Commonwealth of Massachusetts

Department of Public Utilities

Petition of Boston Gas Company d/b/a National Grid for Approval of an Increase in Base Distribution Rates and Performance-Based Ratemaking Plan for Gas Service Pursuant to General Laws Chapter 164, §94 and 220 C.M.R. §§ 5.00, *et seq.*

D.P.U. 20-120

Direct Testimony of Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS

Performance-Based Ratemaking Panel

On behalf of Boston Gas Company
d/b/a National Grid

nationalgrid

November 13, 2020

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TESTIMONY OF MARK E. MEITZEN, PH.D.
AND NICHOLAS A. CROWLEY, MS

I. Introduction

Q. Dr. Meitzen and Mr. Crowley, please state your full names and business address.

A. We are Dr. Mark E. Meitzen and Mr. Nicholas A. Crowley and our business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin, 53705.

Q. On whose behalf are you submitting this testimony?

A. In this proceeding, we are testifying on behalf of Boston Gas Company ("Boston Gas") and the former Colonial Gas Company ("former Colonial Gas") d/b/a National Grid (together, the "Company"). On March 15, 2020, the former Colonial Gas was merged with and into Boston Gas. Therefore, the gas networks formerly designated as Boston Gas and Colonial Gas now operate as one under the name Boston Gas. In this testimony, our references to the "Company" will refer to the Boston Gas and former Colonial Gas, unless separately designated for specific context.

Q. Dr. Meitzen, by whom are you employed and in what capacity?

A. I am a Senior Consultant with Christensen Associates. Christensen Associates is an economic research and consulting firm with expertise in the design and application of incentive regulation plans across a number of network industries and with 40 years of experience in utility industries.

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

A. I have a Bachelor of Science degree in economics from the University of Wisconsin-Oshkosh and a Master of Science from the University of Wisconsin-Madison. I received my Ph.D. in economics from the University of Wisconsin-Madison. I have been at Christensen Associates since 1990. Prior to that, I was a regulatory economist at Southwestern Bell Telephone Company (now AT&T) in St. Louis, Missouri, and I was a member of the economics faculty at the University of Wisconsin–Milwaukee and Eastern Michigan University. Among my various duties at Christensen Associates, I have consulted with firms in several network industries, including the telecommunications, electricity, postal, and railroad industries. I have consulted with these industries on a variety of issues including incentive regulation, productivity, costing, and pricing. I have also sponsored testimony on these issues in regulatory proceedings.

I have co-authored a number of other productivity studies conducted by Christensen Associates, including a recent study prepared on behalf of EPCOR in Alberta, Canada and productivity analysis on behalf of AT&T, which was filed with the Federal Communications Commission. I have also performed numerous analyses for former regional Bell Operating Companies, the United States Telephone Association, the National Cable Television Association, and all the major telecommunications companies in Canada. I have analyzed incentive regulation issues for various network industries including the telecommunications, electric utility and postal industries. I also directed the Christensen Associates team that analyzed incentive-regulation options for the privatization of Peru's telecommunications industry.

Among the articles and reports that I have written, I have recently co-authored two articles on PBR in the electric utility industry.[1] I have also published articles on total factor productivity, incentive regulation in network industries (electricity, gas, and telecommunications), and cross-subsidization issues in the electric utility industry. I was also a principal author of a study of U.S. railroad competition issues commissioned by the U.S. Surface Transportation Board. My curriculum vitae is attached as Exhibit NG-MEM/NAC-2.

Q. Have you previously testified before the Department of Public Utilities or another state's regulatory commission?

A. Yes, I have. I sponsored a total factor productivity study and testified on performance-based ratemaking ("PBR") issues in two proceedings before the Department of Public Utilities (the "Department") on behalf of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid (together, "Mass. Electric") in D.P.U. 18-150,[2] and on behalf of NSTAR Electric Company and Western Massachusetts

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1 Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "The Alphabet of PBR in Electric Power: Why Does Not Tell the Whole Story," *The Electricity Journal*, 30 (2017) 30-37; and Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal,* 31 (2018) 39-46.

2 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.

Electric Company, each d/b/a Eversource Energy in D.P.U. 17-05 (together, "NSTAR Electric").[3]

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

A. I am an economist with Christensen Associates.

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

A. I have a Bachelor of Science in economics, as well as a Master of Science in economics from the University of Wisconsin-Madison. I have worked at Christensen Associates since 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 under Docket RM15-20,[4] 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, vis-à-vis the development of cost benchmarks for power systems and in marginal cost estimation and the development of marginal cost models filed before regulatory authorities in the United States and Canada. My curriculum vitae is attached as Exhibit NG-MEM/NAC-3.

[3] 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.

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

Q. Mr. Crowley, have you previously testified before the Department of Public Utilities or another state's regulatory commission?

A. No, I have not. However, I calculated total factor productivity measures for the electricity sector and developed indexes for use in performance-based ratemaking in proceedings before the Department on behalf of Mass. Electric in D.P.U. 18-150,[5] and on behalf of NSTAR Electric in D.P.U. 17-05.[6]

II. Summary of Testimony

Q. Would you please summarize your testimony?

A. The purpose of our testimony is to develop the PBR indexing formula that is to be used in conjunction with the Company's revenue decoupling mechanism ("RDM").[7]

We begin with a discussion of indexed PBR cap formulas, specifically revenue-per-customer ("RPC") caps. We then present the results of our study of productivity designed to be used for an RPC cap. Lastly, based on the results of this productivity study, we present the *X* factor results for the Company's RPC cap.

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[5] 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.

[6] 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.

[7] It is our understanding that customers included in the RDM are those at the end of the test year. New customer locations added since the end of the test year and their revenue are excluded from the RDM. The benchmark RPCs are based on the rate case's class revenue requirement and test year class number of customers. Therefore, adjusting benchmark RPCs will not set a total revenue requirement cap for the company because the RDM will not pick up those new customers since the end of the test year (ignoring the proposed capital adjustment that would include growth capital, which would make a one-time update to billing determinants and number of customers, and benchmark RPC to match the addition of growth capital). For details of this proposal see the Testimony of the PBR Panel, Exhibit NG-PBRP-1.

Q. Are you sponsoring any exhibits through your testimony?

A. Yes. The table below lists the exhibits that we are sponsoring as part of our testimony in this proceeding.

Exhibit	**Description**
Exhibit NG-MEM/NAC-1	Testimony and Appendix A, Study Methods
Exhibit NG- MEM/NAC-2	Dr. Meitzen's Curriculum Vitae
Exhibit NG-MEM/NAC-3	Mr. Crowley's Curriculum Vitae
Exhibit NG-MEM/NAC-4	Workpaper – Labor Percent of O&M
Exhibit NG-MEM/NAC-5	Workpaper – National Model (Confidential)
Exhibit NG-MEM/NAC-6	Workpaper – Northeast Model (Confidential)
Exhibit NG-MEM/NAC-7	Workpaper – Average Service Lives
Exhibit NG-MEM/NAC-8	Workpaper – Testimony Figures

III. <u>Indexed PBR Cap Formulas</u>

A. Overview

Q. In general, why is PBR viewed as a superior form of economic regulation relative to cost of service regulation?

A. Many forms of regulation fall under the umbrella of PBR or incentive regulation, ranging from largely traditional cost of service regulation ("COSR") with earnings sharing to indexed cap formulas.[8] Given the multitude of regulatory schemes that fall under the general category of PBR, we will define PBR for our purposes to mean indexed cap formulas, such as price caps, revenue caps, or RPC caps.

PBR is generally a form of regulation that provides the regulated firm with stronger incentives for efficiency than traditional COS regulation. Typically, there are also efficiencies in the operation of the regulatory process under PBR. In principle, these incentives can be expected to lead to more efficient firm behavior, efficiency in the regulatory process, and myriad benefits for all stakeholders, including customers of the regulated firm.

Q. What is the general form of an indexed PBR cap formula?

A. A cap formula sets a ceiling on price (i.e., price cap) or revenue (i.e., revenue or RPC cap) rates of change. This cap or ceiling restricts rates of change in prices (or revenues) to be at or below the cap. The cap is based on some measure of economic performance that is external to the regulated firm and cannot be manipulated by the firm (i.e., exogenous). Generally, the cap has the general form of "$I - X$," where I is a measure of inflation and X is a productivity-based offset to the inflation measure. As we discuss

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[8] "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.

below, the specification of *X* depends on how I is specified – that is, *X* is a function of *I,* or $X = X(I)$.[9]

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

A. Under PBR, the utility is allowed the flexibility to pursue cost reduction initiatives and to retain the benefit of those reductions until rates are reset in the future. In contrast, under COS regulation the expectation is that more routine rate-setting processes will occur and that the return earned by the firm will be more consistently aligned with its authorized return. Because the regulated firm retains the fruits of its cost-reducing initiatives for a relatively short time under COS, the incentives to undertake these cost-reducing initiatives are relatively weak.[10]

The strength of these PBR incentives depends on the form of PBR and how much of the cost savings the firm is allowed to retain. For example, under an earnings sharing

[9] As explained below, if *I* is a measure of industry input prices, *X* is determined by a measure of the expected rate of change in industry productivity. Conversely, if *I* is a measure of economy-wide output price growth (such as the GDP-PI used in previous plans in Massachusetts), then, as described below, *X* consists of a differential in a measure of the expected rate of productivity change between the industry and the overall economy, and a differential in input price growth between the overall economy and the industry. See Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "The Alphabet of PBR in Electric Power: Why X Does Not Tell the Whole Story," *The Electricity Journal,* 30 (2017) 30-37. Also, as explained below, *X* and the underlying measure of industry TFP depends on the purpose for which TFP is being calculated.

