Réponses du Distributeur et du Transporteur à la demande de renseignements numéro 1 de l'Association hôtellerie Québec et de l’Association des restaurateurs du Québec (« AHQ-ARQ »)

Annexe

Réponse à la question 2.1

APPENDIX A

Exhibit No. ___

WRITTEN EVIDENCE

OF

TOBY BROWN AND PAUL R. CARPENTER

FOR ENMAX POWER CORPORATION

Proceeding ID No. 21149

December 18, 2015

The Brattle Group
44 Brattle Street
Cambridge, Massachusetts 02138
617.864.7900

Exhibit No. ___

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I. INTRODUCTION

Q1. Who are the authors of this written evidence?

A1. Dr. Paul Carpenter and Dr. Toby Brown are co-authors of this written evidence. We are Principals of The Brattle Group, an economic consulting firm. Dr. Carpenter's office is at 44 Brattle Street, Cambridge, Massachusetts 02138 and Dr. Brown's office is at 201 Mission Street, Suite 2800, San Francisco, California 94105.

Q2. Please describe your qualifications.

A2. Dr. Paul Carpenter is an economist specializing in the fields of industrial organization, finance and energy and regulatory economics. He received a Ph.D. in Applied Economics and an M.S. in Management from the Massachusetts Institute of Technology, and a B.A. in Economics from Stanford University, and has been involved in research and consulting on the economics and regulation of the natural gas, oil and electric utility industries in North America and abroad for over thirty years. He has frequently testified before federal and state regulatory commissions, in federal court and before the U.S. Congress, on issues of pricing, competition and regulatory policy in these industries. Outside of North America, he has advised governments and regulatory bodies on the structure and performance of their natural gas markets and the pricing of gas transmission services. These assignments have included testimony before the U.K. Monopolies and Mergers Commission and the Australian Competition Tribunal, and advice to the governments of and regulators in, Greece, Ireland, the Netherlands, New Zealand and Australia. He has been extensively involved in the evaluation of the economics and regulation of the natural gas pipeline industry in North America. He has testified before the National Energy Board and several provincial regulatory bodies on the subject of business risk and its relationship to the cost of capital for natural gas pipelines and distributors. He testified before the Alberta Utilities Commission in the generic Performance Based Ratemaking proceeding. Further details of his educational and professional background, as well as a listing of publications, are provided in his resume appended to this evidence as Attachment 1.

Dr. Toby Brown specializes in the regulation and economics of the gas and electricity sectors. He has fifteen years of experience across the U.S., Canada, the UK and Australia, primarily consulting for pipelines, utilities, and regulators, together with four years at Ofgem, the energy regulator in Great Britain. He has particular expertise in the application of incentive-based regulation in the energy sector, and provided advice to the ATCO utilities during the generic Performance Based Ratemaking proceeding before the Alberta Utilities Commission. Dr. Brown's project experience includes analysing business risk in pipeline rate cases, assessing the economic impacts of alternative regulatory frameworks and competitive structures in the energy sector, and advising on regulatory best practices based on experience in different jurisdictions worldwide. Dr. Brown also provides litigation support in a wide range of areas, including damages estimations, competition assessments, gas contract arbitrations, and utility and pipeline rate cases. He holds a D.Phil. in chemistry from the University of Oxford. Dr. Brown's resume is appended to this evidence as Attachment 2.

Q3. What assignment were you given in this proceeding?

A3. We were asked to recommend an "X-factor" for use in the ENMAX Power Corporation (ENMAX) 2015–2017 Performance-Based Regulation (PBR) plan. We were asked to review the record of the generic PBR proceeding[1] before the Alberta Utilities Commission (AUC), including the AUC's decision 2012-237, and the list of issues that will be addressed in the next generation generic PBR proceeding.[2] We were asked to assume that the form of the PBR plan to be approved in the present proceeding will be the same as that approved in decision 2012-237, and we were asked to follow the methodology adopted by the AUC in decision 2012-237 in recommending an X-factor. Nevertheless, we were asked to make an X-factor recommendation specific to the current circumstances of ENMAX.

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1 Proceeding 566.

2 Proceeding 20414.

We were also asked to comment on alternative methods for determining an X-factor that would be consistent with the PBR principles that the AUC has adopted.

Q4. What is your understanding of the relationship between this proceeding and the next generation PBR proceeding?

A4. We understand that ENMAX, along with the other electric distribution utilities and the gas utilities are participating in the next generation PBR proceeding, and that that proceeding is to determine the form of the next generation PBR plans which will come into effect when the plans that are currently in operation for the other utilities besides ENMAX end in 2017. We understand that ENMAX intends for this proceeding to determine a formula that will set rates for 2015, 2016 and 2017. As a result, in terms of timing, ENMAX will become "aligned" with the other distribution utilities and will be participating with them in the generic next generation PBR proceeding.

Q5. Are there some issues common to both this proceeding and the next generation generic PBR proceeding?

A5. This proceeding is specific to ENMAX whereas the generic proceeding covers all of the distribution utilities in Alberta; this proceeding relates to the years 2015–2017 whereas the generic proceeding will cover the years after 2017; and the last cost-of-service rate proceeding for ENMAX was for the 2014 test year, whereas the utilities in the generic proceeding are currently under PBR rates (as ENMAX will be, following this proceeding). Nevertheless, some issues will be common to both proceedings. For example, in both proceedings it will be necessary to set an X-factor, albeit that the X-factor determined in this proceeding is for 2015–2017 and the generic proceeding will set an X-factor for 2018 onwards.

Q6. How have you approached your assignment in this proceeding?

A6. In this proceeding we have used the methodology and approach adopted by the AUC in the first generic proceeding, and we have applied that methodology and approach to ENMAX and its current circumstances. We have some concerns with certain aspects of the methodology and approach adopted by the AUC, but we understand that consideration of changing the methodology and approach, or adopting new methods or new designs, will be part of the parallel generic proceeding. ENMAX asked us to assume that the form of its PBR plan for 2015–2017 will be the same as the form of the 2013–2017 PBR of the other utilities.

Q7. Do you recommend that the same X-factor be adopted for ENMAX in this proceeding as was adopted for the other utilities in the first generic PBR proceeding?

A7. No. While we are following the methodology adopted in decision 2012-237, our evidence shows that the X-factor adopted in the generic proceeding is inconsistent with the experience of the industry over the last few years. We therefore recommend that the magnitude of the X-factor should be recalibrated to take account of recent experience and new information. In our evidence we show how this can be done using the same methodology as was adopted by the AUC in the first generic proceeding.

We also recommend that the inconsistency between recent data and the magnitude of the X-factor currently applying to the other distribution utilities be taken into account in the generic proceeding. The generic proceeding should consider whether alternative approaches for setting the X-factor might be more robust and could be developed for application to all the utilities after 2017.

Q8. Please summarize your direct evidence relating to an X-factor for use in this proceeding.

A8. We have developed X-factor evidence using the same Total Factor Productivity (TFP) methodology that was used to calculate the X-factor adopted by the AUC in the first generic proceeding. In the first generic proceeding, the adopted X-factor was equal to the result of a TFP calculation plus a stretch factor, specifically the estimated 0.96% TFP trend over the 1972–2009 period, plus a stretch factor of 0.2%. We have updated the TFP calculation to include data for the years 2010 to 2014.[3] This information was of course not available to the AUC in the generic proceeding. In updating the TFP calculation we followed the same methodology that the AUC relied on in the first generic proceeding.

We find that the TFP methodology previously relied on by the AUC suggests negative TFP growth of −1.25% during the last five years, in contrast to the positive TFP trend of 0.96% identified in the first generic proceeding. Statistical tests suggest that the results of the last five years are inconsistent with and different from the X-factor adopted in the first generic proceeding.

This result may suggest that the utility industry has undergone a change at some point in the last several years, such that a very long-run TFP trend going back to 1972 would not be a reasonable guide to conditions for the 2015–2017 period. Alternatively, it may be that a long-run TFP trend cannot be estimated reliably from the data available, an issue that perhaps should be revisited in the next generic proceeding. In any event, it would not be reasonable to use the same 1972–2009 TFP trend to set the X-factor in this proceeding, nor would it be reasonable to use a 1972–2014 trend. In the first generic proceeding, an alternative recommendation, not adopted by the AUC, was to base the X-factor on a TFP trend of −0.37%, which was the average of the TFP trends for the most recent ten and fifteen year periods (the "ten-to-fifteen year" trend).[4] In contrast to the full 1972–2009 trend, statistical tests show that the ten-to-fifteen year trend of −0.37% is not incompatible with the TFP results of the last five years.

The updated TFP study shows TFP growth of −1.25% over the period 2009–2014; −1.37% over the period 2004–2014; and −0.89% over the period 1999–2014.

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[3] TFP is a rate of change over time. The five years of data from 2010 to 2014 allow a trend to be calculated that includes the five annual growth rates for 2009/10, 2010/11, 2011/12, 2012/13 and 2013/14. The convention we adopt is to refer to this five-year trend as the period 2009–2014.

