Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans

Pacific Economics Group Research, LLC

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Executive Summary

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union) are both subject to incentive regulation (IR) plans that took effect in 2008 and will run through 2012. Pacific Economics Group Research (PEG-R) was asked to advise OEB Staff on how the EGD and Union IR plans operated in practice. Because the plans are currently in effect, our analysis is necessarily partial and cannot assess the entire IR experience. Nevertheless, understanding the available evidence may help the Board determine whether and how to modify the incentive regulation framework.

PEG-R's assessment focused on the Board's key criteria for an effective ratemaking framework, particularly the following issues:

- Did the incentive regulation plans encourage cost control and generate productivity and efficiency improvements?
- Did both customers and shareholders share in the benefits of any efficiency gains that were achieved?
- Did the Companies provide appropriate service quality to their customers?
- Was the incentive regulation framework conducive to capital investment?

One important Board criterion involves the sharing of benefits and/or productivity gains under IR. 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. Given the importance of this issue, PEG-R developed a methodology for quantifying the sharing/distribution of benefits under the IR plans that was designed to be as simple and transparent as possible. This methodology involved a relatively straightforward extension of the 'indexing logic' that has underpinned Ontario's previous IR plans.

Customer benefits under IR would primarily be reflected in the prices they pay for gas delivery services. However, given the multiplicity of rates and variety of mechanisms that enter into gas delivery ratemaking in Ontario, analyzing the Companies' gas delivery prices is not as straightforward as it may seem. There is also no established accounting framework for isolating the impact of every element of the Companies' IR plans on the changes in gas delivery rates under the plans. PEG-R therefore assessed this issue using a variety of information on rate trends for EGD, Union and relevant comparators while the plans were in effect.

Our analysis shows that gas delivery price trends have generally been favorable under the Companies' IR plans. The combined effects of the net inflation mechanism, Y factors, and Z factors in the IR plans have led to declines in allowed gas delivery revenues for both EGD and Union over the 2008-2010 term of the plans. These revenue declines have averaged $1.5 M annually for EGD and $1.8 M annually for Union. The earnings sharing mechanisms (ESMs) have led to even more pronounced revenue declines of $14.1 M per annum for EGD and $15.1 M for Union, on average, over the plan. These revenue declines have been somewhat offset by the average use (AU) factor, which has led to rate increases to recover declines in average use per customer (AUPC) for certain customer classes. Overall, however, PEG-R's gas delivery price indexes show a modest 0.4% annual increase in gas delivery prices for Union's M1, M2, Rate 01, and Rate 10 customers, and an annual 0.32% decline in EGD's gas delivery prices over the terms of the IR plans.

The Companies' price trends compare favorably to other price measures. EGD and Union's residential gas delivery tariffs have grown less rapidly than those for two Massachusetts gas distributors that were subject to incentive regulation at the same time. Residential gas delivery prices have also grown somewhat less rapidly than residential electricity prices in Ontario in recent years. In addition, the Companies' overall prices have grown more slowly than the growth in the GDP-IPI over the 2008-2010 period, which measures inflation in final domestic demand for a basket of goods and services, and have also grown more slowly than the Companies' input prices over the same period.

PEG-R's assessment of the rate adjustment mechanics and regulatory process for ratemaking has also not identified any major concerns. The regulatory process associated with setting the annual IR rate adjustment appears generally to function in a timely manner. Provided the IRM rate application does not involve auxiliary issues, most IRM filings tend to be resolved in no more than 90 days. There appear to be more regulatory issues associated with the ESM applications, especially for Union's 2010 rate year. Computing the returns to be shared in an ESM is an inherently controversial issue, and this process sometimes leads to “mini rate cases” that involve significant regulatory costs and delays. These regulatory costs are a key reason that some energy IR plans have not included ESMs, despite the fact that (as in the Companies' current plans) they have the potential to lead to “real time” benefit sharing with customers.

Nevertheless, it should be recognized that Union and EGD have almost certainly avoided rate case filings because of the IR mechanism. In the three years before the IR plan took effect (2005-2007), Union had two general rate case filings, and EGD had three rate case filings. If these trends persisted, the Board and Stakeholders would have been involved in five additional general rate cases over the 2008-2010 period. These general rate case applications have been avoided because of the IR-based rate adjustments.

Shareholders' main benefit under IR would be reflected in utility earnings. There is little doubt that both Companies have enjoyed healthy returns under IR. Earnings are well above the levels that the Companies generated prior to the implementation of the plans and also above the levels at which earnings are shared with customers. This is particularly true for Union. The relative level and burden of long-term debt has also declined, and other financial ratios have improved. Overall, the financial indicators for both EGD and Union support the conclusion that the IR plans have created an environment that is conducive to attracting capital and funding capital investment.

It is notable that this dramatic improvement in earnings has occurred at the same time that the Companies' allowed prices have grown less rapidly than their input prices. Earnings have therefore not been boosted by an overly generous inflation factor in the IR plan *i.e.* an inflation factor that over-compensates EGD and Union for the change in their input prices. In fact, PEG-R's research indicates that the opposite has been the case.

The Companies' actual investment and system expansion experience under IR is more mixed. Customers have been added to the system less rapidly under IR than in the immediately preceding years, although this is not unexpected given that the 2008-10 period coincided with a recession. Similarly, net plant and equipment has grown less rapidly under IR than in 2005-06, although the deceleration has not been precipitous. A slower rate of capital investment would also be expected since the decline in economic activity reduces customer growth and, accordingly, the need to add capital to serve new customer needs. The slowdown in capital investment is potentially more of a concern for

Union than EGD. It is possible that Union's slower growth in net capital could signal the deferral rather than an efficient reduction of its capital spending under IR.

The main source of benefits under IR for both customers and shareholders are the total factor productivity (TFP) gains generated by the utilities. Total factor productivity growth is equal to output quantity growth minus input quantity growth. PEG-R's results showed that output growth slowed for both Companies during the IR period, particularly for EGD. For both Companies, slower output growth in 2008-2010 undoubtedly reflected the economic recession during these years.

However, the Companies' also slowed their input usage under IR, compared with the years before IR was in effect. EGD's deceleration in input growth reflected savings on both O&M and capital. Union registered a similar decline in input usage under IR, although it reduced its growth in capital inputs more dramatically than EGD under IR.

Over the entire 2005-2010 sample period, EGD's TFP grew by 1.07% per annum. TFP growth was equal to 1.29% in the 2005-07 period, with annual output quantity growth of 2.4% exceeding the 1.12% annual average change in input quantity. Under IR, EGD's TFP growth slowed to 0.93% per annum. This reflected a sizeable 0.82% decline in the output growth rate, from 2.4% in 2005-07 to 1.58% in 2008-2010. EGD was able to keep the decline in its TFP growth below the decline in its output quantity growth because it reduced the change in its inputs from 1.12% per annum in 2005-2007 to 0.65% per annum in 2008-2010.

Union's TFP grew an average rate of 1.65% over the entire 2005-2010 sample period. TFP grew at an average rate of 1.58% in 2005-07 but accelerated to 1.70% per annum after the IR plan took effect. Union experienced a relatively modest deceleration in output quantity under IR, from 1.51% average growth in 2005-07 to 1.25% growth per annum in 2008-2010. However, Union reduced its input usage even more rapidly between these periods. The more rapid decline in inputs allowed the Company to increase its rate of TFP growth in 2008-2010 even as it output growth slowed because of the economic recession in these years.

Although it is very difficult to determine whether cost reductions are in fact cost deferments, PEG-R's analysis of the data available to us cannot find any clear evidence that EGD or Union is deferring a significant amount of costs under IR which could later be recovered in the Companies' base year. We emphasize, however, that this issue can only be fully addressed after the Companies present their base year rate proposals. The Board should investigate these proposals carefully, particularly for Union, which has cut its capital expenditures more rapidly than EGD but provided less evidence for this assessment on its capital expenditures by function.

Our analysis suggests that the IR plans have been successful in encouraging more effective cost control and enhancing TFP growth. While EGD's TFP growth did decline under IR, compared with the immediately preceding years, this TFP deceleration resulted from the recession in EGD's service territory during the IR years. PEG-R performed a "backcast" statistical analysis which shows that conditions in the 2008-2010 period reduced EGD's expected TFP growth by 67 basis points (from 1.92% to 1.25% per annum) between 2005-07 and 2008-2010, which was nearly double the Company's actual decline in TFP growth between these periods.

Nevertheless, our analysis implies that there is scope for EGD to boost its TFP. EGD's TFP growth was below PEG-R's backcast prediction in both the 2005-07 and 2008-2010 periods, although the difference was smaller in the latter years. While EGD's TFP growth was also above the measured TFP growth for the distributors that our analysis indicated were the best peers for EGD and Union, it was substantially below the TFP growth for one of those peers.

Union has exhibited solid TFP growth both before and after IR was implemented. Union's measured TFP grew more rapidly than our backcast prediction in both the 2005-07 and 2008-2010 periods. The difference expanded in the latter years which means that, despite beginning from a more rapid TFP growth rate, Union appears to have responded to the incentives of the IR plan somewhat more strongly than EGD.

Although the methodology could certainly be refined, our analysis also indicates that customers have benefitted from both Companies' TFP growth. Indeed, the analysis suggests that customers captured the lion's share of benefits between 2008 and 2010. While we believe the estimates of customer's share of benefits are exaggerated because of the poor quality of our available earnings measures, the likelihood that customers have gained is reinforced by the revenues the Companies distributed back to customers under the ESMs (because of Company "overearning") in the plans. The overall thrust of our analysis of prices, earnings and TFP is that IR has generated win-win outcomes for customers and shareholders.

PEG-R's assessment of the Companies' service quality performance examined three issues: 1) does each company's measured service quality generally satisfy the Board's service quality requirements?; 2) are there are any noticeable trends in each company's service quality performance over the available time period?; and 3) how do EGD's and Union's measured service quality compare to each other? PEG-R found that Union is satisfying all of the Board's service quality requirements, but this is not consistently true for EGD. There are also some downward trends in service quality performance on some indicators for EGD, although this is not true of Union. Overall, PEG-R concludes that Union is consistently satisfying the standards that the Board has established for appropriate service quality performance, while EGD is not.

Overall, PEG-R concludes that the IR plans satisfied the Board's criterion of encouraging cost control and productivity improvements. Our analysis indicates that the IR plans encouraged both EGD and Union to control costs more effectively and generate productivity and efficiency improvements. Union appears to have responded more strongly to these incentives. However, a careful statistical analysis indicates that EGD also responded positively to IR and improved its efficiency, even though its measured TFP growth fell while the IR plan was in place due to the recession in the Company's service territory that took place in the 2008-2010 period and which led, in turn, to a decline in the Company's output quantity growth.

PEG-R also finds that the IR plans satisfied the Board's criterion that customers and shareholders share in the benefits of efficiency gains achieved under IR. We addressed this question by quantifying the distribution of TFP gains under IR between customers and shareholders. While this methodology was limited by the accuracy and availability of data, the overall thrust of our analysis indicates that the IR plans were effective in generating TFP gains and the welfare of both customers and shareholders improved while the plans were in place. We therefore conclude that customers and shareholders shared in the benefits of the productivity improvements.

PEG-R finds that Union is satisfying the Board's criterion of providing appropriate service quality to its customers. However, this is not consistently true for

EGD. We are not in a position to assess why this is the case, although there are certainly pockets of service quality problems that need to be addressed to satisfy the Board's standards.

PEG-R also finds that the IR plans satisfy the Board's criterion of being conducive to capital investment. The Companies are generating healthy, and generally increasing, returns under IR. The IR plans themselves have also been stable; this is evident in the fact that, when Union's earnings in 2008 prompted a re-opening of its plan, the plan was modified in a way that actually strengthened its incentives and allowed the Company to retain more earnings. The IR regulatory framework therefore adapted effectively to a Company's unexpectedly high earnings, which is an outcome that should reassure investors.

Our analysis also shows that Union has experienced stronger productivity gains under IR than EGD. Although it cannot be established definitively, one of the factors contributing to Union's performance could be that its IR plan has created stronger incentives than EGD's. The main feature of Union's IR plan expected to strengthen incentives, compared with EGD's, is its earnings sharing mechanism. Union's ESM allows shareholders to retain all earnings up to 200 basis points above the approved ROE, while EGD retains all earnings only up to 100 basis points above approved ROE. Both plans share incremental earnings with customers, with EGD sharing 50% of all incremental earnings and Union sharing 50% of incremental earnings between 200 and 300 basis points above approved ROE and 90% of incremental earnings exceeding approved ROE plus 300 basis points. Shareholders are likely to benefit more from cost reductions under Union's more "progressive" ESM, and this feature should, in turn, create stronger incentives for Union to improve cost performance.

This could have implications for EGD's "next generation" IR plan, particularly in light of our conclusion that EGD appears to have more potential for incremental TFP gains going forward than Union. If the next generation IR plan for EGD is to be modified, any modifications should move in the direction of strengthening rather than weakening the Company's incentives. Our work provides evidence supporting the view that an IR plan designed more like Union's (*i.e.* a comprehensive IR plan with a more "progressive" ESM) could tend to strengthen performance incentives, to the ultimate benefit of both customers and shareholders.

Another plan design issue that could be relevant in next generation IR is the relationship between industry input price trends and the inflation factor. Our research shows that input prices for the Companies have grown more rapidly than inflation in the GDP-IPI, the selected inflation measure. Ideally, the inflation factor in a rate or revenue adjustment would be a good proxy for the industry's input price inflation. While the Companies have been able to generate healthy earnings even while their inflation factor did not apparently fully compensate for input price inflation, the relationship between input prices and alternative inflation factors (including industry-specific inflation measures that are explicitly designed to track industry input price trends) could merit greater attention in the next IR plan.

The issue of cost deferments also merits attention during the upcoming rate rebasing. It is not possible to evaluate whether a Company is acting on incentives to defer costs to a base year used to rebase rates without examining the Company's base year rate application. This is a critical issue, however, for ensuring that the incentives created by an IR plan are not undermined by what occurs when the plan expires.

In its upcoming review of the Companies' rate rebasing proposals, the Board can request information that can help it assess the cost deferment issue. In particular, the Board can evaluate whether large scale cost deferments have taken place by requesting information from the Companies on whether any of the capital expenditures reflected in the proposed rate base for the test year represent either: 1) delayed reactions to a previous request for service; or 2) requests for service that were previously rejected because they failed to satisfy the profitability index but have now been reconsidered and deemed to be sufficiently profitable. Any such capital expenditures reflected in a Company's rate rebasing proposal should be subject to greater scrutiny by the Board.

Going forward, the Board can also consider some enhancements in what information is collected and how it is organized with the OEB. PEG-R found there is a wealth of information and data on the IR plans, but a better co-ordination of this data would facilitate the review of IR regulatory filings by interested parties.

Other data enhancements could also improve future analyses and IR plan assessments. One improvement would be a requirement that both EGD and Union file information on their gas delivery revenues by rate class and service type. It could also be valuable to have standardized reporting of the details of capital and operating expenditures. It could also be useful to have a system in place for tracing through and quantifying all IR-related sources of allowed revenue and price change for EGD and Union's gas delivery customers. This would include the impact of the ESM as well as the net inflation, Y and Z factors. One particularly valuable innovation would be to co-ordinate the reporting of earnings for ESM purposes with other cost and operating information. PEG-R developed a methodology to quantify the distribution of TFP gains between customers and shareholders, but the accuracy of our estimates was limited by the data available to estimate refined and accurate earnings measures that are consistent with the Companies themselves report for their ESMs.

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1. INTRODUCTION AND SUMMARY

1.1 Introduction

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union) are both subject to incentive regulation plans that took effect in 2008 and will run through 2012. In autumn 2011, the Ontario Energy Board (OEB, or the Board) will begin a cost of service review that will establish "rebased" rates to take effect in January 2013. In this proceeding, the Board will also examine the Companies' incentive regulation framework and decide what changes should be made to the EGD and Union plans.

This upcoming review will be the first time the Board has actually assessed incentive regulation plans it approved for gas utilities. Although a 'targeted' incentive mechanism was approved for EGD in 1999, and a more comprehensive plan approved for Union in 2000, neither Company chose to update its plan after it expired. One reason is that many stakeholders were dissatisfied with one or more aspects of how these plans operated in practice.

The Board did consider the issue of IR in broad, conceptual terms as part of a comprehensive sector review called the Natural Gas Forum (NGF) that the Board sponsored in 2004-05. A key issue in the NGF was whether incentive regulation should remain part of the ratemaking framework in Ontario. The Board said addressing this issue must take account of its legislated objectives, in particular:

- To protect the interests of consumers with respect to prices and the reliability and quality of gas service
- To facilitate rational expansion of transmission and distribution systems and rational development and safe operation of gas storage
- To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas

The Board said an effective ratemaking framework must fulfill these objectives which, in turn, implies that rate regulation must satisfy the following criteria:

- Establish incentives for sustainable efficiency improvements that benefit both customers and shareholders
- Ensure appropriate quality of service for customers
- Create an environment that is conducive to investment, to the benefit of both customers and shareholders

In its final Report on the NGF, the Board found that

> "…a multi-year incentive regulation (IR) plan can be developed that will meet its (the Board's) criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment…The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan."[1]

In 2008 the Board approved comprehensive IR plans for EGD and Union, both of which were determined through settlement agreements with stakeholders. These plans have now been in effect for three full years. There may accordingly be sufficient information to assess whether the "key parameters" reflected in these approved IR plans have, in fact, been consistent with the Board's stated criteria for an effective regulatory framework.

Pacific Economics Group Research (PEG-R) has been asked to advise OEB Staff on how the EGD and Union IR plans operated in practice. Because the plans are currently in effect, our analysis is necessarily partial and cannot assess the entire IR experience. Nevertheless, understanding the available evidence may help the Board determine whether and how to modify the incentive regulation framework. This may be

[1] *Natural Gas Regulation in Ontario: A Renewed Policy Framework,* Report on the Ontario Energy Board Natural Gas Forum, March 20, 2005 (RP-2004-0213), p. 22. The Board also noted that a targeted incentive approach had been tried for EGD, while comprehensive IR plans were approved for Union and Ontario's electricity distributors, and concluded that "the targeted approach did not work effectively because it diluted and distorted the incentives, and that a comprehensive model is preferable" (p. 22). In addition, the Board found that "utilities should not alternate between a COSR and an IR framework. Switching between rate frameworks could make robust benefit sharing harder to achieve and introduce confusion and mistrust" (p. 22). All else equal, switching between regulatory frameworks would also run counter to the objective of regulatory stability, which in turn tends to promote investment in the industry as well as longer-term cost reduction initiatives that improve gas distribution efficiency.

particularly valuable given the previous, generally unsatisfactory experience with gas distribution IR in the Province.

PEG-R has examined a variety of information on how the Companies' IR plans operated between 2008 and 2010. Our assessment focused on the Board's key criteria for an effective ratemaking framework, particularly the following issues:

- Did the incentive regulation plans encourage cost control and generate productivity and efficiency improvements?
- Did both customers and shareholders share in the benefits of any efficiency gains that were achieved?
- Did the Companies provide appropriate service quality to their customers?
- Was the incentive regulation framework conducive to capital investment?

Our report is organized as follows. We begin by summarizing the features of the Companies' approved IR plans. Section Three describes the conceptual framework that PEG-R will use to assess these IR plans and the distribution of potential benefits under IR between customers and shareholders. Section Four assesses EGD's and Union's prices and revenues under IR. Section Five assesses the Companies' financial performance. Section Six quantifies EGD's and Union's productivity gains under IR and the distribution of those gains between customers and shareholders in the plans. Section Seven assesses EGD's and Union's service quality performance, and Section Eight presents our overall conclusions and assessment of the EGD and Union IR plans.

1.2 Summary of Results

Customer benefits under IR would primarily be reflected in the prices they pay for gas delivery services. However, given the multiplicity of rates and variety of mechanisms that enter into gas delivery ratemaking in Ontario, analyzing the Companies' gas delivery prices is not as straightforward as it may seem. There is also no established accounting framework for isolating the impact of every element of the Companies' IR plans on the changes in gas delivery rates under the plans. PEG-R therefore assessed this issue using a variety of information on rate trends for EGD, Union and relevant comparators while the plans were in effect.

Our analysis shows that gas delivery price trends have generally been favorable under the Companies' IR plans. The combined effects of the net inflation mechanism, Y factors, and Z factors in the IR plans have led to declines in allowed gas delivery revenues for both EGD and Union over the 2008-2010 term of the plans. These revenue declines have averaged $1.5 M annually for EGD and $1.8 M annually for Union. The earnings sharing mechanisms (ESMs) have led to even more pronounced revenue declines of $14.1 M per annum for EGD and $15.1 M for Union, on average, over the plan. These revenue declines have been somewhat offset by the average use (AU) factor, which has led to rate increases to recover declines in average usage per customer (AUPC) for certain customer classes. Overall, however, PEG-R's gas delivery price indexes show a modest 0.4% annual increase in gas delivery prices for Union's M1, M2, Rate 01, and Rate 10 customers, and an annual 0.32% decline in EGD's gas delivery prices over the terms of the IR plans.

The Companies' price trends compare favorably to other price measures. EGD and Union's residential gas delivery tariffs have grown less rapidly than those for two Massachusetts gas distributors that were subject to incentive regulation at the same time. Residential gas delivery prices have also grown somewhat less rapidly than residential electricity prices in Ontario in recent years. In addition, the Companies' overall prices have grown more slowly than the growth in the GDP-IPI over the 2008-2010 period, which measures inflation in final domestic demand for a basket of goods and services, and have also grown more slowly than the Companies' input prices over the same period.

PEG-R's assessment of the rate adjustment mechanics and regulatory process for ratemaking has also not identified any major concerns. The regulatory process associated with setting the annual IR rate adjustment appears generally to function in a timely manner. Provided the IRM rate application does not involve auxiliary issues, most IRM filings tend to be resolved in no more than 90 days. There appear to be more regulatory issues associated with the ESM applications, especially for Union's 2010 rate year. Computing the returns to be shared in an ESM is an inherently controversial issue, and this process sometimes leads to "mini rate cases" that involve significant regulatory costs and delays. These regulatory costs are a key reason that some energy IR plans have not included ESMs, despite the fact that (as in the Companies' current plans) they have the potential to lead to "real time" benefit sharing with customers.

Nevertheless, it should be recognized that Union and EGD have almost certainly avoided rate case filings because of the IR mechanism. In the three years before the IR plan took effect (2005-2007), Union had two general rate case filings, and EGD had three rate case filings. If these trends persisted, the Board and Stakeholders would have been involved in five additional general rate cases over the 2008-2010 period. These general rate case applications have been avoided because of the IR-based rate adjustments.

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It is notable that this dramatic improvement in earnings has occurred at the same time that the Companies' allowed prices have grown less rapidly than their input prices. Earnings have therefore not been boosted by an overly generous inflation factor in the IR plan *i.e.* an inflation factor that over-compensates EGD and Union for the change in their input prices. In fact, PEG-R's research indicates that the opposite has been the case.

The Companies' actual investment and system expansion experience under IR is more mixed. Customers have been added to the system less rapidly under IR than in the immediately preceding years, although this is not unexpected given that the 2008-10 period coincided with a recession. Similarly, net plant and equipment has grown less rapidly under IR than in 2005-06, although the deceleration has not been precipitous. A slower rate of capital investment would also be expected since the decline in economic activity reduces customer growth and, accordingly, the need to add capital to serve new customer needs. The slowdown in capital investment is potentially more of a concern for Union than EGD. It is possible that Union's slower growth in net capital could signal the deferral rather than an efficient reduction of its capital spending under IR.

The main source of benefits under IR for both customers and shareholders are the total factor productivity (TFP) gains generated by the utilities. Total factor productivity growth is equal to output quantity growth minus input quantity growth. PEG-R's results showed that output growth slowed for both Companies during the IR period, particularly for EGD. For both Companies, slower output growth in 2008-2010 undoubtedly reflected the economic recession during these years.

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Union's TFP grew an average rate of 1.65% over the entire 2005-2010 sample period. TFP grew at an average rate of 1.58% in 2005-07 but accelerated to 1.70% per annum after the IR plan took effect. Union experienced a relatively modest deceleration in output quantity under IR, from 1.51% average growth in 2005-07 to 1.25% growth per annum in 2008-2010. However, Union reduced its input usage even more rapidly between these periods. The more rapid decline in inputs allowed the Company to increase its rate of TFP growth in 2008-2010 even as it output growth slowed because of the economic recession in these years.

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Board should investigate these proposals carefully, particularly for Union, which has cut its capital expenditures more rapidly than EGD but provided less evidence for this assessment on its capital expenditures by function.

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Nevertheless, our analysis implies that there is scope for EGD to boost its TFP. EGD's TFP growth was below PEG-R's backcast prediction in both the 2005-07 and 2008-2010 periods, although the difference was smaller in the latter years. While EGD's TFP growth was also above the measured TFP growth for the distributors that our analysis indicated were the best peers for EGD and Union, it was substantially below the TFP growth for one of those peers.

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Although the methodology could certainly be refined, our analysis also indicates that customers have benefitted from both Companies' TFP growth. Indeed, the analysis suggests that customers captured the lion's share of benefits between 2008 and 2010. While we believe the estimates of customer's share of benefits are exaggerated because of the poor quality of our available earnings measures, the likelihood that customers have gained is reinforced by the revenues the Companies distributed back to customers under the ESMs (because of Company "overearning") in the plans. The overall thrust of our analysis of prices, earnings and TFP is that IR has generated win-win outcomes for customers and shareholders.

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Overall, PEG-R concludes that the IR plans satisfied the Board's criterion of encouraging cost control and productivity improvements. Our analysis indicates that the IR plans encouraged both EGD and Union to control costs more effectively and generate productivity and efficiency improvements. Union appears to have responded more strongly to these incentives. However, a careful statistical analysis indicates that EGD also responded positively to IR and improved its efficiency, even though its measured TFP growth fell while the IR plan was in place due to the recession in the Company's service territory, and the decline in its output growth, that took place in the 2008-2010 period.

PEG-R also finds that the IR plans satisfied the Board's criterion that customers and shareholders share in the benefits of efficiency gains achieved under IR. We addressed this question by quantifying the distribution of TFP gains under IR between customers and shareholders. While this methodology was limited by the accuracy and availability of data, the overall thrust of our analysis indicates that the IR plans were effective in generating TFP gains and the welfare of both customers and shareholders improved while the plans were in place. We therefore conclude that customers and shareholders shared in the benefits of the productivity improvements.

PEG-R finds that Union is satisfying the Board's criterion of providing appropriate service quality to its customers. However, this is not consistently true for EGD. We are not in a position to assess why this is the case, although there are certainly pockets of service quality problems that need to be addressed to satisfy the Board's standards.

PEG-R also finds that the IR plans satisfy the Board's criterion of being conducive to capital investment. The Companies are generating healthy, and generally increasing, returns under IR. The IR plans themselves have also been stable; this is evident in the fact that, when Union's earnings in 2008 prompted a re-opening of its plan, the plan was modified in a way that actually strengthened its incentives and allowed the Company to retain more earnings. The IR regulatory framework therefore adapted effectively to a Company's unexpectedly high earnings, which is an outcome that should reassure investors.

Our analysis also shows that Union has experienced stronger productivity gains under IR than EGD. Although it cannot be established definitively, one of the factors contributing to Union's performance could be that its IR plan has created stronger incentives than EGD's. The main feature of Union's IR plan expected to strengthen incentives, compared with EGD's, is its earnings sharing mechanism. Union's ESM allows shareholders to retain all earnings up to 200 basis points above the approved ROE and shares 50% of incremental earnings between 200 and 300 basis points above allowed ROE and 90% of incremental earnings that exceed allowed ROE plus 300 basis points. On the other hand EGD retains all earnings only up to 100 basis points above approved ROE and shares 50% of all incremental earnings with customers. Shareholders are likely to benefit more from cost reductions under Union's more "progressive" ESM, and this feature should, in turn, create stronger incentives for Union to improve cost performance.

This could have implications for EGD's "next generation" IR plan, particularly in light of our conclusion that EGD appears to have more potential for incremental TFP gains going forward than Union. If the next generation IR plan for EGD is to be modified, any modifications should move in the direction of strengthening rather than weakening the Company's incentives. Our work provides evidence supporting the view that an IR plan designed more like Union's (*i.e.* a comprehensive IR plan with a more "progressive" ESM) could tend to strengthen performance incentives, to the ultimate benefit of both customers and shareholders.

Another plan design issue that could be relevant in next generation IR is the relationship between industry input price trends and the inflation factor. Our research shows that input prices for the Companies have grown more rapidly than inflation in the GDP-IPI, the selected inflation measure. Ideally, the inflation factor in a rate or revenue adjustment would be a good proxy for the industry's input price inflation. While the Companies have been able to generate healthy earnings even while their inflation factor did not apparently fully compensate for input price inflation, the relationship between input prices and alternative inflation factors (including industry-specific inflation measures that are explicitly designed to track industry input price trends) could merit greater attention in the next IR plan.

The issue of cost deferments also merits attention during the upcoming rate rebasing. It is not possible to evaluate whether a Company is acting on incentives to defer costs to a base year used to rebase rates without examining the Company's base year rate application. This is a critical issue, however, for ensuring that the incentives created by an IR plan are not undermined by what occurs when the plan expires.

In its upcoming review of the Companies' rate rebasing proposals, the Board can request information that can help it assess the cost deferment issue. In particular, the Board can evaluate whether large scale cost deferments have taken place by requesting information from the Companies on whether any of the capital expenditures reflected in the proposed rate base for the test year represent either: 1) delayed reactions to a previous request for service; or 2) requests for service that were previously rejected because they failed to satisfy the profitability index but have now been reconsidered and deemed to be sufficiently profitable. Any such capital expenditures reflected in a Company's rate rebasing proposal should be subject to greater scrutiny by the Board.

Going forward, the Board can also consider some enhancements in what information is collected and how it is organized with the OEB. PEG-R found there is a wealth of information and data on the IR plans, but a better co-ordination of this data would facilitate the review of IR regulatory filings by interested parties.

Other data enhancements could also improve future analyses and IR plan assessments. One improvement would be a requirement that both EGD and Union file information on their gas delivery revenues by rate class and service type. It could also be valuable to have standardized reporting of the details of capital and operating expenditures. It could also be useful to have a system in place for tracing through and quantifying all IR-related sources of allowed revenue and price change for EGD and Union's gas delivery customers. This would include the impact of the ESM as well as the net inflation, Y and Z factors. One particularly valuable innovation would be to co-ordinate the reporting of earnings for ESM purposes with other cost and operating information. PEG-R developed a methodology to quantify the distribution of TFP gains between customers and shareholders, but the accuracy of our estimates was limited by the data available to estimate refined and accurate earnings measures that are consistent with the Companies themselves report for their ESMs.

2. SUMMARY OF COMPANY INCENTIVE REGULATION PLANS

As discussed in Section One, the Board confirmed its commitment to incentive regulation for gas distributors in its Report on the NGF (NGF Report). In 2006-07, the Board sponsored a generic proceeding to examine and finalize the details of this incentive regulation framework. Although this process did not lead to agreement on some plan parameters, both EGD and Union were able to reach settlement agreements with stakeholders on comprehensive IR plans. The Board approved both agreements, and they took effect in January 2008.

The Board-approved IR plans differed between the Companies, but they shared a basic framework and some common elements. Section 2.1 provides an overview of the basic framework and plan parameters that are common between the plans. Section 2.2 describes the differences between the EGD and Union plans. Section 2.3 summarizes, compares and provides a general overview of the EGD and Union IR plans.