[10] It is generally recognized that regulatory lag can provide some incentive for efficient behavior under COS regulation because the dollar saved is not instantaneously returned to customers. The longer the period of time over which the firm can retain its cost savings, the stronger the incentives for efficient behavior, holding all other factors constant. Quality of service is also an important consideration, as unconstrained cost cutting could lead to service degradation. Also, as discussed below, under most price cap plans, the firm has the incentive to increase output (up to the profit-maximizing point), which may work at cross purposes with conservation goals.

mechanism ("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, a graduated portion of excess earnings are credited to customers. Consequently, the firm has a strong profit motive to become more efficient up to the point of partial or full sharing. Above the full-sharing point, the PBR plan operates much like traditional COSR. On the other hand, a cap or ceiling type of incentive regulation, such as RPC or revenue caps, generally provides stronger incentives for efficient behavior. 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.[11] However, in many applications (including recent distribution rate cases for Mass. Electric and NSTAR Electric), an ESM has been used in conjunction with the revenue cap.

Q. Are there other efficiencies derived from PBR?

A. There are a number of potential regulatory cost savings for regulated firms, regulators and intervening stakeholders. In general, many of the types of filings and/or proceedings that are required under COS may no longer be required or the period between such activities may be extended, saving resources for both. Examples of

[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). Notably, some PBR plans (e.g., Alberta) incorporate an efficiency-carryover mechanism ("ECM") under which there is only a partial true-up of rates at the end of the PBR regime. The ECM provides stronger incentives for efficient performance as the end of the PBR regime approaches because the regulated firm carries over a stipulated share of its gains (losses) into the next PBR regime.

potential regulatory savings include expedited procedures for annual compliance filings and investment decisions, and an extended time frame between rate cases. From the firm's perspective, these regulatory efficiencies allow the firm to devote resources previously dedicated to regulatory efforts to be redirected to the more efficient operation of the company. For example, if there is not a mandated capital cost recovery process and the regulated firm is able to conduct its investment activity on a more flexible basis, firm engineering resources that would otherwise be devoted to supporting capital recovery applications can be redeployed to more productive activities.

Q. What benefit do the firm's customers realize from PBR?

A. 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 compared to alternative COS-based forms of regulation. *Ex post* benefits would include consumers reaping the fruits of more efficient firm behavior and efficiencies in the regulatory process through earnings sharing and rebasing of rates at the time the plan is reviewed.[12] In addition, the firm may be able to invest more efficiently under incentive

[12] 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.

regulation compared to COS and these investments may generate further efficiencies that flow through to customers and may also result in higher quality of services.

Q. Why type of indexed cap formula is the Company proposing?

A. The Company is proposing to implement an RPC cap to make annual adjustments to its RDM. We explain the mechanics of this type of cap formula below. Both RPC and revenue caps have been used in Massachusetts and are viewed as mechanisms that better align the firm's incentives with desired conservation goals while still maintaining the efficiency properties of the cap approach.

B. Revenue per Customer Caps

Q. How does a revenue per customer cap work?

A. Under this type of cap, RPC growth is capped by the $I - X$ adjustment formula:

$$(1)\ \%\Delta RPC = (I - X)$$

As with price caps, the RPC cap provides the firm with the incentives for more efficient behavior relative to COSR.[13]

[13] Also, an RPC cap insulates the utility from customer growth, which is efficient since customer growth is generally considered to be exogenous to the utility.

Q. What does the *I* factor represent?

A. 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: industry input price inflation and economy-wide output price inflation.

Q. What are the two approaches to determining the *I* factor?

A. The first approach uses some measure of industry input price inflation as the *I* factor—i.e., $I = I_I$. This approach was used in the U.S. railroad industry and the energy sector in Canada but is not very common in incentive regulation plans in the United States. The second approach is to use a measure of economy-wide output price inflation, such as the Gross Domestic Product Price Index ("GDP-PI")—i.e., $I = I_E$. This approach is the most common in U.S. incentive regulation plans, including the telecommunications and utilities industries, and has been used in previous incentive regulation plans in Massachusetts, including the recently adopted NSTAR Electric plan in D.P.U. 17-05 and the Mass. Electric plan in D.P.U. 18-150.[14]

Q. How is the productivity adjustment, *X*, determined?

A. The specification of the price cap *X* factor depends on the specification of the *I* factor—that is, $X = X(I)$. When I is a measure of industry input price inflation, X will be

[14] D.P.U. 17-05, November 30, 2017 and D.P.U. 18-150, September 30, 2019. Also see D.P.U. 96-50 (Phase I), November 29, 1996, at 273; D.T.E. 01-56, January 31, 2002, at 20; D.T.E. 03-40, October 31, 2003, at 473; and D.T.E. 05-27, November 30, 2005, at 384; and Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "The Alphabet of PBR in Electric Power: Why X Does Not Tell the Whole Story," *The Electricity Journal,* 30 (2017) 30-37.

represented as the percent change in industry TFP. When *I* is a measure of economy-wide inflation, *X* is specified as the differential between the percent change in industry TFP and the percent change in economy-wide TFP plus the differential between the percent change in economy-wide input prices and the percent change in industry input prices. 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.[15]

Q. Would you please describe the measure of industry expected changes in productivity used in determining the *X* factor for an indexed cap?

A. The productivity concept typically used is total factor productivity ("TFP"), which is generally defined as the ratio of total output to total input:

(2) TFP = Total Output/Total Input

The correct specification of output 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 an indexed PBR cap. In general, when the purpose of TFP measurement is to calibrate an indexed PBR cap, the output measure will be a proper subset of the total output measure used in computing an efficiency measure of TFP.[16]

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[15] The use of the expected rate of productivity change 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.

[16] Another difference between the efficiency and indexed cap measure of TFP is how the various elements of output are weighted together to construct the relevant output index.

Total input includes all resources used by the unit of production in providing those services. 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.

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:

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

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.

Q. What is the appropriate measure of TFP output for an RPC cap?

A. Because the results of the study are to be applied to an RPC cap, it is appropriate to base the output measure on the number of customers served. As noted above, this measure of output is different than the measure of output that would be used in an efficiency measure of TFP. In an RPC cap, the number of customers is the "dual" output measure to the RPC cap (that is, RPC times the number of customers equals total revenue). In an RPC cap, revenues are allowed to increase by the percentage increase in the inflation factor, plus or minus the X factor, plus the percent change in the number of customers.

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

$$(4)\ \%\Delta R_I = \%\Delta RPC_I + \%\Delta CUSTOMERS_I$$

That is, the percent change in industry revenue ($\%\Delta R_I$) is equal to the percent change in industry RPC ($\%\Delta RPC_I$) plus the percent change in the number of industry customers. Rearranging the terms in (4):

$$(5)\ \%\Delta RPC_I = \%\Delta R_I - \%\Delta CUSTOMERS_I$$

Under competitive conditions, the rate of change in the total revenue of the industry is equal to the rate of change in its cost (i.e., $\%\Delta R_I = \%\Delta C_I$). Furthermore, 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 ($\%\Delta Q_I$)—i.e., $\%\Delta C_I = \%\Delta W_I + \%\Delta Q_I$. Substituting $\%\Delta C_I$ for $\%\Delta R_I$ in (5) yields:

$$(6)\ \%\Delta RPC_I = \%\Delta C_I - \%\Delta CUSTOMERS_I$$

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

$$(7)\ \%\Delta RPC_I = \%\Delta W_I + \%\Delta Q_I - \%\Delta CUSTOMERS_I$$

Rearranging:

$$(8)\ \%\Delta RPC_I = \%\Delta W_I - (\%\Delta CUSTOMERS_I - \%\Delta Q_I)$$

Equation (8) defines the RPC cap, where the *I* factor is the rate of change in industry input prices (i.e., $I_I = \%\Delta W_I$). The corresponding *X* factor, $X(I_I)$, is rate of change in TFP using the percent change in customers as the measure of output. We term this version of TFP as *revenue per customer TFP* ("RPC TFP"). It is given by:

$$(9)\ RPC\ TFP = \%\Delta\ TFP^R{}_I = \%\Delta CUSTOMERS_I - \%\Delta Q_I.$$

Q. What are the implications for the RPC cap *X* factor if the *I* factor is a measure of economy-wide output price inflation?