[4] i.e., the average of the result for the ten-year and fifteen-year periods.

These results suggest that an X-factor in the range −0.37% to −1.37% would be reasonable: the high end of this range (the least negative figure) is a recommendation from the prior generic proceeding that, while above the results of the last five years, is not significantly different on a statistical basis; the low end of the range is the trend over the last ten years, which puts more weight on recent data, Our recommendation is an X factor of −0.89%, which is close to the mid-point of this range and is equal to the results of the updated TFP study for the last fifteen years (the period 1999–2014).

In the generic proceeding, the AUC acknowledged the existence of a "productivity gap" between the US and Canada, but found that there was insufficient evidence to determine whether the productivity gap extends to the utility sector. We have reviewed the evidence on this point from the generic proceeding and also more recent productivity data. We conclude that the productivity gap between the US economy and the Canadian economy continues to widen. Reviewing academic literature does not provide grounds for thinking that the productivity gap is confined to sectors of the economy that exclude utilities, but it is difficult to quantify the impact of the productivity gap on the utilities sector. We have not adjusted our X-factor recommendation, although the existence of a productivity gap would suggest adopting a more negative X-factor, because the Alberta PBR plans include a K-factor.

Finally, we have considered whether it would be reasonable to include a stretch factor. We conclude that, following the logic of the AUC's decision in the generic proceeding, a stretch factor is not required because ENMAX has been operating under PBR for some time.

Q9. Is your X-factor recommendation consistent with the proposed structure of the ENMAX PBR plan for the period 2015–2017?

A9. Yes. As was the case for the utilities in the generic proceeding, ENMAX capital-related revenue requirements are expected to grow significantly faster than base revenues (escalated at I – X). As a result, ENMAX is proposing to include a K-factor in its PBR plan.

Q10. Does recommending a negative X-factor have implications for the strength of incentives to control costs under the ENMAX PBR plan?

A10. No. The strength of the incentive to control costs derives from the fact that under PBR the utility's revenues are independent of actually-incurred costs for the term of the plan. The magnitude (and sign) of the X-factor do not change the fact that revenues and costs are independent, so do not change the strength of incentives. Negative X-factors are not unprecedented: we are aware of examples of real terms revenue increases adopted in proceedings in California, the UK and Australia,[5] and we note that in the generic proceeding the AUC recognized that the X-factor can be negative.[6]

Q11. Please summarize your direct evidence relating to alternative methods for determining an X-factor that would be consistent with the AUC principles.

A11. The PBR plans adopted by the AUC in the generic proceeding provide two main revenue streams: the "I – X" revenue, and the "K-factor" revenue. The former is revenue equal to total costs in the test year, increased each year by I – X and by growth in billing determinants. The latter is incremental revenues provided to cover the additional costs of specific projects or programs that are expected to increase faster than I – X. The K-factor revenue is collected on a pass-through basis, whereas the I – X revenue is not trued up for changes in cost.

Various alternative approaches for determining the X-factor, and, more broadly, for determining the amount of PBR revenue in each year of the plan are possible, have been developed in other jurisdictions, and could be implemented in a manner consistent with the AUC's PBR principles. For example, one alternative approach would be to estimate the efficient level of all of the utility's costs for the duration of the PBR plan term. The PBR revenues would be set equal to this forecast, and the X-

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[5] These examples were provided in the generic PBR proceeding. See Exhibit 0211.01, ATCO Gas/ATCO Electric Information Response to NERA Request #14, Attachments 1-3.

[6] "On this issue, the Commission agrees with the companies' argument that, in theory, the X factor does not necessarily have to be always positive." (AUC Decision 2012-237, paragraph 507).

factor could then be set equal to the expected rate of change of costs. In this case the K-factor could be smaller because it would only have to cover those capital programs for which a reliable cost estimate cannot be made.

Q12. How have you structured your direct evidence?

A12. Section II describes the X-factor, its purpose in the 2015–2017 PBR plan, and the TFP study developed in the generic proceeding. Section III describes how we updated the study with data for 2010 through 2014, and the updated results. In Section IV we discuss the relevant time period for estimating the TFP trend. Section V discusses the productivity gap between the United States and Canada and Section VI discusses the stretch factor. Section VII discusses alternative approaches for developing an X-factor, and Section VIII concludes.

II. FRAMEWORK FOR DETERMINING AN "X-FACTOR"

Q13. What is the nature of the PBR plan that ENMAX is proposing?

A13. We understand that ENMAX's proposed 2015–2017 PBR plan follows closely the model provided by the AUC's decision in the generic PBR proceeding (Decision 2012-237). More specifically, we understand that the ENMAX proposal generally adopts the I-factor and K-factor methodologies previously approved by the AUC. Under this model, the total revenue collected under the plan consists of two main parts.[7] The first part is revenue collected through "base rates". Base rates are fixed for the first year of the plan and thereafter increase each year by inflation plus or minus a fixed percentage, "X". The revenue associated with base rates changes in proportion to changes in base rates and also in proportion to changes in billing determinants (number of customers, kWh and kVA). Base rates will depend on how inflation turns out as time goes by, but do not otherwise change. The second part of the total revenue is the K-factor revenue, which is not fixed at the start of the plan term but depends on

7 This evidence addresses I, X and K-factors. We do not address other parts of the overall PBR revenue, such as the "Y-factor" and the "Z-factor". We understand that ENMAX has developed these components of its application in the same way as the other utilities did in the generic proceeding.

an annual “K-factor” filing. Revenue from base rates is not trued up or adjusted, whereas K-factor revenue will be trued up to align with actual capital expenditures on the programs covered by the K-factor.

Revenue from base rates increases with inflation because, as the prices of materials and labor that are inputs for the utility’s operations increase over time, providing utility service becomes more expensive. At the same time as the unit prices of inputs rise (or fall) with inflation, the utility may require more or less of those inputs to continue operating at the same level of output (in terms of the quantity of distribution services provided to customers). This change in the quantity of inputs required to produce a given amount of utility service as output is represented by the X-factor, and is determined without regard to the circumstances or performance of the particular utility—ENMAX in this case.

The second part of the total revenue represents unusual or extraordinary cost pressures facing the utility, for example as a result of having to replace significant amounts of capital assets or as a result of work required by third parties. The K-factor, unlike the X-factor, is specific to the circumstances of the particular utility.

Q14. What is the role of the “X-factor” in the ENMAX 2015–2017 PBR plan?

A14. Leaving aside the revenues authorized for recovery through the annual K-factor process, the X-factor determines the rate at which the authorized PBR rates increase or decrease in real terms. The X-factor adjusts for changes in cost (in real terms) that are to be expected over the term of the plan, measured on the basis of the average trend rate experienced by the utility industry as a whole in the past.

Q15. Why is it necessary to adjust authorized revenues in this way?

A15. One of the goals of PBR is to strengthen the financial incentive on the utility to control costs. In its letter dated February 26, 2010, the AUC advised that it was beginning an initiative (subsequently assigned Proceeding ID No. 566) to reform utility rate regulation in Alberta, initially for electricity and natural gas distribution services. In the letter, the AUC stated the following:

> "There are two principal purposes of the Commission's rate regulation initiative. The first is to develop a regulatory framework that creates incentives for the regulated companies to improve their efficiency while ensuring that the gains from those improved efficiencies are shared with customers. The second purpose is to improve the efficiency of the regulatory framework and allow the Commission to focus more of its attention on both prices and quality of service important to customers."

Strengthening the financial incentive is accomplished by ensuring that the authorized revenues do not depend on the utility's actually-incurred costs during the term of the PBR. During the term of the plan, if the utility is able to reduce its costs, it is able to achieve increased profits because revenues do not go down if costs go down. Equally, if the utility incurs unexpected extra costs, its achieved profits will fall. As a result, the utility sees a strengthened financial incentive to control costs, relative to traditional cost-of-service ratemaking. The functioning of a PBR plan can be contrasted with other frameworks. Under traditional cost of service in Alberta with two forward test years, revenues do not adjust in light of realized costs during the plan term, but the reset happens after two years rather than five with PBR. Under a tracker, deferral account or true-up mechanism, revenues automatically adjust so that actually-incurred costs are recovered.

Although under PBR revenues should not change as actually-incurred costs change, they should change with *expected* changes in cost. This is the purpose of the X-factor and the I-factor.

Q16. Why should revenues track expected changes in cost?

A16. At the beginning of the PBR plan, revenues are (re)set equal to an estimate of the current revenue requirement. Thus, at the beginning of the PBR plan, the utility will be able to earn a normal profit, associated with an achieved rate of return on investment equal to the authorized rate of return, if actual costs are equal to the costs assumed and adopted in the rebasing process. If the PBR revenues were the same each year for the term of the PBR plan, the utility would not have a reasonable opportunity to earn a fair rate of return, and the PBR plan would not be compatible with the fair return standard nor with the AUC's PBR principles.