2.1 Overview and Common Features of the Plans

Both plans have a common structure and some identical features. The main parameters of the EGD and Union IR plans are summarized and defined below:

- ***Annual Adjustment Mechanism***. The annual adjustment mechanism is a formula, which includes an inflation factor, that adjusts either the utility's allowed rates, or its allowed distribution revenues, while the IR plan is in effect. The annual adjustment takes place on January 1 of each year of the plan.

- ***Plan Term***. Both plans apply for a defined, multi-year period. In the first year of the plan, new rates are established based on the outcome of a cost of service proceeding. In each subsequent plan year, rates or allowed revenues are adjusted by the annual rate adjustment mechanism. The plan term is equal to the total number of years for which the incentive regulation plan is in effect.

- ***Average Use***. Each Company's annual adjustment mechanism adjusts (either explicitly or implicitly) for changes in average natural gas usage per customer (AUPC) for at least some customer groups. These adjustments are designed to recover at least some of the revenues that are expected to be lost during the IR plan due to declines in AUPC.

- ***Y Factor***. The Y factor recovers routine, or expected, cost changes that are outside the scope of the annual adjustment mechanism. Each Company files for Y factor adjustments at the same time it files for rate adjustments under the annual adjustment mechanism.

- ***Z Factor***. The Z factor recovers the cost of non-routine events that are not otherwise recovered in the annual adjustment mechanism. To be eligible for Z factor recovery in either plan:
    - The event must be causally related to an increase or decrease in the distributor's cost
    - The cost increase/decrease must be beyond the control of the Company management and not a risk a prudent utility could mitigate
    - The cost increase/decrease must not be otherwise reflected in the annual rate adjustment mechanism
    - The cost increase/decrease must be prudently incurred
    - The amount of the cost increase/decrease, for the sum of all individual events reflected in an annual Z factor filing, must be greater than the materiality threshold of $1.5 million.

The Board also determined that EGD and Union would Z-factor 50% of their estimated cost reductions resulting from a series of tax reductions that were announced in 2007. Cost reductions associated with the tax changes would be estimated annually in each year of the plan term, and 50% of those savings would be passed through to customer rates.

- ***Earning Sharing Mechanism***. The Earnings Sharing Mechanism ("ESM") shares earnings between customers and shareholders according to formulae that depend on the relationship between the utility's actual earnings and a target earnings level. In the Companies' IR plans, the ESMs are calculated on an annual basis and the earnings measure used in the ESM is the utility's return on equity ("ROE"). Any earnings that are shared with customers are reflected in rate changes in the following year.

- ***Off-ramps***. Off-ramps refer to a set of pre-defined conditions which, when satisfied, could lead the IR plan to be terminated or modified before the scheduled end of the plan term.

- ***Reporting Requirements***. The reporting requirements refer to information and data the utility is required to report annually to the Board. Reporting requirements are included in the plans to ensure transparency and promote understanding of Company operations and finances while the IR plan is in effect.

- ***Rebasing***. When the term of the plan is complete, a rate rebasing will take place in which new utility rates are established through a comprehensive, cost of service proceeding. These rebased rates will be the foundation on which rate adjustments in the succeeding IR plan are applied. Rebasing is critical to ensuring that efficiency improvements achieved during the plan term are revealed, and these benefits are passed on to customers through rates in the next period.

In addition to these features of the approved IR plans, the Board implemented service quality requirements (SQRs) prior to the establishment of the IR plans. These service quality requirements refer to standards of performance that the utility is expected to achieve on a defined set of service quality indicators. Even though the SQRs are outside of the IR plans, maintaining appropriate service quality is an important objective for the Board under any ratemaking framework, including IR.

Some of these plan features are identical, or nearly identical, in the EGD and Union plans. In particular:

- The plan term is five years (2008-2012) in each plan.

- The inflation factor in each annual adjustment mechanism is Canada's Gross Domestic Product Implicit Price Index for Final Domestic Demand ("GDP IPI FDD"), as measured by the annualized average of the index for four quarters, from Q2 of the previous year to Q2 of the year in which the proposed rate change is filed

- The criteria that need to be satisfied for Z factor adjustments are the same in each plan.

- Both plans require a cost of service rate rebasing at the end of the plan term

- The annual reporting requirements are essentially identical for the Companies.[2]

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[2] Both companies report:

1. Calculation of revenue deficiency/sufficiency
2. Statement of utility income
3. Statement of earnings before interest and taxes
4. Summary of cost of capital
5. Total weather normalized throughput volume by service type and class
6. Total actual (non-weatherized) throughput volumes by service type and rate class
7. Total weather normalized gas sales revenue by service type and rate class
8. Total actual (non-weatherized) gas sales revenue by service type and rate class
9. Total customers by service type and rate class
10. Other revenue
11. Operating and maintenance expenses by department
12. Calculation of utility income taxes
13. Calculation of capital cost allowance
14. Provision of depreciation, amortization and depletion
15. Capital budget analysis by function
16. Statements of utility rate base

There are some differences in the information provided due to the fact that the Companies provide somewhat different services. EGD also does not provide data on its delivery revenue by service type and rate class while Union does.

- The service quality requirements are also identical between the plans. Both companies are expected to:
    - Answer at least 75% of customer telephone calls to the utility phone center within 30 seconds
    - Have an abandoned call rate (where the customer hangs up before speaking to a customer service representative) of no more than 10%
    - Have a verifiable quality assurance program in place to audit and ensure billing accuracy
    - Have no more than 0.5% of meters go four consecutive months without being read
    - Meet at least 85% of scheduled service appointments within a four hour window around the scheduled appointment time
    - Reschedule 100% of missed appointments within two hours of the end of the original appointment time
    - Respond to at least 90% of gas emergency calls within one hour
    - Respond to at least 80% of written complaints within 10 days
    - Reconnect at least 85% of customers who have been disconnected within two days after they have resolved payment problems

2.2 Differences Between the EGD and Union Plans

There are also some differences between the EGD and Union IR plans, including the following:

- *The **application of the mechanism.*** One intended difference between the plans is that the Union IR plan was described as a price cap plan and therefore should be applied to the adjustment of gas delivery *prices*; the EGD IR plan applies primarily to regulated gas delivery *revenues* per customer. In practice, however, both plans have in part adjusted gas delivery revenues rather than gas delivery prices. This point will be discussed in Section Four of this report.

- *The **annual adjustment mechanism.*** The Union IR plan includes an "inflation minus X" adjustment mechanism, where X is fixed at 1.82% in all years of the plan. In contrast, the EGD annual adjustment mechanism is expressed as the product of inflation and an "inflation coefficient." This inflation coefficient takes a value of 0.60 in 2008, 0.55 in 2009 and 2010, 0.50 in 2011, and 0.45 in 2012. Thus, under this approach, the annual adjustment mechanism would increase EGD's allowed gas delivery rates by 60% of measured GDP IPI inflation in 2008, 55% of measured GDP IPI inflation in 2009 and 2010, 50% of measured GDP IPI inflation in 2011, and 45% of measured GDP IPI inflation in 2012. Because allowed prices go up by only a fraction of measured inflation, the EGD annual adjustment mechanism can be interpreted as having an "implicit X factor," where X is the amount by which rate adjustments are held below inflation, as in the more typical "inflation minus X" formula. The implicit X in the EGD mechanism depends directly on measured inflation and, in fact, is equal to one minus the inflation coefficient in that year. Therefore the implicit X values in the EGD adjustment mechanism would be 40% of GDP IPI inflation in 2008, 45% of GDP IPI inflation in 2009 and 2010, 50% of GDP IPI inflation in 2011, and 55% of GDP IPI inflation in 2012.

- *The **adjustment for changes in average use.*** Both plans include rate adjustments to reflect forecast changes in average gas use per customer (AUPC), although the forms of these adjustments differ by company. We summarize the average use adjustments for each utility below.

  EGD

  EGD's average use (AU) adjustment depends directly on the fact that its IR plan primarily caps overall regulated revenues (per customer) rather than gas delivery rates. This means that EGD's IR plan has effectively *decoupled* most of its allowed regulated revenue from its customers' actual gas consumption over the term of the IR plan. EGD's average use adjustment applies to its Rate 1 and Rate 6 general service rate classes. For these rate classes, the AU is equal to the difference in the revenue impact (excluding gas costs) between the forecast AUPC embedded in the volume forecast used to establish Rates 1 and 6 (the "Forecast AU") and the weather normalized average use in each year of the IR Plan (the "Normalized AU") for these rate classes.[3] EGD established a new variance account, called the "Average Use True-Up Variance Account" (or "AUTUVA") to capture the difference between the forecast AUPC embedded in the volume forecast and the weather normalized AUPC in each year of the IR plan.

Union

Union's AU adjustment applies only to rate classes M1, M2, 01 and 10. For each rate class, the AU adjustment is calculated by adjusting the volume used to determine rates by the average of the three most recent years' actual weather normalized change in volumes (using the 55/45 blended weather method, updated annually) per general service customer within that rate class. Union established a new deferral account to capture the variance between projected use per customer (*i.e.* projecting the three-year historical average one year forward) and actual, observed changes in use per customer during the term of the IR plan.

- ***Y Factors.*** The list of Y factors differed slightly between the Companies. For EGD, the Y factors were:
  - o DSM program costs, previously approved by the Board for the years 2007-2009
  - o Customer information service (CIS)/customer care costs resulting from a true-up process approved by the Board for the Customer Care Settlement Agreement (EB-2006-034)
  - o Upstream gas commodity costs
  - o Upstream transportation, storage and supply mix costs

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[3] The revenue impact of the difference between Forecast AU and the Normalized AU is calculated using a unit rate determined in the same manner as in the Lost Revenue Adjustment Mechanism ("LRAM"), as updated to changes in AUPC and the number of customers.

- Changes in the embedded carrying cost of gas in storage and working cash related to changes in gas costs
- Incremental revenue requirements associated with capital expenditures necessary to attach new gas-fired power generation plants

For Union, the Y factors were:

- Upstream gas commodity costs
- Upstream transportation costs
- Incremental DSM costs and volume reductions (as determined in EB-2006-0021)
- Changes in storage margin sharing (as determined in EB-2004-0551) [4]

- *The **Earnings Sharing Mechanism.*** EGD's ESM is based on the difference between its weather normalized ROE and the ROE resulting from the Board's approved ROE formula in a given year. When the weather normalized ROE exceeds this approved ROE by 100 basis points, the difference is shared 50/50 between customers and shareholders.

  Union's ESM is based on the difference between actual and approved ROE (resulting from the Board's approved ROE formula), and initially any difference between actual ROE and approved ROE formula plus 200 basis points was shared 50/50 between customers and shareholders. Union's ESM was modified after the first year of its IR plan (2008) so that the same sharing formula applied between 200 and 300 basis points above allowed ROE, but whenever actual ROE exceeded approved ROE by 300 basis points, incremental earnings in excess of approved ROE plus 300 basis points are shared 90/10 between customers and shareholders.

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[4] The Union IR plan also eliminated four of Union's existing deferral accounts at the time but retained the LRAM and shared savings mechanism accounts associated with its DSM programs. The deferral accounts that were eliminated were the Transportation Exchange Services Account, Other S&T Services Account, Other Direct Purchase Services Account, and the Hearting Value Account.

- *The* ***off-ramp.*** Both IR plans originally had the same off-ramp provision. This off-ramp compared the weather-normalized ROE in a given year with the Board's approved ROE. The provision specified that whenever weather normalized ROE was at least 300 basis points above or below the approved ROE, the Company would file an application with the Board for a review of the IR mechanism. The EGD plan continues to have this off-ramp provision. In 2008, however, Union's actual ROE exceeded approved ROE by 330 basis points. This led to the elimination of Union's off-ramp provision, as well as the modification of the ESM to allow for earnings to be shared 90/10 when Union's actual ROE exceeded the approved ROE by 300 or more basis points.

- ***Rate Design.*** Each plan allowed for rates to be re-designed, essentially to allow a more rapid increase in the customer charge for certain rate classes than would likely be allowed under the rate adjustment mechanism. The future parameters governing allowed rate re-design were spelled out in each settlement agreement, and they differed slightly between companies.

2.3 Overview of the EGD and Union Plans and Salient Assessment Issues

The main features of the current Union and EGD IR plans are summarized and compared in Table One below.

Table One		
Summary of IR Plans for Union and Enbridge		
Plan Elements	**Union**	**Enbridge**
Base	2007 Approved Rates	
Form	Price Cap (PC)	Revenue per Customer Cap
Annual Adjustment Mechanism	PC=(I-X) +Y +Z+ AU	$DRR_t = \left(\frac{DRR_{t-1} - (Y_{t-1} + Z_{t-1})}{C_{t-1}}\right) * (1 + P * INF) * C_t + Y_t + Z_t$ where, DRR = Annual Distribution Revenue INF = inflation factor C = average # of customers P = inflation coefficient; 2008-2012: 60%, 55%,

Table One		
Summary of IR Plans for Union and Enbridge		
Plan Elements	**Union**	**Enbridge**
		55%, 50%, 45%
Inflation Factor ("I or "INF")	Canada GDP IPI (Final Domestic Demand); updated annually	
X Factor	1.82%; fixed for plan term	No X factor. Annual inflation coefficient (P) is used to adjust the annual distribution revenue by a percentage of the annual rate of inflation.
Average Use ("AU")	Difference between the average of the most recent three years' actual weather normalized volume and actuals; difference is captured in a deferral account; calculated annually.	Difference between forecast use per customer and weather-normalized actual use per customer; difference captured in a variance account; calculated annually.
Term	5 years	
Y Factor	Y factors are outside the price / revenue per customer caps; routine adjustments such as DSM; and considered to be cost pass-throughs.	
Z Factor	Z factors are also outside the price / revenue per customer caps; non-routine (or unexpected) adjustments are outside of management's control; and considered to be cost pass-throughs.	
Off-ramp	In 2008, Union exceeded Board's ROE by 330 bp. As a result, the off-ramp provision was eliminated for the rest of the plan term and ESM was modified to add a second sharing band for earnings in excess of allowed ROE plus 300 bp.	Board to review IR plan if weather-normalized actual ROE differs from approved ROE +/-300 bp (based on Board's ROE guidelines).
Earning Sharing Mechanism	If actual ROE is more than 200 bp but less than 300 bp above approved ROE (based on Board's ROE guidelines), excess earnings will be shared between ratepayer and shareholder on a 50/50 basis; incremental earnings that exceed 300 bp above approved ROE will be shared between ratepayer and shareholder on a 90/10 basis.	Weather normalized actual ROE is 100 bp above approved ROE (based on Board's ROE guidelines); excess earnings will be shared between ratepayer and shareholder on a 50/50 basis.
Reporting Requirements	Annual reports filed with the Board	
Rebasing	Cost of service filing at the end of the IR plan term	

Some of what the NGF termed "key parameters that underpin the IR framework" are identical for EGD and Union and will be important for our assessment. One critical parameter in both plans is using GDP-IPI for the inflation factor in the adjustment mechanism. In theory, the inflation factor in a rate or revenue adjustment mechanism should be a reasonable proxy for input price trends in the respective utility industry.[5] It is important to assess the extent to which this has been the case while Companies' IR plans were in effect. All else equal, if the selected GDP-IPI inflation measure grew more rapidly than the Companies' input price inflation, distributor revenues would rise more rapidly than costs and shareholders would benefit. This financial benefit would be independent of any TFP gains the Companies generated under the plan and which are, in theory, the intended source of financial benefits for shareholders in IR. By the same token, if GDP-IPI inflation was less rapid than input price inflation for the Companies, customers would receive a windfall financial gain. The following section discusses the relationship between changes in utility output prices, changes in utility input prices, and the distribution of benefits under IR.

It is also important to recognize that both plans include an ESM which can create contemporaneous sharing of TFP gains between customers and shareholders. All else equal, more rapid TFP growth leads to higher returns and a greater share of "over-earnings" shared with customers through the ESM. The ESM transfers these gains to customers in the form of price reductions in the year following the financial year in which the earnings were generated. Changes in output prices therefore depend on IR plan design features other than simply the inflation factor. It is important for an IR assessment to take account of the ESM and similar plan features when examining the extent to which customers and shareholders have benefitted during the term of an IR plan.

[5] If this is not the case, and there is a strong expectation that the selected inflation factor will not track the utility's input price trends closely, the X factor in the adjustment mechanism would typically include an "inflation differential," equal to the difference between input price inflation for the utility industry and inflation in the selected inflation factor. This input price differential is usually estimated on a historical basis, using past trends in both inflation measures, although it could in principle also be determined on a forecast basis.

At the same time, it should be remembered that the distribution of benefits under IR depends on rate rebasing in addition to the experience of the IR plan itself. Rebasing is critical to ensuring that efficiency improvements achieved during the plan term are reflected in the rates established for customers in the next IR plan. EGD and Union's rates will be rebased in 2012, so the outcomes of these proceedings clearly cannot be assessed in this assignment. Readers should therefore recognize that benefit sharing to date under the IR plan is necessarily incomplete; by design, some of customers' gains will be reflected in rates that take effect after the current IR plans expire.

However, the 2012 rebasings do raise other issues that are relevant to PEG-R's assessment. Most importantly, rate rebasings at the end of a plan theoretically create incentives for utilities to defer expenditures until the "base" year that will be used to set cost-based, updated rates. If utilities are in fact acting on these incentives, it would mean that their measured TFP gains under the plan would not be consistent with their sustainable rate of TFP change going forward. In effect, part of what utilities book as a cost "reduction" (and TFP gain) would in fact be a "cost deferment" that should have been incurred during the IR plan but is instead pushed into the base year, when utilities have more opportunity to recover such cost items directly in new, cost-based rates.

Separating "cost reductions" from "cost deferments" is difficult. Cost deferments are most likely for capital investments that are not tied directly to new requests for service. A large share of operating expenditures, such as salaries for utility personnel, cannot be deferred, although the timing of some maintenance expenditures can potentially be manipulated and deferred for a future year. Because it inherently involves details of a utility's rate proposal in the base year, it is ultimately not possible to assess the cost deferral vs. cost reduction issue until analysts have examined the data that are proposed to set the rebased rates. PEG-R clearly cannot examine these data in this project, but in Section Six we will examine some EGD and Union 2008-10 data that may shed light on the extent to which costs have been deferred rather than reduced during the IR plans.

There are also differences between the plans that should be kept in mind for the assessment. In general terms, the Union IR plan strikes a different balance between creating incentives and protecting shareholders against risks than the EGD plan. Several features of the Union IR plan should, in theory, create stronger performance incentives, and more upside earnings potential, than EGD's IR plan. Relatedly, the Union plan offers shareholders somewhat less protection against risk than the EGD plan. These conclusions follow from several differences in IR parameters across the EGD and Union plans, in particular:

- Union's ESM allows shareholders to retain all earnings up to 200 basis points above the approved ROE, while EGD retains all earnings only up to 100 basis points above approved ROE. Shareholders are likely to benefit more from cost reductions under Union's more "progressive" ESM, and this feature should, in turn, create stronger incentives for Union to improve cost performance.
- Union has less protection against earnings variations than EGD for two reasons. First, the EGD ESM examines weather-normalized earnings while the Union plan focuses on actual earnings. EGD's ESM therefore "protects" the Company from having to share earnings with customers in particularly cold years, in which gas consumption, revenues and earnings are likely to increase; the Union ESM does not offer this "protection." Second, the Union IR plan was updated to eliminate the off-ramp provision, which provides some explicit protection against earnings declines; the EGD retains an off-ramp provision.[6]
- Union's AU factor is likely to generate less contemporaneous compensation for declines in AUPC than does the EGD average use adjustment, for two reasons. First, EGD has full revenue per customer decoupling for some customer classes. Second, and relatedly, Union's AU factor depends on the three year moving average of average use changes, not full recovery of contemporaneous, year-on-year changes in AUPC relative to forecast AUPC.
- In principle, EGD's annual adjustment mechanism could create either more or less risk for earnings, depending on the rate of inflation in a given year. EGD's adjustment mechanism updates allowed revenues using inflation

coefficients, multiplied by GDP IPI inflation, while Union's allowed delivery prices are updated by the growth in GDP IPI inflation minus 1.82% every year. All else equal, revenues and earnings decline as the value of X (either the explicit or "implicit" X) increases. EGD's implicit X factor could be greater than Union's if inflation was especially high, simply because its implicit X is a fraction of the measured inflation rate. Conversely, if inflation is relatively low, EGD's implicit X factor would be lower than Union's.
In practice, inflation has been relatively low over the 2008-2011 period, and this has tended to lead to a lower X and, all else equal, a more positive impact on earnings for EGD than Union.[7]

The differences in IR plan designs could have implications for PEG-R's analysis. That is, if we find empirical evidence that Union has experienced stronger productivity and efficiency gains under IR than EGD, one of the contributing factors could be that the Union IR plan created stronger performance incentives. Alternatively, if there is no evidence that Union experienced stronger productivity and efficiency gains than EGD (*e.g.* EGD experienced more rapid productivity and efficiency gains), it would suggest that, in spite of the theoretically stronger incentives inherent in the Union IR plan, these plan design differences did not have a material impact on performance gains under IR. Regardless of our ultimate findings, it will not be possible to establish any such linkages unambiguously given the limited available data (only three years under IR) and the wide variety of other factors that can influence productivity and earnings. Nevertheless, even partial and indirect evidence on the impact that different IR plan designs have on productivity gains would be valuable to the Board and have clear policy implications on how the next generation of gas distribution IR plans should be designed.

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[6] However, Union retains the right to apply to the Board for rate relief if it is in financial distress but, compared with the off-ramp, there is arguably more uncertainty associated with this protection since it is not linked to explicitly defined earnings outcomes, as is the off-ramp provision.

[7] It is easy to show that the value of Union's X factor of 1.82% will be greater than EGD's implicit X if inflation is less than 4.55% in 2008, 4.04% in 2009-2010, 3.64% in 2011, and 3.31% in 2012. The actual rates of GDP-IPI inflation in 2008, 2009, and 2010 were 1.54%, 2.73% and 0.72%, respectively, and therefore well below these magnitudes.

3. CONCEPTUAL FRAMEWORK FOR ASSESSMENT

This section will briefly discuss the framework PEG-R will use to assess the EGD and Union IR plans. We begin by discussing the Board's ratemaking objectives for IR and some of the key questions that need to be addressed to determine how effectively these objectives are being met. We then detail the framework that PEG-R will use to assess the extent to which customers and shareholders have shared in any benefits that may have been generated under incentive regulation.

3.1 Main Assessment Issues

PEG-R's assessment will focus on the extent to which the EGD and Union IR plans fulfilled the Board's objectives for incentive regulation. The Board articulated these objectives in its NGF Report. As discussed in Section One, the Board's NGF Report said an effective IR framework must:

- Establish incentives for sustainable efficiency improvements that benefit both customers and shareholders
- Ensure appropriate quality of service for customers
- Create an environment that is conducive to investment, to the benefit of both customers and shareholders

Assessing the extent to which these objectives have been satisfied requires addressing the following general issues:

- Did the incentive regulation plans encourage cost control and generate productivity and efficiency improvements?
- Did both customers and shareholders share in the benefits of any efficiency gains that were achieved?
- Did the Companies provide appropriate service quality to their customers?
- Was the incentive regulation framework conducive to capital investment?

Assessing these issues, in turn, raises a number of more specific questions. One set of questions concerns the prices that customers pay for EGD and Union gas delivery services. The main potential source of benefits for customers under IR is the prices that they pay. All else equal, in an effective IR plan, customers would pay less for utility services than they would if those same services were provided under cost of service regulation. PEG-R's assessment will therefore consider the following questions:

- How much did EGD's and Union's gas delivery prices change under IR?
- Approximately how much of these price changes were due to the rate adjustment mechanism (including Y and Z factors), the ESM and average use adjustments?
- How did gas delivery prices under IR compare to contemporaneous changes in the Companies' change in *input* price inflation and the growth in the GDP-IPI inflation factor?
- How do the Companies gas delivery prices under IR compare with those of other Companies under IR during the same period?

An effective IR plan should also generate benefits for shareholders. The main potential source of shareholder benefits is utility earnings. Measures of financial performance are also critical for assessing whether the IR framework is conducive to capital investment, which is another Board criterion for effective IR. To assess these financial-related issues, PEG-R will examine the following questions:

- How do the financial indicators that the Companies report to the Board compare under IR and for the years immediately before IR was implemented?
- How do the Companies' changes in net plant and equipment and customer additions compare before and after IR was implemented?
- Is there any other evidence on whether the IR plans are or are not creating an environment that is conducive to capital investment?

The ultimate source of gains under IR, for both customers and shareholders, are TFP gains generated by the utility. An effective IR plan will encourage regulated firms to improve productivity more rapidly than they would under cost of service regulation. It is therefore natural that one of the Board's criteria for effective IR is that the plans generate incentives for sustainable efficiency improvements. To assess this objective, PEG-R will consider the following issues:

- What was the rate of TFP growth for EGD and Union under IR?
- How do the Companies' rates of TFP growth compare to their TFP trends immediately before IR was implemented?
- Is it possible to determine how much of any *incremental* TFP change under IR, for EGD and Union, was due to exogenous factors beyond management control, and how much was 'endogenous'?
- How do the rates of TFP growth for EGD and Union under IR compare to those of other 'peer' gas distribution utilities?
- How do the rates of TFP growth for EGD and Union under IR compare to what would be expected for the Companies if they had remained subject to cost of service regulation?
- How were the benefits under IR (including TFP growth) distributed or 'shared' between customers and shareholders?

The methodology used to assess this last issue is detailed in Section 3.2 of this report.

Finally, the level of service quality is an important Board objective in all regulatory regimes, including IR. The Board established service quality requirements that EGD and Union were expected to satisfy even before IR was implemented. The Companies should also obviously satisfy these requirements under an effective IR plan. PEG-R's assessment will therefore consider the following questions:

- Does each Company's measured service quality generally satisfy the Board's service quality requirements?
- Are there any noticeable trends in the Companies' service quality performance under IR?
- How do EGD's and Union's measured service quality compare to each other?

3.2 Methodology for Assessing Benefit Sharing/Distribution of Productivity Gains

One critical issue for PEG-R's assessment is the *sharing* or *distribution* of benefits and/or productivity gains under IR. This issue is implicit in the Board's objectives, which emphasize that an effective IR framework should benefit shareholders and customers. This, in turn, implies that all the benefits of TFP gains generated under IR should not be retained entirely by either customers or shareholders.

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. Given the importance, it is essential that the methodology used to quantify the sharing/distribution of benefits be as simple and transparent as possible. Fortunately, this can be done with a relatively straightforward extension of the 'indexing logic' that has underpinned Ontario's previous IR plans, as we describe below.[8]

The indexing logic shows that there is a relationship between changes in TFP, changes in prices, and changes in what we will call "margins." We define a utility's margins as the difference between the growth in its revenue index and cost index, but we refer to this differential as margins rather than "profits" or "earnings" because the cost measures used in PEG-R's TFP analysis are not identical with the accounting costs used to compute earnings metrics such as return on equity (ROE). In fact, PEG-R includes the approved return on assets as a component of the cost of capital, and this element of capital costs necessarily increases as the net stock of capital assets grows. This is obviously not the case for the Companies' earnings calculations (*e.g.* it would be nonsensical to include "return on assets" as a component of costs when computing the return on assets). In practice, this means the cost measures used in PEG-R's TFP analysis will increase more rapidly than the costs used to compute EGD and Union earnings. Implicitly, PEG-R's cost measures build an average return on assets (*i.e.* the embedded cost of debt plus the ROE approved for each Company for ratemaking) into the baseline cost calculation and assumes these average returns are maintained as the

[8] Similar methodologies have also been presented in the economics literature *e.g.* Salerian (2003).

stock of capital expands. The change in margins can be interpreted as a rough measure of the incremental change in a utility's returns, rather than the change in its total profits, relative to this baseline level of returns.[9]

Let an index of a utility's revenue be given by *R*, an index of the prices it charges for its output given by *P*, and an index of its output quantity given by Y^R. It can be shown that the change in the utility's revenue can be decomposed into the sum of changes in its output price and a revenue-shared weighted index of its output quantity, or

$$\Delta R = \Delta Y^R + \Delta P \tag{1}$$

Similarly, let an index of the utility's cost be given by *C*, an index of the prices it pays for the inputs used in production by *W*, and an index of the quantity of the inputs used in production by *X*. It can then be shown that the change in utility cost can be decomposed into the sum of changes in the firm's input quantity and input price indexes, or

$$\Delta C = \Delta X + \Delta W \tag{2}$$

Furthermore, define the change in the firm's margins as the change in its revenue index minus the change in its cost index:

$$\Delta R - \Delta C = \Delta \pi \tag{3}$$

Substituting (1) and (2) into (3) yields

$$\Delta Y^R + \Delta P - (\Delta X + \Delta W) = \Delta \pi \tag{4}$$

Re-arranging (4) yields

$$\Delta P - \Delta W + (\Delta Y^R - \Delta X) = \Delta \pi \tag{5}$$

TFP change (ΔTFP^R) is defined as the change in output quantity minus the change in input quantity. Substituting this expression and re-arranging (5) is equivalent to

$$\Delta TFP^R = -(\Delta P - \Delta W) + \Delta \pi \tag{6}$$

[9] It is important to emphasize that PEG-R is not trying to replicate either EGD's or Union's reported returns in any given year. A number of accounting and related issues factor into these calculations, many of which vary from year to year and are not necessarily reflected in the basic operating and capital expenditures data that the Companies report and that PEG-R uses to measure costs and, more to the point in a TFP-based analysis, input quantities. Any measures of margins that can be obtained in our TFP-based methodology will necessarily be rough and approximate measures of how much either of the Companies' reported rate of return changes in a given year.

This equation shows that there is a relationship between changes in a utility's TFP^R, changes in its customers' welfare (*i.e.* changes in the prices of utility output relative to changes in prices paid for utility inputs) and changes in shareholders' welfare (*i.e.* changes in margins). The term on the left-hand side of (6) is changes in the utility's TFP. The right-hand side of (6) has two terms: the decline in the utility's output prices (relative to the change in its input prices); plus the change in the utility's margins. This expression shows that TFP growth can enable a firm's margins to increase at the same time that its prices decline. More generally, this expression shows that a firm's TFP gains are "distributed" as price reductions or margin increases.[10]

It may be instructive to explore the intuition behind equation (6) and show why it is sensible. To do this, first recognize that the change in unit cost ΔUC is defined as $\Delta UC = \Delta C - \Delta Y$. Substituting for $\Delta C = \Delta X + \Delta W$ from equation (2) and the definition for the change in TFP, it can be seen that:

$$\begin{aligned} \Delta UC &= \Delta X + \Delta W - \Delta Y \\ &= \Delta W - (\Delta Y - \Delta X) \\ &= \Delta W - \Delta TFP \end{aligned} \qquad [7]$$

The change in a company's unit cost is therefore equal to the change in its input price minus the change in its TFP.[11] It is also easy to show that a firm's margins will be unchanged if its unit costs grow at the same rate as the prices for its output.[12]

Now, consider the case where a firm is not increasing its TFP or its margins. From (7), if TFP growth is zero, the firm's unit cost grows at the same rate as its input prices. If the change in the firm's margins is zero, then the prices for its output grow at the same rate as its unit cost which, in this case (because TFP growth is zero), is equal to the rate of input price inflation. In the absence of TFP growth and any change in

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[10] This analysis assumes service quality is unchanged and the firm's input prices are exogenous; if this is not true, TFP gains can also be "distributed" in the form of improved service quality and/or higher payments for factors of production *e.g.* labor hired by the firm. The latter could, in turn, be interpreted as a further division of margins within the firm ("profit sharing") between labor and owners of capital.

