilities, Inc.	NE	136,116	767.2	84
St. Lawrence Gas Company, Inc.	NE	16,499	770.3	85
Bay State Gas Company	NE	321,449	850.6	86

*indicates the company is one of the five peer companies

The gas distribution unit cost benchmarking results show that FG&E experiences higher total costs per customer compared with most companies in the national sample. On the other hand, FG&E's unit costs are lower than 12 of the 30 northeastern companies, and 21 percent lower than the average peer company.

As with the electric distribution unit cost analysis, these results reflect analytical limitations resulting from a lack of control for any of the factors that drive cost differences. Still, the unit cost approach provides suggestive information. For example, 25 of the 30 northeast companies exhibit costs that are in the upper half of the national sample, which suggests that gas distributors in the northeast share certain conditions unique to the region that drive costs higher. These factors may include piping material, system density, system size, regulatory regime, terrain, climate, peak demand, service quality, current system growth rate, and place in capital replacement cycle, among other factors. Again, none of these differences can be fully captured with a simple average cost comparison. For this reason, it is difficult to reach any definitive conclusions regarding operating efficiency using the unit cost approach.

Econometric Results (Natural Gas)

The results from our econometric benchmarking exercise for natural gas distribution can be found below in Table A.2.11. The regression specification and methodology for the natural gas benchmarking analysis is identical to the description of the econometric approach for electricity operations. I note that this econometric benchmarking method finds that F&GE's unit costs rose at a rate that was 0.14 percent lower than the model's prediction during the sample. This score places it at a rank of 44 out of 86 companies, far higher than its rank as determined by its unit costs in 2021 alone.

Table A.2.11: Econometric Benchmarking Scores (Natural Gas)

Company	Region	Score	Rank
Bluefield Gas Company		-3.08%	1
Illinois Gas Company		-2.79%	2
Arkansas Oklahoma Gas Corp.		-2.71%	3
National Fuel Gas Distribution Corporation	NE	-2.54%	4
Superior Water, Light and Power Company		-2.47%	5
Wisconsin Gas LLC		-1.85%	6
Atlanta Gas Light Company		-1.78%	7
Wisconsin Power and Light Company		-1.76%	8
Northern Indiana Public Service Company		-1.61%	9
Delta Natural Gas Company, Inc.		-1.55%	10
Public Service Electric and Gas Company	NE	-1.42%	11
Duke Energy Ohio, Inc.		-1.36%	12
Ohio Gas Company		-1.23%	13
Sierra Pacific Power Company		-1.18%	14
DTE Gas Company		-1.17%	15
Kansas Gas Service Company, Inc.		-1.12%	16
Spire Missouri Inc.		-1.10%	17
Madison Gas and Electric Company		-1.09%	18
Hope Gas, Inc.		-1.04%	19
Chattanooga Gas Company		-0.98%	20
St. Joe Natural Gas Co, Inc.		-0.94%	21
Duke Energy Kentucky, Inc.		-0.88%	22
Citizens Gas Fuel Company		-0.85%	23
The East Ohio Gas Company		-0.81%	24
Southern Connecticut Gas Company	NE	-0.80%	25
Northern Illinois Gas Company		-0.78%	26
Questar Gas Company		-0.74%	27
Mountaineer Gas Company		-0.67%	28
Oklahoma Natural Gas Company		-0.65%	29
Midwest Natural Gas Corporation		-0.62%	30
PECO Energy Co.	NE	-0.58%	31
Niagara Mohawk Power Corporation	NE	-0.54%	32
North Shore Gas Company		-0.52%	33
Public Service Company of North Carolina, Incorporated		-0.50%	34
Pike Natural Gas Co		-0.45%	35
Southern California Gas Company		-0.44%	36
Black Hills Energy Arkansas, Inc.		-0.41%	37
San Diego Gas & Electric Company		-0.35%	38

