May 14, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Re: EB-2011-0210 Union's Reply Evidence to the Pacific Economics Group Report

Dear Ms. Walli:

Please find attached Union's reply evidence to the Pacific Economics Group Research LLC report titled "Assessment of Union Gas Ltd. And Enbridge Gas Distribution Inc. Incentive Regulation Plans" filed in EB-2011-0210.

Sincerely,

[original signed by]

Chris Ripley
Manager, Regulatory Affairs

c.c: Crawford Smith, Torys
EB-2011-0210 Intervenors

P. O. Box 2001, 50 Keil Drive North, Chatham, ON, N7M 5M1 www.uniongas.com
Union Gas Limited

Response to Pacific Economics Group's September 2011 Report

(Revised April 2012)

by

Melvyn A. Fuss, Ph.D*

May 14, 2012

* Professor Emeritus of Economics, University of Toronto, and Senior Consultant, Charles River Associates

1. Introduction

I have been requested by Union Gas to evaluate Pacific Economic Group's (PEG) September 2011 report with respect to the following question. Does the material in that report provide reliable evidence on which to base the choice of incentive regulation (IR) parameters for the forthcoming IR regime? My answer to that question is no. I do believe that an econometric model such as the one estimated by PEG can provide a reasonable estimate of the TFP growth parameter. However, there are problems with the data developed by PEG which render application of the econometric model unreliable. In this evidence, I will explain why I believe that the material contained in PEG's report, while quite interesting in many ways, is inadequate for the purpose of choosing the parameters of an IR regime.

I will be concerned with three parameters which play important roles in the X factor: (1) total factor productivity (TFP) growth, (2) input price index growth, and (3) the stretch factor. In the next section I will discuss whether the period of time PEG's Ontario data covers is a sufficiently long period of time to form a reliable estimate of IR regime parameters. I conclude that it is not. In section 3 I explain how this problem could be overcome by using an econometric cost model of the kind estimated by PEG. In sections 4 – 6, I discuss some of the details of PEG's construction of data which I believe leads to problems in any application of these data to construct parameters for an IR regime. In particular, I believe that it is likely that PEG underestimates input quantity growth and overestimates input price growth. In section 7, I discuss PEG's estimation of an historical stretch factor. I believe that PEG's approach to estimating a stretch factor is flawed conceptually.

I have also been asked by Union to comment on PEG's statement that Union may be deferring capital expenditures during the IR period and may attempt to recoup a return on these expenditures in the 2013 test year. My comments on this issue are contained in section 8. I conclude that the empirical evidence does not support this statement. While deferment is a theoretical possibility, it should not be of concern to the Board as long as Union has maintained the quality of its service offerings. The evidence suggests that quality has been maintained.

Section 9 provides concluding comments.

2. The Period of Time Covered by the Data

PEG provides estimates of TFP growth and the other parameters over the five year period 2005-2010, usually dividing this period into two periods: 2005-2007 and 2007-10[1]. PEG emphasizes the period 2007-2010, which it calls the IR period. The first question to be asked is whether the five year period 2005-2010 or the three year period 2007-2010 are long enough to provide reliable estimates of the parameters to be used in the next IR regime.

I believe that PEG would agree with my statement that a three or five year period is too short to form IR parameter estimates. The only reason this may become an issue is that at various places in its report PEG leaves an impression (perhaps inadvertently) that it has provided estimates which can be used in the next IR regime. For example, on page 2 of its report PEG states:

> In 2008 the Board approved comprehensive plans for EGD and Union, both of which were determined through settlement agreements with stakeholders.

[1] The 2007-2010 period is labeled by PEG as a 2008-2010 period. However, it is actually a period in which there are three growth years: 2007-2008, 2008-2009, 2009-2010. I do not know why PEG labels this period 2008-2010 rather than 2007-2010 as I have done.

> 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.

In the above quote, PEG could possibly be interpreted as saying that three years is a sufficient period of time to provide data from which one can draw conclusions regarding the parameters of an IR plan. Elsewhere however, PEG explicitly denies that possible interpretation of the above quotation. On page 85 of the report PEG states:

> 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.

PEG has taken positions consistent with the quotation immediately above in other reports to this Board. In its November 2007 report regarding the parameters to be chosen for the current IR regime, PEG states:

> In choosing a sample period for a TFP study it is desirable that the period include the latest available data. It is also desirable for the period to reflect the long run productivity trend. We generally use a sample period of at least 10 years to fulfill this second goal.[2]

In his concept paper presented to the Board in the electricity distribution initiative, Lawrence Kaufmann states:

> …it is often not warranted to assume that TFP growth measured for short historical periods will be a good proxy for future trends. Shorter sample periods are more likely to be distorted by factors such as the timing of expenditures or unusual output growth. There is accordingly less confidence that past TFP trends are a good proxy for the future trend if the available data only allows TFP to be calculated for a relatively short period. As discussed, a general rule of thumb in regulatory proceedings is that a minimum of 10 years of data are

[2] PEG (2007), page 25.

