INCENTIVE RATE-SETTING MECHANISM

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1. The purpose of this evidence is to support Enbridge Gas's request for a multi-year incentive rate-setting mechanism (IRM) to be used to set regulated distribution, transportation, and storage rates for the period January 1, 2025, to December 31, 2028 (IR term), pursuant to Section 36 of the Ontario Energy Board Act, 1998, as amended (the Act). Enbridge Gas is proposing rates during the IR term be set based on a Price Cap Incentive Rate-setting (Price Cap IR) mechanism and associated parameters. The OEB's Filing Requirements for Natural Gas Rate Applications state that under a Price Cap IR, "base rates are set through a Cost of Service process for the first year and then adjusted in years two through five using a formula specific to each year (Price Cap IR)".[1] As proposed in this Application, the first year of the IR term will apply the Price Cap IRM parameters to rates set through Cost of Service for 2024. This IRM proposal is largely consistent with the IRM approved by the OEB and in place over the period 2019 to 2023. The main difference is a proposal of a two-factor inflation factor, which will be discussed further below.

2. The parameters proposed for the Price Cap IR include:
   a) An annual rate adjustment mechanism using a Price Cap Index (PCI), where PCI is determined by an inflation factor (I), less a productivity factor and a stretch factor (X = Productivity + Stretch)

[1] Filing requirements For Natural Gas Rate Applications, February 16, 2017.

b) A Y factor adjustment for costs that are incremental to the costs subject to Price Cap escalation, (i.e., pass-through items or costs approved in other proceedings and implemented as part of the annual rate application)
c) A Z factor adjustment to address material changes in costs associated with unforeseen events outside of the control of management
d) An Incremental Capital Module (ICM) to address incremental capital investment needs
e) An Off-Ramp Mechanism
f) An Earnings Sharing Mechanism (ESM)

3. Enbridge Gas retained Black & Veatch Management Consulting (Black & Veatch) to undertake Total Factor Productivity (TFP) and benchmarking research for an overall X factor (Productivity + Stretch) recommendation and an inflation factor recommendation to support the Company's IRM proposal. The resulting study titled "Total Factor Productivity, Benchmarking, And Recommended Inflation and X Factors for Enbridge Gas Inc. Incentive Rate-Setting Mechanism" (Black & Veatch Study) is provided at Attachment 1.

4. This evidence is organized as follows:
    1. Price Cap Incentive Rate-Setting Mechanism
    2. Y Factors
    3. Z Factor adjustments
    4. Incremental Capital Module
    5. Off-Ramp
    6. Earnings Sharing Mechanism
    7. Annual Adjustment Process and Reporting
    8. Customer Protection Measures

1. Price Cap Incentive Rate-Setting Mechanism (IRM)

5. The OEB provides two options for natural gas utilities for setting rates: Price Cap IR and Custom IR.[2] Price Cap IR is the standard rate setting approach.[3] Enbridge Gas is proposing a Price Cap IR with an ICM option and associated parameters for the purpose of setting rates during the IR term. Enbridge Gas's proposal is in line with the OEB's expectation that the Price Cap IR should be appropriate for utilities for setting rates.

6. A Price Cap IR provides incentives for the utility to implement comprehensive, longer term productivity improvements which are then passed on to customers at the next rebasing and results in more stable and predictable rates. This method of setting rates will also provide the Company flexibility in managing costs effectively to ensure the continued safe and reliable operation of the gas distribution system. Rates set under a Price Cap IR is in line with customer expectations as per Enbridge Gas's customer engagement study conducted by Innovative Research Group provided at Exhibit 1, Tab 6, Schedule 1.

7. Enbridge Gas expects that rates set under a Price Cap IR will allow the Company to manage its investment needs and allow the Company to earn the allowed rate of return. A Price Cap IR also allows for potential recovery of incremental capital investment through the ICM mechanism and the potential to address unforeseen items through a Z factor.

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[2] Ontario Energy Board Handbook to Utility Rate Applications, October 13, 2016, p.25.
[3] Ibid, Appendix 2, page iii.

8. Under the proposed Price Cap IR, rates will be set through Cost of Service for the first year (2024 Test Year)[4] and then adjusted in years two through five (2025 to 2028) using a formula specific to each year[5] as described below.

9. During the IR term, rates will be set based on a Price Cap IR using an Annual Rate Adjustment Formula calculated as (I - X) ± Y ± Z + ICM, where:
   a) I = inflation factor
   b) X = productivity factor and stretch factor
   c) Y = costs that are incremental to the costs subject to Price Cap escalation (i.e., pass-through items or costs approved in other proceedings and implemented as part of the annual rate application)
   d) Z = change in costs associated with unforeseen events outside of management control
   e) ICM = Incremental Capital Module

10. In addition to formulaic changes to rates, Enbridge Gas is also proposing rate adjustments for a phased-in equity thickness increase as provided at Exhibit 5, Tab 3, Schedule 1, and rate adjustments for rate mitigation as provided at Exhibit 8, Tab 2, Schedule 6[6].

1.1 Inflation Factor

11. Enbridge Gas proposes to use a two-factor inflation factor for rate escalation during the IR term, consistent with the OEB's 4th Generation IRM Report of the Board,

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[4] As proposed in this Application.
[5] Ontario Energy Board Filing Requirement for Natural Gas Rate Applications, February 16, 2017, chapter 2, p.4.
[6] Ontario Energy Board Filing Requirement for Natural Gas Rate Applications, February 16, 2017, chapter 2, p.36.

where the inflation factor is calculated as a weighted average of inflation in a labour sub-index and a non-labour sub-index.[7] Enbridge Gas proposes that the inflation factor to be calculated as the weighted sum of:

a) 75% for the non-labour component (calculated as the calendar year-over-year percentage change in the annualized average of four quarters of Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand (GDP IPI FDD[8]) available for the most recent year), and
b) 25% for the labour component (calculated as the calendar year-over-year percentage change in the annualized average of four quarters of Ontario fixed weighted index of Average Hourly Earnings (AHE[9]) available for the most recent year).

12. Enbridge Gas's proposal for a two-factor inflation factor is guided by the following directions from the OEB[10]:
    a) The inflation factor must be constructed and updated using data that is readily available from public and objective sources such as: Statistics Canada, the Bank of Canada, and Human Resources and Social Development Canada,
    b) To the extent practicable, the component of the inflation factor designed to adjust for inflation in non-labour prices should be indexed by Ontario distribution industry-specific indices, and

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[7] Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A performance-Based Approach, October 18, 2012, pp.15-16.
[8] Statistics Canada, Canada-Final Domestic Demand Implicit Price Index, Table 380-0066, v62307283
[9] Statistics Canada, Ontario-Fixed Weight Average Hourly Earnings, Table 121-0027, v1741702
[10] EB-2010-0379, Report of the Board, Rate setting parameters and benchmarking under the Renewed Regulatory Framework for Ontario Electricity's Distributor, November 21, 2013, Section 2.1, pp.5-6.

c) The component of the inflation factor designed to adjust for inflation in labour prices will be indexed by an appropriate generic and off-the-shelf labour price index (i.e., not distribution industry-specific).

13. This approach of developing inflation factors was also supported by the OEB in the generic proceeding to review the 2022 inflation factors to be used in the electricity distribution IRM plans.[11] The OEB found that the 4th Generation IRM methodology for developing inflation factors remained appropriate for 2022.

14. In the 4th Generation IRM methodology, the OEB-approved inflation factor applied a 30% weight to the labour sub-index measured by the average weekly earnings (AWE) for workers in Ontario and a 70% weight to the non-labour sub-index measured by the Canadian GDP IPI FDD. This assumption was initially used in the First Generation IRM plans implemented in Ontario in the late 1990s. The OEB noted that the 70% assumption adopted then may now be outdated, but there was insufficient data to refine or update the estimate. Enbridge Gas proposes a 25% weighting for labour and 75% weighting for non-labour because these weights are broadly consistent with the share of non-labor and labor costs for Enbridge Gas and other gas distributors. They are also similar to recent inflation factor precedents in Ontario.

15. Enbridge Gas is also proposing to use the AHE for the labour sub-index as the AHE is a more representative measure of price inflation for labour inputs than the AWE, and because the AHE is a direct measure of input prices and is more compatible with a Price Cap IR than the AWE.

[11] EB-2021-0212.

16. Enbridge Gas's proposal for the inflation factor is supported by Black & Veatch, as discussed in Section 3.0 of the Black & Veatch Study, provided at Attachment 1, page 7.

1.2 X Factor

17. The X factor has two components: the productivity factor and the stretch factor. Enbridge Gas proposes a productivity factor of -1.35% and a stretch factor of zero, based on the recommendations from Black & Veatch, as discussed in Sections 4.0 and 5.0 of the Black & Veatch Study, provided at Attachment 1, page 10 and 14, respectively.

Productivity factor

18. The productivity component of the X factor is intended to represent the long run TFP trend for the gas distribution industry. The analysis conducted by Black & Veatch estimates a long-run TFP trend for the gas distribution industry of -1.35% per annum. A negative productivity factor is a result of slowing output growth and increasing input quantity growth, particularly more rapid growth in capital inputs. These trends are observed throughout the gas distribution industry. The study has demonstrated that the productivity factor of -1.35% is generally consistent with the productivity offsets that have been approved for U.S. gas distributors in recent Regulatory proceedings. Please see Section 6.2 of the Black & Veatch Study provided at Attachment 1, page 23 for more details.

Stretch factor

19. The stretch factor component of the X factor is meant to reflect the incremental productivity gains that the Utility is expected to achieve during the IR term. The cost benchmarking results from the Black & Veatch Study indicate that Enbridge Gas is

a good cost performer and therefore, has less potential to achieve incremental productivity gains than the rest of the industry. Over the last few IR terms, EGD and Union (prior to 2019) and Enbridge Gas (since amalgamation) have been able to realize significant sustainable efficiencies and synergies, inclusive of embedded productivity savings, and such benefits are being passed on to customers at Rebasing in 2024. Please see Exhibit 1, Tab 9, Schedule 1 for total synergies achieved and Exhibit 4, Tab 4, Schedule 2 for details on productivity savings, all of which are expected to be sustained in the next IR period. Based on the results of the cost benchmarking study and the continued benefits to customers from synergies and productivities, Enbridge Gas proposes a stretch factor of zero.

2. <u>Y Factors</u>

20. Enbridge Gas proposes a Y factor cost recovery mechanism for costs that are incremental to the costs subject to Price Cap escalation (i.e., pass-through items or costs approved in other proceedings and implemented as part of the annual rate application). Enbridge Gas will treat the following costs as Y factors:
    a) Cost of gas and upstream transportation: The cost of gas supply, upstream transportation and gas supply balancing will continue to be passed through to ratepayers through the Quarterly Rate Adjustment Mechanism (QRAM).
    b) Demand Side Management (DSM) costs as determined in DSM proceedings[12]: In accordance with the current treatment, changes to annual DSM Program costs approved as part of DSM Program review process/proceedings will be updated in rates through the annual rate setting application.

[12] Enbridge Gas 2022-2027 Natural Gas Demand Side Management Framework and Plan Application EB-2021-0002, and subsequent proceedings.

c) Lost Revenue Adjustment Mechanism (LRAM): Enbridge Gas DSM programs result in reduction of volume consumption. The utility will continue to adjust the volumes used to calculate rates through the annual rate setting application to capture the impact of DSM activities for contract rate classes (i.e., LRAM volumes).

d) Normalized Average Use Adjustment: As provided at Exhibit 8, Tab 2, Schedule 3 Enbridge Gas is proposing Straight Fixed Variable with Demand (SFVD) rate design for all rate classes, including general service. Once the rate design proposal is approved, upon implementation, there will no longer be a need for a normalized average use adjustment. Until such time the SFVD rate design is implemented, then Enbridge Gas will require a Y factor for a normalized average use adjustment. (Please see Deferral and Variance Account Overview at Exhibit 9, Tab 1, Schedule 2, Section 3.10 pages 25-26).

3. Z Factor Adjustments

21. To address material changes in costs associated with unforeseen events outside of management control, Enbridge Gas is proposing to include a Z factor mechanism as part of the Price Cap IR plan.

22. Enbridge Gas proposes to follow the criteria as defined in the OEB's Filing Requirements for Natural Gas Rate Applications[13] when assessing whether a Z factor event qualifies for recovery:

a) Causation – the cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event and must be clearly outside the base upon which rates were derived.

[13] Filing requirements For Natural Gas Rate Applications, February 16, 2017.

b) Materiality – the cost increase or decrease must meet a materiality threshold, in that its effect on the Utility's revenue requirement in a fiscal year must be equal to or greater than the established threshold.
c) Prudence – the cost subject to an increase or decrease must have been prudently incurred.
d) Management control – the cause of the cost increase or decrease must be:
    i. Not reasonably within the control of utility management
    ii. A cause that utility management could not reasonably control or prevent through the exercise of due diligence

23. Enbridge Gas proposes a Z factor materiality threshold of $5.5 million, which is the same as the threshold approved by the OEB for Enbridge Gas in its MAADs Decision[14]. Enbridge Gas expects that it would request Z factor treatment of material changes in costs, where those changes meet the listed criteria above. Examples of potential Z factors include significant natural disasters, tax changes, and changes in government policy or legislation.

4. Incremental Capital Module

24. Enbridge Gas proposes an ICM as part of the Price Cap IR plan, to recover costs associated with qualifying incremental capital investments beyond what can be funded through approved rates, consistent with the OEB-established policy on ICM.[15] Qualifying capital investments are discrete projects that satisfy the eligibility criteria of materiality, need and prudence as set out in the ICM policy.[16] The level of capital expenditure that Enbridge Gas is expected to fund through approved rates is

[14] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.
[15] Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, and Report of the OEB – New Policy Options for the Funding of Capital Investments: Supplemental Report, January 22, 2016.
[16] Ibid.

determined by the OEB's calculation of the ICM materiality threshold value. Enbridge Gas will be eligible to seek ICM funding for qualifying projects if the proposed in-service capital budget for the year during the IR term exceeds the ICM materiality threshold value.

25. The ICM materiality threshold is determined as follows:

Threshold value = 1+ [(RB/d) x (g + PCI x (1+ g))] x ((1+g) x (1+PCI)) $^{n-1}$ + 10%

where:

a) Rate Base (RB) will be the approved rate base for the 2024 Test Year.
b) Depreciation (d) will be the approved depreciation expense for the 2024 Test Year.
c) Growth (g) will be the percentage difference between the forecasted distribution revenues for the 2024 Test Year and distribution revenue of the most current complete year, expressed as an annual growth rate.
d) Price Cap Index (PCI) is the Price Cap index for the year (% Inflation less productivity factor less stretch factor).
e) Years since rebasing (n) is the number of years since rebasing.

26. Enbridge Gas will seek recovery for the revenue requirement associated with capital spend for projects which are above the ICM threshold and meet the ICM eligibility criteria. ICM requests will be submitted as part of the annual rate setting mechanism during the IR term and supported by an Asset Management Plan, updated where necessary. The revenue requirement calculation will be determined using the cost of capital parameters approved by OEB for the 2024 Test Year.

5. Off-Ramp

27. Enbridge Gas proposes an off-ramp where a regulatory review may be triggered in the event actual utility earnings are outside of +/- 300 basis points from the OEB-approved ROE during the IR term.

6. Earnings Sharing Mechanism

28. Enbridge Gas proposes an asymmetric ESM in its Price Cap IR plan. The ESM protects customers against excess earnings and allows for sharing with ratepayers of efficiencies that result during the IR term. Enbridge Gas will share utility earnings in excess of 150 basis points above the OEB-approved ROE on a 50/50 basis with ratepayers.[17]

29. Enbridge Gas proposes a continuation of the Earnings Sharing Mechanism Deferral Account (ESMDA) to capture the ratepayer share of utility earnings that result from the application of the earnings sharing mechanism. Rather than accumulating amounts in the ESMDA for disposition at the end of the IR term, Enbridge Gas is proposing that amounts held in the ESMDA will continue to be disposed of through annual deferral and variance account proceedings. This is consistent with historical treatment of ESM amounts for Enbridge Gas. The ESM mechanism will be applicable for the years 2025 to 2028.