Q17. Why would constant annual revenues be incompatible with the fair return standard?

A17. Costs change over time, for example as a result of input price inflation. Adjusting the PBR revenues to take into account inflation and other expected changes in costs (in the generic PBR proceeding, via the trend rate from a productivity study) means that on a "business as usual" or expected basis, revenues will follow costs and thus the utility should be able to achieve the authorized rate of return. The utility is not guaranteed to earn the authorized rate of return, however. If it is successful in controlling costs and improving the efficiency of its operations, it will have the opportunity to achieve a return above the authorized amount. Conversely, if it is not successful in controlling costs and improving efficiency, it will not be able to achieve the authorized rate of return.

Q18. What does the "trend rate from a productivity study" mean?

A18. In essence, a productivity study measures the rate at which outputs—the quantity of utility service—change and the rate at which inputs required to produce those outputs change over time. This measurement is made across the industry as a whole by looking at a large number of utilities, and is made over several years. It is thus an average trend rate.

Q19. Is the historical trend rate from a productivity study a reasonable way of determining an X-factor so that PBR revenues will track expected future changes in cost?

A19. If the situation of the utility is such that the cost pressures and other external operating conditions that the utility is likely to face in the future are similar to those that have been experienced by the industry as a whole in the past, it may be reasonable to use historical trends estimated for the industry as a whole as a guide for how the utility's costs will evolve during the PBR plan term. Within the framework set out by the AUC, it is reasonable to use a historical trend in this way, provided that the trend is measured from a time period that is representative and provided that a K-factor mechanism is available to deal with unusual capital investment requirements going forward.

Q20. Have you conducted a new productivity study?

A20. No. Since the PBR plans ultimately adopted by the AUC were designed to include an X-factor that relied on the productivity study commissioned by the AUC in the first generic proceeding, ENMAX has asked us to rely on that same study methodology to develop an X-factor recommendation in this proceeding. We have updated the study to include data for the five years since that study was completed, but have not made any other changes to that study.

Q21. Have you made any changes to the study methodology relative to that which was used by the AUC's consultants in the generic proceeding?

A21. No. We have updated the study that was developed by NERA, consultants to the AUC in the generic proceeding, to include data for the last five years, but have not changed the underlying methodology. As we explain in detail below, we base our recommendation on a subset of the data in the study because it is now more apparent than it was previously that the older data is unrepresentative of the industry's current situation.

Q22. Are you recommending that the same TFP trend be used as was used in the generic proceeding?

A22. No. Several years have passed since the generic proceeding took place. As a result, there is additional information that can be incorporated into the productivity study which was not available at the time of the generic proceeding. Furthermore, the additional data can be used as a test of whether the TFP trend adopted in the generic proceeding has been a reasonable benchmark for the actual experience of the US electric distribution industry over the last five years.

Q23. Why do you refer to the actual experience of the US electric distribution industry?

A23. The TFP study developed in the generic proceeding uses data obtained from the regulatory accounts of US electric utilities. In that proceeding there were no reliable TFP estimates put forward using Canadian data: "the Commission notes that the need to use U.S. data in establishing productivity targets for Alberta regulated companies arose because of the lack of uniform and standardized data for Canadian electric and gas distribution utilities".[8] The approach adopted by the AUC was to use a study of the TFP trend for US utilities to determine the X factor for the Alberta utilities.

Q24. How can you be sure that you are using the same methodology as that on which the AUC relied in the generic proceeding?

A24. In the generic proceeding, the AUC and NERA emphasized the importance of transparency. The productivity study that the AUC commissioned was published on the record of that proceeding so that participants could test it fully, and that study used only publicly-available information. It is therefore a relatively straightforward matter to update the study. The AUC and parties in the generic proceeding were concerned that other TFP analysis that was put forward was based on confidential data and was non-transparent because underlying calculations were not provided. The AUC also said: "As well, there is a concern that such data will not be available at all or that only the original provider using the same assumptions, methodology and adjustments could be engaged to provide a consistent analysis when the parameters of the PBR regime are to be reset."[9] Since NERA provided full underlying calculations, as well as a detailed write-up of their methodology, it was relatively straightforward to update the calculations with new data.

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[8] AUC Decision 2012-237, paragraph 341.

[9] AUC Decision 2012-237, paragraph 355.

Q25. Why do you say that updating the study is "relatively straightforward"?

A25. In terms of the study methodology, updating is straightforward because the methodology does not change. However, the study requires a large amount of data as inputs, and the spreadsheet calculations underlying the original study are complex. Obtaining and using that data to update the productivity study is conceptually straightforward but practically somewhat involved. Section III and the corresponding workpapers explain the updating process.

III. UPDATING THE PRODUCTIVITY STUDY

Q26. How did you go about updating the productivity study upon which the AUC relied in the generic proceeding?

A26. The spreadsheets containing the necessary data and calculations resulting in the adopted TFP trend were published on the record of the generic proceeding. In addition, NERA submitted two reports describing the study and its methodology in detail. We were therefore able to use the same data and follow the same methodology in updating the study.

Q27. Please summarize the results of the updating process.

A27. The original study contained TFP growth estimates for the years 1972/3 to 2008/9.[10] Over the entire study period, the TFP trend was 0.96%. Using only data from the last 15 years of the study, the trend was −0.03%.

After adding results for the five years 2010 through 2014 to the results of the original study, we find a trend rate across the entire period of 0.70% and a trend rate for the last 15 years of −0.89%.

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[10] It is a feature of the methodology used to estimate TFP growth in the generic proceeding that only changes in productivity from one year to another can be measured. The convention adopted was that the figure reported for a particular year (say 1973) represented the productivity growth from the prior year (1972 to 1973 in this case).

We explain below why we consider the trend over the last 15 years to be a more reasonable basis for determining an X-factor than the trend over the entire 1972 to 2014 period.

These results of updating the study are shown in Table 1.

Table 1

TFP Growth: Original Study and Update

	Annual TFP Growth
1973	4.71%
1974	-0.55%
1975	4.58%
1976	4.97%
1977	2.69%
1978	1.16%
1979	1.40%
1980	-0.79%
1981	0.47%
1982	-3.58%
1983	0.93%
1984	2.81%
1985	-0.23%
1986	2.43%
1987	2.48%
1988	5.09%
1989	0.76%
1990	1.01%
1991	0.50%
1992	0.17%
1993	3.00%
1994	1.90%
1995	3.97%
1996	1.62%
1997	0.62%
1998	0.53%
1999	-0.10%
2000	2.10%
2001	-3.39%
2002	1.20%
2003	-2.43%
2004	2.82%
2005	2.08%
2006	-2.46%
2007	0.50%
2008	-4.93%
2009	-2.59%
2010	2.19%
2011	-4.46%
2012	-1.99%
2013	-0.24%
2014	-1.77%
1972 to 2009 Average	0.96%
1994 to 2009 Average	-0.03%
1972 to 2014 Average	0.70%
1999 to 2014 Average	-0.89%

Sources:
1973-2009, Exhibit 0082.07, Proceeding ID 566, reproduced in Workpaper 1.
2010-2014, Update of Exhibit 0082.07, Workpaper 2.
Notes:
TFP Growth indicated for Year i indicates year-over-year change from Year i-1 to Year i.

Q28. Can you explain in conceptual terms what was involved in adding an additional five years of data to the productivity study?

A28. Yes. The productivity study from the generic proceeding used data on 72 utilities across a period of 37 years. One can picture the calculation as a table with 72 columns representing the utilities and 37 rows representing the years. The entries in the table represent the annual rate of productivity growth for each utility. A 73rd column is generated by taking an average across all the 72 utilities, and this 73rd column represents the average annual productivity growth for the utility sector as a whole in each year. Finally, an average is taken over the years in this last column to produce a trend rate of productivity growth for the sector.

In fact the calculations underpinning the productivity study are not implemented precisely in this fashion. However, at a conceptual level this is how the method works.

Conceptually, updating the study involved adding an extra five rows of data to this table.

Q29. How did you go about updating the study in practice?

A29. The table described above had one row for each year of the study, the last year being 2009. In order to accommodate the additional data now available, it was necessary to add five rows to the table in which to put the data for 2010, 2011, 2012, 2013, and 2014. Having added these five rows and obtained the required input data, the necessary calculations could be made by "dragging down" the formulas in the spreadsheet. Since the study methodology is not changing, the formulas which implement the required calculations do not change, except to the extent that it is necessary to adjust the cell ranges that are inputs to the formulas, consequent on adding additional data for the extra five years.

Notes describing the updating process in detail are included with the corresponding workpapers.

Q30. From where did you obtain the spreadsheets used in the generic proceeding?

A30. The spreadsheets used in the generic proceeding were filed on the record of that proceeding and can be downloaded from the AUC website. As a practical matter, NERA implemented the necessary calculations in a set of linked spreadsheets.