> needed to calculate a generally reliable estimate of the industry's long-run TFP trend.[3]

I agree with the sentiments expressed in the last three quotations. The periods of time for which PEG provided data in this report for Union Gas are not sufficiently extensive that an estimate of long-run TFP growth applicable to the next generation IR plan can be estimated from that data alone with any confidence. Regardless of any other possible shortcomings present in PEG's report, this conclusion means that the estimates of annual TFP growth provided, which range between 1.58% and 1.70%, should not influence the choice of parameters for the next IR plan.

However, a sufficiently long data series is available for U.S. utilities (11 years). Abstracting from any specific data issues, PEG's econometric model can be used to provide an alternative estimate of TFP growth applicable to the IR period that avoids the time period problem. I now turn to that issue.

3. An Estimate of TFP Growth Using PEG's Econometric Model

PEG estimates an econometric model of cost using data from U.S. utilities drawn from the 11 years 1999-2009. The results of this estimation are contained in Tables 20-23 of its report. Conceptually, these results can be used to provide an estimate of TFP growth in the IR period for Union if the following two conditions are satisfied:

(1) the econometric cost function as specified by PEG and the parameter estimates contained in Table 20 are applicable to Union Gas.

(2) the business conditions[4] which prevailed during the 2005-2010 period are applicable to the IR period.

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[3] Kaufmann (2011), page 49.

The implications of condition (1) are discussed in more detail in section 7 of this evidence relating to the historical stretch factor. Of importance for this section of my evidence is the fact that the specification of the econometric model estimated implies that any difference in costs between periods 2005-2007 and 2007-2010 (with and without incentive regulation), given identical other business conditions in the two periods, is random with an expected value of zero. The same statement is true for TFP growth. Condition (2) is the usual underlying assumption utilized when historical estimates of TFP growth are applied to future periods.

Given the two conditions stated above, PEG's TFP growth rates that are predicted for Union Gas using the econometric model (contained in Tables 22 and 23) can be used to form an estimate of TFP growth in the IR period. Under the business conditions that prevailed in 2005-07, the econometric model's prediction of Union's TFP growth (which removes random variations in cost during 2005-07) is 1.05% per annum. Under the business conditions that prevailed in 2007-10, the econometric prediction of Union's TFP growth (which removes random variations in cost in 2007-10) is 0.77% per annum. A weighted average of these two predictions is 0.88%[5].

I am not advocating that PEG's report be used to infer an estimate of Union Gas' TFP growth for the purpose of specifying the parameters of the IR regime. I have problems with the data that PEG has used in its estimation procedures, especially its use of its COS model to estimate the capital input. However, it is possible that after the necessary detailed analysis of the data, PEG's data construction procedures do not yield results which are substantive different from those yielded by what I believe are preferred

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[4] The relevant business conditions are the growth rates of: outputs, input prices, the number of power distribution customers, the percentage of mains not cast iron or bare steel, and technological change (represented by the shift in the cost function).

[5] calculated as (1/5)*[2*1.05% + 3*0.77%].

procedures. In that event, PEG's report provides a long run TFP growth estimate of 0.88%, rather than estimates in the 1.58% - 1.70% range.

As I noted above, I do have some problems with the data that PEG has used in its estimation procedures. I now turn to this issue, beginning with the measurement of capital.

4. The Measurement of Capital

(a) Introduction

The measurement of capital quantity and capital price is an important procedure in the evaluation of a utility's performance under a price cap regime, or in the determination of the X factor parameters to be applied in such a regime. This is the case because capital costs typically represent more than one half of the annual costs of a gas utility.

In its report, PEG employs an unconventional model to estimate the growths of capital input quantity and price. This model is labeled by PEG as the Cost of Service (COS) model. To the best of my knowledge, the COS model has only been used by PEG. It has also only been used in some of PEG's recent submissions to regulators. In other recent submissions, PEG has utilized the conventional geometric decay model. For example, in December 2010, PEG presented testimony in California on TFP growth using the geometric decay model (Lowry (2010), Lowry and Hovde (2010)). Kaufmann (2011) used the geometric decay model in his concept paper on measuring capital input quantity and price in Ontario's electricity distribution industry[6].

I begin with a discussion of the conventional geometric decay model in order to place the COS model in perspective.

(b) The Conventional Geometric Decay Model

The capital input at time t is usually measured by the net capital (in constant dollar efficiency units) employed in production at time t. In the conventional model of capital accumulation, this net capital is linked to the series of additions prior to time t by assuming that the constant dollar (real) additions have declined in efficiency according to a geometric pattern of decay.

The price of the capital input associated with this measure of net capital is the user cost (service price) of capital services. The user cost is the cost of employing a unit of net capital for one year. This cost consists of financial costs, economic depreciation, and capital-related taxes. Economic depreciation during year t to t+1 associated with a specific asset is the decline in the current used price of the capital asset as it becomes older during the passage of time from t to t+1. Economic depreciation is not equal to efficiency decline unless the efficiency decline over time follows the geometric decay pattern. This fact creates considerable problems in empirical applications when the efficiency decline is not geometric decay.