A. Assuming the *I* factor is based on a measure of economy-wide output price inflation, like the GDP-PI, the *X* factor would be comprised of a combination of TFP and input price differentials, with the measure of the rate of change in industry RPC TFP given by $\%\Delta\ TFP^R{}_I$. That is:

$$(10)\ I_E = \text{GDP-PI}$$

and

$$(11)\ X(I_E) = [(\%\Delta\ TFP^R{}_I - \%\Delta TFP_E) + (\%\Delta W_E - \%\Delta W_I)]$$

This produces the following RPC cap when *I* is based on GDP-PI:

$$(12)\ \%\Delta RPC_I = \text{GDP-PI} - [(\%\Delta\ TFP^R{}_I - \%\Delta TFP_E) + (\%\Delta W_E - \%\Delta W_I)]$$

C. Summary – The Choice Among PBR Caps

Q. What are the implications of the economic and non-economic considerations in Massachusetts for the choice between the various PBR caps?

A. RPC and revenue caps have been used in various Massachusetts PBR plans where RDM and conservation issues have been an important element of the Department's directive and focus.[17] Revenue per customer and revenue caps allow prices and revenues to increase as output declines. This permits the firm to obtain a level of supplemental revenue support where an RDM is in place, or where customer consumption is declining, thus, removing the incentive to encourage load growth as a means of maintaining revenues. In this respect, these caps are more consistent with other policy goals, such as conservation efforts, than price caps as the firm has a greater ability to counteract the effects of declining output.[18] RPC and revenue caps are also consistent with revenue decoupling as targeted revenues are indexed by the cap.

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[17] D.P.U. 09-39, pp. 73-74. Although the Department endorsed an RPC RDM approach in D.P.U. 07-50-A, it recognized there were company-specific circumstances that would support other adjustment mechanisms to target revenues.

[18] In contrast, subject to profit maximizing conditions, under price caps the firm has the incentive to increase output. At the very least, because prices are capped and revenue would decline as output declines, the firm has a disincentive to discourage output growth under price caps. Thus, price cap regulation can work at cross-purposes with conservation goals. Furthermore, because prices are capped rather than revenues, price cap regulation is not entirely consistent with revenue decoupling.

Q. Would you please describe the general form of the revenue per customer cap that is being proposed by the Company in this proceeding?

A. The Company is proposing an RPC cap as an indexing mechanism to make annual adjustments in distribution target revenues under the Company's RDM. In a given year, the distribution annual target revenue ("ATR") will change in accordance with the PBR indexing formula, and the RDM will be adjusted to recover the new distribution revenue target determined by the PBR indexing mechanism. The new PBR indexing mechanism would be put in place as of October 1, 2021, with the first annual rate adjustment taking effect October 1, 2022. The RPC will not be updated in each period for the number of customers the Company serves, as it will be updated early in the plan period as described in the Testimony of the PBR Panel, when growth capital is proposed to be added to rate base.

The Company is proposing that the GDP-PI be used as the *I* factor and, therefore, the *X* factor consists of the difference between changes in industry RPC TFP and economy-wide TFP plus the difference between changes in economy-wide and industry input prices. As discussed above, RPC TFP is the correct measure of TFP to be used in a revenue cap and should not be confused with a pure efficiency measure of TFP.

IV. Productivity Study for the Company's RPC Cap

A. Overview

Q. Would you please review what the *X* factor represents for a revenue per customer cap?

A. For an RPC cap, the rate of change in TFP is measured with customer growth being the unambiguous measure of changes in output—i.e., RPC TFP = $\%\Delta TFP^{R}_{I}$ = $\%\Delta CUSTOMERS_{I} - \%\Delta Q_{I}$. When economy-wide output price inflation, such as the GDP-PI is the measure of inflation (i.e., I_E = GDP-PI), the *X* factor, $X(I_E)$, consists of the differential in expected rates of change in RPC productivity for the industry (i.e., RPC TFP) and overall economy productivity and the differential in expected rates of change in input prices between the overall economy and the industry.

Although $X(I_E)$ is typically determined by a productivity study that, by its very nature, is based on historical information, $X(I_E)$ is forward-looking as it is based on those differentials that are expected to prevail over the course of the PBR term. That is, the historic TFP (and input price) study is used as a predictor of expected performance over this period.

Q. Is your productivity study based on a methodological model that is the same as the model in the Mass. Electric proceeding, D.P.U. 18-150?

A. Yes, it is. There are two data adjustments that we have made to the model. First, a Bureau of Labor Statistics Producer Price Index ("BLS PPI") is used to deflate capital expenses and certain customer service and information ("CS&I") accounts are added to expenses. Another difference between the model accepted in D.P.U. 18-150 exists because SNL Financial does not collect salary information for gas distributors. This changes the source of labor input used in the model. Rather than pulling data directly from a line item on an annual report, the labor quantity is derived from O&M expenses. Therefore, we calculated that labor constitutes 41.5% of O&M expenses across the gas distribution industry and applied this to the available O&M data to obtain a value of labor expense for each company and each year (presented in Exhibit NG-MEM/NAC-4). These adjustments are discussed in greater detail in Appendix A.

Q. Would you explain why you are now using the BLS Producer Price Index to deflate capital expenses rather than a Handy Whitman index as you used in your electric distribution studies?

A. Whitman, Requardt and Associates publishes a gas Handy Whitman Index. However, this index does not contain a measure of total distribution plant that matches the measure of capital used in the study (distribution plant, including storage). The Handy Whitman data contains an index of "Total Plant," which includes production and transmission plant prices, as well as elements of capital included in the study. This is different than the situation in electric distribution where the Handy Whitman price index matched the elements of capital included in the study. Upon testing the "Total Plant" index in the model, we found unreasonable results. The Handy Whitman Index yielded negative capital stocks, which is non-sensical, as no functioning distribution company would have a negative stock of distribution assets. The Handy Whitman index also produces capital growth numbers empirically at odds with industry distribution pipeline data. For these reasons, we opted to use the Producer Price Index for Construction, published by the Bureau of Labor Statistics. For further discussion of the Producer Price Index, see Appendix A.

Q. What is the timeframe and sample you used to determine RPC TFP and input price growth for establishing the *X* factor?

A. The timeframe is the most recent 15 years for which data are available, 2004-2018. The National sample consists of 85 utilities, comprising 71 percent of national gas utility customers. The Northeast sample consists of 29 utilities, comprising 80 percent of northeast gas utility customers.[19] As we describe below, the Northeast sample of utilities provides the most appropriate sample to use for the establishment of the Company's X factor.

B. Study Results

Q. How did you determine changes in gas distribution industry RPC TFP and input prices?

A. Appendix A provides the methodological details of how we determined percent changes in RPC TFP and input prices for the gas distribution industry, including a list

[19] States comprising the Northeast sample are Massachusetts, New York, Pennsylvania, Connecticut, New Hampshire, New Jersey, and Vermont.

of firms in each sample. The comparable economy-wide sources are also provided in Appendix A.

Q. What are the results of your study of U.S. gas distribution utilities?

A. Figure 1 provides the results for rates of change in total output, total input, RPC TFP and input prices for U.S. distribution utilities over the 2004-2018 period. Recall that RPC TFP = $\%\Delta$ Output -$\%\Delta$ Input or column 2 – column 3 = column 4.

Figure 1

RPC TFP Results for National Gas Distribution Industry 2004-2018

Period	Output	Input	RPC TFP	Input Price
2004	-	-	-	-
2005	1.48%	3.06%	-1.58%	5.91%
2006	1.02%	-2.87%	3.89%	5.43%
2007	2.04%	3.09%	-1.04%	2.15%
2008	0.15%	0.16%	-0.01%	2.11%
2009	0.02%	3.60%	-3.58%	3.71%
2010	0.13%	0.25%	-0.12%	0.27%
2011	0.66%	0.97%	-0.31%	2.65%
2012	0.49%	-0.93%	1.42%	2.82%
2013	0.35%	1.88%	-1.53%	1.92%
2014	1.22%	-0.13%	1.35%	1.84%
2015	2.39%	0.61%	1.78%	2.12%
2016	2.72%	1.38%	1.34%	0.85%
2017	0.82%	1.79%	-0.97%	1.35%
2018	0.89%	2.28%	-1.39%	0.07%
Average	**1.03%**	**1.08%**	**-0.05%**	**2.37%**

Q. What are the results of your study of Northeast gas distribution utilities?

A. Figure 2 provides the results for rates of change in total output, total input, RPC TFP and input prices for Northeast distribution utilities over the 2004-2018 period.

Figure 2

RPC TFP Results for Northeast Gas Distribution Industry 2004-2018

Period	Output	Input	RPC TFP	Input Price
2004	-	-	-	-
2005	0.17%	1.34%	-1.16%	5.84%
2006	1.40%	-3.37%	4.77%	5.44%
2007	2.30%	4.61%	-2.30%	2.09%
2008	-0.70%	2.73%	-3.43%	2.11%
2009	0.66%	3.80%	-3.14%	3.63%
2010	0.39%	1.75%	-1.36%	0.36%
2011	0.99%	0.25%	0.74%	2.65%
2012	0.77%	-2.17%	2.95%	2.81%
2013	0.62%	2.45%	-1.82%	1.91%
2014	0.48%	3.24%	-2.76%	1.83%
2015	0.85%	-0.79%	1.65%	2.11%
2016	0.78%	-0.61%	1.39%	0.89%
2017	0.79%	3.46%	-2.67%	1.40%
2018	0.93%	3.66%	-2.73%	0.13%
Average	**0.75%**	**1.45%**	**-0.71%**	**2.37%**

Q. The results of Figures 1 and 2 indicate that the average rates of change in RPC TFP for the gas distribution industry over the 2004-2018 period was negative for both the National sample of companies and the Northeast sample. Would you please explain?