[11] This expression shows that TFP growth can be interpreted as the extent to which a firm is able to keep the growth in its unit cost below the growth in the prices of the inputs it purchases.

[12] This can be easily demonstrated mathematically. Begin with the definition $\Delta\pi = \Delta R - \Delta C$, substitute for ΔR so that $\Delta\pi = \Delta P + \Delta Y - \Delta C$. Since the change in unit cost ΔUC is defined as $\Delta UC = \Delta C - \Delta Y$, this equation can also be expressed as $\Delta\pi = \Delta P - \Delta UC$. Therefore if $\Delta P = \Delta UC$, then $\Delta\pi = 0$.

company margins, changes in the prices that firms pay for inputs are therefore passed directly into changes in the prices they charge for their outputs.

Now relax one assumption, and allow TFP growth to be positive but assume that margins do not change. From equation (7), when TFP growth is positive, unit costs are growing less rapidly than the growth in input prices, and this difference is exactly equal to the growth in the firm's TFP. We assume none of these TFP gains are captured as increased margins for the firm, so $\Delta\pi = 0, \Delta P = \Delta UC$ and the firm's output prices must be declining by the same amount as the decline in its unit costs, which is exactly equal to the growth in the firm's TFP. Therefore, this example shows that when TFP grows and the firm's margins remain unchanged, input price inflation is *not* passed directly into output price inflation for customers; the TFP gains are "distributed" entirely to customers in the form of output price changes that are kept below the rate of input price inflation.

The most general case would remove the remaining assumption and allow the firm's margins to change. TFP growth would lead to less growth in unit cost which, as discussed above, could lead output prices to grow less rapidly than input price growth. However, since $\Delta\pi = \Delta P - \Delta UC$, declining unit cost can also be reflected in increased margins for the firm. Therefore, in this most general case, TFP gains can be distributed in some combination of higher margins for the firm (benefits for shareholders) and changes in output prices that are kept below the firm's input price inflation (benefits for customers). This set of possibilities is, in fact, reflected in equation (6).

However, one caveat in the analysis above is that TFP growth is measured using a revenue-weighted output quantity index. This is not the appropriate TFP measure when an IR plan includes price adjustments for changes in average use per customer, like the IR plans for both EGD and Union. The reason is that a revenue-weighted output index reflects the impact of output growth –including changes in AUPC - on revenue, and the Union and EGD IR plans already contain separate terms expressly designed to reflect changes in AUPC on revenue. If the adjustment mechanisms in these plans were also calibrated using a TFP measure that reflected the impact of output growth on revenue, these plans would include an element of double-counting for changes in AUPC.

It is therefore appropriate to measure TFP in the EGD and Union IR plans using an output index that reflects the impact of output growth on *cost* rather than revenue. The appropriate output index in this instance is computed by weighting the growth in different outputs by each output's relative *cost elasticity*, rather than by its share of revenues.[13] These cost elasticities can be estimated econometrically.

The indexing logic above can be easily modified so that a TFP measure appropriate to the EGD and Union plans is used. Recall that (6) is equal to

$$\Delta Y^R - \Delta X = -(\Delta P - \Delta W) + \Delta \pi \qquad (8)$$

If the change in a cost-elasticity weighted output quantity index, ΔY^E, is added and subtracted on the left-hand side of (8), nothing is changed. Doing so and re-arranging terms yields

$$\Delta Y^R - \Delta X + (\Delta Y^E - \Delta Y^E) = -(\Delta P - \Delta W) + \Delta \pi \qquad (9)$$

$$\Delta Y^E - \Delta X + \Delta Y^R - \Delta Y^E = -(\Delta P - \Delta W) + \Delta \pi \qquad (10)$$

$$\Delta TFP^E = -(\Delta P - \Delta W) + \Delta \pi - (\Delta Y^R - \Delta Y^E) \qquad (11)$$

ΔTFP^E is equal to the change in TFP when output is measured using a cost-elasticity weighted output index. The term $(\Delta Y^R - \Delta Y^E)$ measures the difference between the impact of output growth on the utility's revenue and the utility's cost. In other words, $(\Delta Y^R - \Delta Y^E)$ should reflect the effect that output changes have on the utility's margins.[14] This implies that the term $\Delta \pi - (\Delta Y^R - \Delta Y^E)$ is an adjusted measure of the utility's change in margins *i.e.* changes in margins net of the impact of changes in output. It is arguably more appropriate to measure a utility's margins in this way, since output growth for utilities is largely exogenous and beyond their control. In addition to being consistent with the appropriate TFP measure, the term $\Delta \pi - (\Delta Y^R - \Delta Y^E)$ is therefore likely to be a more appropriate measure of the impact that a utility's own behavior (rather than its exogenous output growth) has on its financial performance.

Equation (11) can be further re-arranged to "scale" shareholder and customer benefit relative to the TFP gains achieved in each year. Dividing (11) by ΔTFP^E

[13] For further discussion of this point, see Lowry *et al* "Rate Adjustment Indexes for Ontario's Natural Gas Utilities," 8 June 2007, pp. 5, and "Review of Distribution Revenue Decoupling Mechanisms," 19 March 2010, pp. 4, 8, 14, and 70-71.

[14] Output changes impact unit profits due to the fact that traditional utility rate designs collect a relatively large share of revenues through volumetric charges, while a much smaller share of gas distribution costs (particularly in the short term) are driven by changes in volume.

yields the following expression:

$$1 = \underbrace{\frac{\Delta\pi - (\Delta Y^R - \Delta Y^E)}{\Delta TFP^E}}_{\text{Shareholder Share of TFP-generated Benefits}} + \underbrace{\frac{-(\Delta P - \Delta W)}{\Delta TFP^E}}_{\text{Customer share of TFP-generated Benefits}} \tag{12}$$

3.3 Application of Methodology to Assessment

PEG-R will use equation (12) to assess the sharing of benefits and distribution of utility TFP gains between customers and shareholders under IR. In this equation, customers' contemporaneous "share" of benefits is measured by $\frac{-(\Delta P - \Delta W)}{\Delta TFP^E}$, while the contemporaneous "share" of TFP gains retained by shareholders will be given by $\frac{\Delta\pi - (\Delta Y^R - \Delta Y^E)}{\Delta TFP^E}$. These shares should sum to one, although either can be negative in any given year. A negative value for either shareholders or customers would indicate that the other stakeholder retained all TFP gains in that year, and also gained at the expense of the other stakeholder with the negative "share." The metrics ΔTFP^E, $(\Delta Y^R - \Delta Y^E)$, and ΔW can all be measured directly, while $\Delta\pi$ can be measured by differences between ΔR and ΔC, and ΔP measured as the difference between ΔR and ΔY^R.

Several other points about equation (12) are noteworthy. First, all of these index values are volatile from year to year, so readers should not put too much weight on the outcomes of this analysis in any given year. However, this methodology may be useful for understanding how benefits have been distributed between customers and shareholders over a multi-year period, such as the term of a multi-year IR plan.

Second, we reiterate that the change in margins will not be equivalent to the change in a utility's reported earnings. PEG-R's measure of capital costs (which is appropriate to use in an index-based, TFP measurement framework) will differ from the Companies' reported costs. PEG-R did not attempt to replicate the Companies' reported earnings using operating and capital expenditures from their Reporting and Record-Keeping Requirements ("RRR") filings, which may not be possible in any event.

In addition, it should be recognized that the numerator in both terms on the right-hand side measures benefits (for shareholders and customers, respectively). As discussed in Section 2, in an ideal IR plan, the source of all shareholder and customer benefits would be TFP gains generated under the plan, but in practice other plan design features can create windfall gains or losses for stakeholders. Most importantly, all else equal, if the inflation factor grows more rapidly than the inflation in prices of inputs procured by the utility, shareholders experience a windfall gain at the expense of customers (and vice versa, if the inflation factor grows less rapidly than input prices). This phenomenon is reflected in equation (12): customer welfare is measured by the negative of the difference between output price inflation and input price inflation, and if the inflation factor causes output prices to grow more rapidly than input price inflation then this measure of customer benefits will be negative.

It is therefore not an error for our measures of customer and shareholder benefit to include more than the TFP gains that were achieved in a year. In fact, it would be an error if stakeholder benefit measures included only the distribution of TFP gains, because stakeholders' relative welfare also depends on other plan design features, such as the relationship between input price growth and the selected inflation measure. A corollary of this point is that if one stakeholder's share of available TFP gains systematically exceeds one, it is because of an element of the IR plan that is independent of TFP gains. This may indicate a flaw in the design of the plan.

At the same time, some TFP gains by the Company can in fact be shared contemporaneously with customers via the ESM. All else equal, more rapid TFP growth boosts earnings, which is likely to lead to more shared earnings and price reductions for customers. This is also reflected in the PEG-R methodology, which relies directly on an overall index of Company prices, which will incorporate any sharing of utility earnings through the ESM (albeit with a one year lag).

It should also be recognized that PEG-R's methodology relies on measured TFP gains in each year. These are not necessarily equal to the rate of "sustainable" TFP growth, because they can reflect the impact of unsustainable cost deferments rather than sustainable cost reductions. It is appropriate to scale measured benefits relative to actual rather than "sustainable" TFP changes, because in the short run measured shareholder welfare can in fact be improved through unsustainable cost deferments.

Finally, our analysis will naturally only reflect the sharing of benefits and TFP gains under the first three years of the Companies' IR plans. Our assessment excludes an important potential source of benefits for customers, which is the rebasing of rates to reflect realized productivity gains. This potential source of customer gains cannot be assessed until the Companies' proposal for rebased rates is presented to and analyzed by the Board.

4. RATES AND REVENUES

As discussed in the previous Section, changes in utility prices are the main potential source of benefits to customers under incentive regulation. Evaluating the impact of IR on the Companies' rates, however, is not as straightforward as it may seem. Both EGD and Union provide a large number of tariffed services, many of which are also provided on a contract basis for very large volume customers or apply to services other than gas delivery (*e.g.* unbundled storage and transportation). It is difficult to assess the impact of IR on these services because of a relative paucity of data, particularly on the output quantities/billing determinants associated with these rates.

Measuring utility prices is also complicated by the details of ratemaking for the Companies. The primary, IR-based rate adjustments are usually set before the beginning of a plan year using a mix of known and forecast data. Rates are later "trued-up" to reflect the revenue impact associated with differences between actual and forecast values of the variables used to set initial rates. These true-ups take place in the year following the year for which the rates were established. Thus, in each IR plan year, the rates that customers pay reflect forward-looking, IR-based price changes established before the beginning of the year, as well as a backward-looking adjustment that takes effect during the year to correct for differences between actual and forecast values used to set customer rates in the preceding year.

The latter rate adjustment also reflects the cost and/or revenue impact associated with a variety of other mechanisms whose values have been aggregated in "variance accounts" or "deferral accounts" for later disposition. Some of these account balances stem from the costs of activities, such as Ontario Hearing Costs, which would be incurred under either cost of service regulation or IR. Nevertheless, the recovery of these costs clearly impact changes in customer prices and therefore customer welfare while the IR plans are in effect; as long as these accounts recover costs that were incurred during the term of the IR plans, rather than from the distant past, they should not be ignored when assessing the plans. Some of the Companies' deferral account balances, particularly for the ESM, reflect the outcomes of mechanisms that are central to the IR plans themselves.

The assessment of EGD and Union gas delivery prices has been made more tractable by concentrating most (but not all) of our analysis on rates for two general service customer classes for EGD (Rate 1 and Rate 6) and four general service customer classes for Union (Rates 01, 10, M1 and M2). These rates are also the most relevant to the Companies' IR plans. In fact, some important plan features (including the AU adjustments and allowed rate redesign) pertain only to these rates. The selected rates also set gas delivery service prices for the overwhelming share of the Companies' residential and commercial customers and account for a very large portion (about 97% for EGD and 83% for Union) of each Company's regulated gas delivery revenues.

Because of the regulatory complexity associated with the Companies' plans, we begin by describing the general process used to adjust prices under each Company's IR plan. This includes a description of the elements that enter into the rate adjustment calculation, the general steps involved in setting proposed IR-based rates, and the amount of time stakeholders and the Board have spent to review and approve IR Rate Orders for each Company.

We then turn to the rate changes that have taken place under each plan. We review the general sources of price/revenue change in each plan year, which factor into the allowed change in all regulated gas delivery prices. Next, we compare changes in residential tariffs for the Companies and selected IR peers, as well as changes in gas and electricity distribution prices in Ontario. We then compute an overall price index (and associated revenue-weighted output quantity index) for each Company, and compare changes in this index of the Companies' gas delivery prices with inflation in their input prices and broader GDP-IPI inflation. Finally, we provide an overview and preliminary assessment of the rate adjustment process and its outcomes in terms of actual rate trends for EGD and Union.

4.1 Process for Adjusting Rates

We assess two separate aspects of the rate adjustment process for EGD and Union under IR. The first is the mechanics of rate adjustments for each Company. The second is the time it has taken to review and implement IR rate changes for EGD and Union.

4.1.1 Rate Adjustment Mechanics

For both Companies, there are essentially five components of overall price change allowed under the IR plans:

1. Net inflation, equal to GDP-IPI inflation minus the X factor for Union, and GDP-IPI inflation multiplied by the inflation coefficient for Enbridge
2. Allowed Y factor cost
3. Allowed Z factor cost
4. The AU adjustment (an explicit AU adjustment for Union, an implicit AU adjustment under the revenue per customer cap for EGD)
5. Earnings that are shared with customers as price reductions via the ESM

Company proposals on the first four components of price change are filed in September of each year, for a rate change designed to take effect on January 1 of the next year. The first three of these components – the net inflation adjustment, plus the Y and Z factors – impact the total amount of regulated revenues to be recovered in rates.

The AU factor does not affect regulated revenues, but it does influence how those revenues are recovered. The AU factor adjusts the volumetric charges of the effected rate schedules to reflect the measured change in average gas use for customers in that particular rate class.[15] If average use for customers on the rate declines, volumetric charges are increased proportionately to recover revenue losses associated with the measured decline in AUPC. An increase in average use for customers on the rate would lead to an analogous decline in the tariff's volumetric charges. Because the AU factor adjusts one set of billing determinants (*i.e.* the gas delivery volumes for customers in that rate class) with no corresponding offset or change in other billing determinants, the AU adjustment does impact the overall rate of price change under the IR plans.

In the same annual filing before the start of each plan year, Companies are allowed to redesign rates in a way that does not impact overall price change but does affect the relative growth in customer vis-à-vis volumetric charges on selected tariffs. The approved IR plans contain provisions that say precisely what customer charges will

[15] These are Rates 1 and 6 for EGD, and rates 01, 10, M1 and M2 for Union.

be in effect for these tariffs in each year of the plan.[16] The specified changes in these customer charges exceed the amounts that would be allowed under the annual application of the rate adjustment mechanism. To ensure that this allowed increase in the customer charge does not cause the rate of overall price charge on the tariff to exceed the amount allowed under the net inflation, Y and Z factors, volumetric charges on the associated tariffs are reduced so that the overall effect of the rate redesign is revenue (and price) neutral.[17]

The final component of the overall price change is the ESM. As previously discussed, this is a different application that is filed with the Board after the calendar year in which earnings are generated. In this application, the Companies report their ROE for the calendar year and compare it with their allowed ROE in that year (as determined by the Board's ROE formula) plus a 100 basis point deadband for EGD and two different deadbands for Union. For EGD, 50% of earnings outside this band are credited to customer rates; for Union, 50% of earnings between 200 and 300 basis points above allowed ROE, and 90% of incremental earnings exceeding allowed ROE plus 300 basis points, are credited to customer rates. The Board reviews and approves the earning sharing amounts and calculations before the rate adjustments take effect. The application process is to be completed so that any price adjustments from the ESM can take effect with the July 1 QRAM proceeding. The price adjustments at this time are also designed to clear the balances in a number of other variance and deferral accounts.

The precise steps involved in determining allowed revenues per customer for EGD are spelled out in the Company's settlement agreement.[18] Union uses a process that is similar in most respects to set its IR-based rate adjustments. Both plans begin with total approved gas delivery revenue in the previous year, then net out the previous year's

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[16] These customer charges are the following: for EGD Rate 1, $14 in 2008, $16 in 2009, $18 in 2010, $19 in 2011, and $20 in 2012; for EGD Rate 6, $50 in 2008, $55 in 2009, $60 in 2010, $65 in 2011, and $70 in 2012; for Union Rates 01 and M1, $17 in 2008, $18 in 2009, $19 in 2010, $20 in 2011, and $21 in 2012; for Union Rates 10 and M2, no changes in the customer charge are allowed.

[17] This adjustment is both revenue and price neutral because the rate redesign takes place before the AU adjustment, so the billing determinants used to determine allowed revenues are based on the same billing determinants as those in place at the end of the previous year. Because there is no change in outputs (the customer counts and volume billing determinants) involved with the rate redesign, the resulting change in revenue is equivalent to the change in price on the tariff. The AU adjustment then takes place after the rate redesign, and it will impact the overall rate of price change although it will not impact the revenue change allocated to the tariff under the net inflation, Y and Z factors.

recovery of Y and Z factors. The net inflation formula is applied to this resulting net revenue value, to determine the allowed revenue change resulting from the inflation minus X factor formula for Union, or inflation multiplied by the inflation coefficient formula for EGD. Current year values for Y- and Z-factored costs are then added back in and allocated to different rate classes. For the selected rates, customer charges are further increased to the levels allowed each year in the settlement agreement, with revenue neutral changes in the tariffs' volumetric rates applied at the same time. Finally, the AU adjustments are applied to adjust volumetric rates on the selected rate classes for projected changes in average gas use by customers on that tariff in the coming year.

There are two primary differences between the manner in which EGD and Union rate adjustments are applied. First, the EGD net inflation adjustment is applied on a revenue per customer basis. Therefore, EGD's initial revenue base subject to the net inflation escalation formula (gas distribution revenue in the previous year net of the previous year's Y and Z factor recovery) is first divided by its average number of customers at the beginning of the year. This average revenue gas distribution revenue per customer figure is then multiplied by the net inflation adjustment formula and the projected number of average gas distribution customers at the end of the year, to yield a total distribution revenue figure (before adding in allowed Y and Z factors for the year).

The other difference concerns the AU factor. EGD's calculation of AU is based on forecast gas usage for customers on the tariff. This forecast, in turn, depends on a gas demand model for the class and forecast heating degree days and customer numbers for the year. Union's AU calculation is based on a three-year moving average of actual declines in AUPC for customers on the rate class, updated annually.

4.1.2 Regulatory Process for Approving IR Rate Adjustments

EGD and Union have each filed three incentive regulation mechanism (IRM) applications, for the 2009, 2010, and 2011 rate years. Union's filings have generally been processed more quickly than EGD's. One reason appears to be that Union's IRM

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[18] See EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, Appendix C, pp. 47-51.

filings have been more streamlined and focused on IR *per se* rather than involving additional, but related, issues, as did EGD's filings for the 2009 and 2010 rate years.

For the 2009 rate year, Union filed its application with the Board (in EB-2008-0220) on September 26, 2008. The Board's Decision and Rate Order was issued 151 days later on February 24, 2009. One factor slowing the processing of this application was that it included a proposal to Z factor the recovery of $1.511 million of costs related to the transition to international financial reporting standards (IFRS). The Board reviewed the Company's evidence but ultimately rejected the claim.

For Union's 2010 rate year, the Company filed its application with the Board (in EB-2009-0275) on September 3, 2009. The Board issued its Decision and Rate Order 83 days later on November 25, 2009. The only Z factor in this application was a $2.656 million credit to customers to reflect the cost savings of tax changes, which was approved by the Board. The Board had previously ruled (in EB-2007-0606, the same proceeding that approved Union's settlement agreement) that 50% of the savings from tax changes would be Z-factored in Union's IR plan.

Union's application for the 2011 rate year was filed with the Board (in EB-2010-0148) on September 15, 2010. The Board approved this application 75 days later on November 29, 2010. Again, the only Z factor was to pass through 50% of the estimated cost savings from tax changes to customers, and the Board approved Union's $2.064 M. estimate of these savings.

To date, Union's regulatory filings have generally been processed in a timely manner. The only exception is the Company's most recent application regarding earnings to be shared under the ESM (EB-2011-0038) in which Union filed its application on April 20, 2011 and the Board issued its final Decision and Order on February 29, 2012.

EGD filed its IRM application for the 2009 rate year (in EB-2008-0219) on September 26, 2008. This application included seven issues that did not directly pertain to the annual rate adjustment mechanism. EGD proposed to split this application in two phases: Phase I to deal with the rate adjustment mechanism, and Phase II to address the other seven issues. On October 20, 2008, the Board accepted EGD's proposed two-phase approach. The Board accepted a settlement agreement resolving the Phase I, IR-adjustment related issues on December 18, 2008, 83 days after the application was filed. However, the Draft Rate Order was not filed until January 12, 2009, and the final Rate Order for Phase I was not issued until February 23, 2009 (150 days after the initial filing).

EGD's IRM application for the 2010 rate year (EB-2009-0172) was filed on September 1, 2009 and also involved auxiliary, but related, issues. One of these issues was EGD's proposal for regulated recovery of the costs of its Green Energy Initiative. This proposal was ultimately denied, but it did delay the overall consideration of the application.

In the same proceeding, EGD also asked the Board to update the ROE used in its ESM to reflect the Board's Report on Cost of Capital for Ontario's Regulated Entities (EB-2009-0084), which was issued in December 2009. EGD argued that the Board's updated approach to determine the cost of capital constituted a change in a regulatory rule so that a re-opening of the ROE used in the ESM was warranted. On February 10, 2010, the Board began a process to consider the ROE issue.

The Board issued its Rate Order for the 2010 rate year on March 8, 2010. This was 188 days after EGD filed its initial application. On May 18, 2010, the Board issued a Decision and Order (EB-2009-0172) rejecting EGD's claim that the ROE used in the Company's ESM should be adjusted to reflect the Board's updated approach to determine the cost of capital. This was 259 days after the IRM proceeding was initiated.

For the 2011 rate year, EGD filed its application with the Board (in EB-2010-0146) on September 1, 2010. This application was not encumbered with auxiliary issues like those for the preceding two rate years. The Board issued its Rate Order approving 2011 rates for EGD on December 8, 2010, 98 days after the application was filed.

4.2 Rate Changes Under IR

4.2.1 Sources of Revenue/Price Change

In assessing the impact of IR on EGD and Union rates, one fundamental issue is determining how much the different components of the IR plans have contributed to allowed change in revenues in different plan years. Tables Two and Three present information that is relevant to understanding this issue.

Table 2

Net Inflation Changes, 2008-2010

	Enbridge				Union			
	2008	2009	2010	Avg.	2008	2009	2010	Avg.
GDP-PI Inflation	1.54%	2.73%	0.72%	1.66%	1.54%	2.73%	0.72%	1.66%
"X"	0.62%	1.23%	0.32%	0.72%	1.82%	1.82%	1.82%	1.82%
Net Inflation	0.92%	1.50%	0.40%	0.94%	-0.28%	0.91%	-1.10%	-0.16%

Table 3

Sources of Revenue Change ($\$10^6$)

Source	2008		2009		2010		Average	
	Enbridge	Union	Enbridge	Union	Enbridge	Union	EGD	Union
Net inflation	6.6	-2.4	10.9	7.9	3.5	-9.5	7.0	-1.3
Percent of Approved Revenue	0.70%	-0.25%	1.11%	0.83%	0.36%	-1.10%	0.72%	-0.14%
Incremental Y factors	-0.3	7.2	-7.3	0.2	-4.2	0.2	-3.9	2.5
Percent of Approved Revenue	-0.03%	0.75%	-0.75%	0.02%	-0.42%	0.02%	-0.41%	0.27%
Incremental Z factors	-1.8	-4.2	-6.6	-2.7	-5.3	-2.1	-4.6	-3.0
Percent of Approved Revenue	-0.19%	-0.44%	-0.68%	-0.28%	-0.54%	-0.24%	-0.47%	-0.32%
ESM	-5.7	-34.5	-19.5	-7.4	-17.2	-3.4	-14.1	-15.1
Percent of Approved Revenue	-0.60%	-3.58%	-2.00%	-0.77%	-1.74%	-0.40%	-1.46%	-1.63%
Sum Change Revenues	-1.2	-34.0	-22.5	-1.9	-23.2	-14.8	-15.6	-16.9
Approved Revenue	938.0	963.4	974.1	957.9	988.6	863.6	966.9	928.3
% Change Revenues	-0.13%	-3.52%	-2.31%	-0.20%	-2.35%	-1.71%	-1.59%	-1.81%

Table Two presents data on the values for GDP-IPI inflation, the value of X (the X factor for Union and the implicit X factor for EGD) and the net inflation adjustment (*i.e.* GDP-IPI inflation minus "X") in 2008-2010. Measured GDP-IPI inflation averaged 1.66% per annum in 2008-2010, with values of 1.54%, 2.73% and 0.72% in 2008, 2009 and 2010, respectively. EGD's implicit X averaged 0.72% in these years, while the X factor for Union was fixed at 1.82% in all plan years. Thus, the annual net inflation adjustment averaged 0.94% for EGD (*i.e.* 1.66% - 0.72% = 0.94%) and -0.16% for Union (*i.e.* 1.66% - 1.82% = -0.16%). All else equal, the differences in the net inflation mechanisms between the plans therefore caused EGD's allowed revenues and prices to increase by 1.1% more per annum than Union's allowed revenues and prices (*i.e.* the difference between Union's fixed X of 1.82% and EGD's implicit X of 0.72% = 1.1%).

Table Three presents information on allowed revenue change for EGD and Union in 2008-2010 resulting from the net inflation mechanism, Y factors, Z factors, and the ESM. Again, it should be recognized that the revenue changes resulting from the ESM are implemented in a different proceeding from the inflation, Y and Z factors, and the ESM revenue adjustments take effect later in the year. Table Two presents an estimate of the approximate revenue impact resulting from the Y factors, Z factors, and ESM, all expressed relative to approved revenues in the previous year.

It can be seen that the Y and Z factors have had relatively modest impacts on allowed revenue change. The Y factor has decreased allowed revenue by approximately 0.41% per annum in 2008-2010 for EGD (*i.e.* the amount of costs passed through under EGD's Y factor have declined over the 2008-2010 period), but increased Union's annual revenue about 0.27% for the same period. Nearly all of the revenue increases for Union took effect in 2008, and its Y factors have had a small to negligible impact on allowed revenue change in 2009 and 2010.

Z factors have decreased EGD allowed revenues by an average of 0.47% per annum in 2008-10. For Union, Z factors reduced revenues by an average of 0.32% per annum over the same period. Both Companies have applied for revenue increases under the Z factor (Union in EB-2008-0220, EGD in EB-2009-0172), but the Companies' applications were either denied or withdrawn in settlement. In practice, the only Z factor adjustments allowed under the plans have been the credits to customers of 50% of the estimated savings from tax changes, and passing these savings onto customers has led to price reductions.

The most significant source of revenue change under the IR plan has been through the earnings the Companies shared with customers under their ESMs. It can be seen that the ESMs led to revenue declines of about 1.46% per annum for EGD, and 1.63% per annum for Union, over the 2008-2010 period. Most of the earnings that Union distributed to customers occurred in 2008. In total, Union has distributed $45.3 M of its 2008-2010 earnings back to their customers in the form of rate reductions. EGD has distributed $42.4 of its 2008-10 earnings back to customers in the form of rate reductions.

4.2.2 Changes in Tariffs and Average Prices

PEG-R has considered several measures of how EGD and Union gas delivery prices changed over the 2008-2010 period and how those rate changes compare with the years before the IR plans were approved. We begin by considering EGD and Union's residential gas delivery tariffs for the 2005-2010 period. The changes in these tariffs and rate elements are compared with the residential tariffs of two Massachusetts gas distributors who were subject to IR for 2005-2010 period.[19] Next, we consider average gas delivery charges for residential customers between 2005 and 2010 and how these price changes compare with those for average electricity delivery charges for residential customers in Ontario over the same period.

Finally PEG-R estimates broad indices of gas delivery prices for EGD and Union for 2007-2010. These indices should capture all sources of price change under IR, including the effects of the ESM and other variance and deferral accounts. We assess how these price indices changed relative to input price and GDP-IPI inflation over the same period. These latter comparisons can provide context for the *relative* changes in prices for EGD and Union gas delivery services compared with other goods and services in the economy. As the methodology in Section Three shows, the difference between changes in output and input prices also directly affects our measure of customers' share of benefits under IR.

4.2.2.1 Residential Tariffs for Ontario and Massachusetts Distributors Subject to IR

Tables 4 and 5 present information on tariffs for residential customers for EGD, Union and two Massachusetts gas distributors: Boston Gas and Bay State Gas. The Massachusetts distributors have been chosen for comparison purposes because they were subject to IR for all, or nearly, all of the 2005-2010 period.[20] The Boston Gas and Bay State Gas tariffs apply to the residential heating class, which covers nearly all residential customers for both Companies.

PEG-R made two modifications of the Massachusetts (MA) distributors' tariffs to make them comparable to EGD and Union. First, since the MA tariffs are naturally expressed in US currency, all their tariff elements were converted to Canadian dollar equivalents by multiplying them by the purchasing power parity (PPP) exchange rate of approximately 1.21 C$/1 US$.[21] Second, the volumetric charges of Bay State and Boston Gas are based on the therms of natural gas distributed whereas EGD and Union's volumetric charges are based on cubic meters of natural gas distributed. All the MA volumetric charges were therefore converted to a cubic meter equivalent by multiplying them by 0.36339 cubic meters per therm.

Table 4 presents information on the levels and growth rates for the customer and volumetric charges for all four distributors. The re-design of EGD and Union rates is clearly evident in this table. Both Ontario distributors have seen a consistent, and relatively rapid, increase in their customer charges, although this has been offset with very significant declines in their volumetric delivery rates. Boston Gas and Bay State's IR plans have allowed for somewhat more rapid increase in their customer vis-à-vis volumetric charges, but not to nearly the same extent as the EGD and Union plans. Overall, for the 2005-2010 period, the Boston Gas IR plan led to average annual increases in the Company's residential customer and volumetric charges of 2.79% and 2.00%, respectively. The comparable growth rates for the Bay State plan are 1.8% and 2.29%, although Bay State's plan ended in 2009 and its rates were not adjusted in 2010.

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[19] One of those distributors, Boston Gas, was in fact subject to IR in every year between 2005-2010; the other distributor, Bay State Gas, was subject to IR for the 2005 to 2009 period.

[20] Bay State's PBR plan was in effect from 2005 to 2009.

[21] The PPP exchange rates vary slightly over the 2005-2010 period, but are approximately 1.21 C$ for each US$ in each year between 2005 and 2010.