An important characteristic of the user cost of capital under geometric decay is that the user cost does not depend at time t on the historical pattern of past asset prices. While it does depend on the time t price of used assets, this dependency can be expressed

[6] Equations [A-4] and [A-5] on page 14 of Lowry and Hovde (2010) are geometric decay model equations used to calculate capital input quantity and price respectively. Virtually the same equations are utilized in Kaufmann (2011), pages 45 and 47, equations [8] and [10].

in terms of the price of a new asset at time t, thus greatly reducing the data demands. This characteristic has led some commentators to label the model as a current cost model, in contrast to the accounting approach to valuation, in which capital cost is valued on a historical (book value) cost basis.

The geometric decay model has been studied extensively in the scholarly literature. It has also been applied empirically on many occasions, both inside and outside of regulatory settings. Its advantages and limitations have been widely documented, both from a theoretical and empirical standpoint[7].

(c) PEG's COS Model

PEG's COS model differs from the conventional model of geometric decay in two important ways. First, in the construction of the net capital at time t, additions prior to time t are assumed to have declined in efficiency units in accordance with a straight line pattern, rather than a geometric pattern. Second, the price of the capital input is an implicit price, defined as the deflated sum of financial costs and accounting depreciation, deflated by the constant dollar net capital. Financial costs and accounting depreciation are both based on the historical, or book value, cost of plant. This implicit price depends on the pattern of historical prices going back N-1 years from time t, where N is the lifetime of the physical capital.

PEG's COS model is unique, in the sense that, to the best of my knowledge, it has been utilized empirically only by PEG. Also to the best of my knowledge, PEG's model

[7] PEG appears to have developed its COS model in response to the often observed volatility in the user cost estimates, which is usually due to the volatility of the expected inflation (capital gains) term. This volatility issue has been recognized in the literature and smoothing methods have been developed to reduce the volatility.

has not been analyzed as yet in the scholarly literature[8]. Hence, there is no track record of its advantages and limitations, in contrast with the geometric decay model. This renders evaluation of the COS model very difficult.

(d) Conceptual Issues with PEG's COS Model

Theoretical Considerations

From a theoretical perspective, capital input and capital price must satisfy a fundamental equation of capital theory. This fundamental equation states that the price of one unit of the asset must equal the present discounted value (over its future lifetime) of the expected annual service prices, each service price weighted by the associated annual productive efficiencies of that one unit[9]. The capital input quantity and service price obtained under the assumption of geometric decay satisfy this theoretical condition.

It is unlikely that PEG's COS model will satisfy this condition. As I noted above, the model has not been studied in the theoretical literature. However, it is known that if the capital input is constructed using straight line efficiency decay, the economic depreciation component of the service price cannot be of the straight line type (Hulten (1990), p. 129).

There is a second result in the literature which is relevant. Diewert (2005) demonstrates that when economic depreciation is straight-line, the associated prior years capital inputs which should be aggregated over time are the gross additions, not the net additions obtained using straight line decay. Furthermore, he demonstrates that the

[8] Members of PEG have published a paper in which the COS model is used to obtain empirical estimates of TFP growth (Lowry and Getachew (2009)). However, the COS model was a minor part of the paper, and the authors provided only a short, broadly-based description of its characteristics. It is unlikely that the referees of that paper subjected the COS model to detailed peer review.

[9] This equation is constructed under the condition that the market for the capital asset is competitive.

additions cannot just be added up as is usually done (and done by PEG), but must be aggregated using index number procedures. Using the same conceptual framework, Diewert demonstrates that only under geometric decay can the prior additions be added up, and the correct additions in this case are the net additions. Diewert's analysis demonstrates that when we depart from geometric decay, unusual theoretical restrictions on capital inputs and prices are likely.

(e) Discussion of PEG's Data Generation Procedures in Light of the Theoretical Considerations.

Capital Input Quantity

As noted above, the capital input quantity in the COS model at time t is the sum of the vintages of constant dollar net capital surviving at time t. The vintages of net capital are obtained using straight line efficiency decay. The perpetual inventory accumulation equation of the geometric decay model can be given the same interpretation (the adding up of net capital). Hence, if the same vintage data is used, the difference between the COS model and geometric decay model capital inputs will be due to the different efficiency decline patterns (straight line versus geometric). There is no theoretical reason why actual efficiency decline patterns should be dominated by straight line or geometric patterns. It is essentially an empirical question. The empirical evidence that exists (Hulten and Wykoff (1981a, 1981b) favours the geometric decay pattern of decline[10].

Kaufmann (2011) recognizes the conclusions of the Hulten and Wykoff studies regarding depreciation patterns.

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[10] Hulten and Wykoff actually tested patterns of economic depreciation rather than patterns of efficiency decay. However, the self-dual property of the geometric pattern means that when the data favoured geometric economic depreciation, it also favoured geometric efficiency decay.