Q31. Is the study update as straightforward as adding five rows to every tab in the study spreadsheets?

A31. No. Implementing the update required several additional steps beyond adding five rows and copying down the formulas.

- The original study used data for 72 utilities, so, conceptually, the calculation tables have 72 columns. Since 2010 four of the 72 utilities have stopped filing FERC Form 1 data. Therefore (conceptually) in addition to adding five rows it was also necessary to delete four columns.
- A fifth utility, for which new data for 2010–14 could not be reconciled with the data for 2009 in the original TFP study, was also deleted.
- The original study contained a hard-coded number representing the count of the number of data-points in the study, and was used in the calculation of the average productivity growth rate.[11] It was necessary to update this number to reflect the addition of five additional years and the deletion of five utilities. The relevant formulas were adjusted so that the number of data-points was calculated formulaically rather than being entered as a hard-coded number.
- Formulas which referred to cell ranges were also adjusted to ensure that the new data was being correctly incorporated into the calculations.

Q32. From where did you obtain the data for the five additional rows?

A32. With one exception, described below, we were able to obtain data as described in the write-up provided by NERA in the generic proceeding.

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[11] We believe that the original study contained an error in that the hard-coded number intended to represent a count of the number of data-points did not accurately count the number of data-points in fact used. This error had no significant impact on the results for 1972–2009.

Q33. What was the data that you were not able to obtain in this way?

A33. Ratings on utility bonds and bond yields are inputs to the productivity study. Specifically, the study uses yields on an index of utility bonds of various credit ratings, and credit ratings for each utility. A yield is assigned to each utility in each year by looking up the yield on the bond index with the credit rating corresponding to the utility's credit rating. We were not able to use the same bond indices that NERA used because we do not have access to the same data providers and because NERA's reports and spreadsheets did not precisely identify exactly which indices were used. Nevertheless, we were able to obtain similar data from another provider.[12]

Q34. What caused four of the 72 utilities to stop filing data?

A34. Our understanding is that the entities which file a FERC Form 1 do not correspond to independently owned and operated utilities. One holding company may include several utilities, each of which files a FERC Form 1. We understand that over time these entities may be merged for reporting purposes such that separate Form 1s are no longer filed. Since 2010 four of the utilities in the original study have stopped filing FERC Form 1s.

Q35. How did you address the issue of missing data for these four utilities?

A35. We removed the four utilities that no longer file data with FERC from the study, effectively by deleting the columns for these utilities.

Q36. Why did you remove a fifth utility?

A36. When we added data for the additional years 2010-14 we checked to make sure that the data for 2010 was consistent with the data in the original study for 2009. We checked to ensure that the 2010 data was reasonably similar in magnitude to the 2009 data, reasoning that any large discontinuities could be indicative of data errors. For one utility in the sample we found a large discontinuity between 2009 and 2010, and

[12] See workpapers for details.

we were not able to reconcile the 2010 data with the 2009 data in the original study.[13] Since we were not able to reconcile the data, we removed this utility from the sample. As a result, the updated study contains 67 utilities.

Q37. What are the results of the analysis for the years 2010 to 2014?

A37. The study results for the additional years are shown in Table 2. The average trend over the 2009/10 to 2013/14 period is –1.25%.

Table 2

Updated TFP study:
TFP Estimates 2010-2014

	TFP Growth
2010	2.19%
2011	-4.46%
2012	-1.99%
2013	-0.24%
2014	-1.77%
Average	-1.25%

Source: Update of Exhibit 0082.07, Proceeding ID 566, Workpaper 2.

Q38. What are the updated productivity trend results?

A38. The updated trend results (from combining the original TFP study results with the new results) are shown in Table 1 above. The trend for the period 1972 to 2014 is 0.70%. The trend over the last 15 years of the study is –0.89%. Section IV below analyzes whether the entire period is relevant for the purposes of determining an X-factor, and we show that the results for the last five years, shown in Table 2, indicate that the first part of the study period should not be relied on.

[13] Consolidated Edison of New York.

IV. THE RELEVANT TIME PERIOD

Q39. In the generic proceeding, what was said about the relevant time period over which a productivity trend should be estimated?

A39. Broadly speaking, the various parties in the generic proceeding made four points about the time period for estimating TFP growth.

- First, the parties pointed out that it would be unwise to rely on a short period of time for estimating TFP growth because taking the average over a small number of years could give rise to volatile results. All parties in the generic proceeding appeared to agree with this point, although not necessarily on the minimum reliable period.
- Second, some parties argued that data from the 1970s was simply too old to be relevant to the utilities of today, and that various factors including industry restructuring might mean that older data is unreliable and should not be used.
- Third, some parties said that if a shorter period of time was used, it would be necessary to choose the start and end points of the period with care, because of the sensitivity of the results to this choice and because of the influence of business cycles.
- Fourth, some said that the safest course would be to rely on the longest time period available, unless there was strong evidence to suggest that earlier and later periods were different.

Q40. What did the AUC conclude on this point?

A40. The AUC reviewed the arguments of the parties. It concluded by saying "the Commission agrees with NERA's view that using the longest time period for which data are available is theoretically sound and represents the most objective basis for the TFP calculation. In the Commission's view, in the absence of any external scholarly studies pointing to a structural break in the TFP trend of the electric distribution industry, NERA's analysis based on a full 1972 to 2009 sample is the best indicator of the expected industry productivity growth during the PBR term. Moreover, such an approach eliminates the inevitable subjectivity involved in choosing a truncated time period for determining the industry TFP and mitigates the incentive to “cherry-pick” the start and end points to arrive at a desired TFP value.”[14]

Q41. Do you recommend that the TFP trend for the purposes of the present proceeding should be based on the full time period 1972 to 2014?

A41. No. The objective in the generic proceeding was to estimate the expected industry productivity growth during the PBR term. With the passage of time since the decision in the generic proceeding, it is possible to compare the various estimates that were made in the generic proceeding with the actual results from the last five years. Such a comparison illustrates the extent to which an estimate based on the full time period has proved to be reliable or, conversely, the extent to which older data has proven to be out of date.

Q42. Please summarize the TFP trend recommendations made by the various parties in the generic proceeding.

A42. Table 3 shows the TFP trend recommendations that the AUC considered in the generic proceeding. In that proceeding the AUC ultimately accepted the recommendation of its consultants (NERA), shown in column [5].

[14] AUC Decision 2012-237, paragraph 319.

Table 3[15]

Recommended TFP Trend Estimates from the Generic Proceeding

	ATCO Electric / ATCO Gas	Fortis	AltaGas	CCA	AUC Consultants
	[1]	[2]	[3]	[4]	[5]
Time period	1994-2009 and 1999-2009	1999-2009	1999-2009	1989-2007	1972-2009
TFP trend recommendation	-0.7% to 0.0%	-1.0%	-1.7% to -1.0%	1.08% to 1.23%	0.96%

Sources and Notes:
[1]: Carpenter reply evidence in proceeding id 566 (Exhibit 476.01], p. 12 – 13.
[2]: AUC Decision 2012-237, Table 6-2, p. 105.
[3]: AUC Decision 2012-237, Table 6-2, p. 105.
[4]: AUC Decision 2012-237, Table 6-2, p. 105.
[5]: AUC Decision 2012-237, p. 85.

Q43. How have you tested the recommendations in Table 3 using the TFP estimates from the last five years?