Table 4

Residential Rates of Gas Distributors Operating under IR - Levels

	Bay State Gas[3,5]		**Boston Gas**[4,5]		**Enbridge Gas Distribution**[6]		**Union Gas - Rate 01**[7]		**Union Gas - Rate M1/M2**[8]	
Year	Customer Charge[1]	Volumetric Charge[2]	Customer Charge[1]	Volumetric Charge[2]	Customer Charge[1]	Volumetric Charge[2]	Customer Charge[1]	Volumetric Charge[2]	Customer Charge[1]	Volumetric Charge[2]
2005	12.10	11.93	14.90	15.89	11.25	15.26	14.00	9.69	14.00	5.76
2006	12.48	12.22	15.29	16.23	11.25	15.61	14.00	9.69	14.00	5.66
2007	13.06	12.70	15.78	16.64	11.95	15.03	16.00	9.24	16.00	5.17
2008	13.24	12.87	16.26	17.02	14.00	13.69	17.00	8.90	17.00	4.96
2009	13.24	13.38	16.58	17.32	16.00	14.49	18.00	8.71	18.00	4.67
2010	13.24	13.38	17.12	17.56	18.00	8.42	19.00	8.54	19.00	4.46
Average Annual Growth Rate										
2006-07	3.80%	3.11%	2.88%	2.30%	3.02%	-0.75%	6.68%	-2.36%	6.68%	-5.43%
2008-10	0.46%	1.75%	2.72%	1.80%	13.65%	-19.33%	5.73%	-2.60%	5.73%	-4.93%
2006-10	1.80%	2.29%	2.79%	2.00%	9.40%	-11.90%	6.11%	-2.51%	6.11%	-5.13%

[1] Equivalent C$ per month

[2] Equivalent C$ Cents per m^3

[3] Rate shown is the Residential Heating Class. In 2009, the company went to an inverted block rate. Rate of change is calculated for the period 2005-2010 assuming use below the tail block only.

[4] Rate shown is the Residential Heating Class. Through this period Boston Gas employed a declining block rate. Rate of change for the volumetric rate is calculated assuming use below the tail block only.

[5] To facilitate comparisons between Massachusetts and Ontario rates readers can apply Purchasing Power Parity to Boston Gas and Bay State Gas' tariffs. Purchasing Power Parity values for the years 2005 to 2010 are 1.21, 1.21, 1.21, 1.23, 1.20, and 1.22, respectively.

[6] Rate shown is Rate 1. Through this period Enbridge Gas Distribution employed a declining block rate. Rate of change for the volumetric rate is calculated assuming use below 30 m3 only.

[7] Through this period Union Gas employed a declining block rate. Rate of change for the volumetric rate is calculated assuming use below 100 m3 only.

[8] In 2008, residential customers migrated from Rate M2 to Rate M1. Through this period Union Gas employed a declining block rate. Rate of change for the volumetric rate is calculated assuming use below 100 m3 only.

Table 5

Residential Rates of Gas Distributors Operating under IR - Ratios

	Enbridge / Bay State		Enbridge / Boston Gas		Union/ Bay State		Union / Boston Gas	
Year	Customer Charge	Volumetric Charge	Customer Charge	Volumetric Charge	Customer Charge	Volumetric Charge	Customer Charge	Volumetric Charge
2005	93.0%	127.9%	75.5%	96.0%	115.7%	81.2%	94.0%	60.9%
2006	90.2%	127.8%	73.6%	96.2%	112.2%	79.3%	91.5%	59.7%
2007	91.5%	118.4%	75.7%	90.4%	122.5%	72.7%	101.4%	55.5%
2008	105.8%	106.4%	86.1%	80.4%	128.4%	69.2%	104.5%	52.3%
2009	120.9%	108.2%	96.5%	83.7%	136.0%	65.1%	108.6%	50.3%
2010	136.0%	62.9%	105.1%	47.9%	143.5%	63.8%	111.0%	48.7%

Roughly 33% of Bay State and Boston Gas's residential revenues are collected through their customer charges, so the average annual changes in their residential prices were approximately 2.13% and 2.26%, respectively, over the 2005-2010 period. As we shall see in the next section, this is somewhat more rapid than the growth in EGD and Union residential tariffs over the same period.

Table 5 presents data on how EGD's customer and volumetric rate levels have evolved over the 2005-2010 period relative to those for Bay State and Boston Gas. For EGD, it can be seen that the customer charge on Rate 1 was 7% below Bay State's customer charge in 2005 but by 2010 it was 36% higher. However, during this same period EGD's residential volumetric rate went from being 28% above Bay State's to 37% lower.

EGD's residential customer charge was about 25% below Boston Gas's in 2005 but was 5% greater in 2010. However, over the same period EGD's residential volumetric charges went from 4% below to more than 50% below the volumetric charges for Boston Gas. With a customer charge 5% above and volumetric charges more than 50% below those of Boston Gas, EGD's gas delivery prices have almost certainly fallen below those of Boston Gas over the period while both Companies were subject to IR.

The comparisons between residential rates for Union and the MA companies are similar. For both its 01 and M1 residential rates, Union's customer charges over the 2005-2010 period rose from 15% to 43% above those for Bay State; at the same, the volumetric charges for Rate 01 have fallen 37% below Bay State's levels, while M1's volumetric charges have fallen 67% below Bay State's levels. For both Rate 01 and M1, in 2010 Union's residential customer charges were 11% above those of Boston Gas while its volumetric charges were 51% and 75% lower, respectively. As with EGD, this experience shows that Union's gas delivery prices have fallen well below those of Boston Gas at the same time that both Companies were subject to IR.

This comparative experience is suggestive rather than definitive, but it does provide some evidence that EGD and Union's residential customers generally fared better under IR than did the residential customers of Bay State and Boston Gas. There are likely to be a number of reasons for this, and a full analysis of this subject goes well beyond the scope of this assessment. One factor that has no doubt contributed to relatively more rapid price growth for the MA distributors is that the X factors in the Bay State (X=0.51%) and Boston Gas (X=0.41%) plans are lower than those for the Ontario distributors. All else equal, these lower X factors have led to relatively greater price changes under the MA plans. Readers should not, however, draw any inferences about management performance under either the Ontario or MA IR plans from this partial and extremely simple comparative analysis.

4.2.2.2 Residential Tariffs for Ontario Gas and Electricity Distributors

PEG-R also examined average residential price trends for EGD and Union, based on average annual natural gas consumption of 3064 cubic meters (m^3) per residence for EGD and 2600 m^3 for Union. The average price data were provided by EGD and Union. Using this information, PEG-R computed the change in the average price for each Company's gas delivery services over the 2008-2010 term of the IR plans.

We compared these price changes to similar data for a sample of Ontario electricity distributors under IR. The Ontario electricity distribution industry became subject to "second generation" incentive regulation at the beginning of 2007. A "third generation" incentive regulation plan was also approved in late 2008. Third generation IR took effect in 2009 and remains in place. Ontario distributors have therefore been subject to some form of incentive regulation since 2007.

The Board analyzes data on total residential electricity bills for a number of distributors. Average bills are computed using a consumption level of 800 kWh per month and are disaggregated into several different bill components. For the purposes of this comparison, PEG-R used data on electricity distributors' delivery charges. These charges include both distribution and transmission services, since it was not possible to obtain figures for distribution services only in the time frame of this project. PEG-R computed simple averages of average electricity delivery bills for a sample of 13 Ontario distributors, which includes most of the largest distributors in the Province.[22]

To obtain the most relevant comparisons of residential gas delivery and electricity delivery price changes under IR, PEG-R also excluded the 2008 price changes for the electricity distributors. Average prices were distorted in this year because of regulatory issues which led a number of electricity distribution rate riders, which had been in effect since 2004, to expire in that year but then be reinstated in 2009.[23] Many electricity distributors' rates therefore experienced a one-time, anomalous decline in 2008.

In Table 6 below, we report the average residential bill data for EGD, Union, and the sample of Ontario electricity distributors for the 2007-10 period. We believe the most relevant comparative price trends would be the 2007-2010 period for the electricity distributors, excluding 2008, and the 2008-2010 period for the gas distributors. Both instances reflect the IR experiences of the respective industries, excluding one-time regulatory and ratemaking anomalies. The EGD and Union average rates are based directly on tariffed rates and exclude the impact of deferral and variance accounts entirely, including revenues that are shared with customers under the ESM.

It can be seen that Union's prices for its M1 residential customers increased by an average of 1.13% per annum over the 2008-2010 period. Prices for Union's Rate 01 residential customers increased at an average rate of 1.45% per year between 2008 and 2010. EGD's residential customers take service on Rate 1, and their average prices increased by only 0.12% per annum over the 2008-2010 period. In contrast, electricity distributors' delivery prices increased at an average rate of 1.91% annually over the 2007-2010 period, excluding the anomalous 2008 experience.

Again, this comparative evidence is illustrative and not definitive, but it does suggest that EGD and Union residential customers have fared relatively well under their IR plans. Residential gas delivery tariffs have grown more slowly than prices for residential electricity delivery services at a time when both were subject to IR in Ontario. This divergence would likely increase if the measure of gas distribution prices included

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[22] These thirteen distributors are Hydro One, Hydro One Brampton, Toronto Hydro, Hydro Ottawa, Powerstream-Vaughan, Powerstream-Barrie, Horizon-Hamilton, Horizon-St. Catherines, Enersource, London Hydro, Veridian Connections, Enwin, and Kitchener-Wilmot.

[23] In 2004, most electricity distributors in Ontario began recovery of their deferral and variance account balances which reflected a variety of market opening, transition and related costs. The Board approved recovery of these balances over a four-year period, with most of the rate riders recovering these costs expiring in April 2008. Most distributors did not receive approval to clear any additional deferral and variance account balances until the Board's EDDVAR (electricity distribution deferral and variance account report) came into effect in 2009. Because no riders were approved until 2009 to replace the riders that expired on April 30 2008 for most Ontario distributors, there was a temporary, one-time decline in electricity distribution rates in 2008.

Table 6

Ontario Electricity and Natural Gas Distributors - Residential Delivery Charges, 2005-2010

Year	Enbridge Gas		Union Gas				Ontario Electricity Distributors - Average	
			M1		01			
	Index	Actual ($ per year)	Index	Actual ($ per year)	Index	Actual ($ per year)	Index	Actual ($/MWh)
2006								33.44
2007	100.00	426.55	100.00	350.47	100.00	421.33	100.00	34.01
2008	99.53	424.54	100.03	350.56	100.87	424.99	97.36	33.11
2009	100.69	429.49	101.46	355.57	102.08	430.08	99.76	33.93
2010	100.36	428.07	103.44	362.52	104.46	440.12	101.38	34.48
2007-2010, excl. 2008 *	NA		NA		NA		1.91%	
2008-2010	0.12%		1.13%		1.45%			

* PBR period, excluding 2008

rate riders (which are included in the electricity distribution price measure) as well as tariff changes, because riders will include the impact of the Companies' ESMs, which are not a feature of the electricity distribution plans but have led to substantial gas distribution price declines while the Companies' IR plans have been in effect.

4.2.2.3 Overall Price Indexes

PEG-R also estimated overall price indexes for EGD and Union for the 2007-2010 period. These overall price indexes should reflect all the factors that went into revenue and price adjustments for the Companies while their IR plans were in effect. These factors include all the sources of revenue change over the 2008-2010 period that were presented in Tables 2 and 3, and the impact of the AU factor (which impacts gas delivery prices but not revenues) as well as the disposition of balances held in variance and deferral accounts in the previous year. These are accordingly more comprehensive measures of gas delivery prices and customer welfare than the prices that we examined above. For this reason, these are also the price measures that PEG-R will use in Section Six when we assess how the benefits and productivity gains achieved by the Companies under IR were distributed between customers and shareholders.

We examined the 2007-2010 period because these were the only years where we could obtain data on gas delivery revenues, which are necessary to estimate overall price indexes. In our initial data request to the Companies, PEG-R asked for information on each distributor's gas delivery revenues by service class for the 2005-2010 period. These data would have permitted us to construct overall gas delivery price indexes for the 2005-2010 period and thereby compare gas delivery price trends in the years before and after IR was implemented. In response, Union provided gas delivery revenue for the 2007-2010 period only, and EGD said it was not able to provide any of this information. However, PEG-R was able to obtain proxies for EGD's overall gas distribution revenues in 2007-2010 from the Company's annual IRM applications. These applications contain detailed calculations of allowed gas delivery revenue in each plan year, beginning with allowed gas delivery revenue from the year before. The 2008-2010 IRM applications therefore allowed us to obtain estimates of EGD's actual gas delivery revenues for the 2007-2010 period.

While the lack of available data made it impossible to compare comprehensive price measures for EGD and Union for the periods before and after their IR plans took effect, we did examine the Companies' cost of service applications for the 2005-07 period to get some understanding of how their prices and allowed revenues changed over these years. Union had two cost of service-based rate adjustments during this time: a $1.485 M increase in gas delivery revenues that took effect January 1, 2005 (RP-2003-0063); and a $47.794 M, or 5.6%, increase in revenues that took effect on January 1, 2007 (EB-2005-0520).[24] EGD had three cost of service-based rate adjustments between 2005 and 2007; a $51.1 M, or 6.1%, increase in the gas delivery revenues that took effect on January 1, 2005 (RP-2003-0203); a $17.8 M, or 1.9%, increase in the gas delivery revenues that took effect on January 1, 2006 (EB-2005-0001); and a $42.7 M, or 5.2%, increase in gas delivery revenues that took effect on January 1, 2007 (EB-2006-034).

The methodology used to construct gas delivery price indexes for EGD and Union draws on the indexing logic presented in Section 3.2. Recall that equation (1) from that analysis was the following:

$$\Delta R = \Delta Y^R + \Delta P$$

In this equation, a distributor's revenue is given by *R*, an index of the prices it charges for its output is given by *P*, and an index of its output quantity given by Y^R. This equation shows that the change in the distributor's revenue can be decomposed into the sum of changes in its output price index and a revenue-shared weighted index of its output quantity. It follows that an index of a gas distributor's prices for gas delivery services can be computed as the growth in its gas delivery revenues minus the growth in its output quantity index, where the change in each individual gas delivery output (*e.g.* customers served and m^3 natural gas delivered) is weighted by its share of gas delivery revenues. Estimating the change in an overall index of gas delivery prices therefore requires data on gas delivery revenues, the associated billing determinants on the gas delivery tariffs, and each billing determinant's share of gas delivery revenues.

[24] The revenue requirements in EB-2005-0520 were adjusted in two separate Orders: an initial Decision with Reasons on June 29, 2006, which found a revenue deficiency of $24.717 M; and a Decision and Final Order on December 19, 2006, which added in $23.077 M of additional costs (to be recovered on January 1, 2007; there were also $5.793 M costs recovered on January 1, 2008) resulting from other proceedings that the Board concluded since the initial Order.

For Union, we constructed a price index in this manner for the 01, 10, M1 and M2 rate classes only. These rate classes are the most relevant for assessing Union's IR plan and also account for over 80% of the Company's gas delivery revenues. Union provided 2007-2010 revenues for these rate classes, as well as the customer numbers and delivery volumes on each of these tariffs, in response to PEG-R's data request. We estimated the share of revenues associated with customer numbers and delivery revenues from Union's IRM applications in those years (which contain detailed calculations on how revenue is to be allocated to different customer classes and rate elements).

We constructed an analogous price index for EGD's Rate 1 and 6 classes. We obtained data on gas delivery revenues and the shares of revenues associated with customer and volumetric charges from EGD's IRM applications in 2008-2010. EGD provided information on customer numbers and delivery volumes for these rate classes in response to our data request.

It should be noted that there is a slight mismatch between the revenue and output data for EGD. We were not able to obtain gas delivery data for the Rate 1 and 6 classes that were consistent with EGD's overall allowed gas delivery revenues in the relevant years, so we used estimates of EGD's allowed gas delivery revenue for all rate classes in those years. We recognize these inconsistencies, but believe they were unavoidable given the available data. We also believe this mismatch is unlikely to have a significant impact on our empirical results in any case, since Rates 1 and 6 account for about 97% of EGD's overall gas delivery revenues and we are focusing on price changes rather than price levels in this analysis.[25]

The revenue, revenue-weighted output quantity, and gas delivery price indexes for Union and EGD are presented in Tables 7 and 8 respectively. It can be seen that Union's gas delivery revenues increased by 0.33% per annum over 2008-2010 while its revenue-weighted output quantity declined at an average rate of 0.07% over this period. Accordingly, Union's overall gas delivery price index for M1, M2, Rate 01 and Rate 10 services increased at an average rate of 0.40% per annum between 2008 and 2010.

[25] Distortions in the measured price index can therefore only result from the extent to which the growth rate in output quantity for the 3% of gas delivery revenues not accounted for by Rates 1 and 6 differ from the growth rate in output quantity for Rates 1 and 6.

Table 7

Enbridge Gas: Revenues, Outputs, and Prices, 2007-2010

Variable		**Year**				**Average Annual Growth Rate**
		2007	**2008**	**2009**	**2010**	**2008-10**
Delivery Revenue						
	Total ($000)	933,000	938,010	974,140	980,760	
[A]	Growth Rate	NA	0.54%	3.78%	0.68%	**1.66%**
[W_B]	Revenue Weight, Customers	NA	0.350	0.411	0.478	
[W_C]	Revenue Weight, Volumes	NA	0.650	0.589	0.522	
Output						
	Customers	1,822,738	1,863,727	1,886,923	1,925,712	
[B]	Growth Rate	NA	2.22%	1.24%	2.03%	
	Volumes (10^6 m^3)	8,312	8,804	9,128	8,756	
[C]	Growth Rate	NA	5.75%	3.62%	-4.16%	
	Index (Revenue-Weighted)	1.0000	1.0462	1.0741	1.0613	
[D] = [B]·[W_B] + [C]·[W_C]	Growth Rate	NA	4.51%	2.64%	-1.20%	**1.98%**
Price						
	Index	1.0000	0.9610	0.9721	0.9905	
[E] = [A] - [D]	Growth Rate	NA	-3.98%	1.14%	1.88%	**-0.32%**

Table 8

Union Gas: Revenues, Outputs, and Prices, 2007-2010

Variable		**Year**				**Average Annual Growth Rate**
		2007	**2008**	**2009**	**2010**	**2008-10**
Revenue						
	Total Delivery Revenue	559,086	574,924	576,492	564,658	**0.33%**
[A]	Growth Rate	NA	2.79%	0.27%	-2.07%	
$[W_B]$	Revenue Weight, Customers	NA	0.476	0.524	0.552	
$[W_C]$	Revenue Weight, Volumes	NA	0.524	0.476	0.448	
Output						
	Customers	1,288,836	1,308,905	1,324,543	1,343,295	
[B]	Growth Rate	NA	1.55%	1.19%	1.41%	
	Volumes (10^6 m^3)	5,257	5,454	5,290	4,969	
[C]	Growth Rate	NA	3.67%	-3.05%	-6.26%	
	Index (Revenue-Weighted)	1.0000	1.0269	1.0184	0.9980	**-0.07%**
$[D] = [B]\cdot[W_B] + [C]\cdot[W_C]$	Growth Rate	NA	2.66%	-0.83%	-2.02%	
Price						
	Index	1.0000	1.0014	1.0125	1.0120	**0.40%**
[E] = [A] - [D]	Growth Rate	NA	0.14%	1.10%	-0.05%	

For EGD, gas delivery revenues grew by an average rate of 1.66% annually over the 2008-2010 period. The revenue-weighted output quantity index grew even more rapidly, however, at a 1.98% annual rate. EGD's overall gas delivery price index therefore declined by an average of 0.32% per annum during the 2008-2010 IR plan. All of this price decline, however, takes place in the 2008 year, and the measured 3.98% price decline in that year appears implausibly large. This may be due to flaws in our estimates of gas delivery revenues in 2007.[26]

Table 9 shows how the Companies' gas delivery prices compare with growth in their input price inflation (discussed in more detail in Section 6) and GDP-IPI inflation over the same period. As discussed in Section 3, customer benefits under IR are linked to the relationship between changes in a utility's output prices and its input prices. The GDP-IPI is the inflation factor used to adjust prices, or allowed revenues per customer, in the Companies' IR plans, as well as a measure of broad inflation in the Canadian economy. Any difference between GDP-IPI inflation and change in overall gas delivery prices can therefore be interpreted as the "real" or inflation-adjusted decline in gas delivery prices over the term of the IR plan. These real price declines would reflect all elements of the IR plan that lead gas delivery prices to grow less rapidly than the inflation factor, including the X factor in the net inflation formula and the ESM.

It can be seen that EGD and Union's gas delivery prices have grown much less rapidly than either their input price inflation or GDP-IPI inflation. EGD's output price have actually declined by 0.32% per annum in 2008-2010, although this includes the perhaps unrealistic 3.98% measured price decline in 2008. This compares with average input price growth of 2.11%, and broader GDP-IPI inflation of 1.66% per annum, over the same period. EGD was therefore successful in achieving "real" declines in its gas delivery prices of 1.98% per annum (*i.e.* 1.66% - (-0.32%) = 1.98%) over the first three

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[26] Approved revenue in 2007 was actually 1% below that of 2008 in spite of the fact that customer numbers increased by 2.2% between the years. To enhance the comparability of the data, PEG adjusted 2007 approved upward by $12.2 million to reflect the expiration of a $9.2 M notional utility account and a $3 M credit for regulatory costs that were applied in 2008. Because of concerns with EGD's 2007 gas delivery revenue data, and therefore the computed change in EGD prices between 2007 and 2008, PEG-R uses information on EGD's price changes over the 2008-2010 period only when quantifying the distribution of TFP and benefit gains under EGD's IR plan.

Table 9

Growth in Price Indices, 2008-2010

	Enbridge		Union		
Year	Output Price[1]	Input Price[2]	Output Price[1]	Input Price[2]	**GDP-IPI, Canada[3]**
2008	-3.98%	1.72%	0.14%	0.95%	1.54%
2009	1.14%	1.91%	1.10%	2.75%	2.73%
2010	1.88%	2.70%	-0.05%	2.58%	0.72%
Average	-0.32%	2.11%	0.40%	2.09%	1.66%

[1] Revenue-Weighted

[2] Tornqvist

[3] Data calculated in accordance with each Company's IR plan.

years of its price cap plan. This represents a considerable source of benefits to EGD customers.

Union's results are similar, although lower in magnitude. Union's gas delivery price index increased by 0.40% per annum over the 2008-2010 period. This compares with average inflation in its input prices of 2.09% per annum and broader GDP-IPI inflation of 1.66% over this period. Union's gas delivery prices therefore declined in "real" terms by 1.26% per annum (*i.e.* 1.66% - 0.40% = 1.26%). Union's customers have benefitted from this decline in their (inflation-adjusted) gas delivery prices.

It should be recognized that the Companies' overall price indexes are intended to capture all sources of price change in 2008-2010, including the recovery of costs in deferral and variance balances that are outside of the IR plan itself. However, it is likely that the measured inflation in Union and EGD prices would be even lower if all non-IR related changes in revenues were (or could be) eliminated from the computation of these price indices. Table 3 indicates that the IR plan elements have reduced EGD and Union allowed revenues by an average of 1.59% and 1.81%, respectively, in each year from 2008 to 2010. The "real" price decline resulting from the IR plan may therefore be even greater than what is reflected in Table 9.

It may also be valuable to consider the relationship between the Companies' measured input price inflation and the inflation allowed under the GDP-IPI inflation factor. In theory, the inflation factor in an index-based IR plan should be a good proxy for the inflation in the utility's input prices. Table 9 shows that input price inflation for EGD and Union has outstripped the growth in the Company's inflation factor by an average of 0.45% per annum (*i.e.* 2.11% - 1.66% = 0.45%) and 0.43% per annum (*i.e.* 2.09% - 1.66%), respectively, in 2008-2010. If the inflation factor had been constructed to track trends in industry input prices (*e.g.* by constructing an industry-specific inflation factor, or adding an "inflation differential" as an explicit component of the X factor), our results indicate that the Companies' allowed gas delivery prices would have increased by more than 0.40% per annum in each of the first three years of the IR plan.

As discussed in Section 3, all else equal, when the inflation factor grows less rapidly than the inflation in prices of inputs procured by the utility, customers experience a windfall gain at the expense of shareholders, over and above any TFP gains that may be distributed to customers in the form of price reductions. This phenomenon is reflected in equation (12) presented in Section 3, which PEG-R will use in Section 6 to estimate how benefits under the IR plans have been distributed between customers and shareholders. Our finding that the selected inflation rate has grown less rapidly than the growth in the Companies' input price inflation would tend to increase customers' share of benefits realized under IR vis-à-vis those retained by EGD and Union shareholders.

4.3 Assessment of Rates and Rates Changes Under IR

This section assessed the impact of the Companies' IR plans on the gas delivery rates they charge to their customers. Analyzing this issue is not as straightforward as it may seem, given the multiplicity of rates and the variety of mechanisms that enter into gas delivery ratemaking in Ontario. There is no established accounting framework for isolating and tracing the impact of every element of the Companies' IR plans on the changes in gas delivery rates under the plans. PEG-R has therefore assessed this issue using a variety of information on rate trends for EGD, Union and relevant comparators while the plans were in effect.

Our analysis shows that gas delivery price trends have generally been favorable under the Companies' IR plans. The combined effects of the net inflation mechanism, Y factors, and Z factors have led to declines in allowed gas delivery revenues for both EGD and Union over the 2008-2010 term of the plans. These revenue declines have averaged \$1.5 M annually for EGD and \$1.8 M annually for Union.[27] The ESM has led to even more pronounced revenue declines of \$14.1 M per annum for EGD and \$15.1 M for Union, on average, over the plan. These revenue declines have been somewhat offset by the AU factor, which has led to rate increases to recover declines in AUPC for certain customer classes. Overall, however, PEG-R's gas delivery price indexes show a modest 0.4% annual increase in gas delivery prices for Union's M1, M2, Rate 01, and Rate 10 customers, and an annual 0.32% decline in EGD's gas delivery prices over the terms of the IR plans. It should be noted that these overall price trends also include the recovery

[27] From Table 2, the average annual change in revenues from net inflation, Y and Z for EGD are +\$7M-\$3.9M-\$4.6M=-\$1.5 M. For Union, the analogous figures are -\$1.3M +\$2.5M-\$3M= -\$1.8M.

of balances that would be collected if the Companies had been subject to cost of service regulation rather than IR.

The Companies' price trends also compare favorably to other price measures. EGD and Union's residential gas delivery tariffs have grown less rapidly than those for two Massachusetts gas distributors that were subject to incentive regulation at the same time. Residential gas delivery prices have also grown somewhat less rapidly than residential electricity prices in Ontario in recent years.

In addition, the Companies' overall prices have grown more slowly than the growth in the GDP-IPI over the 2008-2010 period. The GDP-IPI measures inflation in final domestic demand for a basket of goods and services. Since the growth in gas delivery prices has lagged growth in this overall inflation measure, this implies that gas delivery services have fallen as a share of customers' budgets over the 2008-2010 period.[28] Gas delivery prices have also lagged gas distributors' input prices over this period which, as discussed, can be interpreted as a measure of consumer benefit under IR.

PEG-R's assessment of the rate adjustment mechanics and regulatory process for ratemaking, *per se*, has also not identified any major concerns. The EGD process for setting allowed revenues per customer is transparent and clearly articulated. The mechanics of Union's ratesetting are somewhat convoluted, but they lead to accurate measures of the price changes that are allowed under the net inflation, Y, and Z factors.[29]

One issue that PEG-R was asked to consider was EGD's use of a forecast AUPC for its revenue per customer cap. In theory, there could be some concern that a Company could game these forecasts in an effort to increase initial prices, which could benefit shareholders in the short run even if the AUPC forecasts are ultimately trued-up to actual consumption levels.[30] PEG-R examined EGD's Average Use True-Up Variance Account ("AUTUVA") over the 2008-2010 period, and we did not identify any systematic forecast

[28] This is independent of the decline in AUPC for most residential and small commercial customers, which further tends to reduce the share of consumer budgets devoted to gas delivery.

[29] Because its current approach for setting allowed rates is somewhat complex, Union could consider measuring its allowed prices using a more formal "actual price index," (API) which have been used in a number of telecom IR plans. However, the incremental costs that the Company and stakeholders would incur in learning how to set and evaluate rate changes under a formal API may exceed the incremental benefits. An API may also be seen as less transparent than Union's method, which ultimately does document the rate changes stemming from each of the elements of the Company's IR rate adjustment.

errors for either the Rate 1 or Rate 6 class. The differences between actual and forecast AUPC for these classes was essentially random for the 2008-10 rate years, with a cumulative balance to be returned to customers over the entire period of only $0.84M. We therefore find no evidence that EGD's forecasts have been gamed or that there are concerns associated with its approach for determining the AU factor.

The regulatory process associated with setting the annual IR rate adjustment appears generally to function in a timely manner. Provided the IRM rate application does not involve auxiliary issues, most IRM filings tend to be resolved in no more than 90 days. There appear to be more regulatory issues associated with the ESM applications, especially for Union's 2010 rate year. Computing the returns to be shared in an ESM is an inherently controversial issue, and this process sometimes leads to "mini rate cases" that involve significant regulatory costs and delays. These regulatory costs are a key reason that some energy IR plans have not included ESMs, despite the fact that (as in the Companies' current plans) they have the potential to lead to "real time" benefit sharing with customers.

Nevertheless, it should be recognized that Union and EGD have almost certainly avoided actual rate case filings because of the IR mechanism. In the three years before the IR plan took effect (2005-2007), Union had two general rate case filings, and EGD had three rate case filings. If these trends persisted, the Board and Stakeholders would have been involved in five additional general rate cases over the 2008-2010 period. These general rate case applications have been avoided because of the IR-based rate adjustments. It is not possible to quantify whether these avoided regulatory costs exceed the regulatory costs associated with the Companies' IR plans, but based on our general experience with both types of regulatory approaches, PEG-R suspects the regulatory process associated with EGD and Union's gas delivery rates has, on net, been less costly and burdensome under IR.

One significant finding in this Section is that the inflation factor selected for the Companies' IR plans has grown less rapidly than their input prices. As discussed in Section 3, when this is the case, utilities can maintain or expand their margins under IR

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[30] Some of the early UK incentive regulation plans actually imposed limits on the amounts of these true-ups, depending on the range of the true-up errors, in an effort to mitigate these gaming concerns.

only by increasing their TFP. The next Section will examine the Companies' financial performance under the IR plans, while the following Section will address the productivity growth that EGD and Union have achieved under IR.

5. Financial Performance

Utilities' financial performance is an important consideration in any regulatory framework. The level and stability of returns is naturally critical to utility shareholders. Adequate financial performance is also important to customers' long-run welfare. Utilities must be able to attract capital by generating (risk adjusted) returns that are commensurate with what investors could earn elsewhere in the market. New capital is necessary to fund expansions of utility delivery systems that are needed to provide service to new customers, as well as to replace aged infrastructure that is serving existing customers. Creating an environment that generates adequate returns and is conducive to capital investment is therefore an important long-run objective for all stakeholders.

PEG-R assessed EGD's and Union's financial performance under IR using two sets of indicators. The first is a number of financial ratios that the Board develops and analyzes using data from the Board's Reporting and Record-Keeping Requirements ("RRR") system. The second are measures of utility system expansion and investment provided by the Companies in response to a PEG-R data request[31].

5.1 Financial Indicators

PEG-R examined six financial ratios for EGD and Union for the 2005-2010 period. These indicators are described and defined below:

1. *Current Ratio* Current assets (*i.e.* cash and assets that are readily convertible to cash) divided by current liabilities

2. *Debt Ratio* Long-term debt plus inter-company long-term debt divided by total assets

3. *Debt to Equity Ratio* Long-term debt plus inter-company long-term debt divided by common equity

4. *Interest coverage* Net income before interest and taxes divided by interest expense, as recorded in accounts 6005-6045 of the Accounting Procedures Handbook (and which includes interest on preferred shares)

[31] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2011-0052&sortd1=rs_dateregistered&rows=200

5. *Return on assets* Net regulatory income divided by total assets (excluding assets reported as negative numbers in the liability section of the balance sheet)

6. *Return on equity* Net regulatory income divided by total common equity plus preferred shares

The first of these indicators, the Current Ratio, is a measure of liquidity, or the amount of assets that is readily available to meet liabilities. The next three ratios – the Debt Ratio, the Debt to Equity Ratio, and Interest Coverage – are leverage ratios, since they reflect the relative magnitudes and/or burden of indebtedness. The final two ratios – return on assets (ROA) and return on equity (ROE) – are measures of utility profitability. Table 10 below presents data on these ratios, as well as the split between long-term debt and equity and net income, for Union and EGD, respectively, for the 2005-2010 period.