> Hulten and Wykoff examined the prices that were actually paid in secondary markets for used capital goods. They found that these prices were most consistent with geometric and not one-hoss shay depreciation patterns. This work has been very influential and is used directly by a number of researchers (including the US Bureau of Economic analysis) to value capital stocks.[11]

Capital Input Price

As noted above, the capital price in the COS model is an implicit price obtained by dividing the sum of financial costs and accounting depreciation by the capital input. PEG develops the COS model without an inclusion of taxes in the definition of capital costs. Taxes should be included since they represent a part of the cost of using the capital input[12]. Since corporate tax rates declined over the 2005-2010 period, exclusion of income tax effects from the price of the capital input would result in an upward bias in the rate of growth of the capital price.

Financial costs as included by PEG are actual costs incurred[13], and in that sense are similar to wages. Accounting depreciation is another matter. It is not equal to the economic depreciation cost incurred. Accounting depreciation is an amount the utility is permitted to charge its customers in lieu of collecting economic depreciation.

As noted earlier, economic depreciation in year t associated with a capital good is defined as the decline in the current price of the used good which occurs when the good becomes one year older (during year t). Notice that there is no reference to the original (book value) price of the good since it is not relevant to the concept of economic

[11] Kaufmann (2011), page 106.

[12] During 2008-2010, 50% of cost changes due to income tax changes were treated as a Z factor. Hence for some purposes, it would be appropriate to adjust capital cost changes for the impact of the Z factor during that period of time However, even in this case, 50% of income tax changes and 100% of property tax changes should be included in the capital input price change calculations.

[13] Equity costs are often not considered costs in an accounting framework. However, they are the returns in the form of dividends and expected capital gains required by investors to induce them to hold the firm's equity, and in that sense are the costs of retaining the mix of liabilities desired by the firm or determined by the regulator. PEG does properly include these costs.

depreciation. Hence any method which calculates depreciation based on book value, as the COS model does, cannot be estimating economic depreciation.

Economic depreciation is the true cost to the firm due to the fact that at the end of the year, the capital good is one year older. Another way of looking at economic depreciation is that it is the amount of money which must be put aside over the year to prepare for the future replacement of the aging capital asset (net of inflation).

I am not aware of any way to calculate economic depreciation when efficiency decline is straight line unless used goods price data are available. However, when efficiency decline is geometric, the calculation is straightforward. The rate of economic depreciation is equal to the rate of efficiency decay. Economic depreciation can be expressed as the rate of economic depreciation (adjusted for the expected inflation rate) times the current price of a new good. This fact probably accounts for the overwhelming use of the geometric decay model in empirical applications, since most researchers are reluctant to use accounting depreciation as a proxy for economic depreciation.

COS and geometric decay estimates of the growth of the capital price are likely to be quite different due to the different concepts of the cost of depreciation. Probably the most important source of difference is the use of original cost prices in the COS model versus current prices in the geometric decay model.

(f) Conclusion

I conclude that PEG's COS model is on weak ground from a theoretical point of view. What is needed is a derivation of the model from first principles so that one can evaluate the assumptions necessary to bring it into line with capital theory. PEG appears committed to its COS model[14] in the case of Ontario gas utilities. Until the time that the theoretical questions are resolved, I suggest that PEG produce geometric decay estimates of TFP growth and input price growth along with their COS model estimates. It will then be possible to see whether the differences are sufficient to pursue further the issue of model selection.

(g) Other Capital Issues

Taxes

As noted earlier, it is not clear from the PEG Report whether income and property taxes have been included in the calculation of capital costs. If they have not, the appropriate taxes should be added. As noted earlier, the exclusion of income taxes will bias upwards the growth rate of the capital input price since over the 2005-2010 period federal and provincial income tax rates declined.

The addition of income taxes is not a straightforward exercise. When a firm is earning a return on equity which exceeds the cost of equity, the taxes paid with respect to this excess return are not a cost of using capital.

Capital Additions

In order to construct estimates of the capital input, PEG employs annual additions data going back to 1986. Apparently the data are not compiled on a consistent basis. PEG had data from 1986-2006 from a previous consultation, and obtained data for 2007-2010 in the current proceeding. According to Union Gas, the 1986-2006 data do not

[14] Although, as noted earlier, as late as December 2010, PEG presented testimony in California on TFP growth using the geometric decay model (Lowry (2010)). In addition Kaufmann (2011) used the geometric decay model in his concept paper on measuring capital input quantity and price in Ontario's electricity distribution industry.

include construction work in progress. Additions data are booked in the year the projects are completed. The additions data for 2007-2010 however include construction work in progress, so that additions are booked on an accrual basis. When projects take several years to complete, the two versions of the additions data could be quite different, especially when the sample period is short as is the case for the 2005-2010 period.