A. Over this period, input growth exceeded output growth for both the National sample and the Northeast sample baseline models. Figure 3 shows that, for the National sample, the greater input growth is attributable to relatively greater capital input growth and, for the Northeast sample, relatively greater materials and capital growth contribute to total input growth being greater than output growth.

Figure 3

Average Output and Input Growth for National and Northeast Gas Distribution Industries
2004-2018

Average	Output	Labor	Materials	Capital	Total Input
National	1.03%	-0.19%	0.97%	1.86%	1.08%
Northeast	0.75%	0.59%	1.74%	1.55%	1.45%

Q. Is there an explanation as to why inputs have grown faster than output (i.e., customer growth) in the gas distribution industry over this period?

A. Yes, as in the electric distribution industry, there is a need in the gas distribution industry to replace aging infrastructure and the modernize gas distribution networks. For gas distribution networks, this largely consists of replacing cast iron and steel mains. For example, using PHMSA data on miles of main pipeline, Figures 4a and 4b below illustrate the replacement of steel and cast-iron mains with plastic in the National and Northeast samples.[20]

[20] The figures are based on percent of miles of pipeline to control for any cost differences between regions. The growth in plastic miles is approximately the same over the 2004-2018 period: 41 percent for the National sample and 39 percent for the Northeast sample. This data is available at the PHMSA website: <https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-mileage-and-facilities>

Figure 4a

Nationwide Miles of Main as a Percentage of Total, by Type 2004-2018

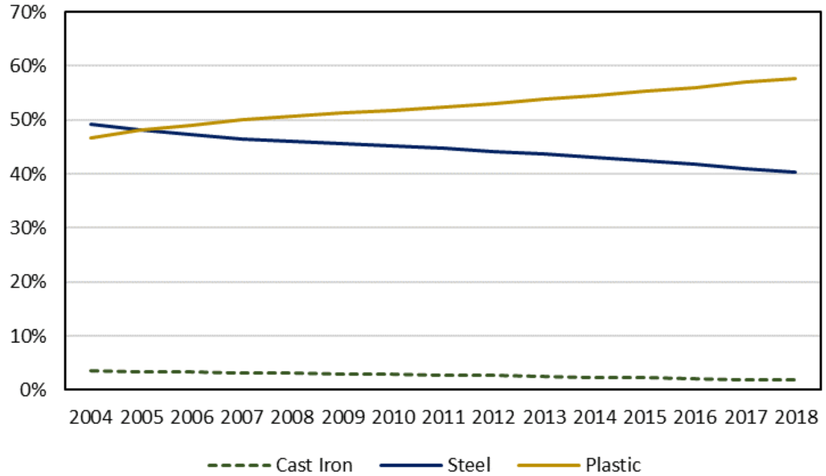
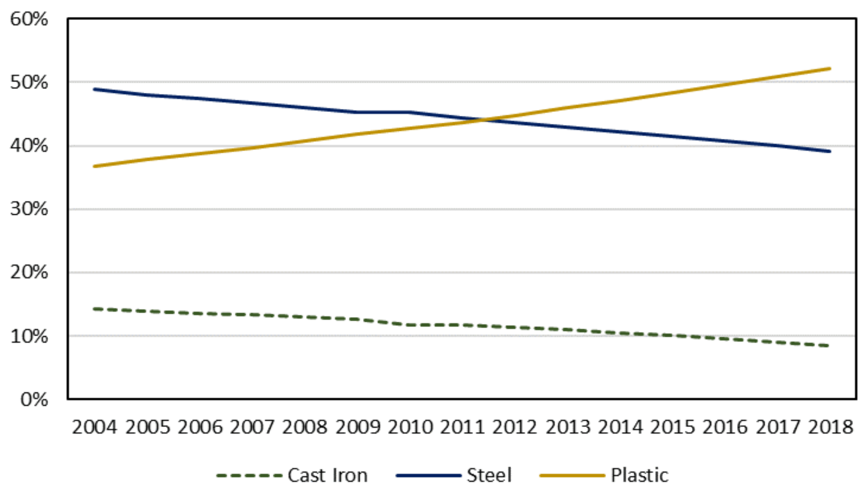


Figure 4b

Northeast Miles of Main as a Percentage of Total, by Type 2004-2018



With respect to RPC TFP, which is not a pure efficiency measure of TFP (as explained above), this relationship where investment is growing faster than measured output does not imply declining industry efficiency. Rather, it recognizes the realities of the gas distribution industry where greater investment has been required by utilities (largely to replacing aging, outdated technologies) to safely and reliably serve their customers.[21]

V. The *X* Factor for the Company's Revenue per Customer Cap

Q. Would you please generally describe your calculation of the *X* factor for the Company's revenue cap?

A. Yes. Since the Company is proposing to use the GPD-PI as the *I* factor, the *X* factor consists of a TFP differential (i.e., the difference between rates of change in RPC TFP and TFP for the overall economy) and an input price differential (i.e., the difference between rates of change in input prices for the overall economy and the industry). Therefore, measures of rates of change in TFP and input prices for the overall economy are needed to compute these differentials.

Q. What are the economy-wide results for changes in TFP and input prices over the 2004-2018 period?

A. Figure 5 provides the economy-wide results over the 2004-2018 period.

21 As discussed below, despite the downward trend in steel and cast iron mains both Nationally and in the Northeast, it is important to note that the Northeast still has a greater proportion of the older cast iron mains and a relatively smaller proportion of plastic mains than the National figures. The percent of steel mains is about the same in the National and Northeast samples.

Figure 5

Economy-Wide Results
2004-2018

Period	GDP PI	TFP	Input Price
2004	-	-	-
2005	3.05%	1.48%	4.53%
2006	3.01%	0.45%	3.46%
2007	2.66%	0.44%	3.10%
2008	1.89%	-1.12%	0.77%
2009	0.78%	0.34%	1.12%
2010	1.16%	2.60%	3.77%
2011	2.06%	-0.24%	1.82%
2012	1.91%	0.60%	2.51%
2013	1.76%	0.37%	2.13%
2014	1.86%	0.50%	2.36%
2015	1.03%	0.91%	1.94%
2016	1.08%	-0.41%	0.67%
2017	1.90%	0.62%	2.52%
2018	2.24%	0.90%	3.15%
Average	**1.89%**	**0.53%**	**2.42%**

Q. What is the *X* factor for the National sample of U.S. gas distribution companies?

A. Figure 6 provides the TFP and input price differentials and the resulting *X* factor using the National gas distribution sample and its RPC TFP and input results over the 2004-2018 period (presented in Exhibit NG-MEM/NAC-5 Confidential).

Figure 6

***X* Factor for the National Gas Distribution Sample**
2004-2018

	TFP			**Input Price**			
Period	**Industry**	**U.S.**	**Difference**	**U.S.**	**Industry**	**Difference**	**X Factor**
2004	-	-	-	-	-	-	-
2005	-1.58%	1.48%	-3.06%	4.53%	5.91%	-1.37%	-4.43%
2006	3.89%	0.45%	3.43%	3.46%	5.43%	-1.97%	1.46%
2007	-1.04%	0.44%	-1.49%	3.10%	2.15%	0.95%	-0.54%
2008	-0.01%	-1.12%	1.11%	0.77%	2.11%	-1.35%	-0.23%
2009	-3.58%	0.34%	-3.93%	1.12%	3.71%	-2.59%	-6.51%
2010	-0.12%	2.60%	-2.73%	3.77%	0.27%	3.50%	0.77%
2011	-0.31%	-0.24%	-0.07%	1.82%	2.65%	-0.83%	-0.90%
2012	1.42%	0.60%	0.82%	2.51%	2.82%	-0.31%	0.51%
2013	-1.53%	0.37%	-1.91%	2.13%	1.92%	0.21%	-1.69%
2014	1.35%	0.50%	0.85%	2.36%	1.84%	0.52%	1.37%
2015	1.78%	0.91%	0.87%	1.94%	2.12%	-0.19%	0.68%
2016	1.34%	-0.41%	1.75%	0.67%	0.85%	-0.17%	1.58%
2017	-0.97%	0.62%	-1.58%	2.52%	1.35%	1.16%	-0.42%
2018	-1.39%	0.90%	-2.30%	3.15%	0.07%	3.08%	0.78%
Average	**-0.05%**	**0.53%**	**-0.59%**	**2.42%**	**2.37%**	**0.05%**	**-0.54%**

Q. What is the *X* factor for the sample of Northeast electric distribution companies?

A. Figure 7 provides the TFP and input price differentials and the resulting *X* factor using the Northeast gas distribution sample and its RPC TFP and input price results over the 2004-2018 period (presented in Exhibit NG-MEM/NAC-6 Confidential).