Table 10

Financial Indicators - Union

Year end	Long-Term Debt-Equity Split	Net Income ($ 000's)	Financial Ratios					
			Liquidity Ratio	Leverage Ratios			Profitability Ratio	
			Current Ratio	Debt Ratio	Debt to Equity Ratio	Interest Coverage	Financial Statement Return on Assets	Financial Statement Return on Equity
2005	61:39	121,323	1.01	47%	1.58	2.07	3.00%	10.07%
2006	61:39	103,696	1.20	47%	1.58	1.87	2.46%	8.26%
2007	56:44	145,163	0.63	41%	1.28	2.19	3.39%	10.66%
2008	61:39	180,641	0.89	47%	1.56	2.44	3.82%	12.70%
2009	58:42	176,656	0.78	39%	1.39	2.41	3.45%	12.34%
2010	58:42	207,487	0.64	37%	1.38	2.59	3.82%	14.34%
Avg 05-07	59:41	123,394	0.95	45%	1.48	2.04	2.95%	9.66%
Avg 08-10	59:41	188,262	0.77	41%	1.44	2.48	3.70%	13.13%

Financial Indicators - Enbridge

Year end	Long-Term Debt-Equity Split	Net Income ($ 000's)	Financial Ratios					
			Liquidity Ratio	Leverage Ratios			Profitability Ratio	
			Current Ratio	Debt Ratio	Debt to Equity Ratio	Interest Coverage	Financial Statement Return on Assets	Financial Statement Return on Equity
2005	56:44	175,243	0.95	38%	1.26	2.32	3.06%	10.25%
2006	61:39	126,255	1.17	47%	1.55	1.83	2.26%	7.47%
2007	57:43	189,092	1.06	43%	1.31	2.27	3.31%	10.09%
2008	57:43	213,013	1.03	42%	1.33	2.49	3.47%	11.07%
2009	55:45	221,323	0.99	36%	1.23	2.56	3.34%	11.32%
2010	58:42	193,243	1.04	38%	1.39	2.36	2.80%	10.08%
Avg 05-07	58:42	163,530	1.06	42%	1.37	2.14	2.88%	9.27%
Avg 08-10	57:43	209,193	1.02	39%	1.31	2.47	3.20%	10.82%

Data source: 2005 -2010 Yearbooks of Natural Gas Distributors, Ontario Energy Board

Turning first to the Union data, it can be seen that the Company has experienced a substantial improvement in its profitability under IR. Union's net income in the three years before IR averaged $121 M, while average net income during 2008-2010 period increased by more than 50% to $188 M. This trend is also reflected in the Company's reported returns. Average ROA rose from 2.95% in 2005-07 to 3.70% in 2008-2010, while average ROE increased from 9.66% in 2005-07 to 13.13% in 2008-2010.

Union's approved ROE for its IR plan is 8.54%, so the Company under IR is outperforming its allowed ROE by a considerable margin.[32] Indeed, Union's returns were so ample in the first year of its plan that they prompted the addition of a second deadband in its ESM and elimination of the plan's "off-ramp" provision. In each of the first three years of the IR plan, Union's returns have exceeded the updated ESM sharing band of approved ROE plus 300 basis points. Moreover, Union's most recent ROE of 14.34% represents considerably higher returns than in the first two plan years. Customers are benefitting directly from these earnings gains, since 90% of earnings in excess of the upper band are returned to customers in the form of rate reductions in the following year.

Regarding the other financial indicators, it can be seen that Union's leverage ratios have all improved under IR. The debt ratio has declined from 45% in 2005-07 to 41% in 2008-2010, while the debt to equity ratio has declined from 1.48 to 1.44 and the interest coverage ratio increased from 2.04 to 2.48 over the same periods. The current ratio has declined somewhat, from 0.95 in 2005-07 to 0.77 in 2008-2010, although this not a concern given the Company's earnings levels and relatively smaller debt burden.

Turning to the EGD data, it is clear that Enbridge's profitability has also improved under IR, although not to the same extent as Union's. EGD's average net income rose from $163 M in 2005-07 to $209 M in 2008-2010, a 28% gain. The Company's ROA increased from an average 2.88% in 2005-07 to 3.20% in 2008-2010, while its ROE rose commensurately over these periods from 9.27% to 10.82%. EGD's approved ROE for its IR plan was 8.39%, and it has outperformed this level of returns in each of the three years of its plan. Like Union, EGD's earnings have also exceeded the

[32] It should be noted that the ROE used in Union's and EGD's ESM is adjusted each year using the Board's 1997 ROE formula. These ROEs differ from those that were approved for ratemaking.

upper band of its ESM in every year of its IR plan, although in EGD's case this band is 100 basis points rather than 300 basis points above the Company's approved ROE.

EGD has also displayed improved performance on the other financial indicators. The Company's average debt ratio has declined from 42% to 39% between 2005-07 and 2008-2010. EGD's debt to equity ratio has similarly declined, from 1.37 in 2005-07 to 1.31 in 2008-2010. The interest coverage ratio has improved from 2.14 to 2.47, and the current ratio has declined only slightly from 1.06 to 1.02, over the same periods.

Overall, the financial indicators show that the IR plans have generated healthy returns for both Union and EGD shareholders. Earnings are well above the levels that the Companies generated prior to the implementation of the plans and also above the levels at which earnings are shared with customers. This is particularly true for Union, where earnings have routinely exceeded the originally established *off-ramp* earnings level (approved ROE plus 300 basis points), although Union's ESM has been restructured so that customers now retain the lions' share of any returns beyond this level. The relative level and burden of long-term debt has also declined. Overall, the financial indicators for both EGD and Union support the conclusion that the IR plans have created an environment that is conducive to attracting capital and funding capital investment.

5.2 Capital Expenditures and Customer Additions

The financial indicators discussed above reflect the Companies' financial capabilities to undertake capital investment. They do not, however, indicate how much investment is actually taking place while the Companies are subject to IR. To assess this issue, PEG-R examined Union and EGD data on system expansion and investment.

We examined two primary measures of system expansion and investment: the change in net property, plant and equipment, and customer additions. The latter metric was explicitly discussed during settlement discussions, when some stakeholders argued that EGD and Union would have therefore weaker incentives to add new customers to the system.[33] While the Board expressed some skepticism regarding this concern, it did

[33] See *Decision With Reasons*, EB-2007-0615/EB-2007-0606, March 11, 2008.

require EGD and Union to file information on the level of customer additions in each year of its IR plan. Table 11 below summarizes this information for EGD and Union.

Table 11

Net Property and Plant & Customers - Union					
Year end	Net Property Plant & Equipment	% Change	No. of Customer Additions		
			Actual	Forecast	Differential
2005	2,859,787	NA	25,094	22,105	2,989
2006	3,056,916	6.67%	23,475	23,077	398
2007	3,133,136	2.46%	21,461	19,423	2,038
2008	3,316,297	5.68%	20,354	20,524	-170
2009	3,439,403	3.64%	14,183	14,159	24
2010	3.464,874	0.74%	16,330	16,121	209
2005-07		4.56%	23,343	21,535	1,808
2008-2010		3.35%	16,956	16,935	21

Net Property and Plant & Customers – Enbridge					
Year end	Net Property Plant & Equipment	% Change	No. of Customer Additions		
			Actual	Forecast	Differential
2005	2,872,200	NA	50,697	51,104	-407
2006	3,005,000	4.52%	47,622	49,011	-1,389
2007	3,185,500	5.83%	42,920	46,228	-3,308
2008	3,269,600	2.61%	41,052	44,534	-3,482
2009	3,411,000	4.23%	32,089	41,241	-9,152
2010	3,571,500	4.60%	36,902	32,379	4,523
2005-07		5.18%	47,080	48,781	-1,701
2008-2010		3.81%	36,681	39,385	-2,704

It can be seen that Union's net assets grew at an average rate of 4.56% from 2005 to 2007.[34] Net assets grew only slightly more slowly, by 3.35% per annum, when the IR plan was in effect from 2008-10. However, the latter growth rate does show continued deceleration, with the change in net assets from the year before slowing from 5.68% in

[34] In response to PEG's data request, Union provided data on its net capital assets for the 2007-2010 period but not for 2005-06. However, PEG imputed values for net assets in 2005-06 using other data on capital expenditures and depreciation that were provided to us.

2008 to 3.64% in 2009 and 0.74% in 2010. This deceleration appears to be only partly explained by the decline in customer additions over these years; for example, more customers were added in 2010 (16,330) than in 2009 (14,183).

Data for EGD also show a slower average change in net assets under IR. Net plant grew at an average rate of 5.18% per annum between 2005 and 2007 but by 3.81% annually between 2008 and 2010. Unlike Union, however, there has been a slight acceleration, rather than deceleration, in EGD's change in net assets over the term of its IR plan. Compared with the previous year, net plant and equipment increased by 2.61% in 2008, 4.23% in 2009, and 4.60% in 2010.[35]

Turning to customer additions, it can be seen that they have fallen for both Companies under IR. Union averaged 23,343 customer additions per annum between 2005 and 2007 but only 16,956 annual additions between 2008 and 2010. EGD added an average of 47,080 customers per year from 2005 through 2007 but only 36,681 from 2008 to 2010.

In both cases, this slowdown was expected because the latter period coincided with the recession. Both Companies forecast slowdowns in customer additions, particularly in 2009-2010. Union's forecast customer additions decline is very similar to the Company's actual experience over the 2008-2010 period. EGD's forecast of customer additions was well above actual additions in 2008 and 2009, consistent with the Company's experience in 2006-07 where actual additions exceeded forecasts. EGD adjusted its 2010 customer additions forecast downward by nearly 20%, to a level very similar to actual customer additions in 2009. However, the Company's actual customer additions actually increased by about 15% in 2010 from the previous year.

[35] It should also be recognized that the net plant and equipment data reported for Union and EGD are their actual values and have not been adjusted for inflation in capital goods prices over the relevant periods. However, the general trends reported above are not materially altered if the data are presented in 'real,' inflation-adjusted terms rather than nominal terms. The comparable, real changes in net plant for Union are 1.61% p.a. over 2005-07 and 0.84% p.a over 2008-10; for EGD, they are 2.23% p.a. over 2005-07 and 1.30% p.a. over 2008-10.

5.3 Assessment of Financial Performance

There is little doubt that both Companies have enjoyed healthy returns under IR. Other financial ratios have also generally improved. All of these factors should create an environment that is conducive to capital investment.

It is notable that this dramatic improvement in earnings has occurred at the same time that the Companies' allowed prices have grown less rapidly than their input prices. Section 3 presented data that showed input price inflation for EGD and Union outstripped the growth in both the GDP-IPI inflation factor and the Companies' gas delivery prices. Earnings have therefore not been boosted by an overly generous inflation factor in the IR plan *i.e.* an inflation factor that over-compensates EGD and Union for the change in their input prices. In fact, our research indicates that the opposite has been the case.

The Companies' actual investment and system expansion experience under IR is more mixed. Customers have been added to the system less rapidly under IR than in the immediately preceding years, although this is not unexpected given that the 2008-10 period coincided with a recession. Similarly, net plant and equipment has grown less rapidly under IR than in 2005-06, although the deceleration has not been precipitous. A slower rate of capital investment would also be expected since the decline in economic activity reduces customer growth and, accordingly, the need to add capital to serve new customer needs.

The slowdown in capital investment is potentially more of a concern for Union than EGD. It is possible that Union's slower growth in net capital could signal the deferral rather than an efficient reduction of its capital spending under IR. It is difficult, however, to assess this issue in isolation, without undertaking a more detailed assessment of the Companies' productivity growth and cost control activities. We turn to this issue in Section Six.

6. COSTS, PRODUCTIVITY, AND DISTRIBUTION OF GAINS

This section presents PEG-R's research on the cost and productivity performance of EGD and Union under IR. The discussions in this section are largely non-technical. Additional and more technical details of our work are provided in the Appendix.

We begin by estimating the input price and TFP growth for the Companies. We compare the Companies' TFP growth before and after IR was implemented. We also undertake a more detailed analysis of EGD and Union's cost changes to assess whether the measured TFP changes reflect sustainable cost reductions or cost deferments.

Next, we assess the Companies' measured TFP growth relative to a number of comparative measures. The first is a "backcast" prediction of EGD and Union's TFP growth over the 2005-10 period using an econometric model. The second is a comparison to the TFP growth of other gas distributors that were subject to IR at the same time. The third compares the Companies' TFP growth to two other gas distributors that our empirical results indicate are 'peers' of EGD and Union.

We then use the methodology outlined in Section 3 to assess how benefits have been distributed between customers and shareholders in the EGD and Union IR plans. Finally, we present our preliminary assessment of the Companies' cost control and TFP gains under IR.

6.1 TFP Estimates

6.1.1 TFP Estimates for EGD and Union

6.1.1.1 Data

The primary data source used in our TFP research was the RRR filings of EGD and Union. This information was supplemented with a data request from PEG-R to the Companies early in the project.[36] PEG-R also had historical data for EGD and Union from our previous work estimating TFP for the Companies.

[36] http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Assessment+of+Incentive+Regulation+Plans

Other sources of data were also used to develop TFP trends. These data were primarily used to measure input prices. The source for almost all of these supplemental data was Statistics ("Stats") Canada.

6.1.1.2 Definition of Cost

The input price and input quantity indexes were constructed as weighted averages of the trends in component subindexes. For both indexes, the weight for each subindex is based on its share of the applicable total cost.

For EGD and Union, the applicable total cost was calculated as applicable O&M expenses plus the cost of gas plant ownership.[37] Applicable O&M expenses were defined as the total net (uncapitalized) O&M expenses of the utility less any expenses for natural gas production or procurement, transmission services provided by others, franchise fees, pension expenses, DSM expenses, and the costs of uncollectible accounts. The operations corresponding to this definition of cost include distribution (local delivery), account, information, and other customer services, and any storage and transmission services that a utility may provide.

We did not include DSM expenses because they are collected through a Y factor in the Companies' plans and therefore are not relevant to the TFP measure used for their net inflation mechanism. Pension and uncollectible expenses were eliminated from our O&M measure because they can be highly volatile from year to year. Volatility in these costs could lead to a distorted estimate of the Companies' underlying TFP growth, particularly given the short period (2005-2010) that is the focus of this project

The cost of capital was calculated using an approach designed to reflect how capital cost is measured under cost of service ("COS") regulation. The salient features of the COS approach to capital costing are a book (historic dollar) valuation of plant and straight line depreciation. This approach requires the decomposition of cost into a capital price and a capital quantity in order to calculate industry input price and productivity trends. The cost of capital is thus the product of a capital quantity index and an index of the price of capital services. The capital price is sometimes called a rental or service

[37] PEG-R used analogous measures of total cost when developing TFP indexes for the "peer" US utilities that are presented in Section 6.2.

price since it reflects the cost of owning a unit of capital, much like prices in competitive rental markets for capital equipment. The capital quantity index is, effectively, an index of the real (inflation-adjusted) value of net plant where indexes of utility construction costs are used to deflate capital additions and other measures of historical plant values.

The capital service price index includes a term for the opportunity cost of capital (return to debt and equity holders). We used each Company's embedded cost of debt (long-term and short-term) and their approved return on equity to measure its opportunity cost of capital. The Companies provided this information, as well as their shares of debt and equity, for 2005-2010 in response to our information requests.[38] As illustrated in the Appendix, the COS capital service price trend will reflect trends in the price of capital goods, depreciation rates, and the cost of acquiring funds in capital markets.

6.1.1.3 Input Prices and Quantities

We developed input price indexes for the applicable O&M and capital inputs. The O&M input price index was a weighted average of input price subinexes for labor and non-labor O&M expenses. The labor price subindex was equal to the Stats Canada index of average hourly earnings for utilities in Canada.[39] The non-labor O&M index was the GDP-IPI for final domestic demand. The weights were 40% for labor and 60% for non-labor expenses and were based on data PEG-R was provided in 2006-07 when we first estimated the Companies' TFP growth for Staff.

As discussed, the opportunity cost of capital in our capital service price index was based directly on each Company's actual capital costs. These capital costs were equal to a weighted average of its embedded cost of debt and its allowed ROE for ratemaking. The capital service price also utilizes information on capital asset prices. PEG-R developed this measure using the ratio of current to constant price values for the Canadian natural gas sector.[40]

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[38] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2011-0052&sortd1=rs_dateregistered&rows=200

[39] We also adjusted this index to add in the difference between the growth in average hourly earnings between Ontario and Canada for the industrial sector. This was designed to make our labor price subindex better reflect wage pressures for the utility sector in Ontario, rather than all of Canada. Stats Canada does not provide an earnings index for Ontario's utility sector.

[40] Statistics Canada, Table 031-0002, *Flows and Stocks of Fixed Non-Residential Capital, by North American Industry Classification System and Asset, Canada, Provinces and Territories.*

6.1.1.4 Outputs

The change in the output quantity index was a weighted average of the growth in two output quantity subindexes: the number of customers served, and the total km of distribution and transmission main. We selected these as the output quantity subindexes because they were statistically significant drivers of gas distribution costs in PEG-R's econometric model of US gas distribution cost whereas delivery volumes was not a statistically significant cost driver.[41] This econometric model is explained in more detail in Section 6.2 and the Appendix.

The econometric cost model also estimated cost elasticities for the two outputs at sample mean values for the business conditions of our US gas distribution sample. The weight applied to each output subindex was its share of the summed output elasticities for the two outputs. PEG-R estimated that the elasticity of cost with respect to customer numbers was 0.716, while the elasticity of cost with respect to km of main was 0.167. The weights were therefore 0.81 for customer numbers (*i.e.* .716/(.716+.167) = 0.81) and 0.19 for km of main (*i.e.* .167/(.716+.167) = 0.19).

As discussed in Section 3, it is appropriate to weight outputs using cost elasticity shares when developing TFP estimates for the EGD and Union IR plans. The reason is that both plans include AU factors that adjust revenues for changes in natural gas consumption. If the output quantity index was developed using revenue weights, there would be an element of "double counting" for changes in AUPC under the IR plan.

6.1.1.5 Index Form

PEG-R used the Törnqvist index form to construct input price, input quantity, and TFP indexes. A Törnqvist input price or input quantity index is a weighted sum of the logarithmic growth rates in the selected input price or input quantity subindexes, where the weights are equal to each subindex's average share of total costs in the current and preceding year. The Törnqvist form has a number of properties that make it attractive for TFP research and is therefore frequently used when estimating TFP using index-based methods.

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[41] In its 2007 TFP research on EGD and Union, PEG-R personnel used volumes as an output quantity subindex.

6.1.1.6 Sample Period (2005 – 2010)

The sample period for our research was 2005 through 2010. In most instances, PEG-R would use a longer sample period to estimate TFP because doing so would be more likely to generate reliable estimates of long-term TFP trends. In this project, however, the time period was driven by the focus of the study (*i.e.* assessing the Companies' performance under their approved IR plans). These plans took effect in 2008, so we had only three full years of IR experience available to investigate. For the sake of consistency, we therefore included the three years immediately before the plans were implemented (2005-2007) in our sample period. Our full sample period was accordingly 2005-2010.

6.1.1.7 Findings

PEG-R's TFP and related findings for EGD and Union are presented in Tables 12 through 15. Table 12 presents details of the Companies' output quantity indexes. Table 13 presents details of the construction of the input price indexes. Table 14 presents information on the Companies' cost, unit cost, and input quantity indexes. Table 15 presents the TFP results.

Beginning with the output quantities, it can be seen that (in Table 12), for the entire 2005-2010 period, that the output quantity index for EGD has grown by 1.91 per annum. Output has grown more slowly for Union over this period, at an average annual rate of 1.35% per annum.

EGD's output has grown more rapidly than Union's because of the more rapid growth in its customer base. EGD's customer numbers grew at an average rate of 2.24% over the 2005-2010 period, while customer numbers grew at a 1.47% annual rate for Union over this period. In contrast, Union's kilometers of main have grown a bit more rapidly than EGD's over the period; Union's and EGD's km of main increased by 0.84% and 0.50% per annum, respectively, over the 2005-2010 period. The combination of slower growth in customer numbers and greater growth in km of main mean that the km of main per customer have been increasing at a more rapid clip for Union than for EGD over the sample period. This, in turn, is likely to signal that the population in Union's

Table 12

OUTPUT QUANTITY INDEXES

	Enbridge						Union					
	Total		**Customers**		**Line Kilometers**		**Total**		**Customers**		**Line Kilometers**	
Year	Index	Growth Rate	Level	Growth Rate	Level	Growth Rate	Index	Growth Rate	Level	Growth Rate	Level	Growth Rate
2005	100.00		1,721,994		33,734		100.00		1,247,919		34,912	
2006	102.86	2.82%	1,780,274	3.33%	33,959	0.66%	101.52	1.51%	1,267,387	1.55%	35,382	1.34%
2007	104.92	1.98%	1,822,738	2.36%	34,086	0.37%	103.06	1.51%	1,288,836	1.68%	35,662	0.79%
2008	106.97	1.94%	1,863,727	2.22%	34,325	0.70%	104.57	1.45%	1,308,905	1.55%	36,038	1.05%
2009	108.05	1.00%	1,886,923	1.24%	34,327	0.01%	105.69	1.07%	1,324,543	1.19%	36,238	0.55%
2010	110.01	1.80%	1,925,712	2.03%	34,592	0.77%	107.00	1.23%	1,343,295	1.41%	36,412	0.48%
2005-2010		**1.91%**		**2.24%**		**0.50%**		**1.35%**		**1.47%**		**0.84%**
2005-2007		**2.40%**		**2.84%**		**0.52%**		**1.51%**		**1.61%**		**1.06%**
2008-2010		**1.58%**		**1.83%**		**0.49%**		**1.25%**		**1.38%**		**0.69%**

Table 13

INPUT PRICE INDEXES

	Enbridge						Union					
	Total		**O&M**		**Capital**		**Total**		**O&M**		**Capital**	
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
2005	100.00		100.00		100.00		100.00		100.00		100.00	
2006	102.17	2.14%	101.83	1.82%	102.78	2.74%	102.72	2.68%	101.83	1.82%	102.73	2.70%
2007	105.69	3.39%	105.10	3.16%	105.39	2.51%	103.47	0.73%	105.10	3.16%	101.36	-1.35%
2008	107.78	1.96%	106.11	0.95%	107.93	2.38%	104.27	0.77%	106.11	0.95%	102.33	0.96%
2009	109.87	1.92%	110.08	3.68%	108.37	0.40%	107.62	3.16%	110.08	3.68%	104.43	2.03%
2010	113.02	2.82%	112.50	2.17%	111.83	3.15%	110.18	2.35%	112.50	2.17%	107.51	2.91%
2005-2010		**2.45%**		**2.36%**		**2.24%**		**1.94%**		**2.36%**		**1.45%**
2005-2007		**2.77%**		**2.49%**		**2.63%**		**1.71%**		**2.49%**		**0.67%**
2008-2010		**2.23%**		**2.27%**		**1.98%**		**2.09%**		**2.27%**		**1.96%**

Table 14

COST AND INPUT QUANTITY INDEXES

Enbridge

	Input Quantities						Cost				Unit Cost	
	Total		O&M		Capital		Total		O&M			
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	$000s	Growth Rate	$000s	Growth Rate	Index	Growth Rate
2005	100.00		100.00		100.00		676,653		264,685		100.00	
2006	103.93	3.86%	105.68	5.53%	102.42	2.39%	718,523	6.00%	284,852	7.34%	103.23	3.18%
2007	102.26	-1.63%	99.90	-5.63%	104.42	1.94%	731,287	1.76%	277,899	-2.47%	103.00	-0.22%
2008	103.50	1.21%	100.40	0.50%	106.34	1.82%	754,820	3.17%	281,965	1.45%	104.28	1.23%
2009	103.30	-0.20%	98.37	-2.04%	107.81	1.37%	767,956	1.73%	286,635	1.64%	105.04	0.72%
2010	104.26	0.93%	99.03	0.66%	109.05	1.15%	797,295	3.75%	294,871	2.83%	107.11	1.95%
2005-2010		**0.83%**		**-0.20%**		**1.73%**		**3.28%**		**2.16%**		**1.37%**
2005-2007		**1.12%**		**-0.05%**		**2.16%**		**3.88%**		**2.44%**		**1.48%**
2008-2010		**0.65%**		**-0.29%**		**1.45%**		**2.88%**		**1.98%**		**1.30%**

Union

	Input Quantities						Cost				Unit Cost	
	Total		O&M		Capital		Total		O&M			
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	$000s	Growth Rate	$000s	Growth Rate	Index	Growth Rate
2005	100.00		100.00		100.00		695,254		246,984		100.00	
2006	100.68	0.68%	99.55	-0.46%	101.76	1.74%	718,981	3.36%	250,365	1.36%	101.87	1.85%
2007	99.85	-0.82%	96.35	-3.26%	103.05	1.27%	718,326	-0.09%	250,107	-0.10%	100.25	-1.60%
2008	101.18	1.32%	98.73	2.44%	103.51	0.44%	733,522	2.09%	258,734	3.39%	100.89	0.64%
2009	97.88	-3.32%	92.23	-6.81%	102.89	-0.60%	732,381	-0.16%	250,754	-3.13%	99.67	-1.22%
2010	98.51	0.64%	94.32	2.25%	102.20	-0.67%	754,581	2.99%	262,074	4.42%	101.43	1.76%
2005-2010		**-0.30%**		**-1.17%**		**0.44%**		**1.64%**		**1.19%**		**0.28%**
2005-2007		**-0.07%**		**-1.86%**		**1.50%**		**1.63%**		**0.63%**		**0.12%**
2008-2010		**-0.45%**		**-0.71%**		**-0.28%**		**1.64%**		**1.56%**		**0.39%**

Table 15

PRODUCTIVITY RESULTS

	Enbridge						Union					
	Output Quantities		**Input Quantities**		**TFP**		**Output Quantities**		**Input Quantities**		**TFP**	
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
2005	100.00		100.00		100.00		100.00		100.00		100.00	
2006	102.86	2.82%	103.93	3.86%	98.97	-1.04%	101.52	1.51%	100.68	0.68%	100.84	0.83%
2007	104.92	1.98%	102.26	-1.63%	102.61	3.61%	103.06	1.51%	99.85	-0.82%	103.21	2.33%
2008	106.97	1.94%	103.50	1.21%	103.35	0.73%	104.57	1.45%	101.18	1.32%	103.35	0.13%
2009	108.05	1.00%	103.30	-0.20%	104.60	1.20%	105.69	1.07%	97.88	-3.32%	107.98	4.38%
2010	110.01	1.80%	104.26	0.93%	105.51	0.87%	107.00	1.23%	98.51	0.64%	108.62	0.59%
2005-2010		**1.91%**		**0.83%**		**1.07%**		**1.35%**		**-0.30%**		**1.65%**
2005-2007		**2.40%**		**1.12%**		**1.29%**		**1.51%**		**-0.07%**		**1.58%**
2008-2010		**1.58%**		**0.65%**		**0.93%**		**1.25%**		**-0.45%**		**1.70%**

service territory is becoming relatively more spatially dispersed than in EGD's territory.[42] This is perhaps not surprising because EGD's service territory is smaller, and already more densely populated, than Union's territory.

Output growth slowed for both companies during the IR period, particularly for EGD. EGD's output quantity grew at an average rate of 2.40% in 2005-07 but a 1.58% rate in the 2008-10 IR period. This slowdown was due to fewer customer additions in the latter period; customer growth declined from 2.84% per annum in 2005-07 to 1.83% per annum in 2008-2010. Union's output also slowed in the latter half of the sample period, but at a more modest rate: output quantity expanded at average annual rates of 1.51% in 2005-07 and 1.25% in 2008-2010. For both Companies, slower output growth in 2008-2010 undoubtedly reflected the economic recession during these years.

Table 13 presents details on the Companies' input price growth. It can be seen that EGD's input prices grew at a somewhat more rapid rate (2.45%) than Union's (1.94%) over the entire sample period. This reflected greater inflation in EGD's capital service price in 2005-07 compared with Union's.[43] In the 2008-2010 IR years, the Companies' input prices have grown at more similar rates. EGD's overall input prices grew by 2.23% per annum over the latter period compared with a 2.09% annual rate for Union. The capital service prices also grew at similar rates (1.98% per annum for EGD and 1.96% per annum for Union) in 2008-2010. PEG-R used the same O&M input price index for each Company, so the inflation in this index is naturally the same for EGD and Union throughout the period.

Table 14 presents details on changes in the Companies' costs, unit costs (*i.e.* total cost divided by the output quantity index in each year) and input quantities. It can be seen that both Companies slowed their input usage under IR. In 2005-07, EGD's input quantity grew by 1.12% per annum, reflecting 2.16% annual growth in capital inputs and a 0.05% decline in O&M inputs per annum. In the 2008-2010 IR years, EGD's input quantity grew at an annual rate of 0.65%, which represents a decline in input usage of 0.37% per annum from the 2005-07 growth rate (*i.e.* 1.12% - 0.65% = 0.37%). This

[42] All else equal, it takes more km of main per customer to serve a less densely populated service territory than a more densely populated territory.

deceleration in input growth reflected savings on both O&M and capital: EGD's O&M input quantity growth declined by a more rapid rate of 0.29% per year, while the growth in its capital input slowed from 2.16% to 1.45% annually.

Union registered a similar decline in input usage under IR. In the 2005-07 period, Union's input quantity index actually declined at an annual 0.07% rate. This was due to a relatively rapid reduction in the Company's O&M inputs of 1.86% per annum in these years. Capital inputs expanded at a 1.5% annual rate in 2005-07.

After the IR plan was implemented, Union reduced its overall input usage at an even more rapid 0.45% rate. In 2008-2010, O&M input quantity declined by 0.71% per annum while capital input declined by 0.28% per annum. Union therefore reduced its capital growth even more dramatically than EGD under IR, and this was the source of the Company's incremental TFP gains under its IR plan.[44]

Table 15 presents details on the TFP findings for EGD and Union. Over the entire sample period, EGD's TFP grew by 1.07% per annum. TFP growth was equal to 1.29% in the 2005-07 period, with annual output quantity growth of 2.4% exceeding the 1.12% annual average change in input quantity. Under IR, EGD's TFP growth slowed to 0.93% per annum. This reflected a sizeable 0.82% decline in the output growth rate, from 2.4% in 2005-07 to 1.58% in 2008-2010. EGD was able to keep the decline in its TFP growth below the decline in its output quantity growth because it reduced the change in its inputs from 1.12% per annum in 2005-2007 to 0.65% per annum in 2008-2010.

Union's TFP grew an average rate of 1.65% over the entire 2005-2010 sample period. TFP grew at an average rate of 1.58% in 2005-07 but accelerated to 1.70% per annum after the IR plan took effect. As noted, Union experienced a relatively modest deceleration in output quantity under IR, from 1.51% average growth in 2005-07 to 1.25% growth per annum in 2008-2010. However, Union reduced its input usage even

[43] This, in turn, is due to differences in the patterns of depreciation between the Companies, as measured by PEG-R's cost of service measure of capital costs. Details on this approach to capital cost measurement are presented in Section A.4 of the Appendix.

[44] Incremental TFP gains here refer to the change in the Company's average TFP growth rate between 2008-2010 and 2005-07; although the decline in O&M inputs in 2008-2010 was greater than the decline in capital inputs in these years, Union's O&M inputs actually declined at an even more rapid rate in 2005-07. The source of Union's incremental TFP gains in 2008-2010 is therefore due entirely to the decline in its capital inputs in these years.

more rapidly between these periods. The more rapid decline in inputs allowed the Company to increase its rate of TFP growth in 2008-2010 even as it output growth slowed because of the economic recession in these years.