7. Annual Adjustment Process and Reporting

30. To set annual rates during the IR term, Enbridge Gas proposes to file the following information annually:
    a) Enbridge Gas will file an application and supporting evidence including a draft rate order by June 30 in each year during the IR term which reflects the

[17] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018

impact of the PCI, Y factors and requested Z factors. The application will also include rate adjustments arising from the phased increase of the equity thickness as provided at Exhibit 5, Tab 3, Schedule 1, implementation of the rate harmonization plan proposal and/or the rate mitigation proposal as provided at Exhibit 8, Tab 2, Schedule 1 and Schedule 6, if applicable. The documentation would be in sufficient detail to allow the OEB to issue a procedural order, such that a final rate order could be issued by November 25 for implementation by January 1.

b) For ICM requests, Enbridge Gas will file an application and supporting evidence, including an AMP (or AMP update/addendum) by October 15 in each year during the IR term. More details on the AMP (or AMP update/addendum) filing are provided at Exhibit 2, Tab 6, Schedule 1, paragraph 4.

31. As soon as reasonably possible following the public release of annual audited financial statements, Enbridge Gas will file actual utility results, including the determination of any earnings sharing amount, and apply for the disposition of deferral and variance accounts that are to be disposed of annually. Enbridge Gas will request that rate adjustments associated with deferral account dispositions be implemented in the earliest possible QRAM following the OEB's Decision.

32. Enbridge Gas will continue to adjust gas supply commodity and upstream transportation costs through the QRAM mechanism as approved by the OEB.

8. Customer Protection Measures

33. Enbridge Gas proposes a continuation of its scorecard to measure and monitor performance during the IR term, subject to certain exemptions. The scorecard

includes measures for customer focus, operation effectiveness, public policy responsiveness and financial performance. Further details of Enbridge Gas's performance measurement and scorecard and the exemptions requested are provided at Exhibit 1, Tab 7, Schedule 1. Enbridge Gas will continue to produce the scorecard annually for review as part of the annual deferral and variance account proceedings.

TOTAL FACTOR PRODUCTIVITY, BENCHMARKING, AND RECOMMENDED INFLATION AND X FACTORS FOR ENBRIDGE GAS INC. INCENTIVE RATE-SETTING MECHANISM

BV PROJECT NO. 409074

PREPARED FOR

Enbridge Gas Inc.

26 OCTOBER 2022

Principal Investigator
Lawrence Kaufmann, Ph.D.
Senior Advisor: Black & Veatch Management Consulting

BLACK & VEATCH

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1.0 Introduction and Summary

Enbridge Gas Inc. ("EGI," or "the Company") will propose an incentive rate-setting mechanism ("IRM") for the 2024-2028 term based on the Price Cap Incentive Rate-setting mechanism ("Price Cap IR") for its regulated gas utility operations. Under the Price Cap IR, rates are set through a cost of service process for the first year (2024) and then adjusted in years two to five (2025-2028) using a Price Cap Index ("PCI"), where base rates are adjusted by an "inflation minus X factor" formula. The X factor in this formula will be calibrated using data on total factor productivity ("TFP") growth in the gas distribution industry, as well as a study benchmarking EGI's cost performance relative to the gas distribution industry.

EGI retained Black & Veatch Management Consulting ("BV") to undertake TFP and benchmarking research to support the Company's IRM proposal. Dr. Lawrence Kaufmann oversaw and managed this work on behalf of BV. Drawing on this research, Dr. Kaufmann recommended an overall X factor to be used in EGI's proposed rate adjustment mechanism. This report presents the results of the TFP and benchmarking studies developed for EGI as well as the following recommendations:

Inflation Factor: The recommended inflation factor in EGI's IRM is a weighted average of growth in the Canadian GDP Implicit Price Index for Final Domestic Demand ("GDP-IPI-FDD") and the Ontario Average Hourly Earnings ("AHE") indexes. This is an example of an "industry-specific" inflation factor, which is designed to track industry input price trends more closely than economy-wide price inflation. A 75% weight is proposed for the GDP-IPI-FDD and a 25% weight is proposed for the AHE. These weights are broadly consistent with the share of non-labor and labor costs for EGI and other gas distributors. They are also similar to recent inflation factor precedents in Ontario.

Productivity Offset: In IRM plans with industry-specific inflation factors, the "productivity offset" component of the X factor should be equal to the long-run TFP trend for the respective utility industry. Because data on Canadian gas distributors are not readily available, this study uses data on the United States ("U.S.") gas distribution industry to estimate industry TFP trends. Our study estimates a long-run TFP trend for U.S. gas distributors of -1.35% per annum. This value is similar to productivity offsets proposed by, and approved for, U.S. gas distributors in recent regulatory proceedings.

Stretch Factor: The recommended stretch factor is zero. This recommendation is supported by cost benchmarking studies that show EGI is a good cost performer and therefore has less potential to achieve incremental efficiency gains than much of the rest of the industry. Over the 2019-2021 period, the Company's average unit cost (*i.e.* total gas distribution costs per customer) was 49.1% below the average unit cost of gas distributors in the Northeast U.S., 28.6% below average unit costs of the entire U.S. gas distribution industry, and 29.8% below the average unit cost of selected gas distribution peers. The Company also performs well against other Canadian gas distributors on measures of operations and maintenance expenditures per customer.

While all the benchmarking evidence supports the view that EGI's cost performance is far above average, BV believes the Northeast U.S. aggregate is EGI's most relevant comparator. This region operates under a business and regulatory/policy environment more similar to Ontario's than much of the rest of the U.S. gas distribution industry. In addition to the empirical evidence, recent stretch factor precedents for electricity distributors in Ontario also support a zero stretch factor for EGI.

Overall X Factor: Given a recommended productivity offset of -1.35% and a recommended stretch factor of zero, an overall X factor of -1.35% is recommended for EGI's IRM plan.

The report is organized as follows. After this brief introduction and summary, Section 2 addresses the framework that underpins the development of Incentive rate-setting mechanisms and the relationship between industry TFP growth and the value of the X factor in rate adjustment mechanisms. Section 3 discusses the inflation factor. Section 4 describes the methodology used to estimate TFP and input price trends and presents TFP trends for the U.S. gas distribution industry, as well as recent historical TFP trends for EGI. Section 5 presents cost benchmarking data that compares EGI's recent cost performance to the U.S. national and regional gas distribution industries, as well as selected U.S. and Canadian gas distribution peers. Drawing on this TFP and cost benchmarking evidence, Section 6 provides recommendations on both the productivity offset and stretch factor components of EGI's proposed X factor, as well as a recommendation on the inflation factor. Section 7 provides additional details of this work in a Technical Appendix.

2.0 Some Principles for Setting X Factors

Rate and revenue indexing mechanisms are widely used in utility regulation. Indeed, Ontario has extensive experience with this regulatory approach, and the Ontario Energy Board ("OEB") has approved numerous indexing plans for gas and power utilities over the last 20-plus years. Many interested parties in Ontario are therefore familiar with the rationale for "inflation minus X" mechanisms, but a brief review of this conceptual framework may nevertheless be helpful.

The North American approach to rate and revenue indexing is grounded in economic reason.[1] The basic principle is that regulation should simulate competitive market outcomes where competition itself is impractical. This principle is sometimes called the competitive market paradigm.

This paradigm can be made operational through the use of economic indexes. Because competitive industries earn a competitive rate of return in the long run, an index of a competitive industry's product prices (*i.e.* the industry output price index) will grow at the same rate as an index of the industry's unit costs (*i.e.* industry cost per unit of output) over the long run. This relationship is presented in equation [2.1] below.

$$trend\ Output\ Prices^{Industry} = trend\ Unit\ Cost^{Industry}. \qquad [2.1]$$

It is important to recognize that, under competitive market conditions, output price changes reflect *industry* conditions, not the unit cost experience of any individual firm. Because industry prices are not sensitive to individual suppliers' cost changes, individual firms keep all the after-tax benefits from efforts to slow unit cost growth. Each firm therefore has strong incentives to keep the growth in its unit cost below the industry-average unit cost trend, which in turn determines long-run price changes for the industry.

A further result of indexing logic is useful for setting the terms of rate and revenue indexing mechanisms. The trend in an industry's unit cost can be shown to be equal to the difference between the trends in its input price and TFP indexes, or

$$trend\ Unit\ Cost^{Industry} = trend\ Input\ Prices^{Industry} - trend\ TFP^{Industry}. \qquad [2.2]$$

TFP is equal to industry output quantity divided by industry input quantity, so the trend in the industry TFP index is equal to the growth in industry output quantity minus the growth in industry input quantity. Equation [2.2] provides an alternative but equally accurate way to understand TFP growth: as the difference between industry input price and unit cost trends. TFP trends capture all the factors that lead an industry's unit cost to grow at a different rate than the trend in industry input prices.

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[1] The U.K. also has a long history with "inflation – X" adjustment mechanisms, but its experience and conceptual rationale for calibrating such mechanisms differs from the standard North American approach. Although the U.K. approach has evolved over time, its basic "I – X" framework is more similar to what in Ontario is termed "Custom IR," or forward-looking, company-specific, cost-based plans.

A PCI in an IRM can be designed to track the industry unit cost trend by conforming to the following formula.

$$\begin{aligned} trend\ PCI &= trend\ Input\ Prices^{Industry} - trend\ TFP^{Industry} \\ &= trend\ Input\ Prices^{Industry} - X \\ X &= trend\ TFP^{Industry} \end{aligned} \quad . \qquad [2.3]$$

Equation [2.3] shows that the growth in the PCI has two terms: 1) an inflation factor that reflects industry input price trends; minus 2) an X factor, which reflects the industry's long-run TFP trend. The competitive market paradigm therefore establishes a direct connection between the inflation factor in an IRM and the trend in industry input prices, and the X factor in an IRM and industry TFP trends. The following section addresses the choice of the inflation factor in more detail.

3.0 Inflation Factor

3.1 Industry-Specific and Economy-Wide Inflation Factors

As discussed, there is a direct conceptual link between the inflation factor in a PCI mechanism and measured input prices in the utility industry. In practice, two main types of inflation factors are used in rate or revenue adjustment mechanisms. One is an industry-specific inflation factor designed to reflect input price trends in the utility industry. The second is a broad, economy-wide measure of output price inflation.

An industry-specific inflation factor is constructed as a weighted average of inflation in two or more price “sub-indices.” Sub-indices are chosen to reflect price changes for different sets of inputs used in production, such as labour prices.[2] In contrast, an economy-wide inflation factor measures input prices using only a single index of output price inflation in the macro-economy.

Of the two options, the industry-specific inflation factor is clearly more compatible with the competitive market paradigm and associated indexing logic. Relatedly, industry-specific inflation factors should provide a more accurate measure of the industry’s actual input price changes than an economy-wide inflation factor.

The main disadvantage of industry-specific inflation factors is they are more complex to implement. For example, constructing industry-specific inflation factors requires choices on the number of input classes included in the factor; specific sub-indices to measure prices for each respective set of inputs; and estimates of the share of each selected input class in total industry cost, to use as weights on the sub-indices.

In contrast, economy-wide inflation factors are simple and straightforward to use. Economy-wide inflation factors use “off the shelf” inflation indices developed by government authorities. There is accordingly no need to construct the inflation factor using disparate sources of information.

There are two main disadvantages with economy-wide inflation factors. The first is they are less likely to track the actual growth in input prices for the utility industry. The second is an economy-wide inflation measure can complicate the calculation of the X factor.

This latter disadvantage can be demonstrated by returning to the indexing logic developed in Section 2. Recall that this logic established a direct link between the X factor and industry TFP trends. However, when a plan uses an economy-wide inflation factor, the X factor in the IRM is often calculated using more than industry TFP trends. The X factors in IRM plans with economy-wide inflation factors often begin with estimates of industry TFP growth but also include other adjustments to help the indexing mechanism better reflect industry unit cost trends.

Consider the common example of indexing plans that use the U.S. gross domestic product price index (GDPPI) as an inflation factor. To examine the impact of this selected inflation factor on the indexing logic, we can simply add and subtract the growth in GDPPI from the right-hand side of equation [2.2]

[2] In practice, it is common for a broad-based, economy-wide inflation measure to be one of the selected subindices used to construct an industry-specific inflation factor. Nevertheless, an inflation factor that includes direct measures of the price of industry inputs (such as labour) enables the inflation factor to track industry input price inflation more accurately than relying entirely on an economy-wide macroeconomic price index.

(previously presented in Section 2 of this report), since adding and subtracting the same term from one side of an equation leaves that equation unchanged.

$$\begin{aligned} trend\ Unit\ Cost^{Industry} = {} & trend\ GDPPI - trend\ TFP^{Industry} \\ & + \left(trend\ Input\ Prices^{Industry} - trend\ GDPPI\right) \end{aligned} \quad [3.1]$$

Next, because the aggregate U.S. economy is broadly competitive, we can apply the same indexing logic to the U.S. economy that was previously undertaken for the utility industry. This logic implies that the trend in GDPPI (*i.e.* an output price index for the entire U.S. economy) can be expressed as the difference between the trends in input price and TFP indexes for the overall U.S. economy.

$$trend\ GDPPI = trend\ Input\ Prices^{Economy} - trend\ TFP^{Economy} \quad [3.2]$$

Substituting equation [3.2] into equation [3.1] and simplifying yields the following:

$$\begin{aligned} trend\ Unit\ Cost^{Industry} = {} & trend\ GDPPI \\ & - \left[\begin{aligned} & \left(trend\ TFP^{Industry} - trend\ TFP^{Economy}\right) \\ & + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) \end{aligned}\right] \end{aligned}$$

The equation above is similar to equation [2.3] in that the trend in industry unit cost is decomposed into two factors: the GDPPI as the inflation factor, and the term in brackets as the X factor. However, this X factor is not equal to the industry TFP trend, as it is when an industry-specific inflation factor is used to measure industry input price trends. Instead, the X factor is now equal to the sum of two other terms: 1) a productivity differential, equal to the difference between the TFP trends of the industry and the overall economy, and 2) an inflation differential, equal to the difference between the input price trends of the economy and the industry.

It should be noted that this X factor is not simply a theoretical implication of the indexing logic when economy-wide inflation factors are used in IRMs. This more complex X factor formula has in fact been implemented in many Performance-Based Regulation ("PBR") plans. For example, the Massachusetts Department of Public Utilities has used the sum of the productivity differential and inflation differential to calculate X factors in at least eight approved indexing plans. This same formula has also been applied in New Zealand and Australia and was recently proposed for a PBR plan in Hawaii.

3.2 Inflation Factor Precedents in Ontario

The OEB has approved both economy-wide and industry-specific inflation factors in incentive regulation plans for energy utilities. The current IRM for EGI uses an economy-wide inflation factor (*i.e.* the GDP-IPI-FDD). Most of the other approved IRM plans for Ontario gas distributors have also used economy-wide inflation factors.

However, there is also precedent for the use of industry-specific inflation factors in Ontario. Most prominently, in Fourth Generation incentive ratemaking for electricity distribution and transmission utilities ("4thGenIR"), the OEB indicated that "it wanted to adopt a more Ontario industry-specific inflation factor than the Canadian economy-wide index used in 3rd Generation IR."[3] The OEB further

[3] *Report of the Board*, EB 2010-0379, November 13, 2013, p. 5.

stated that the development of an appropriate industry-specific inflation factor in 4thGenIR should be constructed and updated using data that are readily available from public and objective sources.

The OEB ultimately approved a two-factor industry-specific inflation factor in 4thGenIR. This inflation factor was a weighted average of inflation in: 1) a labour sub-index measured by the average weekly earnings ("AWE") for workers in Ontario; and 2) a non-labour sub-index measured by the Canadian GDP-IPI-FDD. The OEB considered but rejected a three-factor inflation factor that also included a capital cost subindex (computed as part of the TFP study for OEB Staff) because this sub-index was too volatile. The OEB also noted that the Alberta Utilities Commission had recently implemented a two-factor inflation factor in Alberta that used analogous non-labour and labour price indices (*i.e.* the Canadian GDP-IPI-FDD and Alberta AWE).

The OEB's approved inflation factor applied a 30% weight to the AWE index and a 70% weight to the GDP-IPI-FDD. These weights were based on the estimated labor/non-labor cost split for medium and large electricity distributors in Ontario.[4] The OEB noted that the cost share estimates that were adopted may now be outdated, but there were insufficient data to refine or update the estimate.

In EB 2021-0212, the OEB initiated a generic proceeding to review the 2022 inflation factors to be used in the electricity distribution IRM plans. This review was prompted by Covid-related impacts on measured input prices. The OEB found that the 4thGenIR methodology for developing inflation factors remained appropriate for 2022. This recent precedent (from November 18, 2021) is therefore consistent with the continued use of a two-factor inflation factor.

While the OEB has previously approved the use of the AWE to construct a two-factor inflation factor in IRMs, a strong case can be made that average hourly earnings ("AHE") is a better measure of price inflation for labour inputs. The AWE measures average wages paid in a week, which involves the product of average hourly wages and average hours worked per week. Because average hours worked is a measure of labour input *quantity*, the AWE is the product of input quantity and input price data. In contrast, the AHE measures the price of labour inputs directly and exclusively.