Figure 7

***X* Factor for the Northeast Gas Distribution Sample**
2004-2018

	TFP			Input Price			
Period	**Industry**	**U.S.**	**Difference**	**U.S.**	**Industry**	**Difference**	**X Factor**
2004	-	-	-	-	-	-	-
2005	-1.16%	1.48%	-2.64%	4.53%	5.84%	-1.30%	-3.94%
2006	4.77%	0.45%	4.32%	3.46%	5.44%	-1.98%	2.34%
2007	-2.30%	0.44%	-2.75%	3.10%	2.09%	1.00%	-1.74%
2008	-3.43%	-1.12%	-2.30%	0.77%	2.11%	-1.35%	-3.65%
2009	-3.14%	0.34%	-3.48%	1.12%	3.63%	-2.52%	-6.00%
2010	-1.36%	2.60%	-3.97%	3.77%	0.36%	3.41%	-0.56%
2011	0.74%	-0.24%	0.97%	1.82%	2.65%	-0.83%	0.14%
2012	2.95%	0.60%	2.35%	2.51%	2.81%	-0.30%	2.05%
2013	-1.82%	0.37%	-2.20%	2.13%	1.91%	0.22%	-1.98%
2014	-2.76%	0.50%	-3.26%	2.36%	1.83%	0.53%	-2.72%
2015	1.65%	0.91%	0.73%	1.94%	2.11%	-0.18%	0.56%
2016	1.39%	-0.41%	1.80%	0.67%	0.89%	-0.22%	1.58%
2017	-2.67%	0.62%	-3.28%	2.52%	1.40%	1.11%	-2.17%
2018	-2.73%	0.90%	-3.64%	3.15%	0.13%	3.02%	-0.62%
Average	**-0.71%**	**0.53%**	**-1.24%**	**2.42%**	**2.37%**	**0.04%**	**-1.19%**

Q. Figures 6 and 7 indicate that the *X* factor for the National sample and the Northeast samples is negative. Is it reasonable for the *X* factor to be negative?

A. Yes, it is. A negative *X* factor largely follows from the fact that the measure of RPC TFP has been negative, on average, over the 2004-2018 period and the fact that economy-wide TFP grew faster over this period. We discussed the reasons for a negative RPC TFP in the gas distribution industry above. The recent decisions by the

Department in the Mass. Electric, NSTAR Electric and NSTAR Gas proceedings confirm the validity of a negative *X* factor.[22]

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

A. 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—i.e., the profit motive is fully operative—and this incentive is not dependent on the magnitude or sign of the *X* factor.[23] The *X* factor simply reflects the competitive benchmark that is expected to 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.

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22 D.P.U. 17-05, November 30, 2017; D.P.U. 18-150, September 30, 2019; D.P.U. 19-120, October 30, 2020.

23 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.

Q. In your opinion, what is the appropriate basis of the *X* factor for the Company's revenue cap?

A. The calculations derived from the Northeast sample provide that appropriate basis for the Company's X factor because there are substantial differences between the National sample and the Northeast sample in the growth of the components of RPC TFP. For example, Figure 8 shows average Northeast output growth over the 2004-2018 period is 0.28 percentage points less than average output growth in the National sample. However, average Northeast total input growth over this period is 0.37 percentage points greater than in the National sample. Thus, the Northeast sample has more negative average TFP growth. The largest difference in input growth between the Northeast and National Samples occurs with labor and materials inputs, which both have average growth 0.77 percentage points greater for the Northeast sample than the National sample. Conversely, average capital input growth is lower in the Northeast sample than the National sample.

Figure 8

Comparison of National and Northeast Output and Input Results
2004-2018 Averages

Average	Output	Labor	Materials	Capital	Total Input	TFP
National	1.03%	-0.19%	0.97%	1.86%	1.08%	-0.05%
Northeast	0.75%	0.59%	1.74%	1.55%	1.45%	-0.71%
NE Pct Point Difference From:						
National	-0.28%	0.77%	0.77%	-0.31%	0.37%	-0.65%

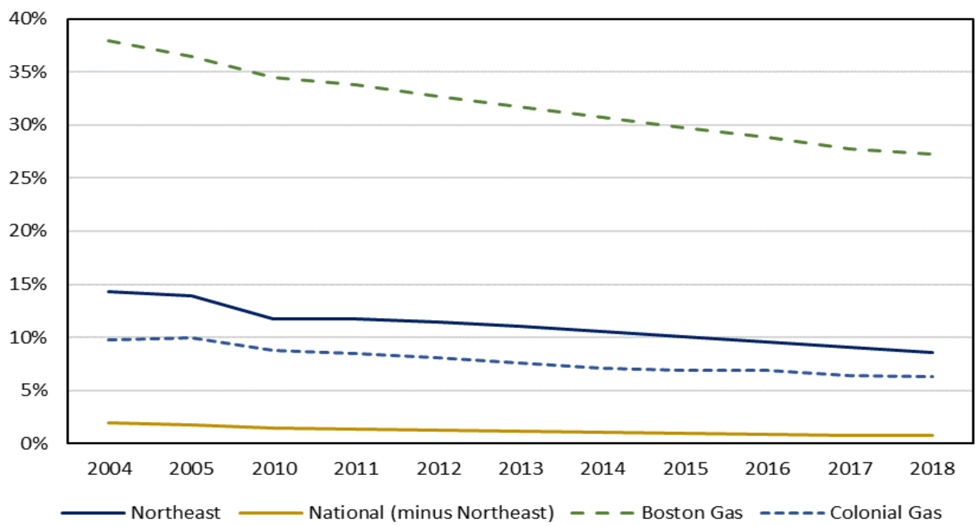
Additionally, a significant difference exists between the National and Northeast samples with respect to the infrastructure of the utilities serving the areas. Figure 9 shows that although the existence of cast iron distribution pipeline as a percent of total distribution miles is diminishing across the U.S. and the Northeast, the Northeast region and the Company's service territory still have a much larger percentage of cast iron distribution pipeline than the rest of the nation. In 2018, cast iron as a percent of total distribution miles was 27 percent for the Boston Gas service territory, six percent for the former Colonial Gas service territory, nine percent for the Northeast region and only one percent for the rest of the nation.

Figure 10 shows that although the proportion of plastic pipeline is growing as a percent of the total across the U.S. and the Northeast, the Northeast region and the Boston Gas and former Colonial Gas service territories have a relatively smaller proportion of plastic pipeline than the rest of the nation. In 2018, plastic as a percent of total distribution miles was 41 percent for the Boston Gas service territory, 52 percent for the former Colonial Gas service territory, 52 percent for the Northeast region and 59 percent for the rest of the nation. These proportions have a direct impact on operating costs. Distribution systems with higher proportions of cast iron, like the Company and other companies in the Northeast, experience higher operating expenses due to gas leaks, and there is an increased emphasis on capital replacement programs in the

Northeast, and Massachusetts in particular, to reduce further the number of miles of leak prone pipe in the ground.[24]

Figure 9

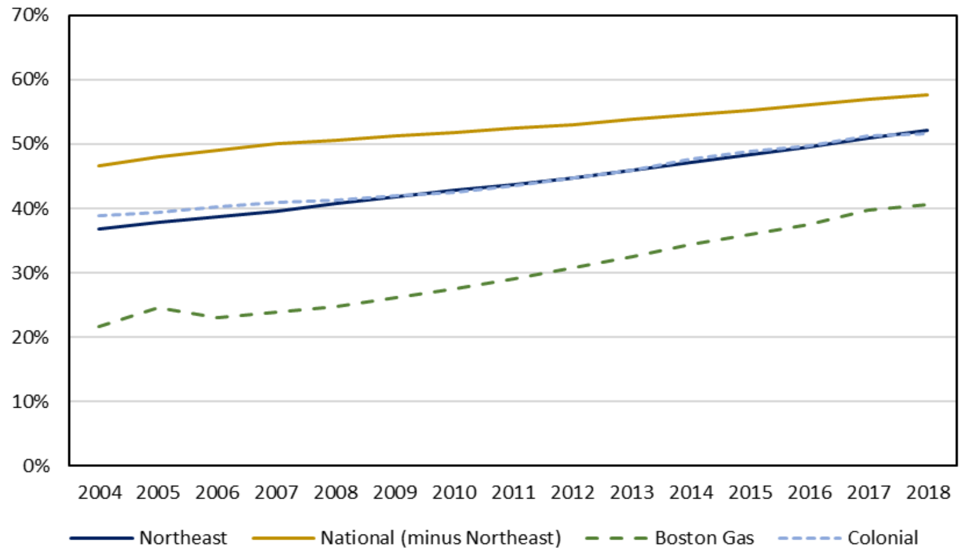
Cast Iron Distribution Pipeline as Percent of Total Distribution Miles 2004-2018



[24] Please see the Benchmarking Study conducted by Dr. Lawrence R. Kaufmann (Exhibit NG-LRK-2).