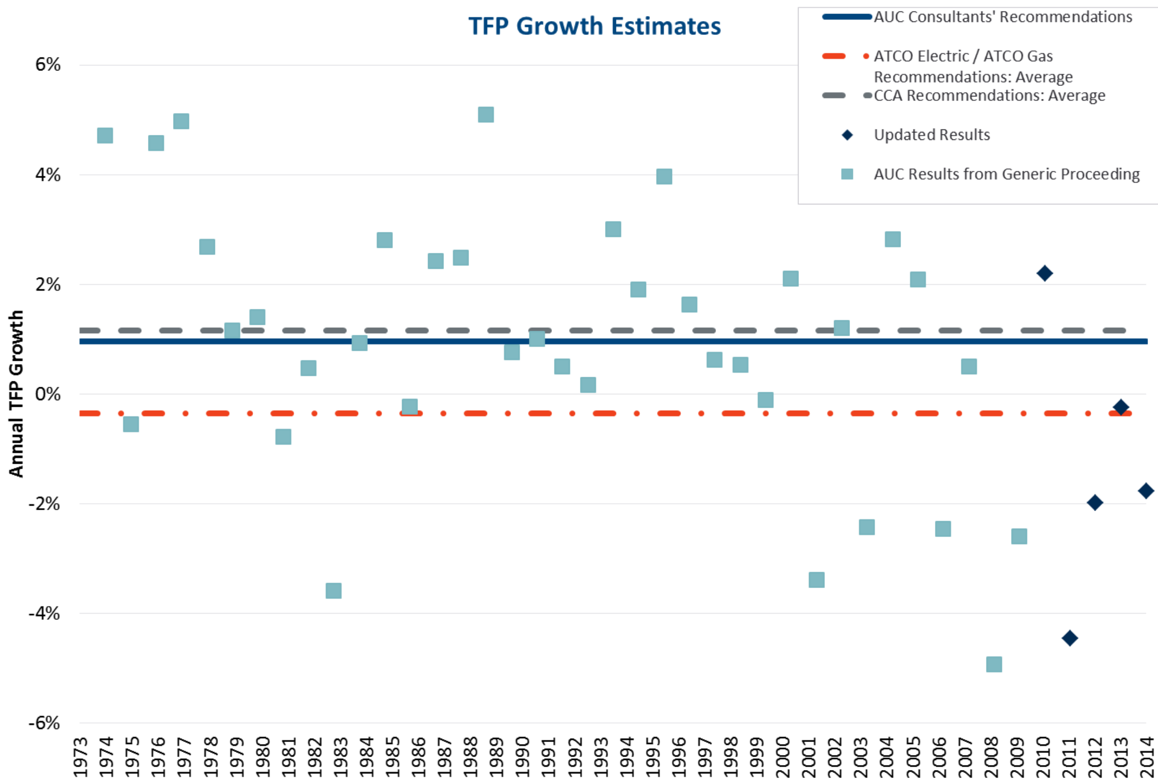
A43. Of the recommendations in Table 3 we concentrate on columns [1], [4][16] and [5] because these recommendations relied solely on the TFP study conducted by NERA, and the only difference between the three recommendations is the period over which the TFP trend was estimated. Figure 1 shows how these recommendations[17] compare to the TFP growth results from the original study (squares) and the last five years (diamonds). The second panel of Figure 1 shows only the last five years.

[15] Table 3 is based on Table 6-2 in AUC Decision 2012-237. The figures for ATCO shown in Table 6-2 were taken from the direct evidence of Dr. Carpenter for ATCO but should have been taken from Dr. Carpenter's rebuttal evidence which reflected changes that NERA made to their TFP study during the proceeding. The figures for ATCO in Table 4, column [1], are taken from Dr. Carpenter's rebuttal evidence (Exhibit 467.01 in the generic proceeding) and are thus consistent with the 0.96% shown in column [5]. The recommendation of EPCOR is not shown in Table 4 because it was a partial factor productivity recommendation and therefore is not consistent with the framework ultimately adopted by the AUC in the generic proceeding.

[16] The CCA and its consultants, PEG, put forward their own productivity study for gas distribution utilities. The recommendation shown above was for the electric utilities, and was based on NERA's TFP study.

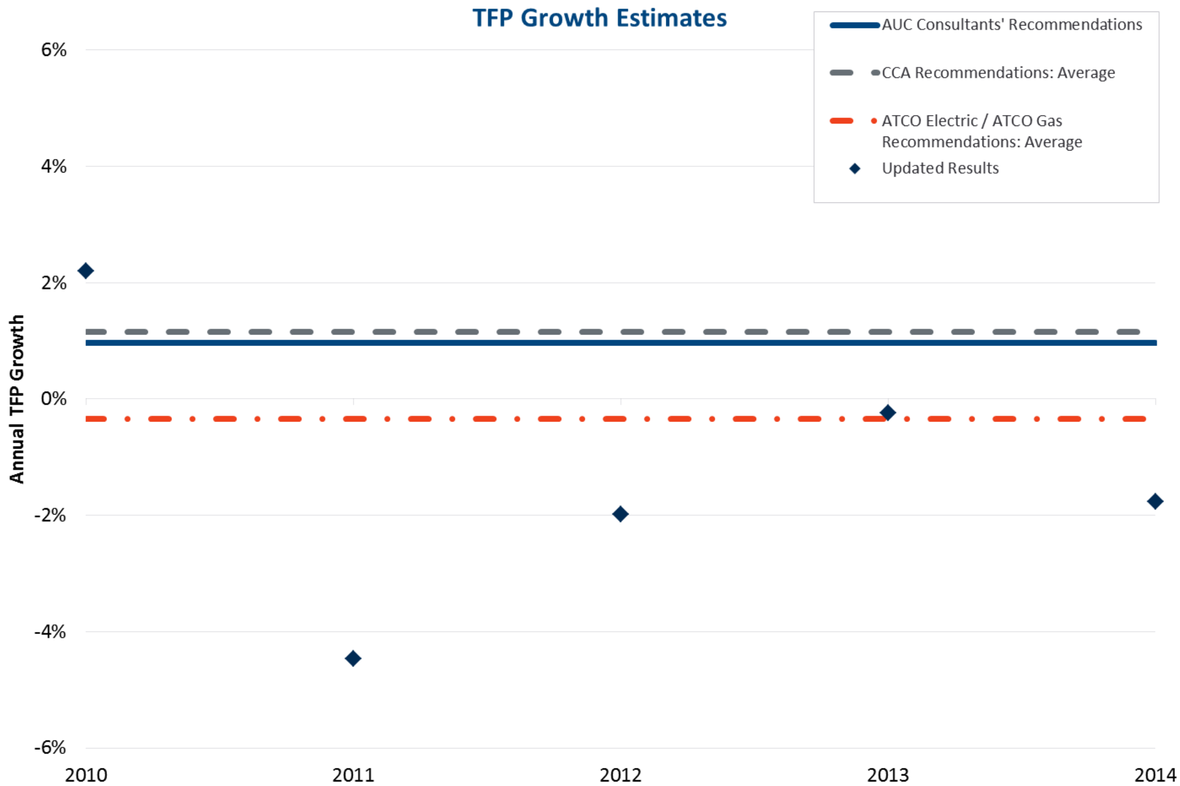
[17] In Dr. Carpenter's evidence in the generic proceeding, an X-factor recommendation was ultimately made by taking the average of the TFP results for 1994/5 to 2008/9 and 1999/2000 to 2008/9, after adjusting for the "productivity gap" (see Exhibit 467.01, Table 1). The average of the two TFP results before adjusting for the productivity gap is −0.37%.

1 **Figure 1**



Source: The Brattle Group. See Table 1: TFP Growth: Original Study and Update and Table 3: Recommended TFP Trend Estimates from the Generic Proceeding.

2



Source: The Brattle Group. See Table 1: TFP Growth: Original Study and Update and Table 3: Recommended TFP Trend Estimates from the Generic Proceeding.

Q44. How do you interpret Figure 1?

A44. We would make two observations about Figure 1. First, four of the five most recent annual estimates are below the TFP trend estimated from the 1972–2009 period and the 1989–2007 period. Second, four of the five most recent annual estimates are closer to the TFP trend estimated from the ten-to-fifteen year period to 2009 than either of the other estimates. These observations suggest that, of the alternatives available using data up through 2008/9, the estimate that was most in line with subsequent results is the one in column [1] of Table 3, based on the ten-to-fifteen year period ending in 2009.

Q45. Have you tested the degree to which the results from the last five years are similar to the estimates shown in Figure 1?

A45. Yes. We have performed some simple statistical tests which show that the estimate based on the more recent period is consistent with the results of the last five years, whereas the estimate based on the full period is not. The latter is significantly different from the average of the last five years, whereas the former is not.

Q46. How did you use the results of the last five years to test the recommendations that were made in the generic proceeding?

A46. The key question is whether the TFP results from more recent years are different from the TFP results in older years, for example because the structure of the industry has changed, because the older data is unreliable or inconsistently measured, or for some other reason. The first approach we took was to select five-year periods from either the full 1972–2009 data set or from the 1994–2009 period. If either of those two periods is representative of more recent performance, the TFP trend from randomly-selected five year periods would sometimes be higher than the trend from the last five years (an average TFP growth of −1.25%) and sometimes lower, but not systematically different.

We find that, taking continuous five year periods, there is only one period prior to 2009 which shows a TFP trend as low as the results from the last five years. If five years are chosen (without requiring them to be continuous), only around 2.5% of the possible combinations produce a result as low as the average from the last five years.

If we apply the same methods to the most recent ten-to-fifteen years of the original study (the basis for the ATCO recommendation shown above), the proportion of historical periods with results below −1.25% is greater. The ten-to-fifteen year trend is consistent with the results of the last five years, whereas the entire 1972 to 2009 trend is not.

Table 4

5-year Periods from Original Study in Comparison to the Most Recent 5 Years

		Proportion of periods with TFP trend less than or equal to -1.25% Continuous [1]	Non-Continuous [2]
Full 37 years	[A]	3.0%	2.5%
Most recent 10 or 15 years	[B]	11.8%	20.9%

Sources:
[1A]: Workpaper 6, [5].
[1B]: Workpaper 6, [10].
[2A]: Workpaper 7, [14].
[2B]: Workpaper 7, [28].
Notes:
"Continuous" means taking the average of continuous sets of five years from the original study. "Non-Continuous" means taking the average of random samples of five years. These averages are then compared to the most recent 5-year average.