The indexing logic presented in Section 2 shows that input quantities and input prices are reflected in different components of the PCI formula: input quantities (including the quantity of labour inputs) are captured in measures of industry TFP trends; input prices are captured in the inflation factor. Neither the industry input price or TFP components of the PCI are measured by the direct product of input price and input quantity data.

Because the AWE is a product of input price and input quantity data while the AHE is a direct measure of input prices, the AHE is more compatible with the underlying indexing logic than the AWE. BV therefore recommends that the Company's inflation factor be computed as a weighted average of the GDP-IPI-FDD and the AHE. BV further recommends weights of 25% and 75% be applied to the AHE and GDP-IPI-FDD respectively. The recommended 25% weight on labour prices is a bit lower than the 30% share approved in 4thGenIR, but a 25% share is more strongly supported by BV's empirical work and estimated labor cost shares for both EGI and the U.S. gas distribution industry.

[4] The estimated 30% cost share for labor assumed that 70% of operations and maintenance ("O&M") costs were associated with labor inputs. This assumption was initially used in the First Generation IRM plans implemented in Ontario in the late 1990s.

4.0 TFP Estimates

The productivity offset component of the X factor is developed using estimates of industry TFP trends. BV estimated the growth in industry TFP and related indices on behalf of EGI. This section discusses the TFP research and results.

4.1 Data Sources and Sample Period

The main data source for the TFP study was provided by S&P Global Market Intelligence. The S&P database compiled most of the cost and output data necessary to estimate TFP trends. BV personnel compiled historical data on several price indices, which were used to deflate changes in input costs and thereby express changes in inputs in "real," quantity terms. These input price indices are described further in Section 4.4.

There were sufficient data from S&P to estimate TFP trends for 54 U.S. gas distributors.[5] This sample includes a diverse array of small, medium and large gas distributors throughout all regions of the country. Notably, 19 of the 54 distributors were located in the Northeast U.S., which is adjacent to most of EGI's customers and distribution service territory. A fifteen-year sample period was used to estimate TFP trends, from 2006 through 2021.

4.2 Applicable Total Cost Measures

Two measures of total costs were developed for EGI: one covering the costs of all the Company's regulated distribution, transmission, and storage operations; the second covering only the Company's regulated distribution operations. In both instances, total costs were computed as the sum of labour costs, non-labour O&M costs, and capital costs for the designated set of EGI operations.

The broader cost measure was developed because the IRM proposal applies to all of the Company's regulated distribution, transmission and storage services. Although the X factor for this IRM is based on industry TFP trends rather than the Company's own TFP growth, TFP growth for Company services subject to the IRM is potentially informative to the OEB and other interested parties.

EGI's distribution cost measure was computed to facilitate "apples to apples" comparisons between EGI and U.S. gas distributors. Most sampled U.S. distributors had negligible (or zero) transmission and storage assets, so BV computed total costs for the gas distribution operations only of sampled distributors. It was therefore necessary to compute measures of EGI's distribution-only costs to enable appropriate benchmarking comparisons between EGI and the U.S. gas distribution industry.

4.3 Output Quantity Index

Output quantity was measured by the total number of customers served. This is the standard output measure in gas distribution TFP studies given the long-term trend of declining gas consumption volumes per customer. These trends have accelerated in recent years because of "energy transition" policies designed to reduce reliance on carbon-based energy sources, including natural gas. As a result, revenue decoupling and related mechanisms have become more prominent throughout the industry. These

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[5] One sampled gas distributor is Colonial Gas in Massachusetts, which filed annual reports through 2020, but was fully absorbed into Boston Gas's operations in 2021. Colonial Gas accordingly did not file an independent report in 2021. The BV team used independently-reported data from Colonial Gas as much as possible, but combined Colonial Gas with Boston Gas when necessary to compute cost and input data.

mechanisms encourage distributors to reduce natural gas sales by compensating them for lost gas distribution margins when sales decline.[6]

Because of these trends and policy efforts, it is inappropriate to include gas volumes in the output quantity index. Doing so would lead to much slower growth in measured distribution output. This would, in turn, greatly reduce measured TFP growth, particularly since few, if any, gas distribution costs are driven entirely by volumes. It is also not practical to include peak demand as an output measure, because high-quality data on distributors' peak demands are not widely available. Given the data constraints, long-term gas consumption trends, and current policy direction, the most appropriate measure of gas distribution output is the number of customers served.

4.4 Input Quantity and Input Price Indexes

Inputs were categorized into three categories: labour, capital, and non-labour O&M inputs. Labour quantity was equal to annual labor costs divided by an employment cost index. The selected employment cost index for sampled U.S. utilities was the Employment Cost Index for private industry utility workers ("ECI"), computed by the U.S. Bureau of Labor Statistics ("BLS"); the employment cost index for EGI was Ontario Average Hourly Earnings ("AHE").

The quantity of non-labour O&M for U.S. distributors was computed by dividing total O&M costs, net of labour costs, by the U.S. GDPPI. The quantity of EGI's non-labour O&M was calculated by dividing EGI's analogous cost measure by the Canadian GDP-IPI-FDD. Capital quantity was computed using a perpetual inventory equation and a hyperbolic decay method of asset depreciation. Details on the measurement of capital quantity and costs are presented in Section Seven's Technical Appendix. A Tornqvist index was used to aggregate the three inputs into an overall index of input quantity.

4.5 TFP Growth

TFP growth was measured directly as the growth in customers minus the growth in overall input quantity.

4.6 Empirical Results

Table 1 summarizes the main results of this indexing research. Data are presented on the growth in output, input quantity and TFP over the 2006-21 period for the U.S. sample, EGI's total regulated services, and EGI's distribution services. In addition, data are presented on the average annual growth in labour, non-labour, and capital inputs over the 2006-21 period for the U.S. sample, EGI's total regulated operations, and EGI's distribution operations.

Table 1: Summary of Results, 2006-2021

	% Change Output	% Change Input	% Change TFP	%Change Labor	%Change Non-labor O&M	%Change Capital
U.S. Sample	0.69%	2.04%	-1.35%	0.89%	1.25%	3.26%
EGI All Regulated Services	1.48%	1.51%	-0.02%	-1.57%	0.63%	3.54%
EGI Distribution	1.48%	1.76%	-0.28%	-1.13%	0.95%	3.47%

[6] EGI does not operate under full revenue decoupling, but it does have an average-use adjustment that encourages less use of natural gas by providing some compensation when gas usage declines.

For the U.S. sample, it can be seen that output (*i.e.* customer numbers) grew by an average of 0.69% per annum, while overall input grew at an average annual rate of 2.04%. As a result, industry TFP declined at an annual rate of 1.35% over the 2006-2021 period. (*i.e.* the average change in TFP for the U.S. gas distribution industry was -1.35% per annum).

Further examination of the input quantity subindices shows that the growth in inputs was driven by greater capital spending. Capital inputs grew at an average annual rate of 3.26% over the sample period. In contrast, labour and non-labor O&M inputs grew at average annual rates of 0.89% and 1.25%, respectively. In both cases, this was less than half the growth rate of capital.

Negative TFP growth for the U.S. gas distribution industry is therefore the result of slowing output growth coupled with simultaneously rapid capital spending. These empirical results are consistent with generally recognized trends in the industry, including energy transition policies that slow output and the need to replace aged gas distribution infrastructure for safety and reliability reasons. Both of these trends are particularly pronounced in the Northeast U.S.

BV's estimate of negative TFP trends in the gas distribution industry is also broadly supported by other evidence recently provided in Ontario. In EGI's MAADs proceeding that approved the current IRM (EB-2017-0306/EB-2017-0307), Pacific Economics Group Research ("PEG") prepared a U.S. gas distribution TFP study on behalf of OEB staff.[7] Table 6 in PEG's report presents estimated trends in gas distribution output quantity, input quantity, and TFP, as well as the trends in capital and O&M input quantities, for a sample period ending in 2016.

Table 2 summarizes PEG's main results for the most recent 15 years of its sample period. The table presents results for the entire 15-year period, as well as the approximate "First Half" and "Second Half" results of the full sample period (*i.e.* the first eight years of the period from 2001-2009, and the last seven years of the period from 2009-2016, respectively).

Table 2: Summary of PEG's TFP Results, 2001-2016 (EB-2017-0306/EB-2017-0307

	% Change Output	% Change Input	% Change TFP	%Change Labor	%Change O&M	%Change Capital
All 15 Years	0.83%	1.40%	-0.57%	NA	0.88%	1.80%
First Half of sample, 2001-2009	0.92%	1.10%	-0.18%	NA	0.76%	1.36%
Second Half of sample, 2009-2016	0.73%	1.75%	-1.02%	NA	1.03%	2.29%

Over the entire 2001-2016 period, PEG estimated that industry TFP declined by 0.57% per annum (*i.e.* average annual TFP growth of -0.57%). Output grew by 0.83% per annum, while industry input quantity grew by 1.40% per annum. Capital inputs grew by 1.80% per annum between 2001-16, which was more than double the 0.88% average growth in O&M inputs over the same period.

PEG's results also indicate that the industry's negative TFP trend is accelerating over time. In 2001-2009, TFP declined by 0.18% per annum. In 2009-16, the TFP decline accelerated to 1.02% per annum.

[7] Lowry, M.N. (2018), "IRM Framework for the Proposed Merger of Enbridge and Union Gas."

Approximately 22.6% of PEG's estimated, accelerated TFP decline was due to slowing output growth.[8] More rapid growth in O&M inputs in 2009-2016 accounted for about 13.6% of the lower TFP growth. However, the lion's share of the accelerated TFP decline (approximately 63.7%) was due to more rapid growth in capital inputs in 2009-16 compared with 2001-09.

Similar to BV's results, PEG's 2018 study provides strong evidence of negative TFP trends in the natural gas distribution industry through 2016. PEG's estimates also show that the rate of TFP decline has been accelerating over time, primarily because of increased capital spending. If PEG's estimated "second half" TFP experience continued beyond 2016, and through the 2016-2021 period, it would naturally lead to an even lower estimate of the industry's long-term TFP trend.[9]

Turning to the EGI results, it can be seen that Company output has grown at an average annual rate of 1.48% over the 2006-2021 period. This is about double the output trend of the U.S. industry, but much of the Company's rapid output expansion occurred in the early years of the sample. For example, in the first two sample years (2006-2007), EGI's customer growth grew at an average annual rate of 2.19%. In the last two sample years (2020-2021), EGI's output growth decelerated to 1.07% per annum. The latter value is more consistent with (but still above) the slower, long-term output trend of the U.S. gas distribution industry.

Input quantity for all of EGI's regulated transmission, distribution and storage services has grown at an average rate of 1.51%, which is somewhat below the 2.04% input growth trend of the U.S. industry. The main reason EGI's input quantity has grown more slowly than the industry average is due to labor inputs. Following the amalgamation of Enbridge Gas Distribution and Union Gas, the Company made significant reductions in labor expenses in 2019-2020. EGI's declines in labour costs have not been replicated industry-wide, although labour inputs have grown more slowly than either non-labour O&M or capital inputs for both EGI and the entire industry.

Importantly, EGI and the industry as a whole exhibit similar capital input trends. For the last 15 years, capital input has grown by more than 3% per annum for EGI's total operations, EGI's distribution operations, and the overall industry. This is evidence of long-standing capital spending pressures throughout the industry. EGI's capital input growth (3.54% for all operations and 3.47% for distribution operations) has been a bit more rapid than the industry's overall trend of 3.26% per annum.

It is also instructive to compare EGI's TFP trends for all regulated services and distribution services. Output growth is the same in both instances. However, input quantity has grown a bit more rapidly for distribution services (1.76% per annum for distribution versus a 1.51% input growth trend for all regulated services). For both sets of EGI services, however, TFP growth has been negative over the 2006-21 period. The main reason EGI's TFP decline has been less rapid than the industry's is because of its more rapid output growth. In recent years, however, the Company's output trend has become more similar to the U.S. industry's long-run trend.

[8] TFP growth declined from -0.18% to -1.02%, or 84 basis points, between the first and second halves of the sample. Output growth declined from 0.92% to 0.73%, or 19 basis points, between the first and second halves of the sample, and 19/84 = 0.226.

[9] For example, if PEG's estimated TFP trend of -1.02% for the 2009-16 period continued in each year between 2017 and 2021, it would yield a 15-year, 2006-2021 TFP trend of -1.05% per annum.

5.0 Cost Benchmarking

5.1 Industry Benchmarking

Data used in the TFP study were also used to benchmark EGI against the U.S. gas distribution industry. This benchmarking study examines EGI's unit cost (UC) of production for gas distribution against the U.S. industry. Unit cost is equal to the total cost of production divided by its output, as measured by customer numbers. Unit costs are therefore equal to total gas distribution costs per customer.

Unit cost levels were computed annually for the 2019-2021 period. The Company's average UC over this period were then compared to analogous UC measures for three different U.S. sample aggregates: 1) the overall U.S. sample of 54 gas distributors; 2) the sample of 19 gas distributors in the Northeast U.S.; and a sample of seven U.S. utilities that were selected as peers of the Company. The selection of peers is discussed below.

5.2 Selection of Peers

Utility benchmarking studies often compare a company to selected "peer" utilities that operate under similar business conditions. Two salient business conditions should be considered when identifying peers for EGI. The first is that EGI is one of the largest gas distributors in North America, serving approximately 3.8 million distribution customers. Larger utilities often benefit from economies of scale that reduce the unit cost of operations.

In addition, the EGD and Union South rate zones serve relatively dense service territories, which include the central business district and metropolitan area of one of North America's largest cities (Toronto). While a certain amount of customer density can reduce the unit cost of gas distribution (*e.g.* by allowing more customers to be served by a single distribution main), "extreme" density levels often create challenges that raise gas distribution costs. The Union North rate zone serves a smaller and much less dense service territory, but it accounts for only about 10% of EGI's overall customers.

Given these operating circumstances, it is reasonable for EGI to be compared against peer utilities that serve a similarly large number of customers, operate within a relatively dense service territory, or both. Our analysis therefore compares EGI to sampled U.S. gas distributors that serve large and/or densely populated territories. Table 3 shows the five largest U.S. gas distributors in the industry sample in terms of 2021 customers served, as well as EGI.

Table 3: Gas Distributors Ranked by Size

Company	Average customers served, 2019-2021
1. Southern California Gas	5,907,112
2. Pacific Gas and Electric	4,533,299
3. EGI	3,756,588
4. Public Service Electric & Gas	1,857,011
5. Consumers Energy	1,795,038
6. Atlanta Gas Light	1,564,628

Table 4 shows the top five U.S. gas distributors ranked in terms of customers per mile of gas distribution main, a common measure of customer density, as well as EGI.

Table 4: Gas Distributors Ranked by Density

Company	Customers per mile of main, 2018-2020
1. Consolidated Edison	247.64
2. People's Gas Light and Coke	197.59
3. Southern California Gas	113.26
4. Pacific Gas and Electric	103.99
5. Public Service Electric and Gas	103.08
6. EGI	76.43

EGI's customer density is lower than the top five U.S. gas distributors, as ranked by customers per miles of distribution main. This is due to the lower customer density in the Company's Union North rate zone operations. If EGD rate zone was treated as a stand-alone distributor, its customer density would be just below the density levels of the two most densely-populated U.S. gas distributors.

Most of EGI's customers, and customer costs, are associated with EGI's southern and not its northern operations. Most of the Company's costs are therefore associated with its densely-populated EGD and Union South rate zones operations, and only a small share are associated with the far less dense Union North rate zone operations. Since the benchmarking analysis compares cost per customer, BV therefore believes it is appropriate to compare EGI's overall costs per customers against the most densely populated U.S. gas distributors, even though EGI's overall customer density is somewhat lower due to the relatively small portion of its operations (in terms of cost) that serves a far less densely populated territory.

A total of seven gas distributors, other than EGI, appear on either the size or density rankings. Three companies appear on both: Southern California Gas, Pacific Gas and Electric, and Public Service Electric and Gas. The four other distributors are Consolidated Edison, People's Gas Light and Coke, Atlanta Gas Light, and Consumers Energy. EGI's unit costs were compared against these seven peer distributors.

5.3 U.S. Gas Distribution Benchmarking

EGI's unit costs (for distribution services) were computed and expressed in U.S. dollars using the average 2018-2020 purchasing power parity exchange rate of 0.84. Table 5 displays these results, averaged over the 2019-2021 period, for the U.S. sample, the Northeast U.S. sample, and the seven peers.