Figure 10

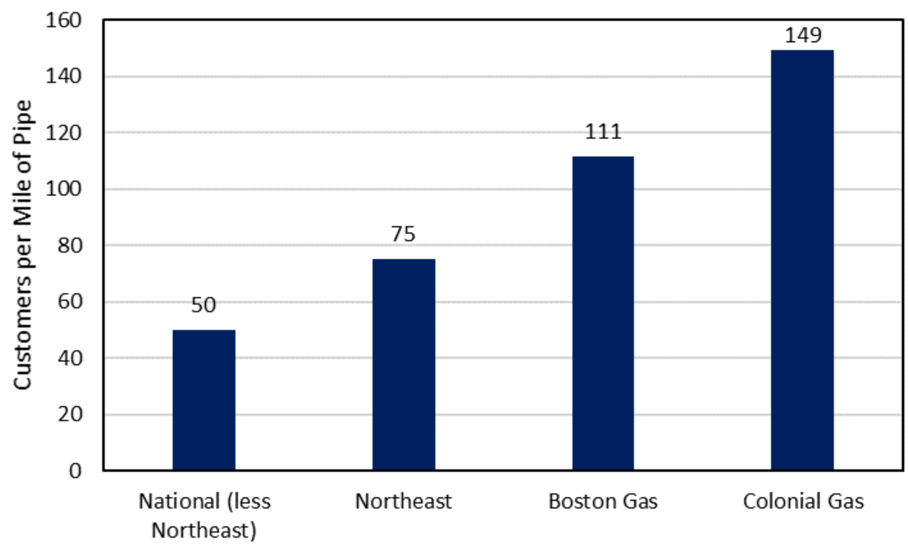
Plastic Distribution Pipeline as a Percent of Total Distribution Miles 2004-2018



1 Lastly, Figure 11 shows 2018 customers per mile of main, a measure of density. In general, density is associated with costs and productivity—i.e., firms with similar densities are likely to have similar cost and productivity performance. The density of service areas in the Northeast (75 customers per mile) is greater than the rest of the nation (50 customers per mile) with the Boston Gas (111 customers per mile) and the former Colonial Gas (149 customers per mile) service territories having much greater density than the rest of the nation.

Figure 11

**Customers per Mile of Main
2018**



Q. Does your X factor calculation include an adjustment for capital expenditures associated with the Gas System Enhancement Program (GSEP)?

A. No, it is not necessary or appropriate. The GSEP is a targeted cost recovery mechanism aimed at enabling the accelerated replacement of leak-prone natural gas pipeline in Massachusetts, which is distinct from the calculation of the X factor. The X factor we have calculated for the PBR mechanism is based on industry TFP measurement, which measures changes in physical productivity and not how incurred costs are recovered. The X factor is calibrated to adjust an annual revenue requirement, not for the purpose of accelerated retirement of leak-prone pipes. As such, cost recovery under GSEP falls outside the purview of the X factor calibration.

Moreover, with respect to the TFP calculation underpinning the X factor, real capital additions funded through GSEP are likely matched by real retirements of the replaced pipeline taken out of service. Therefore, neither capital input nor TFP would be materially modified by GSEP pipe replacement on a net basis. The GSEP program does not bias the X factor one way or the other.

Lastly, even if one wanted to identify capital funded through GSEP, data do not exist at a sufficiently granular level to segregate capital that was funded through GSEP versus capital funded through revenue requirements.

Q. Have you reviewed the Department's Order issued on October 30, 2020 regarding the PBR plan set forth by NSTAR Gas in D.P.U. 19-120?

A. Yes.

Q. In its D.P.U. 19-120 decision, the Department directed that NSTAR Gas Company agree to a stay-out period of 10 years. Is your X factor calibration suitable for a 10-year PBR term?

A. The X factor presented in our testimony is based on a TFP and input price study using historical data from years 2004 through 2018. The historical data is used to calibrate a forward-looking revenue cap that will determine Company revenues for every year in the PBR term. As the Company moves ahead into each additional year in the PBR term, the data underlying the RPC cap falls further back in history. Industry changes, or changes in the economy at large, will, over time, alter the TFP and input price differentials that establish the RPC cap. Accordingly, a five-year PBR term is long enough to provide the Company with efficiency incentives, but short enough that a wedge is not driven between the X factor, as calculated using historical data, and the X factor as it would be calculated with more contemporary data. Without an ability to adjust the RPC cap to account for potential and largely unforeseen changes over the term of the plan, a 10-year term is unusually long and, possibly, too long.

As an example, price cap regulation was established by Congress in 2006 for the U.S. Postal Service. The term of the plan was set for ten years and there was little accommodation for review or adjustment to the plan over its 10-year term. Because of unforeseen changes over this period, particularly a precipitous decline in First Class mail volume, the Postal price cap became a detriment to the financial stability of the U.S. Postal Service without statutory or regulatory means to make needed mid-course changes to the plan.[25]

[25] For example, see Philip Schoech, Mark Meitzen and Michael Kubayanda, "Revisiting the CPI-Based Price Cap Formula for the U.S. Postal Service," 2012 Eastern Conference, Center for Research in Regulated Industries.

Q. In its D.P.U. 19-120 decision, what was the Department's determination about the necessity of adjusting the X factor to account for GSEP?

A. Consistent with our methodological assessment noted above, the Department determined that no GSEP adjustment to the X factor was necessary. The Department stated that the PBRM is not a cost recovery mechanism and, also, that the cost recovery associated with the GSEP represents a distinct recovery mechanism that is not a comprehensive capital recovery mechanism:

> The PBRM, unlike the GSEP, is not a recovery mechanism, and therefore 'double recovery' is not a concern. The X factor estimates productivity based on industry-wide past performance and is then applied to escalate the Company's revenue requirement as a whole. It is not intended for recovery of any specific costs.[26]

The PBR mechanism, by contrast, annually adjusts a company-wide revenue requirement. If the GSEP results in revenues above the accepted revenue stream, overearnings will be returned to customers through the ESM.

Q. In D.P.U. 19-120, what sample did the Department determine was appropriate for establishing the X factor for NSTAR Gas?

A. The Department determined that the Northeast sample was appropriate for gas distribution in its NSTAR Gas decision.[27]

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[26] D.P.U. 19-120, October 30, 2020, p. 96.

[27] D.P.U. 19-120, October 30, 2020, p. 81.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A. STUDY METHODS

This study of total factor productivity ("TFP") is specifically designed to be used in developing the *X* factor for a revenue per customer cap. *Revenue per customer cap TFP* ("RPC TFP") is specified as:

$$\text{RPC TFP} = \%\Delta\ TFP^{R}_{I} = \%\Delta CUSTOMERS_{I} - \%\Delta Total\ Input_{I}$$

Where $\%\Delta CUSTOMERS_I$ represents the measure of industry output for RPC TFP and $\%\Delta Total\ Input_I$ is an index of industry total input. This study is performed using the methodology and approach accepted by the Massachusetts Department of Public Utilities in NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy, D.P.U. 17-05 (2017), as well as Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 18-150 (2019) for the estimation of electric distribution industry TFP. However, certain refinements were implemented to attune the model to the gas industry. Specifically, the model incorporates Customer Service and Information ("CS&I") expenses, and, as in the model accepted under D.P.U. 18-150, the model also incorporates customer accounts and sales expenses. However, accounts that contain Demand Side Management ("DSM") expenses were removed from each of these two categories as appropriate.[28] Administrative and general ("A&G") expenses were also included in the computation of Total Input, apportioned by percentage of distribution plant by company,

[28] For utilities in Massachusetts, DSM expenses were booked in Account 905. For all other utilities, DSM expenses were booked in Account 908.

as in D.P.U. 18-150.[29]

Additionally, a change was made to the index used to deflate plant data and to determine a capital rental price. This study uses the Producer Price Index for Construction, published by the Bureau of Labor Statistics. Whereas the electricity models deflated capital using the Handy Whitman Index, published by Whitman, Requardt and Associates, the present gas distribution study employs the Producer Price Index published by the Bureau of Labor Statistics. While Whitman, Requardt and Associates publishes a gas Handy Whitman Index, this index does not contain a measure of total distribution plant. The data contains a price index of components of distribution plant, such as meters or steel mains, but it does not contain an aggregated index of all distribution plant prices. Instead, the data contains an index of "Total Plant," which includes production and transmission plant prices, as well as distribution plant.

As a sensitivity analysis, we tested the Handy Whitman "Total Plant" index in the TFP model, even though it contains production and transmission plant. As expected, this analysis yielded unreasonable results. Substituting the Total Plant index into the model generated negative capital stocks for six companies. In other words, by the end of the study period, the model indicates these companies had no plant and equipment as part of the operations, which is

[29] A&G accounts reflect the costs of activities that span the functional components of the utility—e.g., distribution, transmission and production. Therefore, the assignment of a portion of these expenses to the distribution function requires that these A&G expenses be apportioned to the utilities' functional components in a non-causal manner. Because there is not a causal relationship between the joint and common A&G expenses and the functional components of the utility, there is no economically unique or acknowledged method to assign these expenses to the distribution functions. However, this methodology was accepted by the Department in D.P.U. 18-150.

obviously incorrect. For other companies, we found that the capital stocks were declining at an implausible rate over the study period.