Overall, our findings show that both Companies have exhibited greater cost control under IR. EGD reduced its input usage by an average of 0.37% per annum under IR. Union's input usage declined by a nearly identical amount of 0.38% per annum over the same years. Union's reduction in input quantity growth led to more rapid TFP growth under its IR plan. EGD, however, experienced a relatively large decline in customer additions after its IR plan went into effect, and this decline in its output growth exceeded the opex and capital cost savings that the Company achieved. The result was that EGD's rate of TFP growth declined under IR compared to the years before the IR plan was in effect. Nevertheless, Union has clearly displayed more rapid TFP growth than EGD both before and after IR was implemented.

It is difficult to determine whether the changes in input quantity that the Companies have experienced under IR are sustainable in the long run. The main reason is simply the lack of data that are available for making such an assessment. Both companies have only been subject to IR for three years. Because TFP often fluctuates significantly from year to year, this three-year sample period is too short to estimate a long-run, sustainable TFP trend with any degree of confidence. Assuming that a new, multi-year IR plan is approved for the Companies in 2012/2013, there should be far more data available for assessing this issue during the term of the subsequent IR plan.

6.1.2 Detailed Analysis of Cost Changes for EGD and Union

Another issue complicating the assessment of long-run TFP gains is the issue of cost deferments. As discussed in Section Two, rate rebasings at the end of a plan theoretically create incentives for utilities to defer expenditures until the "base" year that is used to set updated rates. If utilities are acting on these incentives, it would mean their measured TFP gains under the plan would not be consistent with their sustainable rate of TFP change going forward. In effect, part of what utilities book as a cost "reduction" (and TFP gain) would in fact be a “cost deferment” that should have been incurred during the IR plan but is instead pushed into the base year, when utilities have more opportunity to recover such cost items directly in new, cost-based rates.

Section Two also noted that it is very difficult to separate “cost reductions” from “cost deferments.” It is reasonable to infer, however, that cost deferments are most likely for capital investments that are not tied directly to new requests for service. The Companies evaluate requests for new service based on whether or not the necessary investments satisfy a profitability index (calculated on a net present value basis). In most instances, if an investment satisfies the profitability index it is made relatively quickly rather than deferred. If the investment does not satisfy the profitability index, it is not made at all.

In some instances, however, it may be possible for gas utilities to exercise discretion over extending service to new communities. It could be profitable for a utility to defer these relatively large, “lumpy” investments from within the term of the IR plan to a later base year. PEG-R could not assess this issue because it necessarily involves examining investments that a utility proposes to recover in the test year used to set rebased rates. The Board, however, can evaluate whether such large scale cost deferments have taken place by requesting information from the Companies on whether any of the capital expenditures reflected in the proposed rate base for the test year represent either: 1) delayed reactions to a previous request for service; or 2) requests for service that were previously rejected because they failed to satisfy the profitability index but have now been reconsidered and deemed to be sufficiently profitable. Any such capital expenditures reflected in a Company’s rate rebasing proposal should be subject to greater scrutiny by the Board.

Cost deferments are also possible, but less likely, with respect to operating expenditures. A large share of operating expenditures, such as salaries for utility personnel or basic “day to day” operations, cannot plausibly be deferred until a future date. However, the timing of some maintenance expenditures can possibly be manipulated and deferred until a future year.

In the current assignment, another factor complicating the ability to distinguish cost reductions from cost deferments is that the Companies’ IR period coincides with an economic recession. The decline in economic activity during the IR years would itself tend to reduce the need for investment. Thus, cost declines in the Companies' IR plans can occur for (at least) three different reasons: 1) cost reductions that increase the efficiency of operations; 2) cost reductions due to declines in output and the associated need to provide new service; and 3) cost deferments.

It must also be recognized that the cost deferment issue necessarily involves a utility's base year filing. It is impossible to know whether a Company has acted on incentives to defer costs until the Company presents its proposed cost of service for the base year. Therefore, it is ultimately not possible to assess the cost deferral issue the data that are proposed to set the rebased rates have been examined.

Notwithstanding these complications and limitations, PEG-R did examine some data from the Companies that may shed light on the extent to which costs have been deferred rather than reduced during the IR plans. We investigated details of the Companies' operating and capital expenditures over the 2008-2010 period, which they provided in response to our data request. The intention was to assess whether cost reductions booked by the Companies over the IR period were concentrated in areas, such as non-growth related capital expenditures or maintenance operating expenditures, that might plausibly be deferred until the base year that will be used to rebase their rates.

This information is presented in Tables 16 through 19. Table 16 presents details of EGD's changes in capital expenditures, while Table 17 presents details on the changes in EGD's operating expenditures. Tables 18 and 19 present analogous data for Union.

One factor PEG-R examined was how cost changes under IR in 2008-10 on a capital or operating expenditure item compared with the cost changes on that same line item in 2005-07. If the focus of cost reductions shifted between 2005-07 and 2008-10 towards cost areas that are potentially more deferrable, it could be a sign that some cost reductions have in fact been cost deferments. We were able to make comparisons between the 2005-07 and 2008-10 on EGD's capital and operating expenditures, and Union's capital expenditures, but not on Union's operating expenditures since the Company only provided detailed operating expenditure data for 2007-2010.[45]

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[45] Union's breakdown of operating expenditures, while relatively short, was more detailed than EGD's, although EGD's breakdown of capital expenditures was more detailed than Union's.

Table 16

Enbridge Gas - Changes in Capital Expenditures

	Item	Amount (10^6)						Average Annual Growth Rate	
		2005	2006	2007	2008	2009	2010	2005-07	2008-10
	Customer Related								
[1]	Sales Mains	74.2	71.2	83.9	60.6	48.2	46.7	6.1%	-19.5%
[2]	Services	47.4	52.3	40.9	49.3	48.7	52.6	-7.4%	8.4%
[3]	Meters and Regulation	14.9	11.3	11.4	9.7	11.9	8.3	-13.4%	-10.6%
[4] = [1] + [2] + [3]	Customer-Related Distribution Plant	136.5	134.8	136.2	119.6	108.8	107.6	-0.1%	-7.9%
[5]	NGV/Rental Equipment	0.1	0.2	0.1	0.3	0.2	0.2	0.0%	23.1%
[6] = [4] + [5]	Total Customer-Related Expenditures	136.6	135.0	136.3	119.9	109.0	107.8	-0.1%	-7.8%
	System Improvements and Upgrades								
	Mains								
[7.1]	Relocations	6.5	9.8	11.2	14.8	8.0	13.2	27.2%	5.5%
[7.2]	Replacement	49.1	82.1	49.7	58.8	49.9	55.7	0.6%	3.8%
[7.3]	Reinforcement	4.2	19.0	17.1	16.7	16.8	14.0	70.2%	-6.7%
[7] = [7.1] + [7.2] + [7.3]	Total	59.8	110.9	78.0	90.3	74.7	82.9	13.3%	2.0%
[8]	Services - Relays	38.1	37.5	35.8	30.4	37.0	45.8	-3.1%	8.2%
[9]	Regulators - Refits	8.4	2.4	3.1	3.5	7.7	6.4	-49.8%	24.2%
[10]	Measurement and Regulation	5.9	9.4	15.6	13.4	9.2	10.3	48.6%	-13.8%
[11]	Meters	13.1	16.5	19.3	18.9	15.9	13.1	19.4%	-12.9%
[12] = Sum [7-11]	Total System Improvements and Upgrades	125.3	176.7	151.8	156.5	144.5	158.5	9.6%	1.4%
	General and Other Plant								
[13]	Land, Structures and Improvements	4.6	3.1	2.7	3.4	2.9	14.0	-26.6%	54.9%
[14]	Office Furniture and Equipment	0.9	0.3	0.9	1.0	0.9	1.9	0.0%	24.9%
[15]	Transp/Heavy Work/NGV Compressor Equipment	2.6	9.8	7.4	11.0	11.4	6.5	52.3%	-4.3%
[16]	Tools and Work Equipment	1.5	2.0	1.4	3.6	2.3	2.5	-3.4%	19.3%
[17]	Computers and Communication Equipment	37.6	25.0	17.5	18.3	24.8	32.0	-38.2%	20.1%
[18] = Sum [13-17]	Total General and Other Plant	47.2	40.2	29.9	37.3	42.3	56.9	-22.8%	21.4%
	Miscellaneous Plant								
[19]	Customer Information System	0.0	4.5	32.4	46.4	48.7	-0.3	NA	NA
[20]	Underground Storage Plant	6.4	8.1	4.5	5.9	4.6	14.7	-17.6%	39.5%
[21] = [19] + [20]	Total Miscellaneous Plant	6.4	12.6	36.9	52.3	53.3	14.4	87.6%	-31.4%
[22]	**Total Capital Expenditures**	**315.5**	**364.5**	**354.9**	**366.0**	**349.1**	**337.6**	**5.9%**	**-1.7%**

Table 17

Enbridge Gas - Changes in Operating Expenditures

	Item	Amount ($\$10^6$)						Average Annual Growth Rate	
		2005	2006	2007	2008	2009	2010	2005-2007	2008-2010
[1]	Finance	6.1	5.8	5.9	5.8	6.0	6.0	-1.4%	0.7%
[2]	Risk Management	3.5	2.9	2.4	1.7	2.9	2.1	-17.2%	-4.5%
[3]	Customer Care Service Charges	103.3	107.7	87.6	84.6	82.0	68.7	-8.3%	-8.1%
[4]	Customer Care Internal Costs	4.4	4.8	11.4	9.7	7.9	9.2	47.3%	-6.9%
[5]	Provision for Uncollectibles	11.1	15.5	15.2	16.7	17.9	11.5	15.9%	-9.3%
[6]	Energy Supply, Storage, Regulatory	20.1	21.4	22.6	19.5	19.0	20.5	5.9%	-3.1%
[7]	Legal and Corporate Services	0.9	1.0	1.1	1.1	1.2	1.4	8.1%	9.2%
[8]	Operations	41.2	45.3	43.1	43.3	44.2	50.1	2.4%	5.0%
[9]	Information Technology	19.3	20.2	21.6	21.2	22.7	30.4	5.6%	11.3%
[10]	Business Development & Customer Strategy (excluding DSM)	9.0	10.5	12.7	13.4	14.3	18.6	17.1%	12.8%
[11]	Human Resources (excluding benefits)	22.0	11.7	12.5	13.3	14.6	15.1	-28.3%	6.5%
[12]	Benefits	21.2	21.8	26.4	24.6	26.2	27.3	11.0%	1.1%
[13]	Engineering	17.0	21.2	22.2	22.9	24.9	27.9	13.2%	7.7%
[14]	Public and Government Affairs	4.7	4.9	5.1	5.5	5.8	8.1	4.2%	15.8%
[15]	Non Departmental Expenses	5.6	22.2	23.4	29.5	30.9	24.3	71.4%	1.2%
[16]	Corporate Allocations (including direct costs)	24.1	25.2	27.7	32.2	34.3	36.7	7.1%	9.4%
[17] = Sum [1-16]	**Total**	**313.3**	**342.1**	**340.8**	**344.9**	**354.6**	**358.0**	4.2%	1.6%

Table 18

Union Gas - Changes in Capital Expenditures

Item	Amount ($\$10^6$)						Average Annual Growth Rates	
	2005	2006	2007	2008	2009	2010	2005-07	2008-10
Storage	16.6	38.2	5.7	6.6	3.4	11.9	-53.7%	24.8%
Transmission	51.6	112.4	159.1	84.3	42.7	25.1	56.4%	-61.5%
Distribution	74.7	93.6	93.7	113.1	95.5	101.8	11.4%	2.8%
General	37.6	37.5	28.2	30.7	22.8	31.7	-14.4%	3.9%
Other	50.2	55.9	56.0	61.1	59.5	49.0	5.5%	-4.5%
Total	**230.6**	**337.7**	**342.7**	**295.9**	**224.0**	**219.6**	**19.8%**	**-14.8%**

Table 19

Union Gas - Changes in Operating Expenditures

	Item	Amount ($000's) 2007	2008	2009	2010	Average Annual Growth Rate 2008-10
[1]	Salaries/Wages	165.9	172.3	175.1	183.2	3.32%
[2]	Benefits	56.4	51.4	52.9	70.9	7.63%
[3]	Materials	10.0	10.7	10.7	9.6	-1.16%
[4]	Employee Training	12.0	13.7	10.9	11.8	-0.70%
[5]	Contract Services	51.2	55.3	56.1	57.3	3.78%
[6]	Consulting	7.3	8.3	6.7	7.4	0.58%
[7]	General	21.2	21.8	19.9	22.8	2.33%
[8]	Transportation and Maintenance	7.3	8.2	7.6	6.3	-4.81%
[9]	Company Used Gas	3.2	3.5	3.4	2.5	-8.54%
[10]	Utility Costs	3.3	3.5	3.2	3.7	3.70%
[11]	Communications	8.0	8.2	7.6	6.8	-5.44%
[12]	DSM Programs	11.6	12.5	14.4	16.4	11.71%
[13]	Advertising	2.1	1.5	1.6	1.9	-4.33%
[14]	Insurance	8.0	7.2	7.8	8.5	1.92%
[15]	Donations	0.4	0.5	0.5	0.7	22.88%
[16]	Financial	1.4	2.1	2.9	1.9	11.95%
[17]	Lease	3.4	3.2	3.5	3.6	2.38%
[18]	Cost Recovery from Third Parties	-3.3	-3.8	-5.4	-4.6	11.16%
[19]	Computers	4.2	4.3	4.7	4.9	5.02%
[20]	Regulatory Hearing & OEB Cost Assessment	5.8	4.5	3.7	3.1	-20.36%
[21]	Outbound Affiliate Services	-6.5	-7.8	-9.3	-10.2	15.08%
[22]	Inbound Affiliate Services	6.3	5.9	7.3	9.5	13.54%
[23]	Bad Debt	7.6	9.1	8.6	5.2	-12.62%
[24]	Other	0.1	0.2	0.7	0.2	24.06%
[25] = Sum [1-24]	Sub-Total	386.8	396.3	395.1	423.6	3.03%
[26]	Indirect Capitalization (OH)	-48.9	-52.7	-51.2	-46.3	-1.79%
[27]	Direct Capitalization (DCC)	-7.3	-8.6	-8.3	-13.9	21.64%
[28]	Total Capitalization	-56.1	-61.3	-59.6	-60.2	2.33%
[29] = [25] + [28]	Total	330.7	335.1	335.5	363.4	3.15%
[30]	Non-Utility Costs[1]	-12.6	-12.5	-14.5	-14.0	3.49%
[31]	IFRS Costs	0.0	0.0	-2.9	0.0	NA
[32] = [29] - ([30] + [31])	**Total Net Utility O&M Expenses**	**318.0**	**322.6**	**318.1**	**349.4**	**3.13%**

[1] Includes non utility storage allocation and charitable donations.

Turning first to the EGD data, we find no evidence to suggest that the Company's cost reductions are in fact cost deferments. Table 16 shows that nearly all of the deceleration, or declines, in capital spending in the 2008-2010 period can be attributed to less spending on customer-related sales mains and meters. For example, expenditures on sales mains grew by an average of 6.1% annually between 2005 and 2007 but declined by 19.5% per annum in 2008-2010.

It must be recognized, however, that the -25.6% difference between the growth in sales main expenditures between these periods (*i.e.* -19.5% - 6.1% = -25.6%) is largely matched by an analogous decline in customer additions. Table 11 shows that EGD's customer additions declined from an average of 47,080 per year in 2005-2007 to 36,681 per year in 2008-2010, which represents a 22.1% decline. The declines in sales main capital expenditures in 2008-2010 therefore likely reflect the decline in customer additions on the EGD system over the same period. The Company's annual capital replacement and reinforcement expenditures have been generally steady over the 2005-2010 period (with the exception of one especially large year for replacement, in 2006). Table 17 also shows expenditures were cut in a variety of operating areas and not concentrated in any particular cost category that could be easily reversed at the time of rate rebasing.

It is more difficult to assess Union's expenditures because it has provided less detail on the changes in its capital expenditures. Table 18 presents the information Union provided in response to PEG-R's data request. It can be seen that distribution and general capital spending both increased at modest rates in 2008-2010, although distribution capital expenditures grew at a more rapid pace in 2005-07. However, when Table 10 (in Section Five) is compared with Table 18, it appears that at least some of the pattern in Union's distribution capital expenditures is correlated with its changes in customer additions. For example, distribution capital expenditures fell in the 2009 recession year, when customer additions fell by about a third from the 2008 level; customer additions and distribution expenditures both increased in 2010 but remained below their respective 2008 levels. Most of the difference between Union's 2005-07 and 2008-10 capital expenditures is in the transmission sector, where capital spending can be particularly "lumpy." [46]

Table 19 shows that most categories of Union's operating expenses increased in 2008-2010, although spending declines have been registered in a number of accounts, including materials, employee training, Company used gas, utility costs, communications, advertising, regulatory hearing costs, and the costs of bad debt. Cost reductions have also been recorded for transportation and maintenance, which could be an area where costs could be deferred, although the magnitude of cost reductions in this account are comparable with those recorded elsewhere, so we do not believe this is a concern.

Although it is very difficult to determine whether cost reductions are in fact cost deferments, PEG-R's analysis of the data available to us cannot find any clear evidence that EGD or Union is deferring a significant amount of costs under IR which could later be recovered in the Companies' base year. We emphasize, however, that this issue can only be fully addressed after the Companies present their base year rate proposals. The Board should investigate these proposals carefully, particularly for Union, which has cut its capital expenditures more rapidly than EGD but provided less evidence for this assessment on its capital expenditures by function.

6.2 TFP Comparisons

To provide additional context for the EGD and Union TFP results, PEG-R compared them to a number of related sources of TFP information for the gas distribution industry. We begin by comparing the Companies' measured TFP growth to a "backcast" projection of their TFP growth that was generated using an econometric model. We then compare the Companies' TFP growth to measured TFP growth for two sets of US gas distributors. The first is distributors that were subject to incentive regulation in the 2005-10 period. The second is "peer" distributors identified by our econometric results.

[46] It may also be worth noting that, in its Natural Gas Electricity Interface Review (NGEIR) Decision in 2006 (EB-20050551), the Board refrained from regulating the rates of certain storage services. Union's reported capital expenditures for storage declined sharply in 2007, and in the 2008-2010 period these expenditures have remained well below average capital expenditures for gas storage in 2005-2006. It therefore appears that Union has focused on competitive rather than cost of service-based storage expenditures since the NGEIR Decision.

6.2.1 "Backcast" Comparisons

6.2.1.1 Basics

A "backcast" is analogous to a forecast except it generates counterfactual scenarios for the past rather than hypothetical scenarios for the future. In this instance, our objective was to predict what the TFP growth of a typical North American gas distributor would have been if it had operated under the business conditions of EGD and Union, respectively, in the 2005 – 2010 period. We define a typical gas distributor as one that operates with average efficiency.

PEG-R generated backcast predictions for EGD and Union in the following way. First, we estimated an econometric model of gas distribution cost using sample data from the US gas distribution industry. This yielded estimates of the various "drivers" of gas distribution cost. Next, we inserted EGD's values for the various cost driver variables into the fitted econometric model, for each of the 2005-2010 years. This generated a series of predictions for EGD's predicted costs of gas distribution services for the 2005-2010 years. We performed an analogous process for Union, which generated a series of gas delivery cost predictions for Union for the 2005-2010 years.

The first step in turning these predictions into a series of TFP growth rates for the 2005-2010 period was to transform EGD and Union's 2005-2010 predicted costs into a cost index with base year 2005. We then divided each value of these cost indices by the respective Company's input price index for the year; values for these input price indices were computed and presented in Table 13 of Section 6.1. Using the indexing logic presented in Section 3, a cost index divided by an input price index is equal to an input quantity index. This process therefore yielded a notional input quantity index for each Company in 2005-2010, which can be interpreted as the value of what an average gas distributor's overall input quantity would have been if it had operated under the same conditions as EGD and Union, respectively, in these sample years. We computed the annual changes in this notional input quantity index and subtracted these input quantity growth rates from the respective Company's actual growth in output quantity in that year, as measured in Table 12 of Section 6.1.

This process therefore yields a TFP growth measure that is identical in every respect but one to what PEG-R previously developed using indexing methods. The one difference is that we substituted an econometric projection of each Company's gas distribution costs, in each sample year, for the Company's actual, measured costs in that year. The resulting "backcast" TFP growth estimate therefore represents a kind of benchmark level of TFP growth, or the TFP growth that would be expected if an average firm in the industry had operated under the Company's business conditions for that year. Each Company's actual TFP growth can then be compared to the backcast prediction to assess the Company's TFP performance.

6.2.1.2 Econometric Cost Model

Details of our econometric work are presented in the Appendix. This section briefly reviews our econometric findings, beginning with choices for cost driver variables.

<u>Output Quantity Variables</u>

Economic theory suggests that quantities of work performed by utilities should be included in our cost model. PEG-R identified two statistically significant outputs in our research: the number of retail customers, and the sum of miles of transmission plus distribution main. We also investigated output measures such as the volume of residential and commercial deliveries and the volume of other deliveries, but they were not statistically significant. We expect cost to increase as the values of the two output measures increase, so the coefficients on the output variables are expected to have positive signs.

<u>Input Prices</u>

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In these models, we have specified input price variables for capital and O&M inputs. These are the same input price variables used in the TFP research. We expect cost to be higher as the values of these variables increase, so the coefficients on the input price variables are expected to have positive signs.

Other Explanatory Variables

Two additional business condition variables were found to be statistically significant cost drivers. One is the percentage of distribution main not made of cast iron or bare steel. PEG-R calculates this variable using data from the American Gas Association and provided by EGD and Union. Cast iron and bare steel pipes were common in gas systems constructed in the early days of the industry. They are more heavily used in older distribution systems found and typically involve higher O&M expenses (*e.g.* higher maintenance expenses to repair gas leaks) and may lead to relatively greater levels of capital replacement. As the value of this variable increases, a company has a relatively lower share of cast iron and bare steel main which, in turn, is expected to reduce its gas distribution cost. Hence, we would expect this coefficient to have a negative sign.

A second additional business condition variable in each model is the number of power distribution customers served by the utility. This variable is intended to capture the extent to which the company has diversified into electricity distribution. Such diversification will typically reduce cost due to the ability to spread the costs of certain activities (such as human resources, finance, and the call center) across a greater range of utility services. This is sometimes referred to as achieving economies of scope. Greater values for this variable indicate greater economies of scope. We therefore expect this coefficient to have a negative sign.

Each cost model also contains a trend variable. This allows predicted cost to shift over time for reasons other than changes in the specified business conditions. A trend variable captures the net effect on cost of diverse conditions, which include technological change in the industry.

Estimation results for the gas distribution cost model are reported in Table 20. The parameter values for the first order terms of the input prices and output quantities (*i.e.* terms that do not involve squared values or interactions between different variables) are elasticities of the cost of the sample mean firm with respect to the basic variable. The tables shade the results for these useful elasticity estimates for reader convenience. The tables also report the values of the asymptotic *t* ratios that correspond to each parameter

Table 20

Econometric Cost Model

Variable Key

N = Number of Gas Customers
M = Miles of Distribution and Transmission Main
E = Number of Electricity Customers
BS = % Distribution Mains that are Not Cast-Iron or Bare-Steel
W_K = Capital Input Price
Trend = Time Trend

Explanatory Variable	Estimated Coefficient	T-Statistic	P-Value
N	0.716	20.03	0.000
M	0.167	4.41	0.000
W_K	0.557	208.56	0.000
N·N	-0.257	-3.75	0.000
M·M	0.116	1.49	0.137
$W_K \cdot W_K$	0.322	17.08	0.000
N·M	0.075	1.27	0.206
$N \cdot W_K$	-0.106	-10.59	0.000
$M \cdot W_K$	0.121	11.48	0.000
E	-0.010	-8.41	0.000
BS	-0.529	-10.46	0.000
Trend	-0.006	-3.86	0.000
Constant	12.459	545.09	0.000

System Rbar-Squared	0.959
Sample Period	1999-2009
Number of Observations	374

estimate. A parameter estimate is deemed statistically significant if we can reject the hypothesis that the parameter value equals zero at a 5% significance level.

It can be seen in Table 20 that all of the key cost function parameter estimates were statistically significant and plausible as to sign and magnitude. With regard to the first order terms, cost was found to be positively related to input prices and the two output quantities. At sample mean values of the variables, a 1% increase in the number of customers raised estimated gas distribution cost by 0.716%. A 1% increase in the miles of distribution and transmission main raised cost by about 0.167%.

The number of customers served was clearly the dominant output-related cost driver, and the sum of the elasticities for the output variables was about 0.88. This means that 1% growth in both output dimensions would raise total cost by only 0.88% for a firm with a sample mean operating scale. Because a 1% increase in output growth leads to a less than proportional increase in cost, unit cost declines as output expands. This is equivalent to saying that economies of scale exist for the sample mean gas distributor. Turning to the other independent variables, it can be seen that the elasticity of cost with respect to the price of capital services was about 0.56%. This means that capital accounts for more than half of gas distributors' costs and reflects the capital intensiveness of the gas distribution business. The estimated coefficient for number of electric customers served is -0.01 and highly significant statistically. This estimate means that a 10% increase in the number of electric customers served is expected to reduce a utility's *gas* distribution costs by about 1%. The estimated coefficient on the percent of main not constructed of cast iron or bare steel was -0.529 and statistically significant at the 1% level. This coefficient indicates that having a 1% lower share of gas distribution main that is not constructed with cast iron or bare steel is associated with a 0.53% reduction in gas distribution costs.

6.2.1.3 Projecting EGD and Union's Historical TFP Growth

The cost model presented in Table 20 was used to backcast the Companies' TFP growth. Table 21 presents details of how the cost function coefficients were combined with data on each Company's cost driver variables to project cost changes in 2005-2010. Table 22 presents details on the calculations involved in translating these cost predictions into a TFP backcast for each Company for 2005-2010. Table 23 compares these TFP backcasts to each Company's actual measured TFP growth for the 2005-07 and 2008-10 periods.

Table 21 shows that our econometric model predicts that, if a North American gas distributor of average efficiency had faced EGD's business conditions in 2005-07, its gas distribution costs would have increased by 3.25% per annum over those years. Similarly, if a North American gas distributor of average efficiency had faced EGD's business conditions in 2008-2010, its gas distribution costs would have increased by 2.56% per annum. Recall that EGD's output quantity growth slowed from a 2.40% rate in 2005-07 to 1.58% in 2008-2010. One would expect that this 0.82% decline in the growth of output between these periods would entail less investment and, therefore, a concomitant slowing in cost growth. This intuition is reflected in our econometric projection, which predicts that EGD's growth in cost declined by 0.69% between 2005-07 and 2008-2010 (*i.e.* 3.25% - 2.56% = 0.69%).

Table 21 also shows that our model predicts that, if a North American gas distributor of average efficiency had faced Union's business conditions in 2005-07, its gas distribution costs would have increased by 2.17%% per annum over those years. Similarly, if a North American gas distributor of average efficiency had faced Union's business conditions in 2008-2010, its gas distribution costs would have increased by 2.57% per annum. The econometric prediction of increasing cost growth for Union in the latter period may appear counterintuitive, but recall that Union experienced only a small decline in its output growth between 2005-07 and 2008-2010. Our data also show that the input prices facing Union accelerated in the latter period, from 1.71% per annum in 2005-07 to 2.09% per annum under IR. The 0.40% annual increase in Union's predicted cost partially reflects the impact of this 0.38% acceleration in the Company's input prices.

Table 22 shows how these backcast cost predictions for EGD and Union were translated into backcast TFP projections. It can be seen that our model predicts that an average gas distributor facing EGD's business conditions in 2005-07 would have registered 1.92% annual TFP growth in these years. This relatively rapid projected TFP growth reflects EGD's rapid output growth in these years. In the 2008-2010 IR period,

Table 21

COST GROWTH BACKCAST FROM ECONOMETRIC RESEARCH

	Enbridge		Union	
Sample Years	**2005-2007**	**2008-2010**	**2005-2007**	**2008-2010**
Econometric Coefficient Estimates				
Customers [A]	0.72	0.72	0.72	0.72
Miles of Transmission and Distribution Main [B]	0.17	0.17	0.17	0.17
Number of Electric Customers [C]	-0.01	-0.01	-0.01	-0.01
Percent of Mains not cast iron or bare steel [D]	-0.53	-0.53	-0.53	-0.53
Capital Input Price [E]	0.56	0.56	0.56	0.56
Sum of Output Elasticities [F=A+B]	0.883	0.883	0.883	0.883
Output Index Weights				
Customers [G=A/(A+B)]	81.05%	81.05%	81.05%	81.05%
Total Deliveries [H=B/(A+B)]	18.95%	18.95%	18.95%	18.95%
Subindex Growth				
Customers [I]	2.84%	1.83%	1.61%	1.38%
Miles of Transmission and Distribution Main [J]	0.52%	0.49%	1.06%	0.69%
Number of Electric Customers [K]	0.00%	0.00%	0.00%	0.00%
Percent of Mains not cast iron or bare steel [L]	1.53%	0.58%	0.01%	0.01%
Capital Input Price [M]	4.61%	3.78%	2.65%	3.77%
Subindex Growth * Econometric Coefficients				
Customers [N=A*I]	2.03%	1.31%	1.15%	0.99%
Miles of Transmission and Distribution Main [O=B*J]	0.09%	0.08%	0.18%	0.12%
Number of Electric Customers [P=C*K]	0.00%	0.00%	0.00%	0.00%
Percent of Mains not cast iron or bare steel [Q=D*L]	-0.81%	-0.31%	-0.01%	0.00%
Capital Input Price [R=E*M]	2.56%	2.11%	1.48%	2.10%
Trend [S]	**-0.63%**	**-0.63%**	**-0.63%**	**-0.63%**
Change in Projected Cost [N+O+P+Q+R+S]	**3.25%**	**2.56%**	**2.17%**	**2.57%**

Table 22

TFP "Backcasts" for EGD and Union

	EGD		Union	
	2005-2007	**2008-2010**	**2005-2007**	**2008-2010**
Change in Predicted Cost [A]	3.25%	2.56%	2.17%	2.57%
Change in Input Price Index [B]	2.77%	2.23%	1.71%	2.09%
Change in Predicted Input Quantity Index [C] = [A] - [B]	0.48%	0.33%	0.46%	0.48%
Change in Output Quantity Index [D]	2.40%	1.58%	1.51%	1.25%
Change in Predicted TFP [E] = [D] - [C]	1.92%	1.25%	1.05%	0.77%

Table 23

"BACKCAST" PREDICTIONS and ACTUAL TFP GROWTH

	Enbridge			Union		
	Predicted TFP Growth	Actual TFP Growth	Difference	Predicted TFP Growth	Actual TFP Growth	Difference
2005-2007	1.92%	1.29%	-0.63%	1.05%	1.58%	0.53%
2008-2010	1.25%	0.93%	-0.32%	0.77%	1.70%	0.93%
Estimated Impact of IR on TFP Growth			**0.31%**			**0.40%**

our model predicts the TFP of an average gas distributor facing EGD's conditions would have grown by 1.25% per annum. This marked 0.67% slowdown in projected TFP growth reflects the recession, and associated decline in output growth, in EGD's service territory in the latter years.