Table 5: U.S. Cost Benchmarking Comparisons 2019-2021 (U.S. $)

Aggregate/Peer	Unit Cost	Unit Cost Difference
EGI	$256.2	NA
U.S. Sample	$358.6	-28.6%
Northeast U.S.	$503.3	-49.1%
Peer Average	$365.0	-29.8%
Cons. Edison	$530.5	-51.7%
Peoples GL&C	$552.7	-53.6%
SoCalGas	$294.2	-12.9%
PG&E	$332.8	-23.0%
PSE&G	$343.6	-25.4%
Consumers Energy	$260.1	-1.5%
AGL	$240.8	6.4%

The "Unit Cost Difference" column computes the percentage difference between EGI's unit costs and the analogous unit costs for EGI comparators. In Table 5, these comparators are the U.S. industry aggregate, the Northeast U.S. industry aggregate, the peer average, and each of the seven peers individually. It can be seen that EGI's 2019-21 average unit cost was 28.6% below average unit costs of the U.S. gas distribution industry and 49.1% below the average unit cost of the Northeast gas distribution industry. EGI's average unit cost is also 29.8% below the average unit cost of its seven gas distribution peers, and its unit costs are below six of the seven selected peers. These benchmarking results indicate that the Company is a very good cost performer within the gas distribution industry.

This conclusion is bolstered by at least three factors which suggest that the Northeast U.S. gas distribution industry is a more relevant comparator for EGI than the national industry. One of these factors is that gas distributors in the Northeast have a much larger share of cast iron and bare steel assets within their territory. This, in turn, results from the fact that gas distribution systems in the Northeast U.S. were developed earlier than in most of the U.S., simply because this region was settled earlier and therefore has more long-settled, "mature" large cities where the industry's initial infrastructure was installed.

These initial investments naturally used the materials for fabricating underground pipe that were available at the time. In the earliest days of the industry, pipes were made using cast iron, and in later years "bare" (*i.e.* unprotected) steel became the dominant material. It was not until well after WWII that the now-standard Polyethylene ("PE") pipe was used for most services and local distribution mains.

Because of this historical legacy, a significant number of Northeast U.S. utilities – as well as EGI – continued to have a substantial inventory of aged cast iron and/or bare steel assets until recent years. In contrast, cast iron and bare steel pipe was much less common in other regions.

EGI has now replaced nearly all its aged cast iron or bare steel assets. This is also true of some other U.S. distributors, and every other distributor facing the issue is in the process of doing so. Cast iron and bare steel asset replacement is expensive, particularly since many of these efforts necessarily take place in crowded urban areas and therefore require more time and expense than replacing assets in less densely populated areas. These replacement costs therefore raise the unit cost of gas distribution service in territories with such legacy assets. The concentration of cast iron and bare steel replacements in the Northeast U.S. is an important reason why the region's unit cost of $503 is 40% above the unit cost of the entire U.S. industry.

EGI also faces weather and geography issues that are similar to those in the Northeastern U.S. and which tend to increase costs. The cost of installing and maintaining distribution assets is generally greater where frost depths are deeper and ground conditions are more rocky. Both of these factors are more prevalent in Ontario and the Northeast U.S. than in much of the rest of the U.S.

Finally, the policy and regulatory environment in Ontario is more similar to that of the Northeast U.S. than much of the rest of the U.S. Most northeastern states, as well as Ontario, are emphasizing "energy transition" policies that reduce reliance on fossil fuels. Achieving energy transition goals can both decrease gas distribution output and increase some costs, both of which tend to increase the unit costs of gas distribution service. These unit cost pressures will also be more prominent in the Northeast U.S. than in the overall U.S. gas distribution industry.[10]

For all these reasons, BV believes the best inference on EGI's cost performance can be obtained by comparing the Company to the Northeast U.S. gas distribution industry and to the average performance of its seven selected peers. EGI's unit costs are approximately 49% below those of the Northeast U.S. aggregate, and approximately 30% below those of its selected peers. Unit costs that are between 30% and 49% below those of industry and peer benchmarks are indicative of very good cost performance.

5.4 Canadian Gas Distribution Industry

BV also used data from Canadian gas distributors to benchmark EGI's cost performance. Other than EGI, data were available for seven Canadian gas distributors: 1) Alta Gas (Alberta); 2) Atco Gas (Alberta); 3) Centra Gas (Manitoba); 4) Heritage Gas (Nova Scotia); 5) Liberty Utilities (New Brunswick); 6) Fortis BC (British Columbia); and 7) Pacific Northern Gas, reported separately for its Northeast and Western operations.

There are several concerns associated with the Canadian gas distribution data. One is that the available data are less comprehensive than those for U.S. gas distributors. Importantly, there were not sufficient data to construct capital stocks or estimate capital costs for any sampled Canadian company other than EGI. Benchmarking analyses for Canadian gas distributors are therefore limited to O&M expenditures.

There are also concerns with distributors' reported O&M expenses, particularly regarding data comparability. Unlike U.S. gas distributors, Canadian gas distributors are not required to report output, cost, and related data on standardized forms to federal government authorities. Accordingly, Canadian gas distribution data must be collected from a number of disparate sources. Companies use different formats for itemizing and classifying O&M cost components on these data sources. These differences make it difficult to verify that each sampled distributor is defining and measuring its O&M costs in the same way.

Notwithstanding these concerns, there may still be value in examining how EGI's costs compare against other gas distributors in Canada. Data on O&M costs per customer are therefore presented for EGI and the seven other gas distributors in Table 6.

[10] The U.S. west coast, particularly California, is also pursing energy transition policies. While the two dominant California gas distributors (Southern California Gas and Pacific Gas and Electric) will not be included in the EGI – Northeast regional comparison, they are considered in the peer benchmarking analysis.

Table 6: Canadian O&M per Customer Cost Benchmarking (C$)

Gas Distribution Company	O&M per Customer	Time Period
EGI		
All Regulated Operations	$212	2019-2021
Distribution Operations Only	$145	2019-2021
Other Canadian Gas Distributors		
AltaGas	$538	2019-2021
Atco Gas	$372	2019-2021
Centra Gas	$192	2018-2020
Heritage Gas	$1158	2019-2021
Liberty Utilities	$1192	2019-2021
Fortis BC	$237	2018
Pacific Northern Gas (NE)	$557	2018-2020
Pacific Northern Gas	$1208	2019-2021
Average Canadian O&M per customer (excluding EGI)	$682	
Difference Between EGI and sample Average Other Canadian Distributors		
All regulated operations	-68.9%	
Distribution operations only	-78.7%	

EGI's O&M costs per customer are far below comparable costs for the other seven Canadian gas distributors. O&M costs for the Company's overall regulated operations and distribution operations are 68.9% and 78.7%, respectively, below the average of other Canadian distributors gas distributors. Given the previously cited data concerns, these benchmarking results are less definitive than those against the U.S. gas distributors. Nevertheless, they do not in any way undermine the U.S. evidence showing that EGI's cost performance is well above the industry average. All the benchmarking analysis, in turn, supports a relatively low stretch factor in the Company's IRM proposal.

5.5 Relevant Empirical Evidence and Recommended Stretch Factor

The stretch factor in EGI's current IRM is 0.3%. In approving this value, the OEB rejected the argument that stretch factors should only apply to utilities transitioning from cost of service regulation to an initial IRM. This situation clearly would not apply to the Company, which has been subject to multiple, successive IRMs.

Dr. Kaufmann of the BV team agrees with the OEB's position that stretch factors can be appropriate in updated IRMs. This is evident in his previous work for OEB Staff, which included recommendations to the OEB on stretch factors in 3rdGenIR and 4thGenIR. In both 3rdGenIR and 4thGenIR, Dr. Kaufmann recommended positive stretch factors for all but the most efficient cohort of electricity distributors in Ontario. He has therefore recommended positive stretch factors for the majority of electricity distributors in Ontario in two separate IR proceedings (3rdGenIR and 4thGenIR), both of which updated previously approved IRM plans.

Dr. Kaufmann has made similar recommendations in other jurisdictions. For example, in work on behalf of several energy distributors in Massachusetts, he has recommended positive stretch factors for multiple IRM plans that were updates of previous plans.[11] To the best of his recollection, Dr. Kaufmann has *never* recommended a zero stretch factor in an IRM for a single, individual utility.

Importantly, however, he did support a zero stretch factor in both 3rdGenIR and 4thGenIR for the most efficient *cohort* of Ontario electricity distributors. These recommendations reflect his view that zero stretch factors are appropriate for utilities demonstrating excellent cost performance and/or otherwise providing value to their customers. The OEB agreed with this position in 4thGenIR, which approved zero stretch factors for electricity distributors exhibiting highly efficient cost performance.

In BV's opinion, EGI clearly exhibits highly efficient cost performance. This is true whether the Company is compared to national and regional aggregates of the U.S. gas distribution industry, or selected U.S. gas distribution peers with similar business conditions. EGI also has far lower O&M per customer costs than other Canadian gas distributors.

In addition to the benchmarking studies, other evidence from Ontario supports a reduction in EGI's stretch factor. This evidence includes an analysis indicating that customers have benefitted from previous IRMs for EGD and Union Gas. Broader developments in Ontario's electricity distribution industry also bolster the case for a lower stretch factor for EGI.

Regarding the Company's previous IRM experience, in 2011-12, the OEB hired Dr. Kaufmann to undertake a comprehensive assessment of the IRM plans then in effect for Enbridge Gas Distribution and Union Gas. This assessment specifically addressed whether these IR plans: 1) encouraged cost control and efficiency improvements; and 2) shared these benefits with customers.

Dr. Kaufmann's findings were summarized in an April 2012 report that explored these issues in great detail, using a variety of empirical and analytical techniques.[12] The final report emphasized the importance of quantifying the distribution of benefits, noting that "while the need to design IR plans so that customers and shareholders benefit has long been acknowledged in Ontario, the distribution of benefits under IR has not (to our knowledge) been examined empirically in previous work for the Board." [13] Given the importance of this issue, he developed a rigorous yet relatively transparent methodology for quantifying the sharing/distribution of benefits under the IR plans.

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[11] Examples include Massachusetts Electric in 2018, Boston Gas in 2020, and Eversource Electric in 2022.

[12] Kaufmann, L., D. Hovde, J. Kalfayan, and M. Makos (2012) *Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans*. The report also addressed whether the companies provided appropriate service quality to their customers and was conducive to capital investment. While those objectives are obviously important, most of the analysis concentrated on the design of the IRM plans and whether these plans achieved the main objectives of IRMs to improve cost performance for the ultimate benefit of both customers and shareholders.

[13] Kaufmann, L., *op cit*, p. i.

After a comprehensive assessment, Dr. Kaufmann concluded that "the overall thrust of our analysis of prices, earnings and TFP is that IR has generated win-win outcomes for customers and shareholders."[14] Moreover, "customers captured the lion's share of benefits."[15] On average, 92.5% of measured efficiencies were distributed to EGD and Union customers, while shareholders received 7.5% of efficiency gains.[16] All else equal, EGI's previous distribution of significant efficiency improvements to customers indicates there is less potential for incremental productivity gains in future IRMs.

The experience with stretch factors in Ontario's electricity distribution industry is also relevant to the Company. Although there are clearly differences between the gas and electricity distribution industries, there are also important regulatory parallels. For example, both industries had a "first generation" of IRM plans that were approved in 1999-2000. For a number of reasons, these initial plans were unsuccessful and were either suspended or not renewed after they expired.

However, the Natural Gas Forum ("NGF") in 2004-05 provided a stronger, more secure foundation for incentive regulation in Ontario.[17] While this Forum explicitly focused on the natural gas industry, many of the principles articulated in the NGF proved relevant to electricity distributors as well. As a result of this stronger overall foundation, Enbridge Gas Distribution, Union Gas, and the entire Ontario electricity distribution industry have been subject to ongoing, comprehensive incentive regulation from 2008 through the present.[18]

Ontario's electricity distributors are currently subject to 4thGenIR. One interesting component of 4thGenIR is that stretch factors are linked to each company's measured cost performance under IRM. Distributors are assigned to one of five cohorts each year depending on their cost performance. All distributors in a cost cohort are assigned the same stretch factor. The values of the assigned stretch factors are inversely related to cost performance, with lower stretch factor values applied to better cost performers and vice versa.

However, if a company's measured performance in a given year improves beyond the threshold levels set by the OEB and it thereby moves into a higher-performing cost cohort, its stretch factor is reduced. Similarly, if a distributor's measured cost performance declines beyond threshold levels set by the OEB, and it thereby moves into a worse-performing cost cohort, its stretch factor is increased. Updating stretch factors in this way incentivizes distributors to make ongoing cost performance gains, and the utilities that are successful in doing so are rewarded with greater allowed revenue growth.

Interestingly, electricity distributors' stretch factors have evolved over time under this stretch factor update regime. Table 7 presents data on the distribution of stretch factors across the five stretch factor

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[14] Kaufmann, L., *op cit*, p. v-vi.

[15] Kaufmann, L., *op cit*., p. vi

[16] Kaufmann, L.., *op cit*., see Table 26, p. 111.

[17] The initial IRMs for Enbridge and Union "were viewed as trial plans of three years' duration." (Ontario Energy Board, "*Natural Gas Regulation: A Renewed Policy Framework,"* March 30, 2005, p. 14). Moreover, the initial IRM for EGD applied to only a portion of its regulated costs. While "trial plans" and partial IRMs may be informative, they are less than a firm foundation for ongoing, long-term incentive regulation.

[18] The third Generation Incentive Ratemaking proceeding began in Autumn 2007 and concluded in 2008. Between "First Generation IRM" in 2000-01 and the commencement of 3rdGenIR in 2007, a "Second Generation IRM" took effect in December 2006. This was a transitional plan that led to only one or two rate adjustments for nearly all electricity distributors in the province, before 3rdGenIR was implemented for the industry.

options in 2013, when the IRM was first approved, and the current distribution of stretch factors following the most recent stretch factor update in 2022.[19]

Table 7: Distribution of Ontario Electricity Distributor Stretch Factors

Percentage of Ontario Electricity Distributors	2013	2022
Stretch Factor = 0%	8.2%	26.7%
Stretch Factor = 0.15%	20.5%	25.0%
Stretch Factor = 0.30%	45.2%	38.3%
Stretch Factor = 0.45%	20.5%	6.7%
Stretch Factor = 0.60%	3.3%	5.5%
Average Stretch Factor	0.29%	0.20%

In 2013, the distribution of stretch factors was similar to a classic "bell curve." A relatively small share of utilities were assigned either the lowest stretch factor value of 0% or the highest stretch factor of 0.6% per cent. Nearly 90% of distributors were clustered in the three middle stretch factor values centered around a stretch factor of 0.3%. The average stretch factor value for the industry in 2013 was 0.29%.

The current distribution of stretch factors is very different. The share of electricity distributors with 0% stretch factors has more than tripled between 2013 and 2022, from 8.2% to 26.7% of the industry. As a result, the "top quartile" of cost performers in Ontario's electricity distribution industry now have a stretch factor of 0%. At the other end of the spectrum, the share of distributors with a stretch factor of 0.6% has been relatively stable, increasing by only 2.2%. Consistent with these developments, the average stretch factor value for the industry has declined from 0.29% to 0.2%.

Clearly, these data show that Ontario's electricity distribution industry as a whole has responded positively to the continuous application of IRM, and its cost performance has improved. A considerable number of electricity distributors migrated into lower stretch factor values between 2013 and 2022. Consistent with this improved cost performance, the average stretch factor value for the industry has been reduced.

BV believes the electricity distribution experience strongly supports a reduction in EGI's stretch factor. Like the electricity distributors, EGI has been continuously under IRM since 2008. The discipline and enhanced incentives of ongoing, multiple IR plans has almost certainly improved the Company's cost performance, similar to what has been observed for electricity distributors. In addition to the generally strong incentive properties of IRM, EGI's cost efficiencies are currently being augmented by savings achieved through the amalgamation of EGD and Union Gas.

The evolution of stretch factor values for electricity distributors also supports a reduction in the Company's stretch factor, particularly when benchmarking evidence for the Company is considered. EGI's current stretch factor is 0.3%, which is larger than the 0.2% stretch factor currently in effect for the *average* Ontario electricity distributor. Benchmarking comparisons show the Company's current cost performance far exceeds industry-average levels. Its unit costs are 30% to 49% below its most relevant cost comparators (*i.e.* its seven peer utilities and the Northeast gas distribution industry, respectively). In BV's opinion, EGI's performance levels are commensurate with the thresholds the OEB uses to assign

[19] Table 7 uses data on the per cent, rather than the number, of distributors with a given stretch factor because the number of distributors in the industry declined between 2013 and 2022. Comparing distributor numbers may therefore provide a misleading indicator of the evolution of stretch factors between the two years.

electricity distributors to the “top cohort” of zero stretch factors. Given EGI’s exceptional benchmarking results and other relevant evidence in Ontario, BV recommends a stretch factor of zero for EGI’s IRM proposal.