To further test this issue, we compared the percentage of capital growth across all companies over the study period with the Pipeline and Hazardous Materials Safety Administration (PHMSA) data for miles of main. We found that the average annual capital growth calculated using the Handy Whitman "Total Plant" index is far from the physical plant growth measured by PHMSA. When the model is run using the BLS Producer Price Index for Construction materials, the model's measured growth in capital is closer to the growth in miles of main according to the PHMSA. Miles of main constitutes approximately half of distribution plant measured by this TFP study (see the Average Service Life analysis), so while "miles of main" does not cover all distribution plant and does not cover quality changes in distribution plant over time, it serves as a reasonable proxy.[30] Figure A.1 below, compares the model's calculated annual capital growth using both price indices against the PHMSA miles of main data.

Figure A.1
Average Annual Percent Growth
2004-2018

Captial Deflator	Calculated Capital	Miles of Main (PHMSA)
HW Index	-0.70%	1.36%
Producer Price Index	1.86%	1.36%

[30] In addition, the study includes storage plant, which would not be accounted for in miles of main.

A listing of firms in the sample is provided in Figure A.3, along with data sources for each firm.

Output

Because the results of the study are to be applied to a revenue per customer cap, it is appropriate to base the output measure on the number of customers served. In a revenue per customer cap, the number of customers is the "dual" output measure to the revenue per customer cap (that is revenue per customer times the number of customers equals total revenue).

The data source for the output measure is "Sales to Ultimate Customers" found in the EIA 176 reports, though for companies and years for which EIA did not have this data, customer counts were supplemented using SNL Financial data.

Distribution Labor

Since SNL Financial does not maintain records of wages and salaries by company, we calculated labor input as a percentage of Operations and Maintenance (O&M) costs across the gas distribution industry. The percentage of O&M expenses attributable to labor was calculated by multiplying the average industry compensation[31] by the average number of employees at each company in the sample for which data was available,[32] to obtain a total compensation value for each company. For each company, this total compensation value was

[31] Total Compensation was obtained from the American Gas Association Table 13.2A, "Gas Utility Industry Employees and Payroll by Type of Payroll and Type of Company."

[32] Average number of employees by company was obtained from SNL Financial.

then divided by total O&M expenses to obtain an estimated labor percentage of O&M. The company-level labor percentage of O&M was averaged across all companies. This calculation estimated that 41.5% of O&M expenses were attributable to labor.[33] This value was corroborated using Input/Output data published by the Bureau of Economic Analysis (BEA).[34] The price of labor is based on the Bureau of Labor Statistics Employment Cost Index for utility industry total compensation,[35] with the quantity index of labor derived by dividing the cost of labor by its price.

Distribution Materials

To measure distribution materials input, we base materials cost on operating and maintenance expense for distribution from SNL Financial, less labor compensation described above. The price of materials is based on the Bureau of Economic Analysis Gross Domestic Product Price Index, while the quantity of materials is derived by dividing the cost of materials by its price.

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33 This methodology expanded upon the work by London Economics, Inc. in docket D.P.U. 19-120.

34 The BEA publication can be found here: https://www.bea.gov/industry/input-output-accounts-data. This data suggests 43% of O&M expenses are attributable to labor, using the following calculation:

$$\text{Labor, as a Percentage of O\&M} = \frac{\text{Compensation of Employees}}{(\textit{Total Intermediate Inputs} - \textit{Gas Extraction}) + \textit{Compensation of Employees}}$$

35 Bureau of Labor Statistics, Total Compensation for Private industry workers in Utilities, 12-month percent change, Series ID CIU2014400000000I (http://www.bls.gov/ncs/ect/)

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:

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 (927)
less Maintenance of General Plant (932)

From this summation, the following items were subtracted:[36]

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

The model incorporates CS&I expenses, and, as in the model accepted under D.P.U. 18-150, the model also 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

36 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.

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. 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 principled, 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.[37] 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

[37] 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. See 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.

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 the same regulatory, non-economic apportionment principle for assigning A&G expenses to distribution that was accepted under D.P.U. 18-150. Specifically, 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, 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

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 is derived from a perpetual inventory equation, while the price of capital input is derived from an "implicit rental price" equation.

A. Quantity of Capital Input

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. Capital stock retirements are determined through the one hoss shay model.[38] 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[39] does not deteriorate as the asset ages.[40]

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:

$$K_t = K_{t-1} + I_t - R_t$$

To estimate the quantity of additions during the year, we divide distribution additions to plant in service (see Figure A.4) by the Producer Price Index for construction materials. To estimate the quantity of retirements during the year, we divide distribution retirements from plant in service (see Figure A.4) by an appropriately lagged value of the Producer Price Index for construction materials. We use a lag of 51 years. This lag represents the approximate average

38 As with the electric distribution studies approved in D.P.U. 17-05 and D.P.U. 18-150, the one-hoss-shay efficiency decay method is appropriate for gas distribution. LEI has also used one-hoss shay in its study of the gas distribution industry in D.P.U. 19-120.

39 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.

40 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.

age of assets as they were retired over the course of the study period (see Exhibit NG-MEM/NAC-7).[41]

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 SNL Financial database was 1998, so this is the year we 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.

[41] To calculate the average service life of distribution plants among gas distribution utilities, we began by auditing the study put forth by LEI for Eversource Gas in proceeding D.P.U. 19-120. This meant checking the numbers in the study against those we found in depreciation studies that LEI cited. We removed observations in the LEI study that we could not confirm. We then augmented their study by finding 12 additional depreciation studies from companies in our sample in an effort to confirm that LEI's 51-year average was a reasonable assumption.

We also improved upon the method by which LEI calculated a final weighted average. LEI weighted the average service life of plant from each FERC account only by the percent that each account, on average, compromises of a total distribution plant. In addition to this weight, our study first calculates an average by each account, weighted by company customer count to control for company size, thereby giving larger companies more importance in our estimate. Our work resulted in an average service life of 51.1 years, which falls in line with LEI's calculations.

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.

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

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.

$$KS_t = K_{t-1}$$

B. 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 has the following mathematical representation.

$$PK_t = \frac{1 - uz}{1 - u}(r - i)\left[1 - \left(\frac{1 + i}{1 + r}\right)^{51}\right]^{-1} PPI_{t-1}$$

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 51 is the price formula represents the asset life used in the perpetual inventory equation.

Based on tax law, we use a federal corporate tax rate of 35% for u (adjusted to 21% after 2017), adding state tax to this value, 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.[42] We apply this alternative by computing the average cost of capital rate and the average inflation rate over the 2004-2018 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.[43] The average inflation rate is based on the Consumer Price Index for All Urban Consumers.[44]

42 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.

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

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

Total Input

We construct the quantity index of total input for each firm and each year by using the multilateral Tornqvist indexing procedure.[45] The multilateral Tornqvist index has the form:

$$ln(X_{i,t}) = .5 \cdot \sum_{j=1}^{3} \left(sy_{jit} + \overline{sy_j}\right) \cdot \left(lnX_{jit} - \overline{lnX_j}\right)$$

Where

i = firm (i = 1 … 85)

t = period (t = 2004 … 2018)

j = input (j = 1 … 3)[46]

$X_{i,t}$ = the quantity of total input for firm i in period t

X_{jit} = the quantity of input j for firm i in period t

sy_{jit} = the cost share of input j for firm i in period t

A bar above a variable represents the average value over all firms and all years.

Similarly, the price of total input is computed as a multilateral Tornqvist index of the prices of the individual inputs. The index formula has the form:

[45] The multilateral Tornqvist index was developed in D.W. Caves, L.R. Christensen, and W.E. Diewert, "Multilateral Comparisons of Output, Input, and Productivity Using Superlative Index Numbers," *The Economic Journal*, Vol. 92, 1982, at 73-86.

[46] As described above, the inputs are distribution labor, distribution materials, and capital.

$$ln(P_{i,t}) = .5 \cdot \sum_{j=1}^{3} \left(sy_{jit} + \overline{sy_j}\right) \cdot \left(lnP_{jit} - \overline{lnP_j}\right)$$

Where

i = firm (i = 1 … 85)

t = period (t = 2004 … 2018)

j = input (j = 1 … 3)[47]

$P_{i,t}$ = the price of total input for firm i in period t

P_{jit} = the price of input j for firm i in period t

sy_{jit} = the cost share of input j for firm i in period t

A bar above a variable represents the average value over all firms and all years.

Industry Total Output Growth, Total Input Growth, TFP Growth, and Total Input Price Growth

Once the quantity of output, the quantity of total input, and the price of total input is computed for each firm and each year, one can determine the industry rates of growth. In computing industry rates of growth, each firm is weighted by the its relative number of customers. Denoting the number of customers by CUST, the weighting factors for each firm are computed as follows:

$$s_i = \frac{CUST_{it}}{\sum_i CUST_{it}}$$

[47] Once again, the inputs are distribution labor, distribution materials, and capital.