Q47. Did you also perform more formal statistical tests?

A47. Yes. We conducted three tests. First we tested whether an average trend over the original 1972–2009 period was statistically different from the trend over the more recent ten-to-fifteen year period. Second we tested whether the average trend from the 1972–2009 period is statistically different from the results of the last five years. Third, we tested whether the trend from the ten-to-fifteen year period is statistically different from the results of the last five years.

Table 5

Statistical Tests

Test	T statistic	P value
1: 1972-2009 trend is the same as trend from most recent 10 or 15 years	2.50	0.02
2: 1972-2009 trend is the same as the results from the last 5 years	1.90	0.06
3: Trend from the most recent 10 or 15 years is the same as the results from the last 5 years	0.69	0.50

Sources and Notes:
See Workpaper 8.

Table 5 shows that the 0.96% TFP trend is statistically different from both the average from the more recent ten-to-fifteen year period (−0.37%) and from the results of the last five years (−1.25%). The latter two results, however, are not statistically different from each other.[18]

Q48. Is the statistical analysis you performed similar to the "structural break" analysis discussed by the AUC in the generic proceeding?

A48. The test we have employed is superior to the "structural break" analysis discussed in the last proceeding. This is because we are able to look back at the TFP study employed in the generic proceeding and test the TFP trend recommendations produced by that study against the TFP results from the last five years. Thus, these tests take statistical advantage of recent information that was obviously not available to the AUC in the generic proceeding.

A structural break analysis could be used to determine if and when the average TFP growth rate changed between 1972 and 2009 (or 2014). To evaluate the forecasts made in 2009 this approach is unnecessary because we have the actual forecasts made in 2009 and the subsequent realizations of TFP growth, leading to a straightforward evaluation of the accuracy of the forecasts.

Q49. How have you used the results you discuss above to make a recommendation for the appropriate time period to use for estimating a TFP trend in this proceeding?

A49. First, these results show that it would be unreasonable to rely on the entire 1972–2014 period. The last ten-to-fifteen years of data has been shown to be a much better estimate of recent TFP growth than an estimate that also relies on much older data back to 1972.

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[18] Details of these calculations are in the workpapers.

Second, there is significant year-to-year variation in the TFP results, including over the last five years. This means that the choice of start and end date can have an appreciable influence on the resulting trend estimate. We cannot identify any reason why one would choose an end date other than the most recent year for which data is available. In relation to the start date, we would not recommend a year later than ten years prior to the end of the period, because using fewer than ten years of data is more likely to give rise to a "noisy" estimate (as discussed in the generic proceeding).[19] We have not identified any objective method for determining a start date for the period. On the basis of the discussion above, it would be reasonable to use a start year between 1995/6 and 2004/5.

Q50. Why do you say that it would be reasonable to choose a start date between 1995/6 and 2004/5?

A50. The parties in the generic proceeding agreed that at least ten years of data should be used, which means that the latest acceptable start date is 2004/5.[20] The best-performing recommendation from that proceeding was based on data going back to 1995/6.

Q51. What start year do you recommend?

A51. Table 6 shows TFP trend estimates through 2014 as a function of the start year chosen, going as far back as 1995 (since that year was incorporated in the −0.37% recommendation from the generic proceeding, discussed above).

We recommend that the trend be based on the last 15 years of data—that is, using the period 1999/2000 to 2013/14. The corresponding TFP trend is −0.89%. We

[19] The AUC noted in Decision 2012-237 that "[t]here appeared to be an agreement among the parties that a sample period of at least 10 years is desirable for the purpose of determining the long-term industry TFP" (paragraph 307).

[20] The TFP trend is constructed as the average over annual growth rates, with the annual growth rate calculated from the ratio of index numbers in consecutive years. The convention used by NERA was that the annual TFP growth from one year to the next was labeled as the growth rate for the second of the two years. Thus the first annual growth rate in the study, representing the change in TFP between 1972 and 1973, was labeled as the TFP growth rate for 1973.

recommend using the last 15 years of data because this seems a reasonable compromise between using more data, which risks including out-of-date information, and using less data which risks volatility. The best-performing estimate from the generic proceeding used a combination of a ten-year and a 15-year period, but since more data is now available it seems reasonable to opt for the longer period.

Table 6

TFP Trend Estimates

	TFP Growth	Average TFP Growth through 2014
[1]	[2]	[3]
1995	3.97%	-0.34%
1996	1.62%	-0.56%
1997	0.62%	-0.68%
1998	0.53%	-0.76%
1999	-0.10%	-0.84%
2000	2.10%	-0.89%
2001	-3.39%	-1.11%
2002	1.20%	-0.93%
2003	-2.43%	-1.11%
2004	2.82%	-0.99%
2005	2.08%	-1.37%
2006	-2.46%	
2007	0.50%	
2008	-4.93%	
2009	-2.59%	
2010	2.19%	
2011	-4.46%	
2012	-1.99%	
2013	-0.24%	
2014	-1.77%	

Sources and Notes:
[2]: Table 1.
[3]: Average from year indicated in [1] through 2014.

Q52. Can you be sure that it would not be reasonable to choose 1972 as the start date?

A52. Yes. The TFP results from the last five years are not consistent with an estimate based on the period 1972–2009. One possible explanation for this is that, as discussed in the generic proceeding, the structure of the utility industry in the US was significantly different in the earlier than the later parts of the period.

V. THE "PRODUCTIVITY GAP"

Q53. What is the "productivity gap"?

A53. National statistics agencies and academic researchers have consistently estimated productivity growth of the Canadian economy that is slower (smaller) than productivity growth of the US economy. This difference is often referred to as the "productivity gap". The term "productivity gap" here refers to a slower rate of productivity *growth* in one economy over time than in another economy. There may also be a difference in the absolute levels of productivity in two economies at a given point in time.

Q54. What is the relevance of the productivity gap to this proceeding?

A54. The TFP growth estimates described above in sections III and IV use data for US utilities. They are estimates of the trend rate at which TFP of the US electric distribution sector has been growing over time. In this proceeding the TFP trend is used to determine an X-factor to apply to ENMAX in Canada. Firms in the US economy tend to increase productivity faster than firms in Canada. It may therefore not be reasonable to use a US TFP estimate directly for setting X in this proceeding.

Q55. Was this issue discussed in the generic proceeding?

A55. Yes. The AUC said "Parties did not dispute the fact that there presently exists a well-recognized difference between the rate at which the U.S. and the Canadian economies have been able to improve productivity (referred to as a "productivity gap"). Using macroeconomic productivity data from Statistics Canada and the U.S. Bureau of Labour Statistics, NERA showed that, on average, productivity in the U.S. economy grew 0.95 percentage points per year faster that productivity in the Canadian economy over the 1972 to 2009 period. [f/n omitted]"[21]

Q56. Is there evidence that the productivity gap applies in the utility sector?

A56. If the underlying cause of the productivity gap was something which affected all sectors of the economy equally, the productivity gap would apply to the utility sector as well as to the other sectors of the economy. In contrast, if the underlying cause of the productivity gap was something which only affected some sectors of the economy, not including utilities, it would not be necessary to take a productivity gap into account when determining the X-factor for a Canadian utility.

It is not possible to measure the productivity growth of Canadian utilities and compare that estimate with results from US utilities because the necessary data is not available. If it were possible to measure TFP growth for Canadian utilities, it would not have been necessary for the generic proceeding to rely on a study of US productivity growth. It is therefore impossible to be certain whether the productivity gap applies to the utility sector.

Q57. What is the underlying cause of the productivity gap?

A57. Unfortunately, while there is consensus that the productivity gap exists, there is no such consensus on what causes the gap. Various candidate explanations have been suggested in the literature, including lower spending on R&D in Canada, lower investment in human capital and post-graduate training, and smaller sizes of markets and firms. None of the academic research we have seen leads us to believe that the productivity gap would not affect the utility sector.

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[21] AUC Decision 2012-237, paragraph 441.

Q58. What did the AUC say about whether the productivity gap affects the utility sector?

A58. In the generic proceeding, the AUC said: "In light of the conflicting evidence from the government and academic research, and the uncertainty of whether the results of such research can be used for establishing the existence of a productivity gap between U.S. and Canadian distribution utilities, the Commission considers that no definitive conclusion can be reached on the existence of such a gap."[22]

Q59. Do you agree with the AUC's position?

A59. There is no direct evidence as to the existence of a productivity gap in the utility sector, and the indirect evidence is not conclusive. We therefore agree with the AUC that it is impossible to be definitive as to whether the gap exists for the utility sector.

Q60. Did the AUC adjust the US TFP trend for use in Alberta?

A60. No. The AUC relied on the fact that the business environment, including operational and regulatory conditions, is similar in the US and Canada. The AUC concluded that it was not necessary to make an adjustment on this basis.