6.0 Recommendations for IRM

6.1 Inflation Factor

BV recommends an industry-specific inflation factor for EGI's IRM. Industry-specific inflation factors are more compatible with the competitive market paradigm that underpins the development of IRMs. Ontario's experience also shows that industry-specific inflation factors can be practical and relatively easy to implement.

BV recommends that the inflation factor in EGI's IRM be computed as a weighted average of growth in the Canadian GDP-IPI-FDD and the Ontario Average Hourly Earnings indexes. A 75% weight is recommended for the GDP-IPI-FDD and a 25% weight proposed for the AHE. These weights are generally consistent with the shares of labour and non-labour costs for both EGI and US distributors.

6.2 Productivity Offset

In IRM plans with industry-specific inflation factors, the productivity offset component of the X factor should be equal to the long-run TFP trend for the respective utility industry. Based on a TFP study of the U.S. gas distribution industry, Dr. Kaufmann recommends a productivity offset of -1.35%. This value is equal to the long-run TFP trend for U.S. gas distributors over the 2006-2021 period.

BV's estimated TFP trend is also broadly supported by PEG's 2018 TFP study for OEB Staff, which found evidence of negative TFP growth in the U.S. gas distribution industry. BV's recommendation is also consistent with productivity offsets that have recently been proposed by, and approved for, U.S. gas distributors. In 2020, the Massachusetts Department of Public Utilities ("DPU") approved a multi-year, inflation minus X indexing plan for NSTAR Gas. The approved productivity offset in this plan was -1.18%. In 2021, the DPU approved a multi-year, inflation minus X indexing plan for National Grid/Boston Gas. The approved productivity offset in this plan was -1.30%.[20]

Both the current study and recent precedents provide compelling evidence that TFP trends have turned negative for North American gas distributors. This will occur anytime the growth in industry unit costs exceeds the growth in industry input prices. Unit costs are rising in the gas distribution industry because of slowing output growth coupled with simultaneous capital spending pressures. These developments are being driven by both business conditions and regulatory policies in the industry.

As discussed in the Alberta Utilities Commission's 2016 PBR decision, negative TFP growth is not necessarily a sign of declining efficiency, nor does it undermine performance incentives. Improved efficiency is one component of productivity change, but the latter is a much broader concept that captures the impact of technological change, economies of scale, economies of density, the system age of assets, and other factors. Previous reports to the OEB have explored this relationship both conceptually and mathematically and identified other factors that contribute to productivity change.[21]

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[20] As discussed in Section Three, the productivity offset in Massachusetts includes estimates of productivity and input price differentials and therefore depends on more than just the industry TFP trend. Nevertheless, the fact that regulators have since 2020 approved negative X factors in gas distribution PBR plans is a new and relevant development.

[21] See "*Defining, Measuring, and Evaluating the Performance of Ontario Electricity Networks*: *A Concept Paper*, April 2011, L. Kaufmann. Most of this discussion is on pp. 22-27.

While the OEB has not yet approved a negative X factor in an IRM, it should not be concerned that doing so would be contrary to effective incentive regulation. Whenever business and regulatory conditions put sufficient upward pressure on a regulated industry's unit costs, a negative X factor is both appropriate and warranted. There is abundant empirical and industry evidence to support the conclusion that this is currently the case for the North American gas distribution industry. BV believes that this evidence supports its recommended productivity offset of -1.35%.

6.3 Stretch Factor

BV recommends a stretch factor of zero. The cost benchmarking study indicates that EGI is a very good cost performer and therefore has less potential to achieve efficiency gains than much of the rest of the industry. Over the 2019-2021 period, the Company's average unit cost was 49.1% below the average unit cost of gas distributors in the Northeast U.S., 28.6% below average unit costs of the entire U.S. gas distribution industry, and 29.8% below the average unit cost of selected gas distribution peers. All the benchmarking evidence supports the view that EGI is a very good cost performer, but BV believes the Northeast U.S. aggregate is a more relevant comparator than the overall U.S. industry since this region operates under a business and regulatory/policy environment more similar to Ontario's than much of the rest of the U.S. gas distribution industry.

Other evidence from Ontario supports BV's recommended stretch factor. Previous assessments of Company IRM plans indicate that the lion's share of achieved cost savings in these plans have been distributed to customers. All else equal, this reduces the Company's potential to achieve incremental cost performance gains.

The evolution of stretch factor values for Ontario electricity distributors also supports BV's recommendation. Like the electricity distributors, EGI has been continuously under IRM since 2008. The discipline and enhanced incentives of ongoing, multiple IR plans has almost certainly improved the Company's cost performance, similar to what has been observed for electricity distributors. In addition to the generally strong incentive properties of IRM, EGI's cost efficiencies are currently being augmented by savings achieved through the amalgamation of EGD and Union Gas.

EGI's current stretch factor of 0.3% also exceeds the 0.2% stretch factor currently in effect for the average Ontario electricity distributor. EGI's 0.3% stretch factor is inconsistent with benchmarking comparisons showing the Company's current cost performance is above industry-average levels by a wide margin. Indeed, the Company's current cost performance is commensurate with the thresholds the OEB has used to assign zero stretch factors to electricity distributors. BV believes all this evidence supports a recommended stretch factor of zero.

7.0 Technical Appendix

7.1 Capital Costs

A service price approach was used to compute capital quantities and capital costs. BV's approach has a solid basis in economic theory, and its general approach is employed by the U.S. Bureau of Labor Statistics ("BLS") when estimating multi-factor productivity ("MFP") growth for the aggregate U.S. economy and important economic sectors. The BLS has been estimating U.S. MFP growth since the early 1980s, when it became the first government agency in the world to develop MFP estimates.[22] The approach controls for differences across utilities in the age of plant additions. It improves on standard utility accounting of capital costs, which is based on a book valuation of capital and therefore does not reflect inflation in the value of capital assets.

Capital cost in year t (CK_t,) is the product of a capital service price index, WKS_t, and a capital quantity index, XK_{t-1}.

$$CK_t = WKS_t \cdot XK_{t-1}$$

The capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index measures the hypothetical, competitive market price of capital services provided by assets. Price and quantity indexes both depend on a mathematical characterization of the process of plant depreciation.

The following formula was used to compute values of the capital quantity index:

$$XK_t = XK_{t-1}*(1-d_t) + (\text{Capital Additions}_t/PK_t)$$

Here, the quantity of capital input in year t is equal to capital quantity in the previous year t-1, minus the depreciation on the preceding year's capital quantity, plus capital additions in year t deflated by an asset price index in year t (PK_t). BV used Handy-Whitman data on gas distribution capital costs and quantities to calculate the asset price index PK.

In constructing capital quantity and cost indices for the US sample, we took 1998 as the benchmark year. We estimated the benchmark capital value by subtracting accumulated depreciation in 1998 from 1998 gross plant for both distribution and general plant and adding distribution plus general net plant values together.[23] This sum was then divided by a "triangularized" weighted average of the values of the producer price index. A triangularized weighting gives greater weight to more recent values of the producer price index.[24]

The *d* variable refers to depreciation, which is discussed further below.

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[23] S&P's dataset has some missing values for 1998 accumulated depreciation. BV interpolated the value of 1998 accumulated depreciation using surrounding values for three sampled utilities: Atlanta Gas Light, Niagara Mohawk Power, and Public Service Electric and Gas.

[24] For example, in a triangularized weighting of 20 years of index values, the oldest index value has a weight of 1/210, the next oldest index has a value of 2/210, and so on. 210 is the sum of the numbers from 1 to 20. A discussion of triangularized weighting of asset price indexes is found in Stevenson (1980).

7.2 Depreciation and Capital Quantity

The MAADs proceeding that approved EGI's current IRM (EB-2017-0306/EB-2017-0307) involved a vigorous debate over depreciation. The Company's consultant, National Economic Research Associates ("NERA") advocated what is known as One Hoss Shay ("OHS") depreciation. Under OHS, assets retain their full level of productive efficiency from the time they are installed until the time they are retired, at which point they depreciate entirely.

In contrast, OEB Staff consultant PEG recommended a geometric decay ("GD") approach to depreciation. Under GD, assets lose productive efficiency at a constant percentage rate every year they are in place. PEG identified a number of concerns with the OHS approach.

In its Decision, the OEB did not make any specific findings on the appropriate TFP methodology. Accordingly, it did not assess the merits of the OHS and GD depreciation alternatives. In past Decisions, however, the OEB has been critical of OHS and relied on TFP studies that used geometric decay.

In previous TFP and benchmarking work for OEB Staff, Dr. Kaufmann used a GD depreciation approach. He has also echoed some of PEG's concerns regarding OHS. Notwithstanding those precedents, there are legitimate concerns with geometric decay, and these concerns should be acknowledged and examined. While a complete analysis of the merits of GD, OHS and other depreciation approaches is complex and goes beyond the scope of this Appendix, in Dr. Kaufmann's opinion the two main concerns with GD depreciation are: 1) it conflicts with the gas distribution industry's experience and understanding of how gas distribution assets depreciate over time; and 2) assets *never* fully depreciate under geometric decay.

On the first point, Dr. Kaufmann has interacted with utility engineering and operational professionals many times, and in diverse locations, over the last 25 years. These experts overwhelmingly believe that gas distribution assets show little physical decay or loss of efficiency in the years immediately after they put in place. Instead, the industry's accumulated experience is that newly-installed gas distribution assets are "like new" for several, and sometimes many, years. However, as assets progress towards the end of their useful lives, they begin to perform less efficiently, and efficiency losses accelerate as assets approach the time when they are retired.

This accumulated industry expertise is essentially the opposite of how assets depreciate under GD. Geometric decay assumes that assets decline at a constant percentage rate every year they are in use. For example, suppose capital additions of $1,000,000 are made in year one and the assumed depreciation rate is 5%. Under GD, the measure of physical capital services provided by this capital investment over the first four years of its life will be:

Year (January 1)	Measured Efficiency Services	Loss of Efficiency Services
One	$1,000,000	
Two	$950,000 [=$1,000,000*(1-.05)]	$50,000

Three	\$902,500 [=\$950,000*(1-.05)]	\$47,500
Four	\$857,375 [=\$902,500 *(1-.05)]	\$45,125

After the initial capital investment in year one, capital additions lose \$50,000 of productive services by the beginning of year two. They lose an additional \$47,500 of efficiency by the beginning of year three, and lose an additional \$45,125 of productive efficiency by the beginning of year four. An identical decay process occurs in each subsequent year, where physical capital services in year *t* are equal to services provided in year *t-1* minus five per cent depreciation of year *t-1* capital services.

The capital investment therefore loses more productive services during the first year of operation than during the second year, and it loses more capital services during the second year of operation than it does in the third year. This pattern continues in each subsequent year of the assets' remaining life. Under GD, capital therefore loses the greatest amount of its productive efficiency during the first year of operation, and as capital ages the incremental loss of efficiency declines in each subsequent year.[25]

This pattern of depreciation essentially inverts the industry's accumulated expertise. Industry professionals believe new gas distribution assets operate "like new," with little to no significant decay, immediately after they are installed. Under GD, depreciation is front-loaded, with the greatest amount of decay occurring during the first year of operation. Industry professionals believe depreciation increases as assets age and approach the end of their useful lives. Under GD, depreciation tapers off as assets age.

This decay pattern also sheds light on the concern that assets never fully depreciate under GD. Assets that decay at a constant percentage rate will approach a value of zero efficiency services as time goes toward infinity, but they can never reach that value in any finite period. Every gas distribution asset installed must therefore provide a non-zero level of measured efficiency services under GD. Taken at face value, this means that no gas distribution asset ever fully depreciates and every gas distribution asset provides some productive services forever, which is obviously not accurate.

Dr. Kaufmann chose a depreciation approach, known as hyperbolic decay, that avoids the unrealistic and problematic implications of the OHS and GD options debated in Ontario. This approach has been used less often in regulatory proceedings, but it has been employed for decades by the BLS to compute TFP growth in the U.S. economy. The BLS is a highly-respected institution and authority on TFP and related measurement issues. It chose the hyperbolic decay approach only after thorough examination of all depreciation options, including OHS and GD.[26]

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[25] This example focuses on the "age-efficiency" profile, which measures capital efficiency and services *per* se. The "age-value" profile concerns changes in the value of capital assets over time.

[26] This examination took place in the early 1980s and involved many leading experts on depreciation and capital measurement. Until that time, the BLS had only provided measures of labor productivity for the aggregate economy and different economic sectors. It was tasked with developing multi-factor productivity measures in the early 1980s.

Under hyperbolic decay, capital services are computed using the hyperbolic function below:

$$S_t = \frac{N - t}{N - \beta t}$$

Here, S_t is the relative efficiency of assets in year t, N is asset service life, and β is a parameter reflecting the rate of decay. In its computation of TFP growth for the U.S. economy, the BLS computes capital services provided by structures using a value of 0.75 for β, and the same value for β is used in this study. Drawing on the most recent National Grid precedent, the service life for assets is 51 years. Under this hyperbolic decay formula, assets retain nearly all their productive efficiency during their early years of operation. Efficiency losses increase as assets age, and assets are fully depreciated in the last year of their service life.

Another benefit of the hyperbolic decay approach is that it is better tailored to the "vintaging" of each distributor's assets. The average loss of asset efficiency depends on capital investment patterns, which will differ both across time and across different distributors in the sample. The application of the hyperbolic formula captures differences in asset vintaging, both across time and across sampled companies. In contrast, the geometric decay approach assumes a single depreciation rate that applies in each year to every distributor.

7.3 Capital Input Price

The price of capital input is equivalent to the implicit rental price associated with the perpetual inventory equation. The implicit rental price formula 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. Implicit rental price formulas are derived using rigorous mathematical techniques, but the formulas resulting from this process are sometimes critiqued as being opaque and difficult to interpret or understand.

The capital input price used by BV is based directly on the capital input price formula used by BLS when estimating MFP growth for the U.S. economy. Dr. Kaufmann of the BV team consulted directly with BLS personnel to ensure that the capital input price in this study was as consistent as possible with the BLS formula. Recall that the BLS uses a hyperbolic decay approach to depreciation, which BV also utilizes in this study. The BLS capital input price is therefore also consistent with hyperbolic decay.

In each year t, the capital service price is given by the formula below:

$\text{Rental price}_t = [PK_t\ ((R\text{-}I)\text{-}D_t)\text{-}\%\Delta PK_t]\ *[(1\text{-}uz)_t/(1\text{-}u)_t]$

In this equation, PK is the capital asset price, (R – I) is a measure of the real internal rate of return, D is the loss of efficiency services, u is the corporate tax rate, and z is the present value of each dollar of depreciation deduction.

As previously explained, PK was computed for each year using Handy-Whitman data. The value of %ΔPK is equal to the average change in this capital asset price over the most recent three years. The value of R was measured by Moody's AAA bond rate data. The value of I was measured by the CPI. The value of D was computed directly using the hyperbolic decay formula, as applied to each utility's capital stock. Corporate tax rates were the sum of federal and state (or provincial) tax rates paid by each distributor. The value of z was computed using the sum of digits method.

It is not unusual in empirical work to smooth some of these variables that are especially volatile from year to year. BV used smoothed values of the real internal rate of return and the value of z, using the average value of each over the 1998-2020 period. Depreciation was also smoothed using a three-year, moving average approach.

While the capital input price is somewhat complex, closer inspection shows that most of its elements can be interpreted and understood. It can be seen that the value of the rental price is positively related to the capital asset price PK and the real rate of return on capital (R-I). This is intuitive, because payments for capital services should clearly increase as the prices of capital assets themselves rise and as real returns on assets increase.

It can also be seen that the capital service price is negatively related to the values of depreciation D and the effective tax rate after deductions, uz. Again this is intuitive, because capital becomes less valuable as it depreciates and as taxes on capital returns increase.