Benchmarking Issues

In order to calculate the rates of growth of the capital input over the 2005-2010 period, it is necessary to start with an estimate of the net capital in 2005. This involves combining the net (surviving) vintages of capital stretching back N-1 years, where N is the average lifetime of capital. Capital additions data exist only back to 1986, so as long as N is greater than 20, some net capital surviving to 2005 cannot be calculated directly. The conventional method to deal with this problem is to establish a benchmark in 1985, which is an estimate of the net capital surviving to 1985. PEG establishes such a benchmark.

In order to establish the 1985 benchmark, it is necessary to assume a distribution of net (constant dollar) capital additions for vintages prior to 1986. In its report, PEG does not provide information regarding this necessary assumption[15]. However, if PEG is continuing the methodology it implemented in its November 20, 2007 report, it is possible to infer the assumption it is using. On page 79 of its 2007 report, PEG states,

> Our calculations of the capital cost and quantity in the benchmark year are based on the net value of plant. The capital quantity index in the base year is the inflation adjusted value of net plant in that year. We calculated this by dividing the net plant (book) value by an average of the values of a construction cost index for a period ending in the benchmark year.

[15] PEG also does not provide information on the assumed average lifetime of capital, an important parameter in the capital accumulation procedure.

In the appendix to this evidence, I develop the implications of the above statement. The statement implies that PEG is assuming that equal amounts of each vintage of net capital survive to 1985 regardless of their age in 1985. For example, if the average age of survival is greater than 40 years, equal amounts of capital added in 1984 and in 1946 will survive (in efficiency units) to 1985. This does not seem to me to be a reasonable assumption, and will lead in general to an overestimate of the constant dollar capital in 1985, as long as years prior to 1985 were years of positive inflation. The more conventional assumption used by those who estimate a benchmark capital stock in this manner[16] is to assume declining ratios of a surviving vintage of capital relative to the total net capital as the age of the vintage increases. This latter assumption implies that survival of older capital is not on a par with that of newer capital.

An often used declining weight procedure is the sum of years digits method introduced into the literature by Stevenson (1980). An example using Stevenson's procedure will provide an idea of the approximate magnitude of PEG's overestimate of the 1985 benchmark net capital.

Suppose asset price inflation was 2% per year for each year of the 46 years prior to 1985. Then it is possible to demonstrate that the 1985 benchmark capital stock utilizing PEG's procedure is 15% greater than the 1985 benchmark capital stock utilizing Stevenson's procedure. The differential will have narrowed by 2005, but an overestimate will remain. This overestimate will imply that PEG underestimates the growth rate of the capital quantity and overestimates the growth rate of the capital input price. I am not able to determine whether this impact is quantitatively important without access to PEG's detailed capital data.

[16] This method is known as the triangularization method.

5. The Measurement of Operations and Maintenance (O&M) Expenses

Labour

PEG states that it excludes costs of pensions from labour costs[17] because these costs tend to be volatile, which causes difficulty when the sample period is short. But pension costs are real costs from the point of view of the utility and have tended to increase faster than other labour costs in recent years. By excluding pension costs, PEG has likely underestimated the growth rate of O&M expenses.

I believe that PEG, if concerned about volatility, rather than eliminating pension costs should have used a smoothing technique for these costs. This can be accomplished by using earlier years' data which are available to PEG as a result of their earlier consultancy.

Compressor Fuel

PEG excludes compressor fuel costs from its definition of O&M costs. My understanding from discussions with Union Gas is that compressor fuel costs are part of O&M costs subject to the X factor.

O&M Costs

Table 19 in PEG's report contains Union's O&M expenditures (excluding compressor fuel) for the period 2007-2010. From that table, it can be seen that Utility O&M expenses grows at an annual rate of 3.13% over the 2007-2010 period. When one eliminates DSM and bad debt expenses (which I agree with), the rate of growth becomes 3.05%. The rate of growth used by PEG for the 2007-2010 period is 1.56%[18] Since

[17] It is not clear how pension costs were removed since the O&M data given to PEG by Union did not include a breakdown of benefits into pension costs and other benefits.

[18] PEG April 2012 Report (Table 14). Recall that PEG labels the 2007-2011 period as 2008-2011. I am unable to reproduce the 1.59% growth rate from the detailed O&M expenses data in Table 19.

35% of costs in PEG's data are O&M costs, the difference in growth rates leads to a reduction of 0.52% in the estimate of TFP growth over the 2007-2010 period.

6. The Impact of Deregulation of Ex Franchise Storage

In 2007 the Board decided to deregulate a portion of Union's activities primarily connected with the provision of ex franchise storage services. The remaining regulated services became known as utility services. Union provided PEG with O&M expense and capital additions data on a utility basis for 2007-2010. All of the other data used by PEG include non-utility data unless PEG has adjusted those data to place them on a utility basis. PEG does not indicate in its report that any adjustment has taken place. The only reference to the Board's deregulation decision is in footnote 46. In that footnote, the issue of data consistency over the full 2005-2010 time period is not raised.