Turning to the Union results, our model predicts that an average gas distributor facing Union's business conditions in 2005-07 would have averaged TFP growth of 1.05% per annum. This is a lower projected rate of TFP growth than for EGD because Union's output grew more slowly in these years. In the 2008-2010 IR period, our model predicts TFP growth of 0.77% by an average gas distributor facing Union's business conditions in those years. This does represent a reduction in Union's TFP "target" because of the recession, although the reduction is not as marked as for EGD because the decline in economic activity reduced EGD's output growth more than Union's.

Table 23 compares the Companies' actual TFP growth to the TFP backcasts. It can be seen that EGD's actual TFP growth has been below our model's projection in both the 2005-07 and 2008-2010 periods. However, the difference between EGD's actual and backcast TFP growth was lower under IR than before IR was implemented. In 2005-07, our model projected TFP growth of 1.92% per annum for EGD, which was 0.63% above the Company's actual TFP growth of 1.29% in those years. In the 2008-2010 IR years, the TFP backcast for EGD was 1.25% per annum while the Company's actual TFP growth was 0.93% per annum, or 0.32% below the backcast prediction.

The "difference of the differences" between actual and projected TFP growth in the different periods can be plausibly interpreted as a measure of the impact that the IR regime had on EGD's TFP growth. The reason is that the difference between actual and projected TFP growth can be viewed as a measure of the impact that management (or other unmeasured and/or unmeasurable variables) have had on a gas distributor's TFP performance. Assuming that EGD's managerial "inputs" were essentially the same in the 2005-07 and 2008-10 periods, the difference between the unmeasured management factor in 2005-07 and in 2008-2010 can be interpreted as the impact that the one observable change – *i.e.* the change from a COS to IR regulatory regime – has had on managerial efficiency. It can be seen that this "difference of differences" for EGD is 0.31% (*i.e.*

-0.32% - (-0.63%) = 0.31%).[47] This appears to be a reasonable result and is certainly in line with the "stretch factor" values that are often included in IR plans to reflect the incremental TFP growth expected to occur when IR plans are implemented.

For Union, it can be seen that the Company's actual TFP growth exceeded the backcast predictions in both periods. In 2005-07, Union's projected TFP growth was 1.05% per annum while the Company's actual TFP growth was 1.58% per annum. Union's actual TFP growth therefore exceeded the econometric TFP prediction by 0.53% annually in 2005-07. In the 2008-2010 IR years, Union's projected TFP growth declined to 0.77% while the Company's actual TFP growth increased to 1.70% annually. The difference between actual and predicted TFP growth therefore increased to 0.93% per annum when the Company was subject to IR. The "difference of differences" for Union is equal to 0.40% (*i.e.* 0.93% - 0.53% = 0.40%), which implies that the switch from a COS to IR regime has increased Union's TFP growth by 0.40%. This again appears to be a plausible result that is in line with approved stretch factors in IR plans.

Overall, PEG-R's econometric "backcasts" suggest that the IR plans have had a positive impact on the TFP growth of both EGD and Union. The impact has been especially strong for Union, which displayed higher TFP growth that EGD in both periods and also appears to have responded more strongly to the incentives in the IR plan than EGD. It should be noted that the backcasts presented here are not tantamount to a full "benchmarking" analysis. Nevertheless, they do provide some illustrative evidence that, while EGD has responded positively to its IR plan, the Company has more unexploited potential to boost its TFP, and achieve incremental TFP gains, than does Union.

6.2.2 Peer Comparisons

PEG-R also compared the Companies' TFP growth to the TFP growth for two other sets of gas distributors. One was three US distributors that were subject to IR over

[47] Alternatively, a different unmeasured or unmeasurable factor, which is not reflected in PEG-R's model, may have changed between 2005-07 and 2008-2010 and accounted for the difference. It is impossible for PEG-R to distinguish between these hypotheses without information on what such a change might have been and, in the absence of further information, we believe the more reasonable conclusion is that the observed change in the regulatory regime has had a positive impact on EGD's TFP growth.

all, or most, of the 2005-2010 period. The second was companies that PEG-R identified as peers for EGD and Union, using the results of our econometric model and a clustering-type selection algorithm. The algorithm is completely general and does not depend on any of the restrictive assumptions that are involved in some clustering approaches. We discuss our method for selecting peers in detail in the Appendix.

6.2.2.1 Comparisons with IR Distributors

PEG-R selected three gas distributors subject to IR for the purposes of comparing TFP trends. These distributors were Boston Gas, Bay State Gas, and Atlanta Gas Light (AGL). As discussed in Section Four, Boston Gas and Bay State Gas are Massachusetts-based gas distributors who were subject to incentive regulation over all, or nearly all, of the 2005-2010 period. Although AGL has not been subject to an index-based IR plan, it has a straight fixed variable (SFV) rate design which allows its distribution rate structure to be consistent with cost causation. This has, in turn, allowed AGL to operate under a series of long-term rate freezes since the mid-1990s. An extended rate freeze creates incentives similar to what would be expected under the Companies' approved IR plans.

TFP trends for EGD, Union, and the three IR peers are presented in Table 24. PEG-R estimated TFP growth for the US distributors using identical methods as those used to estimate TFP for EGD and Union. There were only two, data-related differences between our US and Ontario TFP methods. One is that US-based input price measures must naturally be used in the US TFP research. PEG-R relied on input price indices we have used in a large number of US gas distribution TFP studies and which are comparable to the counterpart indices we used for EGD and Union. Second, much of the 2010 output data for the US gas distributors is not publicly available, so our sample period for the US distributors ends in 2009. We have therefore computed a 2004-09 TFP trend for the US distributors.[48]

It can be seen that AGL had the highest TFP growth, by far, of any of the selected US utilities subject to IR. AGL's TFP grew at an average rate of 2.66% per annum over the 2004-09 period. This TFP growth performance was mostly driven by a substantial

[48] Unlike the Ontario distributors, we did not divide the US sample period into halves because doing so would not coincide with the 'pre' and 'post' IR periods for the US distributors.

Table 24

Productivity Comparison: Ontario and US IR Gas Distributors

Ontario Distributors

Company	Average Output Growth	Average Input Growth	Average Growth in Total Factor Productivity
Enbridge			
2005-07	2.40%	1.12%	1.29%
2008-10	1.58%	0.65%	0.93%
2005-10	1.91%	0.83%	1.07%
Union			
2005-07	1.51%	-0.07%	1.58%
2008-10	1.25%	-0.45%	1.70%
2005-10	1.35%	-0.30%	1.65%
Average, 2005-10	*1.63%*	*0.27%*	*1.36%*

US IR Distributors

Company	Average Output Growth, 2004-09	Average Input Growth, 2004-09	Average Growth in Total Factor Productivity, 2004-09
Atlanta Gas Light	0.14%	-2.52%	2.66%
Bay State Gas	0.25%	0.91%	-0.67%
Boston Gas	0.57%	2.50%	-1.93%
Average	*0.32%*	*0.30%*	*0.02%*

decline in input usage of 2.52% per annum over the sample period. In contrast, Boston Gas and Bay State Gas each registered significant TFP declines between 2004 and 2009. Boston Gas had TFP growth of -1.93% per annum, and Bay State had TFP growth of -0.67% per annum, between 2004-09. In both cases, the utilities have been undertaking massive capital replacement programs to replace aged distribution systems. This has involved dramatic expansions in these utilities' capital input which was not associated with any increase in output (since the investment was only replacing capital that was at or beyond its useful life, not serving new customer demands). Because of these large-scale capital replacement programs, the combined negative TFP growth for the MA distributors essentially offsets the rapid TFP gains for AGL, with the result that a simple average of TFP growth for these IR peers is only 0.02% per annum. A simple average of TFP growth for EGD and Union is 1.36% over the 2005-2010 period. This is well above that registered by the three IR peers on average, although below that exhibited by AGL.

6.2.2.2 Comparisons with Other Peers

PEG-R also compared the Companies' TFP growth with those of two US gas distributors that our empirical results suggested were "peers" of EGD and Union.[49] The distributors identified as the top two peers in our work were New Jersey Natural Gas and Washington Gas Light. On the face of it, these seem to be reasonable peers for the Companies. Both are relatively large, stand-alone gas distributors that serve a mix of urban and suburban customers near or in a major city in a cold-weather territory. The Appendix provides further details on the process for selecting these peers as well as information on the peers themselves.

Table 25 presents data on TFP growth for EGD, Union, and the peers. It can be seen that Washington Gas Light's TFP grew by an average of 1.6% per annum over the 2004-2009 period. New Jersey Natural, on the other hand, registered an annual TFP decline of 0.73% per annum. A simple average of the peers' TFP growth was 0.44%

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[49] We did not search for separate peers for EGD and Union, but rather for peers that were similar to both EGD and Union. Implicitly, this analysis assumes that EGD and Union can be viewed as 'peers' for each other.

Table 25

Productivity Comparison: Ontario and US Peer Gas Distributors

Ontario Distributors

Company	Average Output Growth	Average Input Growth	Average Growth in Total Factor Productivity
Enbridge			
2005-07	2.40%	1.12%	1.29%
2008-10	1.58%	0.65%	0.93%
2005-10	1.91%	0.83%	1.07%
Union			
2005-07	1.51%	-0.07%	1.58%
2008-10	1.25%	-0.45%	1.70%
2005-10	1.35%	-0.30%	1.65%
Average, 2005-10	*1.63%*	*0.27%*	*1.36%*

US Peer Gas Distributors

Company	Average Output Growth, 2004-09	Average Input Growth, 2004-09	Average Growth in Total Factor Productivity, 2004-09
New Jersey Natural	1.42%	2.14%	-0.73%
Washington Gas Light	1.68%	0.08%	1.60%
Average	*1.55%*	*1.11%*	*0.44%*

over the 2004-09 period. This is well below the 1.36% average TFP growth of EGD and Union between 2005 and 2010.

These comparisons suggest that Union's TFP is growing more rapidly than rates displayed by peer gas distributors. EGD's TFP growth is also above the average of the peer distributors, but below that of one of the peers (Washington Gas Light). Overall, we believe these comparisons with specific distributors identified as "peers" reinforce the conclusions of PEG-R's backcast model, which shows that EGD has greater opportunity to boost its TFP growth, and achieve incremental TFP gains, than does Union.

6.3 Distribution of Gains

PEG-R also assessed the distribution of benefits, and TFP gains, under the Companies' IR plans using the methodology outlined in Section Three. Recall that the equation used to assess the distribution of these gains under IR is the following:

$$1 = \underbrace{\frac{\Delta\pi - (\Delta Y^R - \Delta Y^E)}{\Delta TFP^E}}_{\text{Shareholder Share of TFP-generated Benefits}} + \underbrace{\frac{-(\Delta P - \Delta W)}{\Delta TFP^E}}_{\text{Customer share of TFP-generated Benefits}}$$

In this equation, customers' share of benefits is measured by $\frac{-(\Delta P - \Delta W)}{\Delta TFP^E}$, or the negative of the difference between the growth in utility's output prices minus the growth in utility's input prices. Shareholders' share of benefits will be given by $\frac{\Delta\pi - (\Delta Y^R - \Delta Y^E)}{\Delta TFP^E}$, or the change in their measured margins (revenue growth minus cost growth) minus the difference between the growth in a revenue-weighted output quantity index and the growth in a cost-elasticity weighted output quantity index. Both measures of benefits are divided by the growth in TFP, which should be the long-run source of benefits for both shareholders and customers in an IR plan. Dividing the benefit measures by the growth in TFP effectively scales the benefit measures relative to the ultimate source of benefits under IR, and transforms the benefit metrics into the shares of TFP gains that have been distributed to customers and shareholders under the IR plan.

PEG-R did not have to undertake any additional quantitative analysis to estimate the distribution of benefits under IR. The Companies' revenue growth rates and revenue-weighted output quantity indexes were estimated and presented in Tables 7 and 8 in Section Four. The changes in cost, cost-elasticity weighted output indexes, input prices, and TFP were presented in this Section.

Table 26 brings this information together for the 2008-2010 period and estimates how TFP gains were distributed between customers and shareholders in the IR years. It should be noted that we used data for all three years of the IR period when undertaking this analysis for Union. Because of concerns with EGD's 2007-2008 gas delivery revenue data, we did not have confidence in the results that we obtained for EGD in the 2008 year. We therefore used changes in the relevant variables for the last two years in the IR period to estimate the distribution of TFP gains for Enbridge.

It can be seen that, according to our analysis, customers have enjoyed the overwhelming share of gains under IR. Our methodology indicates that 99.8% of Union's TFP gains, and 83.1% of EGD's TFP gains, have essentially been distributed to customers. Union's shareholders have retained only 0.3% of the Company's TFP gains, while EGD shareholders have retained 16.4% of that Company's TFP gains. The shares do not sum exactly to one because of slight rounding errors in the indexes.

We believe this method almost certainly overstates the share of TFP gains that have been distributed to customers. The reason is that our estimate of margins does not replicate the earnings that the Companies report. In fact, it may not be possible to replicate these calculations precisely given the data PEG-R was provided by the Companies. The fact that final, 2010 earnings measures have still not been agreed for the purposes of implementing Union's ESM also suggests that computing Company earnings can be a laborious and sometimes controversial process. PEG-R therefore relied on relatively crude and imprecise estimates of changes in Company "margins" for the purposes of assessing the distribution of TFP gains.

Nevertheless, while we believe these estimates of customers' share of gains are exaggerated, we also believe it is fair to conclude that customers have certainly gained under the Companies' IR plans. This conclusion is consistent with our analysis of EGD and Union rates in Section 4. By the same token, Section 5 provides ample evidence that

Table 26

Distribution of TFP Gains and Benefits Among Customers and Shareholders under IR

		Enbridge*	Union
Recent Trends		Trend 2009-10	Trend 2008-10
Revenue	A	2.23%	0.33%
Cost	B	2.74%	1.64%
Margin	A - B	-0.51%	-1.31%
TFP	C	1.04%	1.70%
Revenue Weighted Output	D	0.72%	-0.06%
Econometrically Weighted Output	E	1.40%	1.25%
Output Prices	F	1.51%	0.40%
Input Prices	G	2.37%	2.09%
Total Benefits			
To Customers	H = -1 x (F - G)	0.86%	1.70%
To Shareholders	I = ((A-B)-(D-E))	0.17%	0.004%
Source of Benefits Under IR Plan			
TFP Growth	C	1.04%	1.70%
"Distribution" of TFP Gains as Benefits to Customers and/or Shareholders			
Customers's Share of TFP Growth	CS = H / C	83.1%	99.8%
Shareholders' Share of TFP Growth	SS = I / C	16.4%	0.3%
Total	J = CS + SS	99.5%	100.1%

* The trend for Enbridge does not include 2008 because of concerns regarding the accuracy of the Company's 2007-2008 revenue data.

EGD and Union shareholders are also benefitting from the plans. Overall, the Companies' IR plans appear to be successful in generating incremental TFP gains that have led to "win win" outcomes for both customers and shareholders.

6.4 Assessment of Costs and Productivity

Our analysis suggests that the IR plans have been successful in encouraging more effective cost control and enhancing TFP growth. While EGD's TFP growth did decline under IR, compared with the immediately preceding years, this TFP deceleration resulted from the recession in EGD's service territory during the IR years. PEG-R's statistical analysis shows that conditions in the 2008-2010 period reduced EGD's expected TFP growth by 67 basis points (from 1.92% to 1.25% per annum) between 2005-07 and 2008-2010, which was nearly double the Company's actual decline in TFP growth between these periods.

Nevertheless, our analysis implies that there is scope for EGD to boost its TFP. EGD's TFP growth was below PEG-R's backcast prediction in both the 2005-07 and 2008-2010 periods, although the difference was smaller in the latter years. While EGD's TFP growth was also above the measured TFP growth for the distributors that our analysis indicated were the best peers for EGD and Union, it was substantially below the TFP growth for one of those peers.

Union has exhibited solid TFP growth both before and after IR was implemented. Union's measured TFP grew more rapidly than our backcast prediction in both the 2005-07 and 2008-2010 periods. The difference expanded in the latter years which means that, despite beginning from a more rapid TFP growth rate, Union appears to have responded to the incentives of the IR plan somewhat more strongly than EGD.

Although the methodology could certainly be refined, our analysis also indicates that customers have benefitted from both Companies' TFP growth. Indeed, the analysis suggests that customers captured the lion's share of benefits between 2008 and 2010. While we believe the estimates of customer's share of benefits are exaggerated because of the poor quality of our available earnings measures, the likelihood that customers have gained is reinforced by the revenues the Companies distributed back to customers under the ESMs (because of Company "overearning") in the plans. The overall thrust of our analysis in Sections Four through Six is that IR has generated win-win outcomes for customers and shareholders. The only potential caveat to this conclusion is whether service quality has also been maintained, and we examine this issue in the following Section.

7. SERVICE QUALITY PERFORMANCE

As discussed in Section One, both EGD and Union are subject to service quality requirements, or standards of performance that the utility is expected to achieve on a defined set of service quality indicators. These requirements were actually established in a separate proceeding that led to an amendment of the Gas Distribution Access Rule on March 27, 2006, before the Board approved the Companies' IR plans. Nevertheless, the Board in its NGF Report stated that maintaining appropriate service quality is an important objective in any rate regulation framework.

The service quality requirements are identical for EGD and Union. Both companies are expected to:

- Answer at least 75% of customer telephone calls to the utility phone center within 30 seconds on an annual basis, with a minimum monthly standard of 40%
- Have an abandoned call rate (where the customer hangs up while waiting to speak to a live operator) of no more than 10%
- Have a verifiable quality assurance program in place to audit and ensure billing accuracy
- Have no more than 0.5% of meters go four consecutive months without being read
- Meet at least 85% of scheduled service appointments within a four hour window around the schedule appointment time
- Reschedule 100% of missed appointments within two hours of the end of the original appointment time
- Respond to at least 90% of gas emergency calls within one hour
- Respond in writing to at least 80% of written complaints within 10 days
- Reconnect at least 85% of customers who have been disconnected within two days after they have resolved payment problems

These requirements are essentially an example of a "target" regulatory regime. On all but one of the service quality indicators (billing performance), the Board has set specific, quantitative levels of performance that EGD and Union are expected to achieve. The Board monitors information the Companies provide each year on their performance on the selected indicators, and if the Board believes there are service problems it can investigate the issues, request more in-depth explanations from Company managers, or work co-operatively with the Company to develop an action plan to become compliant with a requirement. However, there are no monetary penalties (or rewards) tied specifically to EGD's or Union's measured performance on the selected service quality metrics relative to their standards.

7.1 Data

Data on the service quality requirements are available for four years, from 2007 to 2010. This sample period exceeds the term of the EGD and Union IR plans by one year, but this is not a sufficient period of time to undertake meaningful comparisons of each utility's service quality performance before and after their IR plans have taken effect. Table 27 below summarizes the available service quality data for EGD and Union over the 2007-2010 period.

Table 27

Service Quality Requirements - Union (%)									
Year End	Telephone Answering Performance		Billing Performance	Meter Reading Performance	Service Appointment Response Times		Gas Emergency Response	Customer Complaint (Written) Response	Disconnection /Reconnection
	Call Answering Service Level (>= 75%)	Abandon Rate (<= 10%)		(<= 0.5%)	Appt Met Within Designated Time Period (>= 85%)	Percentage Not Rescheduled (= 100%)	(>=90%)	(>= 80%)	(>= 85%)
2007	78.4	4.2	Met QAP	0.1	93.2	90	97.9	100	87.8
2008	78.2	3.6	Met QAP	0.1	89.4	100	97.5	100	92.5
2009	77.2	4.3	Met QAP	0.2	96	100	97.7	100	93.2
2010	82.5	3.2	Met QAP	0.1	97.1	99.9	98	100	91.5
Average	79.08	3.83		0.13	93.93	97.47	97.78	100	91.25

Service Quality Requirements - Enbridge (%)										
Year End	Telephone Answering Performance		Billing Performance	Meter Reading Performance	Service Appointment Response Times		Gas Emergency Response	Customer Complaint (Written) Response	Disconnection /Reconnection
	Call Answering Service Level (>= 75%)	Abandon Rate (<= 10%)		(<= 0.5%)	Appt Met Within Designated Time Period (>= 85%)	Percentage Not Rescheduled (= 100%)	(>=90%)	(>= 80%)	(>= 85%)
2007	77.2	3.6	Met QAP	0.6	89.4	57.7	91.4	100	98
2008	76	3.7	Met QAP	0.7	93.7	62.8	94.2	100	97.7
2009	74.1	7.2	Met QAP	0.5	97.4	97.6	96.2	100	94.3
2010	65.3	11.6	Met QAP	0.7	94.7	94.79	94.2	N/A	93.9
Average	73.15	6.53		0.63	93.8	78.22	94	100	95.98

These data can be used to determine the number of years (out of the four year sample period) each Company satisfied or exceeded the level of performance it is expected to achieve on the selected indicator. In Table 28 below, this value is presented for each company in the "Yrs. ≥ Standard" columns. It is also relatively straightforward to assess whether there are any "up" (*i.e.* positive) or "down" (*i.e.* negative) trends in the Companies' performance on these indicator over the four year period. For each company, this information is summarized in the "Trend" columns of Table 28 below.

Table 28

Comparing Measured Quality to Service Quality Requirements

	EGD		Union	
Measure	Yrs. ≥ Standard	Trend	Yrs. ≥ Standard	Trend
Call Answering	2	Down	4	None
Abandon call	3	Down	4	None
Billing	4	None	4	None
Meter reading	1	None	4	None
Appts. Met	4	None	4	Up
Appts. not resched.	0	Up	2	Up
Gas emergencies	4	None	4	None
Customer complaint	4	None	4	None
Reconnect	4	Down	4	None

7.2 Assessment

PEG-R's assessment of the Companies' service quality performance is necessarily more limited than our assessment of their costs, prices or financial performance. We have a shorter time series of data for each Company, and essentially no comparative information from other gas distributors. We accordingly confined our service quality assessment to three issues: 1) does each company's measured service quality generally satisfy the Board's service quality requirements?; 2) are there are any noticeable trends in each company's service quality performance over the available time period?; and 3) how do EGD's and Union's measured service quality compare to each other?

7.2.1 Satisfying Board Service Quality Requirements

On the first issue, Union is clearly satisfying the Board's service quality requirements. In all four years, Union has achieved or exceeded the Board's standard of performance on eight of the nine service quality metrics. The only metric for which this is not the case is rescheduling 100% of missed appointments within two hours of the end of the original appointment time. This standard, literally, requires perfect performance and leaves no room for error. Nevertheless, Union has satisfied this standard in two of the four years, and in one of other years (2010) its performance was 99.9%. Only in 2007, before its IR plan took effect, was there anything other than a trivial difference between Union's measured performance and the performance standard for this indicator. Based on these data, PEG-R concludes that Union has clearly complied with the Board's service quality requirements during the term of its IR plan.

This is noticeably less true for EGD. EGD has failed to satisfy the Board's standards for four of the nine selected service quality indicators in at least one year between 2007 and 2010. EGD did not comply with the call response standard in two different years; the abandoned call standard in one year; the meter reading standard in three different years; and with the percent of appointments not rescheduled standard in all four years. For four of the eight indicators with quantitative standards, EGD's performance fell below the Board's standards more than half the time (*i.e.* on these four indicators, EGD failed to comply with standards a total of ten times, out of 16 possible).

7.2.2 Trends in Company Performance

There has been a noticeable downward trend in EGD's service quality performance on three of the nine indicators. EGD's measured quality has declined in each successive year between 2007 and 2010 on the call answering response rate, the abandoned call rate, and the disconnection/reconnection rate. On the latter metric, EGD's performance has declined from a very high level to a level that remains high and well above the Board's standard. On the two telephone center indicators, however, EGD's downward trend performance has caused the company to fall below the Board's standards on both metrics (in 2009 and 2010 for the call answering rate, and in 2010 for the abandoned call rate). On the plus side, it should be noted that EGD registered a marked improvement over the sample period in the percent of missed appointments that were not rescheduled.

There are fewer trends evident in the Union service quality data. On most indicators, Union's measured quality has fluctuated in a relatively small range around an average performance level that complies with the Board's standard. However, there has been a moderate upward trend over the term of Union's IR plan in the percentage of appointments met within a four hour window. Union also appears to have eradicated the gap in the number of missed appointments that were not rescheduled within two hours during the years when it has been subject to IR.

7.2.3 Comparing EGD and Union's Service Quality Performance

Table 29 below presents data comparing the service quality performance of EGD and Union over the 2007-2010 period. We present information on each Company's average value of the eight service quality metrics with quantitative standards, as well as the number of years where EGD's measured performance was superior to Union's on that metric (in the "EGD Better" column), the number of years where Union's measured performance was superior to EGD's (in the "Union Better" column), and the number of years in which the Companies' measured performance on the indicator was identical (in the "Union and EGD Same" column).

Table 29

Comparison of EGD and Union Service Quality

Indicators	**Union**	**EGD**	**Union Better**	**EGD Better**	**Union and EGD Same**
Call answering	79.1	73.15	4	0	0
Abandoned call	3.83	6.53	3	1	0
Meter reading	0.13	0.63	4	0	0
Appointments met	93.9	93.8	2	2	0
% Not Rescheduled	97.5	78.2	4	0	0
Gas emergencies	97.8	94.0	4	0	0
Customer complaints	100	100	0	0	4
Disconnect/Reconnect	91.3	96.0	0	4	0

It can be seen that Union registers better performance than EGD on five of the eight service quality indicators: 1) the call answering rate; 2) the abandoned call rate; 3) the meter reading rate; 4) the percent of appointments not rescheduled rate; and 5) the gas emergency response rate. EGD registers better performance than Union on one indicator: the percent of customers reconnected within two days after they have been disconnected for payment problems. Union and EGD have identical or nearly identical performance on two indicators: resolving written customer complaints, and the percent of appointments met within a four hour window.

Compared with Union, EGD's measured service is noticeably lower on service indicators associated with the phone center. The call answering and abandoned call indicators deal directly with service provided by the utility's telephone center. Rescheduling missed appointments also depends to at least some extent on the telephone center. It is perhaps noteworthy that EGD's performance on the phone center indicators was similar to Union's in 2007-08, but this is no longer the case. This reflects the fact that EGD's measured performance on the phone center indicators has declined over time, to the point where EGD currently does not satisfy the Board's standards on either of these metrics.

7.2.4 Overall Service Quality Assessment

Overall, PEG-R concludes that Union is satisfying all of the Board's service quality requirements, but this is not consistently true for EGD. We are not in a position to assess why this is the case. Furthermore, we emphasize that the simple comparative analysis presented above should not be viewed as an example of "benchmarking." Any benchmarking analysis should attempt to control for differences beyond management control on a utility's measured performance, and such an analysis goes well beyond PEG-R's current assignment.

Nevertheless, for the purposes of assessing the effectiveness of the IR plans, it is necessary to consider whether EGD and Union are providing appropriate service quality to their customers. This was one of the criteria that the Board said must be satisfied for any ratemaking framework to be effective. For EGD and Union, the Board has established standards for what it considers to be appropriate service quality on nine different service quality metrics. PEG-R concludes that Union is consistently satisfying these Board requirements, while EGD is not.

8. CONCLUSION

In this project, PEG-R was asked to assess EGD and Union's IR plans. This was a challenging assignment in light of the myriad issues to be addressed and the limitations of some available data. PEG-R approached the assessment by undertaking a variety of empirical (and at times theoretical) analyses, while attempting to keep in mind the inter-relationships among various aspects of performance and implications for different stakeholders.

This Section provides some brief concluding remarks. We begin by providing a summary assessment of the outcomes of the Companies' IR plans. We then present some concluding comments regarding the IR plan design in Ontario. Next, we provide concluding remarks regarding the IR regulatory process. Finally, we provide an overview of available data sources and data enhancements that would be desirable for developing and assessing future IR plans.

8.1 Assessing the Outcomes of the IR Plans

PEG-R's main focus was assessing how the IR plans performed in practice. We approached this issue by addressing whether the IR plans satisfied the Board's stated criteria for an effective ratemaking framework. In particular, our analysis was centered on answering the following questions:

1. Did the incentive regulation plans encourage cost control and generate productivity and efficiency improvements?
2. Did both customers and shareholders share in the benefits of any efficiency gains that were achieved?
3. Did the Companies provide appropriate service quality to their customers?
4. Was the incentive regulation framework conducive to capital investment?

Our answer to the first question is yes. Our analysis indicates that the IR plans encouraged both EGD and Union to control costs more effectively and generate productivity and efficiency improvements. Union appears to have responded more strongly to these incentives. However, a careful statistical analysis indicates that EGD also responded positively to IR and improved its efficiency, even though its measured TFP growth fell while the IR plan was in place. This decline in EGD's TFP growth was due to the recession in the Company's service territory, and the decline in its output growth, that took place in the 2008-2010 period. Notwithstanding its positive response to the IR incentives, our analysis indicates that EGD still has more potential to expand its TFP growth than Union.

Our answer to the second question is yes. PEG-R attempted to address this question rigorously by quantifying the distribution of TFP gains under IR between customers and shareholders. We believe the methodology we developed is conceptually sound, but its application was limited by the accuracy and availability of data. Nevertheless, the overall thrust of our analysis indicates that the IR plans were effective in generating TFP gains and the welfare of both customers and shareholders improved while the plans were in place. We therefore conclude that customers and shareholders both shared in the benefits of the productivity improvements that were achieved.

On the third question, our answer for Union is yes. Union is satisfying all the service quality requirements the Board has established. However, this is not consistently true for EGD. We are not in a position to assess why this is the case, but EGD's measured service is noticeably lower on service indicators associated with its phone center. Performance on several of the phone center indicators has declined rather than improved over time, although EGD has shown progress on remediating its appointments indicator. On balance, PEG-R is not prepared to say that EGD's overall service quality either is or is not "appropriate," but there are certainly pockets of problems that need to be addressed to satisfy the Board's standards.

On the fourth question, our answer is yes. The Companies are generating healthy, and generally increasing, returns under the IR plan. Their financial performance has also improved on a number of liquidity and leverage measures. The IR plans themselves have also been stable; this is evident in the fact that, when Union's earnings in 2008 prompted a re-opening of its plan, the plan was modified in a way that actually strengthened its incentives and allowed the Company to retain more earnings. The IR regulatory framework therefore adapted effectively to a Company's unexpectedly high earnings, which is an outcome that should reassure investors.

8.2 Plan Design Issues

In light of the positive outcomes generated under the IR plans, it may be instructive to consider what aspects of the IR plans contributed to these beneficial results. Recall that in Chapter Two we noted that there were a number of differences between the Union and EGD IR plans, the net effect of which created theoretically stronger incentives for Union. In considering these differences we wrote:

> The differences in IR plan designs could have implications for PEG-R's analysis. That is, if we find empirical evidence that Union has experienced stronger productivity and efficiency gains under IR than EGD, one of the contributing factors could be that the Union IR plan created stronger performance incentives. Alternatively, if there is no evidence that Union experienced stronger productivity and efficiency gains than EGD (*e.g.* EGD experienced more rapid productivity and efficiency gains), it would suggest that, in spite of the theoretically stronger incentives inherent in the Union IR plan, these plan design differences did not have a material impact on performance gains under IR. Regardless of our ultimate findings, it will not be possible to establish any such linkages unambiguously given the limited available data (only three years under IR) and the wide variety of other factors that can influence productivity and earnings. Nevertheless, even partial and indirect evidence on the impact that different IR plan designs have on productivity gains would be valuable to the Board and have clear policy implications on how the next generation of gas distribution IR plans should be designed.