The remaining element in the formula is %ΔPK, which is sometimes described as asset capital gains. This element is less easy to interpret, and it has in fact been controversial in academic research. Because of these controversies, some analysts do not include this term in capital service prices. However, this term is included in BLS's capital price measure, and it has theoretical support. It has accordingly been retained in BV's work.[27]

7.4 O&M Costs

For every sampled gas distributor, total O&M expenses were computed as:

Total Distribution O&M Expenses plus

Total Underground Storage Expenses plus

Total Other Storage Expenses plus

Customer Service & Information Expenses plus

Customer Accounts Expenses plus

Sales Expenses *minus*

Franchise Requirements (acct 927) *minus*

Maintenance of General Plant (acct 932) *minus*

Uncollectible Accounts (acct 904) *minus*

Proxy for DSM expenses (acct 905 for MA distributors, acct 908 for all others) **plus**

Allocated A&G expenses, equal to total gas A&G multiplied by (Gross gas distribution plant divided by total gas plant), in each sample year

[27] In the 2018 TFP study submitted on behalf of OEB Staff, PEG also smoothed its measure of the real rate of return. PEG's capital service price does not utilize a "z" term. In the past PEG has included a similar capital gains term in its capital service price, but to the best of our knowledge no longer does so.

7.5 Sampled Gas Distributors

Table 8: Sampled Gas Distributors

Sample Company	
Atlanta Gas Light Company	North Shore Gas Company
Avista Corporation	Northern Illinois Gas Company
Baltimore Gas and Electric Company	Northern Indiana Public Service Company
The Berkshire Gas Company*	Northern States Power Company
Black Hills Energy Arkansas, Inc.	Ohio Gas Company
Bluefield Gas Company	Orange And Rockland Utilities, Inc.*
Boston Gas Company*	Pacific Gas and Electric Company
Brooklyn Union Gas Company*	The Peoples Gas Light and Coke Company
Cascade Natural Gas Corporation	Peoples Gas System
Central Hudson Gas & Electric Corporation*	Public Service Company Of North Carolina, Inc.
Colonial Gas Company*	Public Service Electric and Gas Company*
Columbia Gas of Kentucky, Inc.	Puget Sound Energy, Inc.
Columbia Gas of Maryland, Inc.	Questar Gas Company
Connecticut Natural Gas Corporation*	Rochester Gas and Electric Company*
Consolidated Edison Company Of New York, Inc.*	South Jersey Gas Company*
Consumers Energy Company	Southern California Gas Company
Corning Natural Gas Corporation*	The Southern Connecticut Gas Company*
Delta Natural Gas Company, Inc.	Southern Indiana Gas and Electric Company
DTE Gas Company	St. Joe Natural Gas Co, Inc.
Duke Energy Ohio, Inc.	St. Lawrence Gas Company, Inc.*
Louisville Gas and Electric Company	Superior Water, Light and Power Company
Madison Gas and Electric Company	The East Ohio Gas Company
Mountaineer Gas Company	Virginia Natural Gas, Inc.
National Fuel Gas Distribution Corporation*	Washington Gas Light Company
New Jersey Natural Gas Company*	Wisconsin Gas LLC
New York State Electric & Gas Corporation*	Wisconsin Power and Light Company
Niagara Mohawk Power Corporation*	Yankee Gas Services Company*

7.6 Annual TFP Results

Table 9: Annual TFP Results

Year	% Change Output	% Change Input	% Change TFP	% Change Labour	% Change Non-Labour O&M	% Change Capital
2006						
2007	0.75%	1.13%	-0.37%	-0.17%	0.24%	2.74%
2008	0.53%	0.63%	-0.09%	-1.02%	-0.10%	2.79%
2009	0.14%	5.27%	-5.13%	6.40%	7.05%	2.66%
2010	0.55%	1.88%	-1.33%	1.16%	1.89%	2.75%
2011	0.49%	1.26%	-0.77%	0.01%	0.09%	3.07%
2012	0.48%	0.38%	0.10%	-1.27%	-1.27%	2.88%
2013	0.64%	3.50%	-2.86%	3.59%	3.72%	3.22%
2014	0.54%	0.93%	-0.39%	-1.17%	-0.93%	3.67%
2015	0.81%	1.40%	-0.58%	-1.14%	0.01%	4.28%
2016	0.87%	3.41%	-2.54%	2.00%	3.09%	4.43%
2017	0.75%	2.30%	-1.54%	0.56%	1.11%	4.27%
2018	0.87%	5.73%	-4.86%	5.65%	6.15%	4.11%
2019	0.82%	1.86%	-1.04%	-0.14%	0.75%	4.29%
2020	0.71%	0.42%	0.28%	-3.04%	-1.56%	3.51%
2021	1.35%	0.43%	0.92%	1.98%	-1.47%	0.17%
Avg. 2006-21	0.69%	2.04%	-1.35%	0.89%	1.25%	3.26%

7.7 Dr. Kaufmann's CV

Lawrence Kaufmann

Resume

September 2022

Address: 12520 Central Park Drive
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Education:

Ph.D.:	Economics, University of Wisconsin-Madison, 1993
BA & MA:	Economics, University of Missouri-Columbia, 1984
High School:	St. Louis University High, St. Louis, MO, 1980

Relevant Work Experience, Primary Positions:

February 2021 – present: President, LKaufmann Consulting
Senior Advisor, Black & Veatch Knowledge Network

December 2008 – February 2021: President, LKaufmann Consulting
Senior Advisor, Pacific Economics Group and Navigant Consulting
Fellow, Canadian Energy Research Institute

Advise companies and public agencies, particularly energy utilities and regulators, on various regulatory and industry restructuring issues. Duties include consultation on performance-based regulation (PBR), developing service quality incentive plans, analyzing appropriate code of conduct policies for competitive markets, and providing supporting empirical research. Duties involve preparing public testimony and written reports, overseeing empirical research, client contact and briefings, and public presentations.

January 2001 – December 2008:Partner, Pacific Economics Group, Madison, WI
November 1998 – December 2000: Vice President, Pacific Economics Group, Madison, WI

Advise energy utilities and regulators on various industry restructuring issues. Duties include consultation on performance-based regulation (PBR), developing service quality incentive plans, analyzing appropriate code of conduct policies for competitive markets, and providing supporting empirical research. Duties involve preparing public testimony and written reports, overseeing empirical research, client contact and briefings, and public presentations.

August 1993 – October 1998: Senior Economist, Christensen Associates, Madison, WI

Assisted in the development and evaluation of PBR plans for energy utilities and other regulated enterprises. Duties included theoretical and empirical research (including the estimation of total factor productivity trends), written reports, client contact and briefings, public presentations, and monitoring regulatory trends in the United States and overseas.

January 1993 - July 1993:	Research Assistant to Dr. Robert Baldwin, Department of Economics, University of Wisconsin-Madison

Project investigated whether dumping penalties imposed by the United States have led to a diversion of imports from the nations on which the duties were assessed to other exporters.

January 1991 - May 1993:	Dissertation research on the impact of foreign investment on Mexican firms.

Dissertation examined whether there has been any spillover of advanced multinational technologies to competing Mexican firms. Research included development of a theoretical model of spillovers through Mexican recruitment of multinational personnel, interviews and data collection in Mexico, and empirical tests of theoretical conclusions. Dissertation research was funded through a fellowship from the Mellon Foundation.

June 1989 - December 1990:	Research Associate, Credit Union National Association, Madison, WI

Initiated and assisted on several long-term research projects, including the assessment of capital positions at Corporate credit unions, comparing the asset portfolios of credit unions and banks, and analysis concerning the development of credit union industries in Poland and Costa Rica.

January 1988 - August 1988:	Investment Banking Officer and Associate Economist, Centerre Bank, St. Louis, MO
April 1985 - December 1987:	Assistant Economist, Centerre Bank, St. Louis, MO

As Assistant Economist, the primary duty was to prepare country risk reports on nations to which the bank was lending. As Associate Economist and Investment Banking Officer, duties expanded to include writing a twice-weekly column on interest rate trends and preparing special reports on regional, national and international economic trends for senior management.

August 1983 - December 1984 and four semesters during the period September 1988 - May 1993:

Teaching assistant for classes in introductory microeconomics, introductory macroeconomics, international economics and the history of economic thought.

Professional Memberships:	American Economic Association National Association of Business Economists
Foreign Language Proficiency:	Spanish

Major Consulting Projects:

1. Plan design, policy testimony, total factor productivity and cost benchmarking in support of a performance-based regulation plan, EGI, 2021-2023.

2. Plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan. Plan confidential at this time, 2021-2022.
3. Plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan. Eversource Energy, 2021-2022.
4. Advise on appropriate labor and consumer price indices in labor compensation dispute. Crescent River Port Pilots' Association.
5. Plan design, policy testimony and cost benchmarking study in support of performance-based regulation plan. National Grid/Boston Gas, 2020-2021.
6. Advice on PBR strategy and application. Fortis BC, 2018-2020.
7. Policy testimony and cost benchmarking study in support of performance-based regulation plan. National Grid/Massachusetts Electric, 2018-2019.
8. Confidential advice on regulatory strategy. Client wishes to remain anonymous at this time, 2018.
9. Advice on regulatory environment and investment strategy. Client wishes to remain confidential at this time, 2017-2018.
10. Escalators for operating and construction expenses. Epcor Water West, 2017-18.
11. Rebuttal testimony on cost and wage benchmarking. Puerto Rice Electric Power Authority, 2016-2017.
12. Review and respond to comments on Epcor Water testimony. Epcor Water, 2016.
13. Review of regulatory framework to encourage efficient investment and accommodate uncertainty. Client wishes to remain confidential at this time, 2016.
14. Assessment of Ontario Power Generation ratemaking proposal. Ontario Energy Board, 2016.
15. Testimony on cost and wage benchmarking. Puerto Rico Electric Power Authority, 2016.
16. Testimony recommending updated inflation escalators in performance-based regulation plan. Epcor Water, 2015-2016.
17. Testimony recommending productivity factor for updated performance-based regulation plan. Epcor Water, 2015-2016.
18. Finalize reliability standards for electricity distributors in Ontario. Ontario Energy Board, 2015-2016.
19. Testimony on benefits of expanding bidding process for expansion of Alliant Riverside Energy Center facility. Associated Builders and Contractors of Wisconsin, 2015.
20. Cost benchmarking study. Puerto Rico Electric Power Authority, 2015.
21. Multi-client “Utility of the Future” and PBR study. Clients wish to remain confidential at this time, 2015.
22. Advise on benchmarking methods for electricity distribution. ANEEL, Brazilian Electricity Regulatory Agency, 2014.

23. The impact of gas extension tariffs on the development of the CNG market in Wisconsin. Reinhart Boerner Van Deuren on behalf of Kwik Trip, 2014.
24. TFP study and review of price controls in New Zealand. New Zealand Electricity Network Association, 2014.
25. Advise on benchmarking and regulatory issues in Toronto Hydro Custom IR application. Ontario Energy Board, 2014-15.
26. Advise on interrogatory responses. Consumer Energy Coalition of British Columbia, 2014.
27. Survey and analysis of implementation issues associated with customer-specific reliability metrics. Ontario Energy Board, 2013-15.
28. Empirical analysis and recommendation of appropriate reliability benchmarks. Ontario Energy Board, 2013-15.
29. Cost of service review (transmission and distribution operations) and cost benchmarking for Israel Electric Corporation. Public Utility Authority of Israel, 2013-15.
30. Value of reliability improvements from undergrounding power lines. Wisconsin Public Service, 2013.
31. Advise on and assess gas distribution incentive regulation plans. Ontario Energy Board, 2013-14.
32. Advise on price control application. UK Power Networks, 2013.
33. Advise on electricity distribution incentive regulation plans and other aspects of renewed regulatory framework for electricity. Ontario Energy Board, 2012-13.
34. Response to Productivity Commission Report on Energy Network Regulatory Frameworks. Energy Safe Victoria, 2012.
35. Statement on appropriate opt-out policies for smart meters to Wisconsin Public Service Commission. SMART Water, 2012.
36. Submission to Australia's Productivity Commission on the role of benchmarking in utility regulation. Energy Safe Victoria, 2012.
37. Assist Staff on review of cost of service applications for Enbridge Gas Distribution and Union Gas. Ontario Energy Board, 2012.
38. Assist with responses on data requests in testimony on alternative regulation plan. Potomac Electric Power, 2011-12.
39. Assess incentive regulation plans for Union Gas and Enbridge Gas Distribution in Ontario. Ontario Energy Board, 2011.
40. Advise on demand-side management and decoupling plans, and utility involvement in conservation and renewable energy businesses. ATCO Gas, 2011.
41. Advise on defining and measuring utility performance and the use of performance measures and standards in electric utility regulation. Ontario Energy Board, 2011-12.
42. Advise on rate mitigation strategies. Ontario Energy Board, 2011.
43. Advise on PBR strategy in Alberta. EDTI, 2011-12.

44. Estimate total factor productivity trend for gas distributors in New Zealand. Powerco, on behalf of industry, 2011.

45. Evaluation of reliability standards and alternative regulatory approaches for maintaining the reliability of electricity supplies. Ontario Energy Board, 2010-12

46. Prepare submission on rule change application and respond to consultant reports on TFP spreadsheet simulations and the impact of the regulatory framework on energy safety. Energy Safe Victoria, 2010.

47. Research on operating productivity and input price changes and testimony in support of an incentive-based formula to recover changes in gas distribution operating expenses. National Grid, 2010.

48. Prepare submission on rule change application and respond to consultant reports on TFP methodology. Essential Services Commission, 2010.

49. Advise on submission on rule change application. Victoria Department of Primary Industries, 2010.

50. Productivity research Victoria gas distribution industry, Essential Services Commission, 2010.

51. Productivity research Victorian power distribution industry, Essential Services Commission, 2010.

52. Advise on revenue decoupling and alternative regulatory strategies in context of upcoming gas distribution rate case. Northwest Natural Gas, 2009-2010.

53. Advise on revenue decoupling. Ontario Energy Board, 2009-2010.

54. Develop a "top down," econometrically-based measure of reductions in gas consumption resulting from utility DSM programs, and evaluate the merits of this approach compared to the existing "bottom up" methodology. Ontario Energy Board, 2009-2010.

55. Respond to proposals to amend National Energy Regulatory Framework to allow alternative approaches to incentive regulation. Essential Services Commission, 2009-2010.

56. Evaluate consultant reports and prepare submission on the update of price control formulas. New Zealand Energy Network Association, 2009.

57. Evaluate consultant reports in review on alternate regulatory arrangements. Essential Services Commission 2009.

58. Estimate TFP trend for New Zealand electricity distributors. New Zealand Energy Network Association 2009.

59. Evaluate consultant reports in review on alternate regulatory arrangements. Essential Services Commission 2009.

60. Submission on the application of total factor productivity in utility network regulation. Essential Services Commission, 2008-09.

61. Estimate total factor productivity trends, benchmark gas distribution cost performance, and testify in support of research. Bay State Gas, 2008-09.

62. Advise on appropriate regulatory treatment of early termination fees in retail energy markets. Essential Services Commission, 2008.
63. Advise on appropriate regulation of gas connection charges. Essential Services Commission, 2008.
64. Advise on appropriate cost of capital. Jamaica Public Service, 2008.
65. Estimate total factor productivity trends and benchmark bundled power cost performance for use in a productivity based regulation plan. Jamaica Public Service, 2008.
66. Estimate gas distribution total factor productivity trends. Essential Services Commission, 2008.
67. Update estimate total factor productivity trends electricity distributors. Essential Services Commission, 2008.
68. Respond to productivity and benchmarking studies. New Zealand Electricity Networks Association, 2008.
69. Response to comments on appropriate productivity and input price measures to be used to update gas distributors' operating expenses. Essential Services Commission, 2007-08.
70. Advise on update of performance based regulatory plan for power distributors, including recommendations for total-factor productivity based X factors. Ontario Energy Board, 2007-08.
71. Estimate lost wage and health damages. Wolfgram and Associates, 2007.
72. Response to critique of X factor recommendations. Ontario Energy Board, 2007.
73. Review of benchmarking methods and proposed benchmarking for the pricing of unbundled copper local loop. Telecom NZ, 2007.
74. Report on the relationship between revenue decoupling and performance-based regulatory mechanisms. Massachusetts energy distribution companies, 2007.
75. Research on revenue decoupling experience in California. National Grid, 2007.
76. Report on regulatory reforms needed to facilitate demand response, advanced metering infrastructure and energy efficiency objectives. Essential Services Commission, 2007.
77. Estimate lost wage and health damages. Wolfrgram and Associates, 2007.
78. Evaluation of gas distribution construction cost trends. Essential Services Commission, 2007.
79. Appropriate productivity trends and labor inflation rates to be used to adjust operating expenses in incentive-based ratemaking. Essential Services Commission, 2007.
80. Testify in support of rate adjustment under a performance based regulation plan. Bay State Gas, 2007.
81. Report on service quality regulation and benchmarking, submitted as expert witness testimony. Detroit Edison, 2007.

82. Develop and testify in support of alternative regulation plan for gas distribution services. Client confidential at this time, 2007.