Q61. Do you agree that the business, operating, and regulatory conditions are similar for utilities in the US and Canada?

A61. Yes. However, we would expect that the business, operating and regulatory conditions for most or all sectors of the economy are similar in the US and Canada.

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22 AUC Decision 2012-237, paragraph 448.

Q62. Has the magnitude of the productivity gap changed since the generic proceeding?

A62. No. The difference between the TFP trend for Canada and the US has remained approximately constant. Over the most recent 15 years for which data is available, TFP growth in Canada has been about 1.2% lower than TFP growth in the US.[23]

Q63. Does the existence of the productivity gap cause you to adjust your estimate of US electric distribution industry TFP growth for use in Canada?

A63. The productivity gap means that a TFP trend estimated from US data is more likely to be too high than too low when applied in Canada. Unfortunately we have not been able to identify a good way to quantify the necessary adjustment. We have adopted an X-factor recommendation based on a US TFP trend without adjustment, while noting that the existence of the productivity gap means that this recommendation is more likely to be too high than too low.

VI. A "STRETCH" FACTOR

Q64. What is a "stretch factor"?

A64. Sometimes when implementing PBR for the first time regulatory commissions have set the X-factor at a level above a historically-determined trend. The rationale given is that when a utility has been operating under a regulatory framework with relatively weak incentives to control costs, some "inefficiencies" may be built into the utility's operations that are relatively easy to improve. If a utility is inefficient, once the incentives to control costs are strengthened, the utility may be able to reduce costs faster than might otherwise be expected on the basis of a historical industry-wide TFP trend.

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[23] See workpaper 4.

Q65. What is your view of this rationale?

A65. Unfortunately, it is difficult or impossible to measure the extent to which, if at all, a particular utility is more inefficient. Therefore, while the logic makes sense, we do not see how it would be possible in practice to determine the magnitude of a stretch factor that might be reasonable in a particular circumstance. However, in this proceeding there is in any case no rationale for a stretch factor since PBR is not being implemented for the first time.

Q66. Why do you describe the rationale for a stretch factor in connection with implementing PBR for the first time?

A66. When the strength of incentives to control costs is increased, there may be scope for the utility to reduce costs faster than a historical trend measured for the industry because of accumulated inefficiencies as we explained above. In the generic proceeding, the AUC said: "The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime."[24]

Q67. Would you support using a stretch factor in this proceeding?

A67. No. From 2007 until rebasing in 2014, ENMAX has been operating under FBR[25] rather than traditional cost-of-service regulation. The current situation for ENMAX is therefore different from that facing the other utilities in Alberta in the generic proceeding (and is also different from the situation of ENMAX when its 2007 FBR plan was designed), and a stretch factor is not justified.

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[24] AUC Decision 2012-237, paragraph 479.

[25] From 2007 ENMAX was operating under a plan known as "Formula-Based Ratemaking" or FBR. Conceptually FBR and PBR are very similar.

VII. THE K-FACTOR

Q68. Has ENMAX prepared a forecast of its costs?

A68. ENMAX has produced a forecast of expected costs in order to forecast its expected ROE over the term of the PBR plan. We understand that this forecast contains the Company's current view of expected capital expenditures, operating expenditures and associated revenue requirements[26] that will be incurred over the plan term. Table 7 shows several figures which provide a summary of the forecast.

Table 7

Summary of ENMAX Application Schedules

Average Annual Increase (2014 – 17)	
PBR Base Revenue	3.6%
Revenue Requirement	8.3%
Capital-related revenue requirement	9.0%
Total (2015 – 2017)	
PBR Base Revenue ($m)	614
Revenue Requirement ($m)	679

Sources and Notes:
EPC Appendix to 2015-2017 Performance Based Rates Application, Schedules 1.0 and 2.0. See Workpaper 10.

Q69. What is the significance of the figures in Table 7?

A69. Table 7 shows that the capital-related elements of the revenue requirement (depreciation, interest and equity return) are forecast to grow at about 9.0% per annum on average between 2014 authorized amounts and the forecast for 2017. In contrast, PBR base revenue is forecast to increase at an average rate of 3.6% per annum on average. 3.6% represents the aggregate of expected inflation, the X factor,

[26] By revenue requirement, we mean the revenue that would be required in order to earn the authorized return on equity, given the forecasts of costs and billing determinants.

growth in billing determinants, and an adjustment to going in revenues of 1.63%.[27] There is a mismatch between the rate at which base revenues are expected to grow (3.6%) and the rate at which capital-related revenue requirements are expected to grow (9.0%).

Similarly, revenue requirements (the revenue that would need to be collected in order to earn the authorized ROE) would need to grow at about 8.3% per annum.

In order for base revenues to grow at a rate similar to the expected growth in capital-related or overall revenue requirements, the X-factor would need to be about −6% instead of −0.89%.

Q70. Does this analysis suggest that your recommended X-factor of −0.89% is too high (i.e., a more negative X-factor should be adopted)?

A70. This analysis does suggest that if there were no K-factor revenue, an X-factor of −0.89% would be too high (not sufficiently negative) to support the capital expenditures that ENMAX is forecasting. However, we understand that ENMAX is requesting additional K-factor revenue.

Q71. Are you aware of other approaches for determining the path of base revenues under a PBR plan?

A71. Yes. As mentioned in the introduction above, an alternative to the historical TFP-based trend approach adopted by the Commission in the generic proceeding would be to determine the path of base revenues on the basis of a forecast of costs likely to be incurred over the term of the PBR plan. This approach is used in the UK and in Australia. It is also similar to the traditional version of cost-of-service regulation in Alberta, but with the traditional one or two-year forward test period extended to five years.

[27] The adjustment to going-in revenues represents the difference between authorized and actual billing determinants for 2014.

Q72. If this approach is similar to cost-of-service regulation as implemented in Alberta, does it change the strength of incentives to control costs relative to cost-of-service?

A72. Yes, it does. There are strong incentives to control costs under a PBR plan that will be in place for five years because the path of revenues is independent of *realized* costs during the term of the plan. It is true that under a "cost forecast" approach the utility's own forecast of costs is a significant influence on revenues, so it is important that appropriate mechanisms are in place to review such forecasts.

Q73. Could an X-factor be determined with reference to a cost forecast without regard to the TFP analysis?

A73. Yes. An X-factor of about −6% is required to produce revenues equal to the forecast revenue requirements over the plan term.

Q74. Are you aware of the criticisms that have been levied against this approach in relation to possible incentives to "over-forecast"?

A74. Yes. For example, we understand that there was some discussion of this point in the generic proceeding. However, various mechanisms can be implemented to guard against the risk of over-forecasting. One possibility is to conduct a thorough independent review of the forecasts. A second is to design an incentive arrangement which provides a financial reward to the utility if its cost forecast turns out to be accurate. This is sometimes referred to as the "menu" approach.

VIII. CONCLUSIONS

Q75. Please summarize your conclusions.

A75. We have updated the TFP study commissioned by the AUC in the generic proceeding by adding five additional years of data, and we have investigated whether the TFP results from the last five years are consistent with the TFP trend for the 1972–2009 period on which the AUC based its X-factor decision. We find that the results from the last five years are not consistent with that trend but are consistent with a trend measured using more recent data, for example over the last 15 years. We interpret this result as support for the suggestion that TFP results from the earlier part of the period are not representative of the modern industry. We therefore base our X-factor recommendation on the results of the updated study for the last 15 years (i.e., the period 1999–2014).

It would not be reasonable to include a “stretch factor”. Following the logic of the AUC’s decision in the generic proceeding, a “stretch factor” is not required for ENMAX because it has been operating under PBR for some time.

Following the AUC’s approach and methodology in the generic proceeding, we therefore recommend an X factor equal to the TFP trend we have estimated: −0.89%.

Q76. Does this conclude your evidence?

A76. Yes.

Attachment 1

Dr. Paul Carpenter holds a Ph.D. in applied economics and an M.S. in management from the Massachusetts Institute of Technology, and a B.A. in economics from Stanford University. He specializes in the economics of the natural gas, oil and electric utility industries. Dr. Carpenter was a co-founder of Incentives Research, Inc. in 1983. Prior to that he was employed by the NASA/Caltech Jet Propulsion Laboratory and Putnam, Hayes & Bartlett, and he was a post-doctoral fellow at the MIT Center for Energy Policy Research. He is currently a Principal and Chairman of The Brattle Group.

AREAS OF EXPERTISE

- Energy economics
- Regulation
- Corporate planning
- Pricing Policy
- Antitrust

EXPERIENCE

Natural Gas and Electric Utility Industries

- Consulting and testimony on nearly all of the economic and regulatory issues surrounding the transition of the natural gas and electric power industries from strict regulation to greater competition. These issues have included stranded investments and contracts, design and pricing of unbundled and ancillary services, evaluation of supply, demand and price forecasting models, the competitive effects of pipeline expansions and performance-based ratemaking. He has consulted on the regulatory and competitive structures of the gas and electric power industries in the U.S., Canada, the United Kingdom, continental Europe, Australia and New Zealand.