Our analysis clearly shows that Union did, in fact, "experience stronger productivity and efficiency gains under IR than EGD." Although it cannot be established definitively, one of the factors contributing to Union's performance could be that its IR plan has created stronger incentives than EGD's. The main feature of Union's IR plan that creates stronger incentives, compared with EGD's, is its earnings sharing mechanism. Union's ESM allows shareholders to retain all earnings up to 200 basis points above the approved ROE, while EGD retains all earnings only up to 100 basis points above approved ROE. Shareholders are likely to benefit more from cost reductions under Union's more "progressive" ESM, and this feature should, in turn, create stronger incentives for Union to improve cost performance.

This could have implications for EGD's "next generation" IR plan, particularly in light of our conclusion that EGD appears to have more potential for incremental TFP gains going forward than Union. We believe that if the next generation IR plan for EGD is to be modified, any modifications should move in the direction of strengthening rather than weakening the Company's incentives. Our work provides evidence supporting the view that an IR plan designed more like Union's (*i.e.* a comprehensive IR plan with a more "progressive" ESM) could tend to strengthen performance incentives, to the ultimate benefit of both customers and shareholders.

Another plan design issue that could be relevant to next generation IR concerns the relationship between industry input price trends and the inflation factor. Our research shows that input prices for the Companies have grown more rapidly than inflation in the GDP-IPI, the selected inflation measure. Ideally, the inflation factor in a rate or revenue adjustment would be a good proxy for the industry's input price inflation. While the Companies have been able to generate healthy earnings even while their inflation factor did not apparently fully compensate for input price inflation, the relationship between input prices and alternative inflation factors (including industry-specific inflation measures that are explicitly designed to track industry input price trends) could merit greater attention in the next IR plan.

8.3 Regulatory Process and Reporting Issues

PEG-R wishes to make two concluding comments regarding the regulatory process and reporting for the IR plans. The first concerns the issue of cost deferments. As discussed, it is not possible to evaluate whether a Company is acting on incentives to defer costs to a base year used to rebase rates without examining the Company's base year rate application.

This is a critical issue, however, and a proper consideration of the deferment issue increases the importance of rate rebasing. Setting rebased rates is important not only for establishing appropriate cost-based rates, but also for ensuring that the incentives created by an IR plan are not undermined by what occurs when the plan expires. This would in fact occur if what appeared to be cost "reductions" under an IR plan suddenly re-appear in a base year application and are then reflected in the rates established for that year.

As discussed in Section 6, as part of its review of Companies' rate rebasing proposals, the Board can request information that can help it assess the cost deferment issue. In particular, the Board can evaluate whether large scale cost deferments have taken place by requesting information from the Companies on whether any of the capital expenditures reflected in the proposed rate base for the test year represent either: 1) delayed reactions to a previous request for service; or 2) requests for service that were previously rejected because they failed to satisfy the profitability index but have now been reconsidered and deemed to be sufficiently profitable. Any such capital expenditures reflected in a Company's rate rebasing proposal should be subject to greater scrutiny by the Board.

Some regulatory mechanisms are also potentially useful for addressing the cost deferment issue.[50] It may be too late to consider these options in the short time that is available to establish rebased rates for EGD and Union. However, this issue merits greater consideration during the term of the Companies' next generation IR plan.

The second point concerns the reporting and availability of information on the Companies' IR plans. PEG-R found there is a wealth of information and data on these plans, but it can be better co-ordinated within the OEB. For example, available data and regulatory filings from different but related proceedings are often not coordinated, and sometimes the data available from different sources (or even sometimes within a single regulatory filing) are not internally consistent. The time and costs needed to collate and organize the available information complicates the review of IR regulatory filings by interested parties.

PEG-R cannot offer expert advice on how to improve the organization of this information, but one straightforward modification could be to provide "tags" on files. This would allow all relevant files associated with, say, the gas IR plans to be coded with the same tag (and other relevant tags), so that when that tag is linked, all relevant files will be accessed. This is a fairly common feature on a number of computer sites. In any event, a better organized information gathering and processing system should reduce regulatory costs and facilitate information flow within Ontario's regulatory community.

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[50] These are sometimes referred to as "efficiency carry over mechanisms," and they have been employed in British and Australian variants of incentive regulation. PEG-R briefly discussed these mechanisms in its reports to Board Staff in both second- and third-generation incentive regulation for Ontario's electricity distributors.

8.4 Data Issues

In addition, a number of other data enhancements could be considered that would improve future analyses and IR plan assessments. One improvement would be a requirement that both EGD and Union file information on their gas delivery revenues by rate class and service type. The accuracy of certain parts of PEG-R's analysis was reduced by the lack of this gas delivery revenue data.

It could also be valuable to have standardized reporting of the details of capital and operating expenditures. In this consultation, Union provided us a more detailed and useful breakdown of its operating expenditures, while EGD provided a more detailed and useful breakdown of its capital expenditures.

It could also be useful to have a system in place for tracing through and quantifying all IR-related sources of allowed revenue and price change for EGD and Union's gas delivery customers. This would include the impact of the ESM as well as the net inflation, Y and Z factors. It would also include a clear statement of how the AU factor impacted prices, and separate itemization of the impact of trued-up forecasts on final revenues and prices.

One particularly valuable innovation would be to co-ordinate the reporting of earnings for ESM purposes with other cost and operating information. PEG-R attempted to develop a methodology to quantify the distribution of TFP gains between customers and shareholders. This is a relatively new tool which has not, to the best of our knowledge, been previously applied in the assessment of any previous IR plan. While this methodology provided illustrative results, the accuracy of our findings was limited by having the data available to estimate distributor returns that are identical with the distributors themselves will report. If the Board and Stakeholders believe this methodology has merit, and should potentially be applied in other initiatives, efforts should made to ensure data availability so a more refined and accurate earnings measures could be developed.

A number of other data enhancements could improve TFP estimates. One would be a disaggregation of O&M expenses into labor and non-labor costs by account. Another would be greater details on what sources of capital and operating costs have been outsourced to third parties. A third would be greater detail on capital expenditures by function (*e.g.* growth-related, replacement).

EMPIRICAL APPENDIX

This appendix contains additional details of our empirical research. Section A.1 addresses the output quantity indexes. Section A.2 addresses input price indexes. Section A.3 addresses the input quantity indexes, including the calculation of capital cost. Section A.4 discusses the calculation of capital cost. Section A.5 addresses our method for calculating TFP growth rates and trends. Section A.6 discusses the econometric cost modeling. The methods for peer group selection are discussed in section A.7.

A.1 Output Quantity Indexes

The output quantity indexes used in our TFP index were estimated using the following general formula:

$$\ln\left(\text{Output Quantities}_{\text{t}} \middle/ \text{Output Quantities}_{\text{t-1}}\right) = \sum_i \left(SE_i\right) \cdot \ln\left(Y_{i,t} \middle/ Y_{i,t-1}\right). \quad \text{[A1]}$$

Here in each year *t*,

$Output\ Quantities_t$ = Output quantity index

$Y_{i,t}$ = Amount of output *i*.

SE_i = Share of output measure *i* in the sum of the estimated output elasticities.

The growth rate of the quantity index is therefore a weighted average of the growth rates of the output subindexes. The growth rate in each subindex is calculated as the logarithm of the ratio of the quantities in successive years. The weight applied to each output quantity subindex was its cost elasticity, divided by the sum of cost elasticities for all statistically significant outputs in our econometric gas distribution cost model.

PEG-R also derived revenue-weighted output quantity indexes in our analysis of the Companies' output prices using the following formula:

$$\ln\left(\text{Output Quantities}_{\text{t}} \middle/ \text{Output Quantities}_{\text{t-1}}\right) = \sum_i \left(SR_i\right) \cdot \ln\left(Y_{i,t} \middle/ Y_{i,t-1}\right). \quad \text{[A2]}$$

Here in each year *t*,

$Y_{i,t}$ = billing determinant *i* for companies in the region

$SR_{i,t}$ = share of billing determinant *i* in applicable gas distribution revenue.

The growth rate of the summary output index is once again a weighted average of the growth rates of the output quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. The revenue weights in this index were equal to the average of each billing determinant's share of gas distribution revenue in the current and preceding year and were updated annually, for all years in which we had the available revenue data.

A.2 Price Indexes

The input price indexes in this study are of Törnqvist form, where the annual growth is computed using the following general formula:[51]

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(SC_{j,t} + SC_{j,t-1} \right) \cdot \ln\left(\frac{W_{j,t}}{W_{j,t-1}} \right). \qquad [A3]$$

Here for each company in each year *t*,

$Input\ Prices_t$ = Input price index

$W_{j,t}$ = Price subindex for input category *j*

$SC_{j,t}$ = Share of input category *j* in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. Weights are equal to the average shares of each input in the applicable total gas delivery cost of distributors during the current and preceding year.

[51] For seminal discussions of this index form see Törnqvist (1936) and Theil (1965).

A.3 Input Quantity Indexes

A.3.1 Index Form

The input quantity index for each company was of Törnqvist form, where the annual growth rate is computed using the following general formula:

$$\ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right) = \sum_j \ \frac{1}{2} \cdot \left(SC_{j,t} + SC_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \quad [A4]$$

Here for each company in each year t,

$Input\ Quantities_t$ = Input quantity index

$X_{j,t}$ = Quantity subindex for input category j

$SC_{j,t}$ = Share of input category j in applicable total cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Weights are equal to the average shares of each input in the applicable total gas delivery cost of distributors during the current and preceding year.

A.3.2 Input Quantity Subindexes

Our general approach to measuring input quantity trends relies on the theoretical result that the growth rate in the cost of any input j is equal to the sum of the growth rates in appropriate input price and quantity indexes for that input *i.e.*

$$growth\ Input\ Quantities_j = growth\ Cost_j - growth\ Input\ Prices_j . \qquad [A5]$$

A.4 Capital Cost

The service price approach to the measurement of capital cost has a solid basis in economic theory and is widely used in scholarly empirical work.[52] It facilitates the use of cost data for utilities with different plant vintages. In this section, we explain the calculation of capital costs, prices, and quantities using the COS service price method.

[52] See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

The basic idea of the COS approach to calculating capital costs and quantities is to decompose the cost of capital computed under traditional COS accounting into a price and quantity index. The hallmarks of this accounting approach are straight line depreciation and book (historic) valuation of plant.

Glossary of Terms

For each utility in each year, t, of the sample period let

ck_t = Total non-tax cost of capital

$ck_t^{Opportunity}$ = Opportunity cost of capital

$ck_t^{Depreciation}$ = Depreciation cost of capital

VK_{t-s}^{add} = Gross value of plant installed in year t-s

WKA_{t-s} = Cost per unit of plant constructed in year t-s (the "price" of capital assets)

a_{t-s} = Quantity of plant additions in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$

xk_t = Total quantity of plant available for use and that results in year t costs

xk_t^{t-s} = Quantity of plant available for use in year t that remains from plant additions in year t-s

VK_t = Total value of plant at the end of last year

N = Average service life of plant

WKS_t = Price of capital service

Basic Assumptions

The analysis is based on the assumption that depreciation and opportunity cost is incurred in year t on the amount of plant remaining at the end of year t-1, as well as on any plant added in year t. This is tantamount to assuming that plant additions are made at the beginning of the year.

Theory

The non-tax cost of capital is the sum of depreciation and the opportunity cost paid out to bond and equity holders:

$$ck_t = ck_t^{opportunity} + ck_t^{depreciation}.$$

Assuming straight line depreciation and book valuation of utility plant, the cost of capital can be expressed as

$$\begin{aligned} ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot I_t + \sum_{s=0}^{N-1} WKA_{t-s} \left(1/N\right) \cdot a_{t-s} \\ &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot I_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{\left(1/N\right) \cdot a_{t-s}}{xk_t} \end{aligned} \qquad [A6]$$

Where

$$xk_t = \sum_{s=0}^{N-1} xk_{t-s}.$$

Under straight line depreciation we posit that in the interval $\left[N-1, 0\right]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \qquad [A7]$$

The formula for the capital quantity index is thus

$$xk_t = \sum_{s=1}^{N\text{-}1} \frac{N\text{-}S}{N} a_{t-s}\ . \qquad [A8]$$

The size of the addition in year t-s of the interval (t-1, t-N) can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \qquad [A9]$$

Equations [A6] - [A9] imply that

$$\begin{aligned} ck_t &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot I_t \ + \ xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \\ &= xk_t \cdot WKS_t \end{aligned} \qquad [A10]$$

Where

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot I_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s}. \qquad [A11]$$

It can be seen that the cost of capital is the product of a capital service price and a capital quantity index. The capital service price in a given year is a function of the construction cost index values in the N most recent years (including the current year).

The importance of each WKA_{t-s} depends on the share, in the total amount of plant that contributes to cost, of plant remaining from additions in that year. This share is larger for more recent plant additions (since there is less depreciation) and for larger plant additions in that year. Absent a decline in I, *WKS* is apt to rise each year as the WKA_{t-s} for each of the *N* years is replaced with the generally higher value for the following year. Note also that the depreciation rate varies with the age of the plant. For example, the depreciation rate in the last year of an asset's service life is 100%.

A.5 TFP Growth Rates and Trends

The annual growth rate in each TFP index is given by the formula

$$\ln\left(\frac{TFP_t}{TFP_{t-1}}\right) = \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \qquad [A12]$$

The long run trend in each TFP index was calculated as its average annual growth rate over the sample period.

A.6 Econometric Cost Research

In this study, an econometric cost model was used to estimate weights for the output quantity indexes and to "backcast" the expected rates of TFP growth for EGD and Union over the 2005-2010 period. This section discusses details of the econometric work.

A.6.1 Cost Models

A cost model is a mathematical representation of the relationship between the cost of an enterprise and external business conditions. Business conditions are defined as aspects of a company's operating environment that affect its costs but are beyond management control. Models can in principle be developed to explain total cost or important cost subsets such as O&M expenses. In this study, total cost models were developed to support the TFP research.

Economic theory can be used to guide cost model development. According to theory, the minimum total cost of a firm is a function of the amount of work that it performs and the prices it pays for capital, labor, and other production inputs. The amount of work performed can be multidimensional and may need to be measured by multiple output variables. Theory also provides some guidance regarding the nature of the relationship between these business conditions and cost. For example, it predicts that a firm's cost will typically increase as input prices and the workload increase.

A.6.2 Form of the Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, the double log and the translog. A simple example of a linear cost model is

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot W_{h,t} + e_{h,t} \qquad \text{[A13]}$$

Here, for each firm h in year t, cost is a function of the number of customers served ($N_{h,t}$), the prevailing wage rate ($W_{h,t}$), and an error term ($e_{h,t}$). Here is an analogous cost model of double log form.

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + e_{h,t}\,. \qquad \text{[A14]}$$

Notice that in this model the dependent variable and both business condition variables have been logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the output quantity. It is also noteworthy that in a double log model, the elasticities are *constant* across every value that the cost and business condition variables might assume.[53]

A more sophisticated translog functional form was used in this report.[54] This very flexible function is common in econometric cost research and, by some accounts, the most reliable of several available flexible forms.[55] Here is a cost function of translog form that is analogous to [A13] and [A14].

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[53] Cost elasticities are not constant in the linear model that is exemplified by equation [A17].

[54] The transcendental logarithmic (or translog) cost function can be derived mathematically as a second order Taylor series expansion of the logarithmic value of an arbitrary cost function around a vector of input prices and output quantities.

[55] See Guilkey (1983), et. al.

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot ln W_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} + a_4 \cdot \ln W_{h,t} \cdot \ln W_{h,t} + a_5 \cdot \ln W_{h,t} \cdot \ln N_{h,t} + e_{h,t} \quad [A15]$$

This form differs from the double log form since it adds quadratic and interaction terms. Quadratic terms such as $\ln N_{h,t} \cdot \ln N_{h,t}$ enable the elasticity of cost with respect to each independent variable to differ for different values of the variable. This allows the estimated impact of economies of scale from output growth to diminish (or increase) at as the scale of operations increase. Interaction terms like $\ln W_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one independent variable to depend on the value of other such variables.

Cost theory requires a well-behaved cost function to be linearly homogeneous in input prices. This implies the following three sets of restrictions on the parameter values.

$$\sum_{j=1}^{J} \frac{\partial \ln C}{\partial \ln W_j} = 1 \quad [A16]$$

$$\sum_{i}^{M} \frac{\partial^2 \ln C}{\partial \ln Y_i \partial \ln W_j} = 0 \qquad \forall j = 1,..., J \quad [A17]$$

$$\sum_{n=1}^{N} \frac{\partial^2 \ln C}{\partial \ln W_j \partial \ln W_n} = 0 \qquad \forall j = 1,..., J \; . \quad [A18]$$

These conditions were imposed prior to model estimation.

Estimation of the parameters of equation [A15] is now possible but this approach does not utilize all of the information available in helping to explain the factors that determine cost. Better parameter estimates can be obtained by augmenting the cost equation with some of the cost share equations implied by Shepard's Lemma. The general form of a cost share equation for a representative input price category, *j*, can be written as:

$$SC_j = \alpha_j + \sum_i \gamma_{ij} \ln Y_i + \sum_n \gamma_{jn} \ln W_n . \quad [A19]$$

The parameters in this equation also appear in the total cost function. Thus, information about cost shares can be used to sharpen estimates of the cost model parameters.

A.6.3 Estimating Model Parameters

A branch of statistics called econometrics has developed procedures for estimating parameters of economic models using historical data on the dependent and explanatory variables.[56] For example, cost model parameters can be estimated econometrically using historical data on the costs incurred by utilities and the business conditions they faced. The sample used in model estimation can be a time series (consisting of data over several years for a single firm), a cross section (consisting of one observation for each of several firms), or a panel data set that pools time series data for several companies. In this study we have employed panel data because such data are available and their use should enhance the precision of the parameter estimates.

Numerous statistical methods have been established for estimating parameters of economic models. The desirability of each method depends on the assumptions that are made about the probability distribution of the error term. The assumptions under which the best known estimation procedure, ordinary least squares, is ideal often do not hold in statistical cost research.

In this study, we employed a variant of an estimation procedure first proposed by Zellner (1962).[57] If there is a contemporaneous correlation between the error terms in a system of regression equations, more efficient estimates of their parameters can be obtained using a Feasible Generalized Least Squares (FGLS) approach. To obtain an even better estimator, we also corrected for heteroskedasticity in the error terms and iterated the procedure to convergence.[58] Since we estimated these unknown disturbance matrices consistently, our estimators are equivalent to Maximum Likelihood Estimators (MLE).[59] Our estimates thus possess all the highly desirable properties of MLEs.

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[60] This does not pose a problem since the MLE procedure is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

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[56] The estimation of model parameters in this type of model is sometimes called regression.

[57] See Zellner, A. (1962)

[58] That is, given any two estimated consecutive disturbance matrices, if we form another matrix that is their difference, this determinant is approximately zero in the final run.

[59] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

[60] This equation can be estimated indirectly if desired from the estimates of the parameters remaining in the model.

The results of econometric research are useful in selecting business conditions for cost models. Specifically, hypothesis tests can determine whether the estimated parameter for a business condition variable is zero. If this hypothesis is rejected, the variable in question can be deemed a statistically significant cost driver.

A.6.4 Multicollinearity

Multicollinearity exists if sample data on independent variables are correlated. Multicollinearity tends to reduce the efficiency of statistical estimates. A conventional remedy for multicollinearity is to pool time series data for numerous companies to create a large panel data set. Kennedy, for instance, states that

> Panel data create more variability, through combining variation across micro units with variation over time, alleviating multicollinearity problems. With this more informative data, more efficient estimation is possible.[61]

And that

> Practitioners should…view a multicollinearity problem as equivalent to having a small sample. Realize that getting more information is the only solution.[62]

Baltagi states that

> Panel data give more informative data, more variability, less collinearity among the variables, more degrees of freedom and more efficiency. Time-series studies are plagued with multicollinearity:… With additional, more informative data one can produce more reliable parameter estimates.[63]

Greene states that

> Strategies have been proposed for coping with multicollinearity. Under the view that a multicollinearity "problem" arises because of a shortage of information, one suggestion is to obtain more data. One might argue that if analysts had such additional information available at the outset, they ought to have used it before reaching this juncture.[64]

PEG-R uses a large panel dataset to estimate the parameters of a gas distribution cost function. In gas utility cost research, a large panel dataset can be valuable in several ways. Estimates of output elasticities will be estimated from utilities with substantial

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[61] Kennedy, Peter. *A Guide to Econometrics*, Fifth Edition. MIT Press, Cambridge, 2003, p. 402.
[62] *Ibid*, p. 412.
[63] Baltagi, Badi. *Econometric Analysis of Panel Data*. Wiley, 1995, p. 4.

differences in the scale of their output as well as in the mix of residential, commercial and industrial customers that they serve. All else equal, this diversity of operating conditions increases the precision of the estimated cost function parameters.

A.6.5 Gas Utility Cost Model

Output Quantity Variables

As noted above, economic theory suggests that quantities of work performed by utilities should be included in our cost model as business condition variables. PEG-R identified two statistically significant outputs in our research: the number of retail customers, and the sum of miles of transmission plus distribution main. We also investigated output measures such as the volume of residential and commercial deliveries and the volume of other deliveries, but they were not statistically significant. We expect cost to increase as the values of the two output measures increase, so the coefficients on the output variables are expected to have positive signs.

Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In these models, we have specified input price variables for capital and O&M inputs. These are the same input price variables used in the TFP research. We expect cost to be higher as the values of these variables increase, so the coefficients on the input price variables are expected to have positive signs.

Other Explanatory Variables

Two additional business condition variables were found to be statistically significant cost drivers.[65] One is the percentage of distribution main not made of cast iron or bare steel. PEG-R calculates this variable using data from the American Gas Association and provided by EGD and Union. Cast iron and bare steel pipes were common in gas systems constructed in the early days of the industry. They are more heavily used in older distribution systems found and typically involve higher O&M expenses (*e.g.* higher maintenance expenses to repair gas leaks) and may lead to

[64] Greene, William H. *Econometric Analysis*, Fourth Edition. Prentice Hall, 2000, p. 258.
[65] Variables that were *not* found to be statistically significant cost drivers included frost depth and an earthquake risk measure.

relatively greater levels of capital replacement. As the value of this variable increases, a company has a relatively lower share of cast iron and bare steel main which, in turn, is expected to reduce its gas distribution cost. Hence, we would expect this coefficient to have a negative sign.

A second additional business condition variable in each model is the number of power distribution customers served by the utility. This variable is intended to capture the extent to which the company has diversified into power distribution. Such diversification will typically reduce cost due to the ability to spread the costs of certain activities (such as human resources, finance, and the call center) across a greater range of utility services. This is sometimes referred to as achieving economies of scope. Greater values for this variable indicate greater economies of scope. We therefore expect this coefficient to have a negative sign.

Each cost model also contains a trend variable. This allows predicted cost to shift over time for reasons other than changes in the specified business conditions. A trend variable captures the net effect on cost of diverse conditions, which include technological change in the industry.

Data

The primary source of the data used in our US gas utility cost research has changed over time. For the earliest years of the sample period the primary source was *Uniform Statistical Reports* ("USRs"). Many US gas utilities file these annual reports with the American Gas Association.[66]

USRs are unavailable for most sampled utilities for the later years of the sample period. Some utilities do not file USRs. Some that do file do not release them to the public. The development of a satisfactory sample therefore required us to obtain operating data from alternative sources including, most notably, reports to state regulators. Companies filing reports with state regulators often use as templates the Form 2 report that interstate gas pipeline companies file with the Federal Energy Regulatory Commission ("FERC"). A uniform system of accounts has been established by the FERC to help utilities prepare this filing. Gas utility operating data from state reports are

[66] USR data for some variables of interest are aggregated and published annually by the AGA in *Gas Facts*.

also compiled by commercial venders such as Platts. We obtained our operating data from the Platts *GasDat* package.

Other sources of data were also employed in the US research. Detailed data on the delivery volumes and customers served by US gas utilities were obtained from Form EIA 176. Data on input prices were drawn from several sources. Whitman, Requardt & Associates prepare Handy Whitman Indexes of trends in the construction costs of US gas utilities. Other sources of input price data include R.S. Means and Associates; the Bureau of Labor Statistics ("BLS") of the US Department of Labor; and the Energy Information Administration ("EIA") of the US Department of Energy.

We estimated the parameters of a cost model using data for 34 US gas distributors for the1999-2009 sample period. These distributors are listed in Table A1. Our cost measure was identical that used to estimate TFP for EGD and Union and, in particular, used the COS approach to capital costing.

Estimation Results

Estimation results for the gas distribution cost model were reported in Table 19. The parameter values for the additional business conditions and for the first order terms of the input prices and output quantities are elasticities of the cost of the sample mean firm with respect to the basic variable. The first order terms are the terms that do not involve squared values of business condition variables or interactions between different variables. The tables shade the results for these useful elasticity estimates for reader convenience.

The tables also report the values of the asymptotic *t* ratios that correspond to each parameter estimate. A parameter estimate is deemed statistically significant if the hypothesis that the parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the asymptotic *t* ratio. In this study, we employed a critical value that is appropriate for a 5% significance level given a large sample. The critical value was 1.96.

Table A1

Sample of Gas Distributors Used in Econometric Cost Model

Alabama Gas Corporation	NSTAR Gas Company
Atlanta Gas Light Company	Orange and Rockland Utilities, Inc.
Boston Gas Company	Pacific Gas and Electric Company
Brooklyn Union Gas Company	PECO Energy Company
Cascade Natural Gas Corporation	Peoples Gas Light and Coke Company
Central Hudson Gas & Electric Corp	Peoples Natural Gas Company
Connecticut Natural Gas Corporation	Public Service Company of North Carolina, Inc
Consolidated Edison Company of New York, Inc.	Public Service Electric and Gas Company
Consumers Energy Company	Puget Sound Energy, Inc.
East Ohio Gas Company	Questar Gas Company
Louisville Gas and Electric Company	Rochester Gas and Electric Corp
Madison Gas and Electric Company	San Diego Gas & Electric Co.
New Jersey Natural Gas Company	Southern California Gas Company
Niagara Mohawk Power Corporation	Southern Connecticut Gas Company
North Shore Gas Company	Washington Gas Light Company
Northern Illinois Gas Company	Wisconsin Gas LLC
Northwest Natural Gas Company	Wisconsin Power and Light Company

Total Number of Distributors: 34

It can be seen in Table 19 that all of the key cost function parameter estimates were statistically significant and plausible as to sign and magnitude. With regard to the first order terms, cost was found to be positively related to input prices and the two output quantities. At sample mean values of the variables, a 1% increase in the number of customers raised estimated gas distribution cost by 0.716%. A 1% increase in the miles of distribution and transmission main raised cost by about 0.167%.

The number of customers served was clearly the dominant output-related cost driver, and the sum of the elasticities for the output variables was about 0.88. This means that 1% growth in both output dimensions would raise total cost by only 0.88% for a firm with a sample mean operating scale. Because a 1% increase in output growth leads to a less than proportional increase in cost, unit cost declines as output expands. This is equivalent to saying that economies of scale exist for the sample mean gas distributor.

Turning to the other independent variables, it can be seen that the elasticity of cost with respect to the price of capital services was about 0.56%. This means that capital accounts for more than half of gas distributors' costs and reflects the capital intensiveness of the gas distribution business. The estimated coefficient for number of electric customers served is -0.01 and highly significant statistically. This estimate means that a 10% increase in the number of electric customers served is expected to reduce a utility's *gas* distribution costs by about 1%. The estimated coefficient on the percent of main not constructed of cast iron or bare steel was -0.53 and statistically significant at the 1% level. This coefficient indicates that having a 1% lower share of gas distribution main that is not constructed with cast iron or bare steel is associated with a 0.53% reduction in gas distribution costs.

The table also reports the system R^2 statistic for the model. This measures the ability of the model to explain variation in the sampled costs of distributors. Its value was 0.96, suggesting that the explanatory power of the model was high. Please note, however, that high R^2 values are often encountered in cost models estimated using a sample of companies with diverse operating scales.

A.7 Peer Group Selection

A peer group should consist of utilities facing similar drivers of TFP growth. Mathematical theory and econometric research provide a rigorous basis for identifying these drivers and choosing peer groups.

Our selection of peers was informed both by our econometric research and by some basic methods of cluster analysis. The objective was to identify companies that are closest to Enbridge and Union in terms of their cost drivers. Using our sample of 34 US gas distributors, minus the three distributors that were subject to IR and already to be used as peers for EGD and Union in an alternate analysis, we examined all 4920 possible combinations of five companies within the sample space, where each group of five companies included EGD and Union, plus three additional possible firms to be selected as peers of EGD and Union.

We measured the "tightness" of each possible cluster of five companies using changes in the independent variables (other than the capital service price) that were identified as statistically significant cost drivers in our econometric model of gas distribution cost. These variables used were the number of customers; the miles of distribution plus transmission main; the number of electric customers served; and that percent of distribution main that is not constructed with cast iron or bare steel.

These variables were scaled according to their impact on cost, with weights applied to each variable based on the coefficients estimated in the econometric model. In particular, the number of electricity distribution customers and the percent of distribution main variables were scaled by multiplying these variables by their regression coefficients. The two output variables (customers and miles of main) were used to calculate the cost elasticities for each distributor (*i.e.* the elasticity of cost with respect to that distributor's actual output levels, not at sample mean output levels) that are consistent with its actual output levels. Changes in these four variables (customer numbers, miles of main, number of electric customers, and percent of distribution main not constructed of cast iron or bare steel), all weighted by their relevant cost function coefficients, were the basis for selecting which gas distributors were most similar to EGD and Union.

"Similarity" was measured using within-group variation, where the group included the two Ontario companies and the candidate peers. More similarity would be indicated by a smaller within-group variation or, more formally, by minimizing the Euclidian distance of companies from their common center, given by the mean values of the three variables described for the group. This was done by:

1. For each company in the group, calculating $(x_i - \text{average}(x_i))^2$ for each variable x_i , where i = customer numbers, miles of main, electric customers and percent of distribution main, weighted as described above
2. Summing the four variables computed above for each company in the cluster.
3. Summing the results computed above for each company in the cluster
4. Ranking clusters from lowest to highest values, based on the number resulting from steps one through three above

This process yielded 4920 combinations of distributors, with EGD and Union in each combination plus three other candidate peers. We selected the ten highest ranked (*i.e.* lowest quantitative value) clusters generated from the process above. We then counted the number of times different companies appeared in the total number of 30 companies that appeared in the six top-ranked clusters. Only five companies appeared, and the numbers that appeared most often were Washington Gas Light (seven times) and New Jersey Natural Gas (seven times). These were, accordingly, the peers we selected for our analysis. Table A.2 below presents basic summary information on the cost drivers for these companies, along with the associated cost drivers for EGD and Union.

Table A-2

Average Business Conditions of Enbridge, Union, and U.S. Peers

		Gas Customers		Electricity Customers	Miles of Main		% Main Not Cast Iron or Bare Steel	
Company	**Period**	**Average**	**Average Annual Growth Rate**		**Average**	**Average Annual Growth Rate**	**Average**	**Average Annual Growth Rate**
Enbridge	2005-10	1,833,561	2.24%	0	21,186	0.50%	97.54%	0.96%
Union	2005-10	1,296,814	1.47%	0	22,180	0.84%	99.05%	0.01%
New Jersey Natural Gas	2004-09	474,988	1.49%	0	6,709	1.12%	90.54%	0.46%
Washington Gas Light	2004-09	1,032,369	1.82%	0	11,838	1.07%	93.25%	0.23%
Mean EGD and Union		1,565,188	1.85%	0	21,683	0.67%	98.29%	0.48%
Mean NJNG and WGL		753,679	1.65%	0	9,274	1.09%	91.89%	0.35%

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