If PEG has not adjusted its data, what are the implications for the measurement of TFP growth? First, consider O&M inputs. The expenses for 2005 and 2006 would include expenses that would not be consistent with the regulated expenses from 2007-2010. These expenses would be too high, and this fact would lead to an underestimate of the rate of growth of O&M expenses and O&M quantity input. This in turn would lead to an overestimate of TFP growth over the 2005-2010 period.

Now consider capital. The capital input in 2005 would be too large, since it would include storage capital used in the ex franchise operations that became deregulated. The rate of growth of the capital input over the 2005-2010 period and its sub-periods would be underestimated. The effect in 2007-2010 would be more pronounced unless the 2005 and 2006 additions data were adjusted for non-utility storage. This under-estimation would lead to over-estimation of TFP growth.

Without access to PEG's detailed data, it is not possible to determine the exact effect on TFP growth if PEG has not adjusted the data for the effects of deregulation. However, a rough approximate impact can be calculated as follows. From Union Gas' submissions to the Board in 2010 and 2011[19], it is possible to calculate the proportion of expenses that were non-utility expenses in 2008, 2009, and 2010. In each of these years, non-utility expenses were 4% of utility expenses for the categories: O&M expenses, financial expenses, and depreciation expenses. Therefore in each of 2008, 2009, 2010, the total of these costs on an unadjusted basis were 4% higher than the corresponding utility costs. I will assume the same was true for 2005.

If the 2005 total costs were not adjusted by PEG to place them on a utility-only basis, total costs would have been 4% higher than the 2005 costs which are comparable to the costs in 2008 - 2010. This implies there would have appeared to be a 4% total cost reduction between 2005 and 2010 which should have been attributed to the impact of deregulation. That 4% decline translates into an annual decline of 0.78%. The impact on TFP growth would be to overestimate that growth by 0.78% per annum.

7. The Stretch Factor

In the section of the report titled "Projecting EGD and Union's Historical TFP Growth"[20], PEG describes a method it claims provides an estimate of the increase in TFP growth attributable to IR regulation (a historical stretch factor). For Union, this increase is estimated as a "difference in differences": the difference between its actual TFP growth and the TFP growth predicted by PEG's econometric model during 2007-2010

[19] EB-2010-0039, Union Gas Evidence Exhibit A, Tab 2, Appendix A, Schedule 3, Page 1 of 1, Corrected and EB-2011-0038, Union Gas Evidence Exhibit A, Tab 2, Appendix A, Schedule 3.

[20] This section begins on page 98 of the report.

minus the difference between its actual TFP growth and the TFP growth predicted by PEG's econometric model during 2005-2007.

I will demonstrate that PEG's conclusion is not warranted. Given the structure of the econometric model, the "difference in differences" described above can only be interpreted as a combination of random residuals whose expected value is zero, and hence has no systematic (long term) interpretation.

PEG describes Union's predicted TFP growth as the growth Union would have sustained if it had the same level of cost efficiency as the average U.S. utility. Alternatively, PEG describes the predicted TFP growth as the growth the average US utility would have sustained if it faced the same business conditions as Union faced in 2005-2007 and 2007-2010. The latter statement is a conceptually correct statement. The former statement, which PEG relies on for the results in Table 22 and 23, is not necessarily correct. For this former statement to be correct, the estimated cost function must be applicable to Union Gas. However, if the econometric model is applicable to Union, a basic assumption under which the econometric model is estimated implies that any difference between Union's predicted TFP growth and its actual TFP growth is a random occurrence due to chance. If it is not random but systematic over time, the econometric model is misspecified and needs to be altered. I develop these themes below.

I begin with the relationship between TFP growth and the growth in cost in equation (1) below.

TFP growth = growth of output – growth of input

= growth of output – (growth of cost – growth of input price)

$$= \text{growth of output} + \text{growth of input price} - \text{growth of cost} \qquad (1)$$

In PEG's calculations of both actual and predicted TFP growths, the growth of output and the growth of input price are the same. Therefore the difference between predicted TFP growth and actual TFP growth can be expressed from equation (1) as

$$\text{predicted TFP growth} - \text{actual TFP growth}$$
$$= \text{actual growth of cost} - \text{predicted growth of cost} \qquad (2)$$

The average annual growth rate of cost is measured by the average difference in the logarithms of cost in the final and beginning years of the growth rate calculation. For example, the average annual growth rate of cost (AAGR) over the 2005-2007 period is calculated by

$$AAGR = (1/2)*(\ln C_{2007} - \ln C_{2005}) \qquad (3)$$

where C_{2007} is the cost in 2007. The difference in the logarithms is divided by 2 because there are two growth years (2005-6 and 2006-7) in the calculation.

Equation (3) can be combined with equation (2) to obtain the following expression for the difference in TFP measures.

$$\text{predicted TFP growth} - \text{actual TFP growth} \ \ \text{(average annual rates 2005-2007)}$$
$$= (1/2)*[(\ln C_{2007} - \ln C_{2005})^{actual} - (\ln C_{2007} - \ln C_{2005})^{predicted}]$$
$$= (1/2)*[(\ln C_{2007}^{actual} - \ln C_{2007}^{predicted}) - (\ln C_{2005}^{actual} - \ln C_{2005}^{predicted})]$$

$$= (1/2)*[e_{2007} - e_{2005}] \quad (4)$$

where e_{2007} is the error of prediction in 2007: actual minus predicted logarithm of cost in 2007.