Valuation and Damages

- Expert testimony before courts, tribunals and in arbitrations concerning asset valuation and damages associated with breach of contract, bankruptcy and commercial disputes. Experience includes expert testimony in U.S. federal and state courts, the British High Court of Justice, the Australian Competition Tribunal and various arbitration and mediation panels in Australia, Canada, New Zealand and the U.S.

Antitrust

- Expert testimony in several of the seminal cases involving the alleged denial of access to regulated facilities; analysis of relevant market and market power issues, business justification defenses, and damages.

Regulation

- Studies and consultation on alternative ratemaking methodologies for oil and gas pipelines, on "bypass" of regulated facilities before the U.S. Congress; advice and testimony before several state utility commissions and the National Energy Board of Canada on new facility certification policy.

Finance

- Research on business and financial risks in the regulated industries and testimony on risk, cost of capital, and asset valuation for network industries, airports and seaports in the U.S., Canada., Australia and New Zealand.

PROFESSIONAL AFFILIATIONS

- American Economic Association

ACADEMIC HONORS AND FELLOWSHIPS

- Stewart Fellowship, 1983
- MIT Fellowships, 1981, 1982, 1983
- Brooks Master's Thesis Prize (Runner-up), MIT, 1978

PUBLICATIONS

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Attachment 2

Dr. Toby Brown specializes in the regulation and economics of the gas and electricity sectors. He has consulted for pipelines, utilities, and regulators in the U.S., Canada, Europe, and Australia, and he has particular expertise in incentive regulation in the energy sector.

Dr. Brown's experience in energy regulation includes: analyzing business risk; designing frameworks for performance-based regulation; cost allocation; rate structure; and advising on regulatory best practices based on experience in different jurisdictions worldwide.

Dr. Brown also provides litigation support in a wide range of areas, including damages estimation, gas contract arbitrations, and utility and pipeline rate cases. He has provided expert advice to parties in gas contract arbitrations in Australia and New Zealand.

Prior to joining Brattle Dr. Brown worked at the UK energy regulator, Ofgem. He holds a D.Phil. and a B.A. in chemistry from the University of Oxford.

EXPERIENCE

Energy Regulation and Ratemaking

- Dr. Brown has provided advice to utilities and regulators on many aspects of the regulatory framework applied to gas and electric distribution networks. In many instances the advice has included identifying good practice by examining how regulators in different jurisdictions treat a particular issue. Examples of topics on which Dr. Brown has advised include third-party access and liberalization, the rules for secondary trading of pipeline capacity, the structure of distribution network prices, methods for determining the cost of capital, business risk, network reliability, and information-gathering powers of utility regulators.

- Dr. Brown has advised on developing formula-based rates, or "performance-based" regulation (PBR), in several jurisdictions. He advised ATCO Electric and ATCO Gas on the design of their PBR plans during the generic proceeding to develop PBR for all gas and electric distribution utilities in Alberta. He testified on PBR and incentive regulation for the Hawaiian Electric Companies in a proceeding to adjust the design of formula-based revenue adjustments between test years. He has also advised the Australian Energy Market Commission in connection with determining five year revenue requirements for gas and electric distribution utilities.

- In addition to his consulting experience, Dr. Brown has spent four years at Ofgem, the energy regulator for Great Britain.

Energy Contract Arbitrations and Energy Litigation

- In connection with price reviews under long-term natural gas supply agreements, Dr. Brown has advised on the economic theory of long-term contracts and the market price of gas in New Zealand, the eastern states of Australia, and Western Australia.

This advice has included analyzing the non-price terms of contracts produced in discovery, criteria for identifying comparable contracts, and adjusting for differences in non-price terms where necessary. Dr. Brown also analyzed net-backs for transportation costs and processing.

- Dr. Brown has supported testifying experts in connection with estimating damages in a variety of commercial disputes in the energy sector. For example, in an action in the British High Court, Dr. Brown analyzed claims of damage associated with a problematic IT project at an energy retailer, including in relation to unrecovered customer debt and changes in retail market share. In connection with the bankruptcy of a midstream oil company, Dr. Brown analyzed losses associated with the company's positions in oil and gas derivatives.

PUBLICATIONS AND PRESENTATIONS

These publications are available at http://brattle.com/experts/toby-brown.

Efficient Tariff Structures for Distribution Network Services, with Ahmad Faruqui, and Léa Grausz, Economic Analysis and Policy 48:139-149, December 2015.

International Review of Demand Response Mechanisms, with Samuel A. Newell, David Luke Oates, and Kathleen Spees, report prepared for the Australian Energy Market Commission (AEMC), October 2015.

Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs, with Ahmad Faruqui, report prepared for the Australian Energy Market Commission, August 2014.

Incentive-based ratemaking: Recommendations to the Hawaiian Electric Companies, with Michael J. Vilbert and Joseph B. Wharton, report prepared for the Hawaiian Electric Companies and submitted to the Public Utilities Commission of Hawaiʻi in Docket No. 2013–0141.

International Experience In Pipeline Capacity Trading, with Dan Harris and Alessandro Massolo, report prepared for the Australian Energy Market Operator, August 2013.

Wholesale Gas Price for AGL's VPA Proposal for 2014–16 (public version), with Paul Carpenter, prepared for AGL and submitted to the Independent Pricing and Regulatory Tribunal of New South Wales, February 2014.
Estimating the Cost of Equity for Regulated Companies, with Bente Villadsen, Paul R. Carpenter, Michael J. Vilbert, and Pavitra Kumar, report prepared for the Australian Pipeline Industry Association, February 17, 2013.

Estimating the Cost of Debt, with Bente Villadsen, a report for the Dampier-Bunbury Pipeline, March 4, 2013.

Framework for Assessing Capex and Opex Forecasts as Part of a "Building Blocks" Approach to Revenue/Price Determinations, with Pinar Bagci, Paul R. Carpenter, and Philip Q Hanser, report prepared for the Australian Energy Market Commission, June 2012.

Approaches to Setting Electric Distribution Reliability Standards and Outcomes, with Serena Hesmondhalgh and William P. Zarakas, a report to the Australian Energy Market Commission, January 2012.

Does the Market Risk Premium Change Over Time?, discussion at the Australian Competition and Consumer Commission Regulatory Conference 2011, July 28, 2011.

Is "Cost-of-Service Plus Incentives" the Best We Can Do?, with William B. Tye, paper presented to the Australian Competition and Consumer Commission Regulatory Conference 2011, July 28, 2011.

Incentive Regulation: Lessons from other Jurisdictions, with Paul R. Carpenter and Johannes P. Pfeifenberger, presented at the Alberta Utilities Commission Performance Based Ratemaking workshop, the Van Horne Institute, May 26-27, 2010.

Price Re-Openers in Natural Gas Supply Contracts: Avoiding Costly Mistakes in Arbitration, with Paul Carpenter, Brattle Newsletter 2010 No. 1 (Energy).

Is the smart grid going to fare better in competitive markets?, with Ahmad Faruqui, presented at the Gulf Coast Power Association Spring Conference, Houston, TX, April 14, 2010.

Options for Reforming the Building-Blocks Framework, with Paul Carpenter, a report to the Australian Energy Market Commission, December 16, 2009.

Review of Incentive Power and Regulatory Options in Victoria, with Paul Carpenter, a report to the Australian Energy Market Commission, December 2009.

Incentives under Total Factor Productivity Based and Building-Blocks Type Price Controls, a report to the Australian Energy Market Commission, with Boaz Moselle, June 2009.

EU Climate and Energy Policy to 2030 and the Implications for Carbon Capture and Storage, a report for Alstom Power Systems, with Serena Hesmondhalgh and David Robinson, March 2009.

Use of Total Factor Productivity Analyses in Network Regulation: Case Studies of Regulatory Practice, a report to the Australian Energy Market Commission, with Boaz Moselle, October 2008.

Critique of the Industry Codes Governance Arrangements, a report to Ofgem, with Serena Hesmondhalgh, Boaz Moselle, and Simmons & Simmons, June 2008.

Models of Inter-regional Transmission Charging, a report to the Australian Energy Market Commission, with Boaz Moselle, March 2008.

International Review of Transmission Planning, presentation at Transmission and Distribution 2008, Amsterdam, March 12, 2008.

International Review of Transmission Planning Arrangements, a report to the Australian Energy Market Commission, with Boaz Moselle, October 2007.

TESTIMONY

Incentive-based ratemaking: Recommendations to the Hawaiian Electric Companies, before the Public Utilities Commission of Hawai‘i, Docket 2013–0141, May 2014 and September 2014.

Wholesale Gas Price for AGL's VPA Proposal for 2014–16, with Paul Carpenter, submitted to the Independent Pricing and Regulatory Tribunal of New South Wales, February 2014.