83. Evolution of energy asset management companies and outsourcing relationships. Davidson Kempner Advisers, 2007.

84. O&M partial factor productivity trends for gas distribution services. Essential Services Commission, 2006-07.

85. Principles for designing gas supply PBR plans and assessing the impact of retail gas costs. DLA Piper Rudnick, 2006-07.

86. Framework for analyzing appropriate early termination fees in competitive retail electricity markets. Essential Services Commission, 2006-07.

87. Testify in support of exogenous factor recovery of revenues lost due to declining natural gas usage. Bay State Gas, 2006.

88. Service quality benchmarking. Canadian Electricity Association, 2006.

89. Analyze natural resource and recreational damage calculations for environmental damage to trout stream. Michael, Best and Friedrich, 2006.

90. Evaluate outsourcing contract and report benchmarking Envestra's gas distribution operations and maintenance expenses. ESCOSA, 2006.

91. Report on the use of partial factor productivity trends in the updated gas access arrangement. Essential Services Commission, 2006.

92. Advise on approved X factors and total factor productivity trends in approved alternative regulation plans for electric utilities. Central Maine Power, 2006.

93. Estimate total factor productivity and input price trends power distribution industries in all Australian States and territories, Essential Services Commission, 2006.

94. Develop and testify in support of an alternative regulation plan for gas distribution services. Client wishes to remain confidential at this time, 2006.

95. Develop and testify in support of an alternative regulation plan for gas distribution services. Client wishes to remain confidential at this time, 2006.

96. Testimony on treatment of outsourcing contract costs and labor-nonlabor cost allocations. Essential Services Commission, 2005-06.

97. Incorporate lessons from incentive regulation and benchmarking overseas into newly-established regulatory framework for nation's electric utilities. Bundesnetzagentur (BNA), Bonn Germany, 2005-2006.

98. Submission to Ministerial Council on Energy related to Regulatory Rulemaking. Essential Services Commission, 2005.

99. Evaluation of early termination fee policies for energy retailers. Essential Services Commission, 2005.

100. Advise on alternative regulation strategies for gas distribution services. Client wishes to remain confidential at this time, 2005-2006.

101. Report on comprehensive framework for using performance indicators to evaluate market power abuses, efficiency gains, and the distribution of benefits to stakeholders. Essential Services Commission, 2005.

102. Evaluation of regulatory options and estimation of total factor productivity for Port of Melbourne Corporation. Essential Services Commission, 2005.

103. Evaluation of regulatory options for taxi services in Melbourne, Australia. Essential Services Commission, 2005.

104. White Paper advising government agency on regulatory reform of State's electric power industry. Department of Natural Resources Newfoundland and Labrador, 2005.

105. Review report on CAPM and differences in beta between rural and urban power distributors. Essential Services Commission, 2005.

106. Develop "incentive power" model and apply towards evaluation of regulatory options in Victoria, Australia. Essential Services Commission, 2004-2005.

107. Review report on labor price forecasts for Victoria, Australia. Essential Services Commission, 2004-2005.

108. Develop and testify in support of performance-based regulation plan. Bay State Gas, 2004-2005.

109. Review of gas regulatory framework in Ontario, Canada. Ontario Energy Board, 2004-2005.

110. Benchmarking gas distribution operations. Powerco, Vector, NGC (New Zealand), 2004.

111. Report on methodologies for updating CPI-X price controls and assemble US gas transmission pipeline data, to be used in update of price controls for gas transmission services. Comision Reguladora de Energia (Mexico), 2004-2005.

112. Benchmark comprehensive power and water utility operations. Aqualectra (Curacao, Netherlands Antilles), 2004-2005.

113. Benchmarking power distribution operations. Energex and Ergon Energy, 2004.

114. Regulatory treatment of hub and storage facilities. NICOR Gas, 2004.

115. Review and comment on proposed service quality regulation. Essential Services Commission, 2004.

116. Review and contribute to report on ring fencing policies. Essential Services Commission, Victoria Australia, 2004.

117. Estimate lost earnings in litigation case. Wolfgram and Gherardini, 2004.

118. Respond to Productivity Commission report on Gas Access Arrangements. Essential Services Commission, Victoria Australia, 2004.

119. Analysis of PBR plans for rates and service quality worldwide. Jamaica Public Service, 2004.

120. Undertake benchmarking and total factor productivity studies in support of an X factor in a performance-based regulatory plan. Jamaica Public Service, 2003-2004.

121. Evaluate incentive regulation options. Questar Gas, 2003-2004.

122. Project evaluating implementation of total factor productivity in energy utility regulation. Essential Services Commission, Victoria Australia, 2003-2005.
123. Evaluate incentive regulation reports commissioned by Australian Competition and Consumer Commission. Essential Services Commission, Victoria Australia, 2003.
124. Evaluate proposed regulatory thresholds regime. Powerco New Zealand, 2003.
125. Evaluate benchmarking methods and regulatory reform proposals. Jamaica Public Service, 2003.
126. Evaluate proposals for service quality regulation in province of Ontario. Hydro One, 2003.
127. Evaluate benchmarking methods and regulatory reform proposals. Overseas New Zealand client wishes to remain confidential at this time, 2003.
128. US-Japan power transmission benchmarking. Central Research Institute of Electric Power Industry (Japan), 2003.
129. Benchmarking power distribution operations and maintenance (O&M) costs benchmarking and O&M productivity growth. Superintendente de Electricidad (Bolivia), 2003.
130. Benchmarking gas distribution operations and maintenance expenses. ACTEW (Australia), 2003.
131. Estimate lost earnings in wrongful death case. Wolfgram and Gherardini, 2003.
132. Advise on updating incentive plan for demand-side management. Hawaiian Electric, 2003.
133. Estimate and testify in support of damages in patent infringement case, Trombetta, LLC vs. Dana Corporation and AEC. Ryan, Kromholz and Mannion, 2003.
134. Analyze service quality proposals for a natural gas distributor, recommend modifications and testify in support of recommendations. New England Gas, 2002-2003.
135. Develop a service quality incentive plan for power distributors in Queensland, Australia; the plan is to be developed through a consultative process between the companies, major customer groups, and the regulator. Queensland Competition Authority, 2002-2003.
136. Consultation on developments regarding Wisconsin Electric's "Power the Future" initiative. Fidelity Investments, 2002.
137. Confidential report on US experience with benchmarking and alternative regulation. Central Research Institute of Electric Power Industry (Japan), 2002-2003.
138. Confidential report on capital cost measurement. Central Research Institute of Electric Power Industry (Japan), 2002-2003.
139. Report on merits and feasibility of benchmarking New Zealand power distributors. United Networks, 2002.
140. Impact of gas marketing expenditures on residential gas consumption. Envestra, 2002.

141. Advise on index-based performance-based regulation plan for a power distribution utility. Client wishes to remain confidential at this time, 2002.

142. Estimate productivity trend gas distribution industry and testify in support of trend. Boston Gas, 2002-2003.

143. Gas distribution benchmarking study. TXU Australia, Envestra and Multinet, 2002.

144. Benchmarking power transmission cost. Transend, 2002.

145. Advise on the development of an incentive regulation proposal for a North American power transmission utility. Hydro One Networks, 2001-2002.

146. Application of productivity and econometric benchmarking in an update of an incentive regulation plan. Ameren UE, 2001-2002.

147. Litigation regarding violations of Unfair Trade Practices Act for Tamoxifen, Taxol, and Buspar prescription drugs. Miner, Barnhill, and Galland, P.C., 2001-2002.

148. Recommend reforms of Western Australia power market, including reforms of wholesale markets, retail markets, structure of the incumbent utility, and regulatory arrangements; work was summarized in a report to the Electricity Reform Task Force. Western Power, 2001.

149. Faculty member of Regulatory Training Seminar in Bolivia. Seminar organized by the Public Utility Research Center and sponsored by SIRESE, 2001.

150. White Paper on implementing total factor productivity measures in regulation for the Utility Distributor's Forum. CitiPower, 2001.

151. Electronic forum on service quality incentives and research topics. Edison Electric Institute, 2001.

152. Economies of scale and scope in power services. Western Power, 2001.

153. Report evaluating the merits of alternative benchmarking methods and their application to energy distributors. Electricity Supply Association of Australia, 2001.

154. Response to report on benchmarking and incentive regulation. Client confidential at this time, 2000-2001.

155. Report on consistency of Price Determination with legislative mandates. TXU Australia, 2000-2001.

156. Develop methodology for service quality benchmarking and construction of appropriate deadbands. Massachusetts Gas and Electric Distribution Companies, 2000.

157. Advise on Performance-Based Regulation strategy, including development of a service quality incentive. BCGas, 2000.

158. Power distribution benchmarking. Queensland Competition Authority, 2000.

159. Develop and testify in support of service quality incentive. Western Resources, 2000.

160. Response to regulatory proposals for "ring fencing" operations. CitiPower, 2000.

161. Benchmarking evaluation of power distribution costs. Client name withheld, 2000.

162. Updated White Paper on Metering and Billing Competition in California. Edison Electric Institute, 2000.

163. Economies of scale and scope in power delivery and metering services. Massachusetts Utility Distribution Companies, 2000.

164. Evaluation of merger benefits. Client wishes to remain anonymous at this time, 2000.

165. Response to study on benchmarking capital spending. CitiPower, 2000.

166. Response to incentive regulation proposals of Pareto Economics in Victorian distribution price review. CitiPower, 2000.

167. Estimate scale economies in power generation, scope economies between power transmission and power generation, and implications for public policy in Western Australia. Western Power, 2000.

168. White Paper on "best practice" regulation and evaluation of price and non-price regulation of energy and water utilities in Australia, the US, and the UK. Electricity Association of New South Wales, 2000.

169. Power transmission benchmarking. Client confidential at this time, 2000.

170. Development of performance-based regulation plan for power distribution services. Texas Utilities, 2000.

171. Response to UMS benchmarking study on O&M costs. Victorian power distributors, 2000.

172. Response to Consultation Paper on Detailed Proposal for Form of the Price Control. CitiPower, 1999-2000.

173. White Paper on cost structure of power distribution. Australian power distributors (coalition contact: the Electricity Supply Association of Australia), 1999-2000.

174. White Paper on benchmarking principles and applications. Victorian power distributors, 1999-2000.

175. Service quality testimony. Hawaiian Electric, Maui Electric, and Hawaii Electric Light, 1999.

176. Faculty member of Regulatory Training Seminar in Argentina. Seminar organized by the Public Utility Research Center and sponsored by Enargas, 1999.

177. Service quality benchmarking study. Southern California Edison, 1999.

178. US-Australia performance benchmarking study. Victorian Distribution Businesses, Victoria, Australia, 1999.

179. Cost benchmarking for power delivery and customer services. Southern California Edison, 1999.

180. Development of Service Quality Incentive and Testimony in Support of Plan. Oklahoma Gas and Electric, 1999.

181. Evaluation of Intervenor Assessments of Customer Benefits in Proposed Merger. Western Resources, 1999.

182. Response to Regulator Proposals for Regulatory Methodology, Efficiency Measurement and Benefit-Sharing, and Form of Distribution Price Controls. CitiPower, Australia, 1999.

183. Response to Incentive Regulation Proposal of Australian Competition and Consumer Commission. CitiPower, Australia, 1998.

184. Report on Metering and Billing Competition in California. Edison Electric Institute, 1998-99.

185. Evaluation of Economies of Vertical Integration for Electric Utilities in Illinois. Edison Electric Institute, 1998.

186. Assessment of Cost Performance of Power Distributors in the United States and Australian state of Victoria. Victorian Power Distributors, 1998.

187. Formal Response to Regulatory Proposals for Price Cap Regulation/Development of Regulatory Options. Victorian Power Distributors, 1998.

188. Development of Service Quality Incentive and Testimony in Support of Plan. Louisville Gas and Electric/Kentucky Utilities, 1998.

189. Regulatory Support for Overall PBR Strategy. Louisville Gas and Electric/Kentucky Utilities, 1998.

190. Testimony on Impact of Brand Name Restrictions in Maine's Retail Energy Markets. Edison Electric Institute, 1998.

191. Development of Service Quality Incentive. Hawaiian Electric, 1998.

192. Regulatory Support for Comprehensive PBR Strategy and Feasibility of Retail Competition in Power Supply Services. Hawaiian Electric, 1997-98.

193. White Paper on Controlling Cross-Subsidization in Electric Utility Regulation. Edison Electric Institute, 1997-98.

194. White Paper on Cost Structure of Integrated Electric Utilities and Implications for Retail Competition. Edison Electric Institute, 1997-98.

195. Regulatory Support for a Price Cap Plan for Combination Utility. San Diego Gas and Electric, 1997-98.

196. White Paper on Price Cap Methodologies for Power Distributors in Victoria, Australia. Victorian Power Distributors, 1997.

197. Development of a Price Cap Plan for a Local Gas Distribution Utility. Atlanta Gas Light, 1997.

198. White Paper on Price Cap Regulation for Power Distribution. Edison Electric Institute, 1997.

199. Comprehensive Report on Performance-Based Regulatory Options for a Local Gas Distribution Utility. Atlanta Gas Light, 1997.

200. White Paper on Use of Electric Utility Brand Names in Competitive Markets. Edison Electric Institute, 1997.

201. Options for Price Cap Regulation for Power Distribution in Colombia. Comision Reguladora de Energía y Gas en Colombia, 1997.

202. Options for Performance-Based Regulation for Power Transmission and Stranded Cost Recovery for an Electric Utility. Client wishes to remain confidential at this time, 1997.

203. Regulatory Support for an Index-Based Incentive Plan of a Local Gas Distribution Utility. BCGas, 1997.

204. Recommendations for a service quality incentive plan. Hawaiian Electric, 1997.

205. Survey of Service Quality Incentive Plans and Assessment of Options. BCGas, 1996.

206. Regulatory Support for a Price Cap Plan. Southern California Gas, 1996.

207. Determination of service territories for newly-privatized gas distributors in Mexico. Comisión Reguladora de Energía, 1996.

208. Assessment of Regulatory Options for a Public Enterprise. United States Postal Service, 1996-97.

209. Regulatory support for a Price Cap Plan of a Local Gas Distribution Utility. Brooklyn Union Gas, 1996.

210. Development of a Price Cap Plan for the Gas Operations of a Combination Utility. Client wishes to remain confidential at this time, 1996.

211. Assessment of Options for Service Quality Incentives. Client wishes to remain confidential at this time, 1996.

212. Development of a Price Cap Plan for an Electric Utility. Client wishes to remain confidential at this time, 1996.

213. Assessment of Lessons from Natural Gas Restructuring for Electric Utilities. Client wishes to remain confidential at this time, 1996.

214. Advised on the Establishment of a Regulatory Framework for the Mexican Natural Gas Industry. Comision Reguladora de Energia, 1996.

215. White Paper on Unbundling Electric Utility Services. Edison Electric Institute, 1996.

216. Regulatory support for a Price Cap Plan of a Local Gas Distribution Utility. Boston Gas, 1995.

217. Development of a Price Cap Plan for a Local Gas Distribution Utility. Client wishes to remain confidential at this time, 1995.

218. Assessment of Incentive Regulation Options in the Context of a Proposed Restructuring of the Electric Utility Industry. Client outside of the United States wishes to remain confidential at this time, 1995.

219. Organization of a Conference on Price Cap Regulation. Edison Electric Institute, 1995.

220. Development of Regulatory Strategies Regarding the Transition to Retail Competition in the Electric Power Industry. Niagara Mohawk Power, 1995.

221. Assessment of Incentive Regulation Options in the Context of a Proposed Restructuring of the Electric Utility Industry. Alberta Power Limited, 1995.

222. Development of a Price Cap Plan for the Gas Operations of a Combination Utility. Public Service Electric and Gas, 1995.

223. Development of a Price Cap Plan for the Electric Operations of a Combination Utility. Public Service Electric and Gas, 1995.

224. White Paper on Incentive Regulation Theory and Its Application to Electric Utilities. Electric Power Research Institute, 1994-95.

225. Productivity Trends of U.S. Gas Distributors. Southern California Gas, 1994-95.

226. White Paper on Price Cap Regulation. Edison Electric Institute, 1994.

227. Regulatory Support for a Price Cap Plan. Central Maine Power, 1994.

228. Advanced Benchmarking Methods for U.S. Electric Utilities. Southern Electrical System, 1994.

229. Development of and Regulatory Support for a Price Cap Plan. Niagara Mohawk Power, 1994.

230. Competitive Price Scenarios for Power Markets in the Northeastern U.S. Niagara Mohawk Power, 1993-94.

231. Survey of Price Cap Plans in the U.S. and Abroad. Niagara Mohawk Power, 1993.

Expert Witness Testimony:

1. Before the Ontario Energy Board, evidence on behalf of Enbridge Gas Inc., 2021-2023. Subject: plan design, policy testimony, total factor productivity and cost benchmarking in support of a multi-year, incentive ratemaking plan.