It can be shown that the model assumptions imply that the expected values of e_{2007} and e_{2005} are equal to zero.[21] Hence, the expectation of $[e_{2007} - e_{2005}]$ is equal to zero. From equation (4), the expectation of the difference between the predicted and actual growth rates of TFP is zero.

Therefore, if the cost model is correctly specified and applicable to Union Gas' data in 2005 and 2007, any deviation between the actual and predicted annual average TFP growth rates over the 2005-07 period is due to random variation and would not be expected to persist. Conclusions based on this difference such as those contained in Table 23 are not warranted.

Similarly, it can be shown that the difference between the actual and predicted TFP growth rates over the 2007-2010 period can be expressed as

predicted TFP growth – actual TFP growth

$$= (1/3)*[(\ln C_{2010} - \ln C_{2007})^{actual} - (\ln C_{2010} - \ln C_{2007})^{predicted}]$$

$$= (1/3)*[(\ln C_{2010}^{actual} - \ln C_{2010}^{predicted}) - (\ln C_{2007}^{actual} - \ln C_{2007}^{predicted})]$$

$$= (1/3)*[e_{2010} - e_{2007}] \quad (5)$$

[21] Technically speaking, this statement would be true if PEG estimated the cost model using ordinary least squares. However, PEG used a more complicated estimation method which means that a large sample counterpart to this statement is required. That statement says that given the assumptions of the model, the asymptotic expectation of the prediction error is zero. This depends on the consistency of the estimator of the model's parameters.

In this case the difference in the logarithms is divided by 3 because there are three growth years (2007-8, 2008-9 and 2009-10) in the calculation.

Once again, it can be shown that the model assumptions imply that the expected values of e_{2010} and e_{2007} are equal to zero.[22] Hence, the expectation of $[e_{2010} - e_{2007}]$ is equal to zero. From equation (5), the expectation of the difference between the predicted and actual growth rates of TFP is zero.

Therefore, if the cost model is correctly specified and applicable to Union Gas' data in 2007 and 2010, any deviation between the actual and predicted annual average TFP growth rates over the 2007-10 period is due to random variation and would not be expected to persist. Conclusions based on this difference such as those contained in Table 23 are not warranted.

It also follows then that conclusions based on the "difference in differences" calculations are not warranted. Whether or not there was a surge in TFP growth from 2005-7 to 2007-10 due to IR regulation cannot be determined from the results in Table 23.

I now demonstrate that PEG's calculations of the differences between actual and predicted TFP growth in Table 23 can be calculated in terms of the residuals directly as $(1/2)*[e_{2007} - e_{2005}]$ and $(1/3)*[e_{2010} - e_{2007}]$ as determined by equations (4) and (5). I use PEG's results in Table 23 to demonstrate empirically this relationship.

First consider equation (4).

Actual growth rate of cost, 2005-2007 = $(1/2)*(\ln C_{2007} - \ln C_{2005})^{actual}$ = 1.63%[23]

Predicted growth rate of cost, 2005-2007 = $(1/2)*(\ln C_{2007} - \ln C_{2005})^{predicted}$ = 2.17%[24]

[22] Footnote 21 is also applicable to this statement.
[23] PEG Report, Table 14.

Predicted – actual cost growth, 2005-2007 = (1/2)*[e_{2007} - e_{2005}] = 2.17% - 1.63% = 0.54%. In Table 23, the difference between actual TFP growth and predicted TFP growth in 2005-2007 is 0.53%. The two numbers are the same, subject to round-offs in the intermediate calculations.

Now consider equation (5).

Actual growth rate of cost, 2007-2010 = (1/3)*(ln C_{2010} – ln C_{2007})^{actual} = 1.64%[25]

Predicted growth rate of cost, 2007-2010 = (1/3)*(ln C_{2010} – ln C_{2007})^{predicted} = 2.57%[26]

Predicted – actual cost growth, 2007-2010 = (1/3)*[e_{2010} - e_{2007}] = 2.57% - 1.64% = 0.93%. In Table 23, the difference between actual TFP growth and predicted TFP growth in 2007-2010 is 0.93%. The two numbers are the same. In this case there is no round-off to consider.