Colonial Gas Company	NE	-0.33%	39
Indiana Gas Company, Inc.		-0.31%	40
Consumers Energy Company		-0.24%	41
Pike County Light and Power Company	NE	-0.18%	42
Rochester Gas and Electric Corporation	NE	-0.15%	43
Fitchburg Gas and Electric Light Company	NE	-0.14%	44
Northwest Natural Holding Company		-0.02%	45
Peoples Gas System		-0.01%	46
Peoples Gas Light and Coke Company		-0.01%	47
Ohio Valley Gas Corporation		0.08%	48
Philadelphia Gas Works Co.	NE	0.09%	49
NSTAR Gas Company	NE	0.14%	50
Cascade Natural Gas Corporation		0.19%	51
Louisville Gas and Electric Company		0.19%	52
St. Lawrence Gas Company, Inc.	NE	0.29%	53
Columbia Gas of Ohio, Inc.		0.45%	54
Connecticut Natural Gas Corporation	NE	0.45%	55
Washington Gas Light Company		0.45%	56
New York State Electric & Gas Corporation	NE	0.47%	57
Yankee Gas Services Company	NE	0.53%	58
Fillmore Gas Company, Inc.	NE	0.61%	59
Columbia Gas of Kentucky, Incorporated		0.63%	60
Northern States Power Company – Wi		0.73%	61
Virginia Natural Gas, Inc.		0.77%	62
Southern Indiana Gas and Electric Company		0.87%	63
Puget Sound Energy, Inc.		0.94%	64
Bay State Gas Company	NE	0.97%	65
Orange and Rockland Utilities, Inc.	NE	1.17%	66
Brooklyn Union Gas Company	NE	1.18%	67
Avista Corporation		1.24%	68
New Jersey Natural Gas Company	NE	1.26%	69
Spire Mississippi Inc.		1.27%	70
Midwest Natural Gas, Inc.		1.40%	71
Baltimore Gas and Electric Company		1.45%	72
Berkshire Gas Company	NE	1.45%	73
Columbia Gas of Maryland, Incorporated		1.49%	74
UGI Penn Natural Gas, Inc.	NE	1.56%	75
Pacific Gas and Electric Company		1.71%	76
Boston Gas Company	NE	1.79%	77
Liberty Utilities (EnergyNorth Natural Gas) Corp.	NE	1.87%	78
Vermont Gas Systems, Inc.	NE	2.14%	79
Columbia Gas of Pennsylvania, Inc.	NE	2.23%	80

Central Hudson Gas & Electric Corporation	NE	2.24%	81
Corning Natural Gas Corporation	NE	2.49%	82
Columbia Gas of Virginia, Incorporated		2.49%	83
South Jersey Gas Company	NE	2.83%	84
Wyoming Gas Company		4.13%	85
Consolidated Edison Company of New York, Inc.	NE	5.21%	86

8.4. Conclusions and Recommendation

This study provides two perspectives on benchmarking F&GE's costs. The unit cost perspective provides a comparison of total costs per customer between FG&E and peer companies in different groups—national, northeast, and a specific set of peers. This analysis produces mixed results that appear to be driven by the company's uniquely small size. In particular, FG&E's gas and electric operations, which serve significantly fewer customers than the median sample company, currently experience higher costs than most U.S. distributors. Among the northeast sample, FG&E's electric operations exhibit higher costs than most distributors, but FG&E's gas operations are more in line with the typical company—slightly below the median company, slightly above the average northeastern gas distributor's unit cost. Compared with similarly sized peers, FG&E's electric distribution costs are above average, but within a smaller margin than when compared to the national or northeast samples. FG&E's gas distribution cost are lower than the average unit costs of its peers. The similarity of FG&E's costs with peer companies indicates that size may contribute to national and northeast results, which contain much larger companies.

The second perspective provided by this benchmarking study uses econometrics to assess FG&E's cost trends over time. This analysis shows that, over the past fifteen years, FG&E's electricity operations costs grew 0.81 percentage points *faster* than expected growth. FG&E's gas operations costs grew 0.14 percentage points *slower* than expected growth. The econometric results indicate that FG&E does not differ substantially from the broader industry in terms of its ability to control costs over time.

FG&E is a unique company, smaller than 75 out of 88 of the sampled gas distribution companies and 68 of the 70 sampled electric distribution companies. The qualities that make this company unique also limit the conclusive power of its cost benchmarking results—particularly using the unit cost approach. However, the results of this analysis indicate that FG&E may have some room to find efficiencies through PBR.

No direct methodology to translate benchmarking results into a consumer dividend value is currently in use in North America. Part of the reason for this is that every utility is different, and every PBR plan has its own unique characteristics. Thus, the consumer dividend is typically set using a combination of regulatory precedent, cost benchmarking analysis, and professional judgment. One of the key factors to consider when assessing FG&E electric's consumer dividend is that FG&E will operate under a revenue cap with no growth factor. In other words, FG&E electric's PBR framework already contains a considerable *implicit* consumer dividend equal to the rate of customer growth. In addition, FG&E's plan for both electric and gas divisions proposes an X factor of zero, significantly above the negative X factor found in the empirical evidence. This corresponds to an effective consumer dividend of -1.45 and -1.30 for FG&E's electric and gas divisions, respectively. In light of these facts, together with the results of this benchmarking study and Department precedent, I recommend an additional consumer dividend of 0.00 percent for both the electric and gas operations of FG&E.