The industry rate of total output growth for the RPC measure of TFP is then derived from the following formula:

$$ln\left({}^{Y_t}/_{Y_{t-1}}\right) = \sum_i s_i \cdot ln\left({}^{CUST_{it}}/_{CUST_{i,t-1}}\right)$$

The industry rate of total input growth is likewise computed using the formula:

$$ln\left({}^{X_t}/_{X_{t-1}}\right) = \sum_i s_i \cdot ln\left({}^{X_{it}}/_{X_{i,t-1}}\right)$$

The industry rate of total input price growth is computed using the formula:

$$ln\left({}^{P_t}/_{P_{t-1}}\right) = \sum_i s_i \cdot ln\left({}^{P_{it}}/_{P_{i,t-1}}\right)$$

Lastly, the industry rate of RPC TFP growth is the difference between the industry rate of total output growth (given by the growth in customers) and the industry rate of total input growth:

$$\ln\left({}^{TFP_t}/_{TFP_{t-1}}\right) = \ln\left({}^{Y_t}/_{Y_{t-1}}\right) - \ln\left({}^{X_t}/_{X_{t-1}}\right)$$

Figure A.2 provides average growth of input components for the National Sample and Northeast Sample.

Figure A.2
Average Output and Input Growth for Gas Distribution Industry
2004-2018

	Output	Labor	Capital	Materials	Total Input
National	1.03%	-0.19%	0.97%	1.86%	1.08%
Northeast	0.75%	0.59%	1.74%	1.55%	1.45%

Sample and Data Sources

The national sample consists of 85 firms across 32 states. The Northeast sample consists of 29 companies in Massachusetts, New York, Pennsylvania, Connecticut, New Hampshire, New Jersey, and Vermont. The EIA Form 176 provided customer count data for most of these companies. In cases where the EIA did not have customer count data available, we used SNL Financial to fill in missing dates. SNL Financial served as the primary source of input data, although for two companies this data was supplemented by the FERC Form 2. In a limited number of observations, gaps existed in the SNL Financial data. To fill these holes in the data, we obtained annual filings from state commissions. If data was missing after this process, we interpolated gaps using surrounding data. Figure A.3 shows the companies included in the study, with an asterisk indicating which companies were included in the Northeast sample.

Figure A.3
List of Companies in Sample

ARKANSAS OKLAHOMA GAS CORP.	NORTH SHORE GAS COMPANY
ATLANTA GAS LIGHT COMPANY	NORTHERN ILLINOIS GAS COMPANY
AVISTA CORPORATION	NORTHERN INDIANA PUBLIC SERVICE COMPANY
BALTIMORE GAS AND ELECTRIC COMPANY	NORTHERN STATES POWER COMPANY - WI
BAY STATE GAS COMPANY*	NORTHWEST NATURAL HOLDING COMPANY
BERKSHIRE GAS COMPANY*	NSTAR GAS COMPANY*
BLACK HILLS ENERGY ARKANSAS, INC.	OHIO GAS COMPANY
BLUEFIELD GAS COMPANY	OHIO VALLEY GAS CORPORATION
BOSTON GAS COMPANY*	OKLAHOMA NATURAL GAS COMPANY
BROOKLYN UNION GAS COMPANY*	ORANGE AND ROCKLAND UTILITIES, INC.*
CASCADE NATURAL GAS CORPORATION	PACIFIC GAS AND ELECTRIC COMPANY
CENTRAL HUDSON GAS & ELECTRIC CORPORATION*	PECO ENERGY CO.*
CHATTANOOGA GAS COMPANY	PEOPLES GAS LIGHT AND COKE COMPANY
CITIZENS GAS FUEL COMPANY	PEOPLES GAS SYSTEM
COLONIAL GAS COMPANY*	PHILADELPHIA GAS WORKS CO.*
COLUMBIA GAS OF KENTUCKY, INCORPORATED	PIKE COUNTY LIGHT AND POWER COMPANY*
COLUMBIA GAS OF MARYLAND, INCORPORATED	PIKE NATURAL GAS CO
COLUMBIA GAS OF OHIO, INC.	PUBLIC SERVICE COMPANY OF NORTH CAROLINA
COLUMBIA GAS OF PENNSYLVANIA, INC.*	PUBLIC SERVICE ELECTRIC AND GAS COMPANY*
COLUMBIA GAS OF VIRGINIA, INCORPORATED	PUGET SOUND ENERGY, INC.
CONNECTICUT NATURAL GAS CORPORATION*	QUESTAR GAS COMPANY
CONSOLIDATED EDISON COMPANY OF NEW YORK*	ROCHESTER GAS AND ELECTRIC CORPORATION*
CONSUMERS ENERGY COMPANY	SAN DIEGO GAS & ELECTRIC COMPANY
CORNING NATURAL GAS CORPORATION*	SIERRA PACIFIC POWER COMPANY
DELTA NATURAL GAS COMPANY, INC.	SOUTH JERSEY GAS COMPANY*
DTE GAS COMPANY	SOUTHERN CALIFORNIA GAS COMPANY
DUKE ENERGY KENTUCKY, INC.	SOUTHERN CONNECTICUT GAS COMPANY*
DUKE ENERGY OHIO, INC.	SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
FILLMORE GAS COMPANY, INC.*	SPIRE MISSISSIPPI INC.
HOPE GAS, INC.	SPIRE MISSOURI INC.
ILLINOIS GAS COMPANY	ST. JOE NATURAL GAS CO, INC.
INDIANA GAS COMPANY, INC.	ST. LAWRENCE GAS COMPANY, INC.*
KANSAS GAS SERVICE COMPANY, INC.	SUPERIOR WATER, LIGHT AND POWER COMPANY
LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS)*	THE EAST OHIO GAS COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY	UGI PENN NATURAL GAS, INC.*
MADISON GAS AND ELECTRIC COMPANY	VERMONT GAS SYSTEMS, INC.*
MIDWEST NATURAL GAS CORPORATION	VIRGINIA NATURAL GAS, INC.
MIDWEST NATURAL GAS, INC.	WASHINGTON GAS LIGHT COMPANY
MOUNTAINEER GAS COMPANY	WISCONSIN GAS LLC
NATIONAL FUEL GAS DISTRIBUTION CORPORATION*	WISCONSIN POWER AND LIGHT COMPANY
NEW JERSEY NATURAL GAS COMPANY*	WYOMING GAS COMPANY
NEW YORK STATE ELECTRIC & GAS CORPORATION*	YANKEE GAS SERVICES COMPANY*
NIAGARA MOHAWK POWER CORPORATION*	

*Northeast

TFP and Input Price for the U.S. Economy

The Gross Domestic Product Price Index (GDPPI)[48] is a comprehensive measure of output prices in the U.S. economy. Changes in the GDPPI over time are driven by changes in input prices for the U.S. economy and changes in total factor productivity in the U.S. economy. Using W_E to represent input prices for the U.S. economy and TFP_E to represent total factor productivity in the U.S. economy, the percentage change in the GDPPI is related to percentage changes in economy-wide input prices and total factor productivity in the following way.

$$\%\Delta GDP\text{-}PI = \%\Delta W_E - \%\Delta TFP_E$$

The broadest measure of total factor productivity for the U.S. economy is the BLS multifactor productivity index for the private business sector.[49] We use the private business sector multifactor productivity index as a proxy measure of total factor productivity in the U.S. economy. To obtain a measure of input price changes for the U.S. economy, we rearrange terms in the above equation to obtain:

$$\%\Delta W_E = \%\Delta TFP_E + \%\Delta GDP\text{-}PI$$

Having obtained a proxy measure of total factor productivity for the U.S. economy, we can simply calculate the percentage change in U.S. economy input prices for any given year by

48 U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts, Table 1.1.4, line 1. (http://www.bea.gov/iTable/index_nipa.cfm)

49 U.S. Department of Labor, Bureau of Labor Statistics, Multifactor Productivity for the Private Business Sector, Series ID MPU4900012 (02). (http://www.bls.gov/mfp/)

adding the percentage change in GDPPI and the percentage change in U.S. economy total factor productivity.

Supporting Documentation

There are two workbooks that show the computations underlying the results for the nationwide sample and the Northeast subsample. Results for the nationwide subsample are found in the workbook “National Model,” (Exhibit NG-MEM/NAC-5 Confidential) while the results for the Northeast subsample are found in the workbook “Northeast Model” (Exhibit NG-MEM/NAC-6 Confidential). Both workbooks have the same structure. The worksheet “RoR” shows the Moody’s bond yields that were used in the analysis, the worksheet “CPI” shows the downloaded Consumer Price Index, the worksheet “Priv Biz MFP” shows the downloaded multifactor productivity index for the private business sector, the worksheet “GDP-PI” shows the downloaded Gross Domestic Product Price Index, the worksheet “ECI” shows the downloaded Employment Cost Index, and the worksheet “PPI-Construction” shows the downloaded Producer Price Index for Construction.

The worksheet “Capital Stock” shows the computations of the capital stock index using the perpetual inventory equation described above, while the worksheet “Calculation” shows the other calculations that underlie the TFP results for each firm and year. In the Calculation worksheet, Columns G through M show the computation of the price, quantity, and value of labor input. Columns O through W show the computation of the price, quantity, and value of material input. Columns Y through AJ show the computation of the price, quantity, and value of capital input. Columns AL through BT show the computation of the quantity of total input that results from the application of the multilateral Tornqvist index formula. Lastly, the worksheet "Results" shows the final results for the nationwide sample and the Northeast subsample.