2. Currently in settlement negotiations, client confidential at this time, 2021-2022. Subject: plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan.

3. Before the Massachusetts Department of Public Utilities, evidence on behalf of Eversource Electric, 2021-22. Subject: performance-based regulation and performance benchmarking.

4. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2020. Subject: rebuttal testimony on performance-based regulation and performance benchmarking

5. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2020. Subject: performance-based regulation and performance benchmarking.

6. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2019. Subject: rebuttal testimony on performance-based regulation and performance benchmarking.

7. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2018. Subject: performance-based regulation and performance benchmarking.

8. Before the Puerto Rico Energy Commission, evidence on behalf of the Puerto Rico Electric Power Authority, 2016. Subject: rebuttal testimony on cost and wage benchmarking.

9. Before the Puerto Rico Energy Commission, evidence on behalf of the Puerto Rico Electric Power Authority, 2016. Subject: cost and wage benchmarking.

10. Before the Edmonton City Council, evidence on behalf of Epcor Water and Sewer Inc., 2016. Subject: updated inflation factors in a performance-based regulation plan.

11. Before the Edmonton City Council, evidence on behalf of Epcor Water and Sewer Inc., 2016. Subject: updated inflation factors in a performance-based regulation plan.

12. Before the Wisconsin Public Service Commission, evidence on behalf of Associated Builders and Contractors of Wisconsin, 2015. Subject: assessing the merits of an expanded bidding process for the expansion of the Alliant Riverside Energy Center facility.

13. Before the Ontario Energy Board, evidence on behalf of OEB Staff, 2015. Subject: review of Custom Incentive Regulation proposal and benchmarking evidence of Toronto Hydro.

14. Before the Wisconsin Public Service Commission; evidence on behalf of Kwik Trip, 2014. Subject: surrebuttal testimony on the impact of gas extension tariffs on the development of the CNG marketplace in Wisconsin.

15. Before the Wisconsin Public Service Commission; evidence on behalf of Kwik Trip, 2014. Subject: the impact of gas extension tariffs on the development of the CNG marketplace in Wisconsin.

16. Before the Ontario Energy Board; evidence on behalf of OEB Staff, 2014: Subject: review of Customized Incentive Regulation proposal for Enbridge Gas Distribution.

17. Before the Ontario Energy Board; evidence on behalf of OEB Staff, 2013. Subject: total factor productivity estimation, cost benchmarking, and establishing incentive regulation plans for Ontario electricity distributors.

18. Before the Wisconsin Public Service Commission; evidence on behalf of Wisconsin Public Service, 2013. Subject: sur-surrebuttal testimony on the value of reliability improvements from undergrounding power lines.

19. Before the Wisconsin Public Service Commission; evidence on behalf of Wisconsin Public Service, 2013. Subject: rebuttal testimony on the value of reliability improvements from undergrounding power lines.

20. Before the Wisconsin Public Service Commission; evidence on behalf of SMART Water, 2012. Statement on appropriate opt-out policies for smart meters.

21. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of National Grid, 2010. Subject: rebuttal testimony in support of a net inflation adjustment mechanism applied to operating and maintenance expenditures.

22. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of National Grid, 2010. Subject: empirical support for a net inflation adjustment mechanism applied to operating and maintenance expenditures.

23. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2009. Subject: direct testimony on performance based regulation.

24. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2008. Subject: estimating partial factor productivity growth for O&M expenditures for natural gas distributors.

25. Before the Ontario Energy Board, 2008. Subject: appropriate values for total factor productivity-based productivity factor; benchmarking-based productivity "stretch factors;" and appropriate thresholds for capital investment modules; in an incentive regulation plan for electricity distributors in the Province.

26. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2007. Subject: direct testimony on performance based regulation.

27. Before the Circuit Court of the City of St. Louis, Missouri, Division 9, in Michele Thrash v. Freightliner *et al*, 2007. Subject: deposition testimony on estimated damages for lost income and medical treatment.

28. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2007. Subject: panel testimony on revenue decoupling and performance based regulation.

29. Before the New Zealand Commerce Commission, evidence on behalf of Telecom New Zealand, 2007. Subject: principles for price benchmarking and the merits of alternative methods of benchmarking unbundled copper local loop prices.

30. Before the Circuit Court of the City of St. Louis, Missouri, Division 13, in Anastacia McNutt v. Globe Transport, Inc *et al*, 2007. Subject: deposition testimony on estimated damages for lost income and past and future medical treatment.

31. Before the Michigan Public Service Commission; evidence on behalf of Detroit Edison, 2007. Subject: service quality regulation and benchmarking.

32. Before the Appeal Panel, South Australia, Australia; evidence on behalf of the Essential Services Commission of South Australia, 2006. Subject: the operating expenditures and outsourcing management fee of Envestra Ltd.

33. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2006. Subject: rebuttal testimony on exogenous recovery of revenues lost due to declining natural gas usage.

34. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2006. Subject: direct testimony on exogenous recovery of revenues lost due to declining natural gas usage.

35. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2006. Subject: regulatory treatment of an outsourcing contract to a related corporate party in a power distribution price determination.

36. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2005. Subject: labor and non-labor shares in operating expenditures.

37. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2005. Subject: rebuttal testimony on performance based regulation and benchmarking.

38. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2005. Subject: performance based regulation and benchmarking.

39. Before the New Zealand Commerce Commission, evidence on behalf of Vector and NGC, 2004. Benchmarking evidence for New Zealand gas distributors.
40. Before the New Zealand Commerce Commission, evidence on behalf of Powerco, 2003. Evaluation of total factor productivity and benchmarking evidence in studies undertaken for the Commission.
41. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Boston Gas, 2003. Subject: rebuttal testimony on performance based regulation, total factor productivity measurement and benchmarking
42. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Boston Gas, 2003. Subject: performance based regulation, total factor productivity measurement and benchmarking
43. Before the US District Court for the Western District of Wisconsin, Trombetta, LLC vs. Dana Corporation and AEC, 2003. Subject: estimate damages in solenoid patent infringement case.
44. Before the Rhode Island Public Utilities Commission: evidence on behalf of New England Gas, 2003. Subject: direct testimony on alternative service quality regulation proposals.
45. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2001. Subject: reply to surrebuttal testimony in support of service quality incentive plan.
46. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2000. Subject: rebuttal testimony in support of service quality incentive plan.
47. Before the Supreme Court of Victoria, Australia; evidence on behalf of TXU Australia, 2000. Subject: Whether the regulator's price determination complied with legal mandates to use price-based incentive regulation.
48. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2000. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.
49. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Massachusetts gas and electric distribution companies, 2000. Subject: Service quality benchmarking.
50. Before the Hawaii Public Service Commission; evidence on behalf of Hawaiian Electric, 1999. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.
51. Before the Oklahoma Corporation Commission; evidence on behalf of Oklahoma Gas and Electric, 1999. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.
52. Before the Kentucky Public Service Commission; evidence on behalf of Louisville Gas and Electric and Kentucky Utilities, 1998. Subject: Rebuttal testimony in support of service quality incentive plan and benefits of companies' regulatory proposal to low-income customers.
53. Before the Kentucky Public Service Commission; evidence on behalf of Louisville Gas and Electric and Kentucky Utilities, 1998. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

54. Before the Maine Public Utilities Commission, evidence on behalf of the Edison Electric Institute, 1998. Subject: Merits of allowing utility companies to use their brand names in competitive retail energy markets.

55. Before the California Public Utilities Commission, evidence on behalf of the Edison Electric Institute, 1997. Subject: Merits of allowing utility companies to use their brand names in competitive retail energy markets.

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1. *The Price Cap Designers Handbook* (with M. N. Lowry), Edison Electric Institute, 1995.
2. "The Treatment of Z Factors in Price Cap Plans" (with Mark Newton Lowry), *Applied Economics Letters*, 2: 1995.
3. "Forecasting Productivity Trends of Natural Gas Distributors" (with Mark Newton Lowry), *AGA Forecasting Review*, March 1996.
4. *Performance-Based Regulation for Electric Utilities: The State of the Art and Directions for Further Research* (with Mark Newton Lowry), Palo Alto: Electric Power Research Institute, 1996.
5. *Developing Unbundled Electric Power Service Offerings: Case Studies of Methods and Issues* (with Laurence Kirsch), Washington: Edison Electric Institute, 1996.
6. "A Theoretical Model of Spillovers Through Labor Recruitment", *International Economic Journal*, Autumn 1997.
7. *Branding Electric Utility Products: Analysis and Experience in Related Industries* (with Mark Newton Lowry and David Hovde), Washington: Edison Electric Institute, 1997.
8. "The Branding Benefit", *Electric Perspectives*, November 1997.
9. *Price Cap Regulation for Power Distribution* (with Mark Newton Lowry), Washington: Edison Electric Institute, 1998.
10. *Controlling for Cross-Subsidization in Electric Utility Regulation* (with Mark Meitzen and Mark Netwon Lowry), Washington: Edison Electric Institute, 1998.
11. "Price Caps for Distribution Service: Do They Make Sense?", *Edison Times*, December 1998 (with Eric Ackerman and Mark Newton Lowry).
12. *Economies of Scale and Scope in Power Distribution* (with Mark Newton Lowry), Washington: Edison Electric Institute, 1999.
13. *Competition for Metering, Billing and Information Services: The Experience in California So Far*, Edison Electric Institute, 1999.
14. *Third Party Metering, Billing and Information Services: Further Evidence from California*, Edison Electric Institute, 2000.
15. "Performance Based Regulation of Energy Utilities" (with Mark Newton Lowry), *Energy Law Journal*, 2002
16. "Performance Based Regulation and Business Strategy" (with Mark Newton Lowry), *Natural Gas*, 2003.

17. “Performance Based Regulation and Energy Utility Business Strategy” (with Mark Newton Lowry), *Natural Gas and Electric Power Industries Analysis 2003*, Financial Communications, Houston, 2003
18. “Price Control Regulation in North America: Role of Indexing and Benchmarking,” (with M.N. Lowry and L. Getachew), *Proceedings of Market Design Conference*, Stockholm, Sweden, 2003.
19. ”Performance Based Regulation Developments for Natural Gas Utilities” (with Mark Newton Lowry), *Natural Gas and Electricity*, 2004.
20. “Incentive Power and the Design of Regulatory Regimes,” *Network*, December 2005.
21. “Alternative Regulation for Electric Utilities” (with Mark Newton Lowry), *Electricity Journal*, June 2006.
22. ”Performance Indicators and Price Monitoring: Assessing Market Power,” *Network*, March 2007.
23. “Incentive Regulation in North American Energy Markets” *Energy Law and Policy*, Carswell Publishing, Toronto, Canada, 2009.
24. “Regulatory Reform in Ontario: Successes, Shortcomings and Unfinished Business” *Public Utilities Fortnightly*, November 2009
25. “An Update to Keystone XL Development,” *CERI Crude Oil Report*, September 2015
26. “Mexico Natural Gas Reform,” *Geopolitics of Energy*, January-February 2016
27. “Clean Energy Policy in the U.S.” *Geopolitics of Energy*, July 20616.
28. “The Energy Policy Outlook Under President Trump,” *Geopolitics of Energy*, November-December 2016.
29. “Electricity Security, Renewables, and the South Australia Power Outages,” *Geopolitics of Energy*, April-May 2017.
30. “Prospects for Nuclear Power in the U.S.,” *Geopolitics of Energy,* August 2017.
31. “The Past and Future of the X Factor in Performance-Based Regulation,” *Geopolitics of Energy*, February 2019
32. “The Past and Future of the X Factor in Performance-Based Regulation,” *The Electricity Journal*, April 2019

Presentations at Seminars and Professional Meetings:

1. Department of Energy/NARUC, Orlando, FL, 1995.
2. Illinois Commerce Commission and the Center for Regulatory Studies, St. Charles, IL, 1995.
3. Regulatory Studies Program, NARUC/Michigan State University, East Lansing, MI, 1995.
4. Marketing Conference, Edison Electric Institute, Chicago, IL, 1997.
5. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 1997.
6. Code of Conduct Conference, Denver, CO, 1997.
7. Code of Conduct Conference, Denver, CO, 1998.

8. Forum on Price Cap Regulation for Power Distribution. Melbourne, Australia, 1998.
9. Conference on Competition and Regulatory Reform in Hawaii. Honolulu, HI, 1998
10. Alternative Approaches Towards Price Cap Regulation. Melbourne, Australia, 1998.
11. Economics Meetings, Edison Electric Institute. Charlotte, NC, 1998.
12. Metering, Billing and Information Services Policy Convention, EEI, Chicago, IL, 1999.
13. Electricity Deregulation Conference. Vail, CO, 1999.
14. PURC Regulatory Training Seminar for Natural Gas Policy, Buenos Aires, Argentina, 1999.
15. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2000.
16. Seminar on Theory and Practice of Economic Regulation, Sydney, Australia, 2000.
17. Power Delivery Reliability Conference. Denver, CO, 2000.
18. Performance-Based Regulation Conference. Chicago, IL, 2000.
19. Regulatory Studies Program, NARUC/Michigan State University, East Lansing, MI, 2000.
20. Performance-Based Ratemaking Conference, Denver, CO 2000.
21. Energy Forum, Institute of Public Affairs, Melbourne, Australia, 2000.
22. Chamber of Commerce and Industry, Perth, Australia, 2001.
23. Energy Regulation Conference, Melbourne, Australia, 2001.
24. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 2001.
25. PURC Regulatory Training Seminar, La Paz, Bolivia, 2001.
26. Performance-Based Regulation Conference, Denver, CO, 2001.
27. Cost Structure of Energy Networks, Sydney, Australia, 2002.
28. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 2002.
29. Performance-Based Ratemaking Conference, Denver, CO 2002.
30. How to Regulate Electricity Lines Companies?, New Zealand Institute for the Study of Competition and Regulation, Wellington, New Zealand, 2003
31. Public Utility Regulation Seminar: Tariff Design and Incentives, Acapulco, Mexico, 2003
32. Rates and Regulation Meeting: Southeastern Electric Exchange, Williamsburg, VA, 2003.
33. Workshop on Service Quality Regulation in Ontario, Toronto, ON 2003.
34. Joint Canadian Electricity Association Distribution Council and Customer Council Meeting, Halifax, Nova Scotia, 2004.
35. Asia-Pacific Productivity Conference, Brisbane, Australia, 2004. [invitation, paper submitted]
36. Workshop on Productivity Measurement, Melbourne Australia, 2005.
37. Utility Regulators Forum, Canberra Australia, 2005.
38. CAMPUT Energy Regulation Course, Kingston Canada, 2006.
39. Performance Based Regulation Seminar, Toronto Canada, 2006.
40. Performance Benchmarking for Energy Utilities, Arlington, Virginia, 2006.
41. Performance Benchmarking for Energy Utilities, Seattle, Washington, 2007.
42. Alternative Regulation Seminar, Boston, Massachusetts, 2007.
43. CAMPUT Energy Regulation Course, Kingston Canada, 2007.
44. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2008.
45. Performance Benchmarking for Energy Utilities, Denver, Colorado, 2008.
46. Alternative Regulation Seminar, Toronto, Canada, 2008.
47. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2008.
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50. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2009.
51. Alternative Regulation Seminar, Boston, MA, 2009.
52. CAMPUT Energy Regulation Course, Kingston Canada, 2009.

53. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2010.
54. Alternative Regulation Seminar, Boston, MA, 2010.
55. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2010.
56. CAMPUT Energy Regulation Course, Kingston Canada, 2010.
57. Alternative Regulation Seminar, Toronto Canada 2010.
58. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2011.
59. Alternative Regulation Seminar, Philadelphia PA, 2011.
60. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2012.
61. Alternative Regulation Seminar, Chicago, IL, 2012.
62. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2013.
63. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2013.
64. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2014.
65. Alternative Regulation Seminar, Chicago, 2014.
66. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2014.
67. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2015.
68. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2015.
69. CERI Oil and Gas Conference, Calgary, Canada. 2015.
70. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2016.
71. Latin American Natural Gas Conference, Naturgas, Cartegena, Colombia, 2016.
72. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2016.
73. CERI Electricity Conference, Calgary, Canada, 2016.
74. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2017.
75. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2018.
76. Florida Infrastructure Conference, Gainesville, FL, 2018.
77. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2018.
78. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2019
79. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2019.
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