As demonstrated above, PEG calculates that (1/3)*[e_{2010} - e_{2007}] is greater than (1/2)*[e_{2007} - e_{2005}], and interprets that result as evidence of a positive historical stretch factor. How do I interpret that result in light of the foregoing analyses? The above numerical calculations demonstrate that the TFP growth differences in PEG's Table 23 are differences in residuals. First, the calculations are based on a very small number of observations, and so positive differences in residuals are not inconsistent with zero expectations. Second, in a well specified model, no significance can be attributed to these differences, although the residuals can provide clues as to how to improve the model specification. If PEG's calculated positive differences in residuals are indicative of persistent (non-random) effects, then the model is misspecified, since positive non-

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[24] PEG Report, Table 21
[25] PEG Report, Table 14.
[26] PEG Report, Table 21

random prediction residuals imply that the parameter estimates are biased[27]. One possibility is that incentive regulation has an effect on costs, but this effect is not included in the cost model. Some of the U.S. utilities in the data sample used in the regression were subject to incentive regulation during all or part of the 1999-2009 period, and some were not. A variable which represented incentive regulation should have been included in the list of business condition variables if one of PEG's purposes in estimating the econometric cost model was to try to provide an empirical measure of the impact of incentive regulation on the two Ontario utilities. In addition, tests of the appropriateness of applying the cost model and the parameter estimates obtained from U.S. data to Ontario utilities should have been undertaken.

8. Deferring Capital Expenditures

(a) Introduction

Union Gas has also asked me to comment on PEG's statement that during the IR period Union may be deferring capital expenditures on which it plans to recover a return in the test year 2013, and that this possible deferment is a cause of concern to the Board. PEG admits that it is very difficult to determine whether cost reductions are in fact cost deferments, but states that this difference may be discernable by studying carefully Union's proposed 2013 capital expenditures.

PEG distinguishes between replacement investment and expansion investment. This is a useful separation. PEG argues that expansion investment is less likely to be deferred than replacement investment[28] . I will also argue that expansion investment is

[27] Technically speaking, the correct word to use here is "inconsistent".
[28] PEG Report, page 86.

unlikely to be a deferral problem. Deferred replacement investment could be an issue, but only if it is accompanied by a decline in quality of service.

(b) The Evidence Regarding Deferral

PEG's evidence that deferral may be a problem appears to be contained in Table 18 of their report. In that table, the IR period annual rate of growth of capital expenditures declines in three of the five categories of capital, compared with the 2005-7 period. The implication drawn by PEG is that Union may recoup the decline in the 2013 test year. Table 18 in the PEG report does not separate out capital expenditures into their expansion and replacement components. If replacement investment is more likely to be deferred, such a separation is required. PEG appears to be basing its capital expenditures deferral conclusion on data that are inadequate for this purpose.

Union has made me aware of its answer to an interrogatory from Canadian Manufacturers and Exporters ("CME") which contains that data[29]. In each of the years 2008 through 2010, replacement investment (labeled in the table "maintenance and IT") is greater than actual replacement investment in 2007, which is prior to the IR period. The forecast replacement investment in 2013 is not unusually high, and in fact is less than the replacement investment in 2011.

I conclude from the table in the interrogatory answer that replacement investment does not appear to have declined in the IR period, and more importantly , there is not a "loading up" of replacement investment in the test year 2013. Both observations are at odds with the idea that Union adopted a strategy of deferred investment during the IR period.

[29] EB-2011-0210, J.B -1–14-6, Attachment 1.

(c) The Theory of Capital Expenditures Deferral

I begin by defining the concept of deferred capital expenditures. Consider those capital expenditures that would have been proposed by Union and accepted as prudent had Union been subject to annual cost of service regulation during 2008-2012 rather than incentive regulation. Any such expenditures which were not executed during 2008-2012, but instead are contained in the 2013 test year proposed expenditures, will be defined as deferred expenditures.

The reason it is useful to consider replacement and expansion expenditures separately is that under IR, replacement investment that increases the rate base does not generate additional revenue earning opportunities, whereas expansion investment does generate these opportunities. This is in contrast with cost of service (COS) regulation, where both types of investment generate revenue earning opportunities.

Consider first expansion capital expenditures. These expenditures will normally be made when a profitability criterion is satisfied, whether the regulation is IR or COS. There is no particular profit advantage in deferring such investment until the test year. PEG suggests (page 86) that "it could be profitable to defer (these) relatively large "lumpy" investments from within the term of the IR plan to a later base year". But since these projects, once completed, generate revenue whether they are booked in the IR period or in the test year, the timing of such investments should not matter. Only if the projects are multi year in duration *and* Construction Work in Progress (CWIP) are allowed in the rate base would it be strategic to defer the expansion project so that it is in progress during the test year. In that case, revenue could be generated in the test year which would not occur in the IR period. The Board generally has not allowed CWIP to be included in the rate base and Union has not included CWIP in its proposed test year rate base. I conclude that the incentive to defer expansionary capital expenditures is not present to any significant extent.

Now consider replacement capital expenditures. In the IR period, replacement capital expenditures do not generate additional revenue opportunities, so deferral of such expenditures prevents a decline in the utility's profits that would result from the additional expenditures. There clearly is an incentive for the utility to defer capital expenditures during the IR period until the test year, where such expenditures could generate additional revenue opportunities.

A reduction in capital expenditures without a compensating increase in O&M expenditures improves total factor productivity (TFP) as long as quality-adjusted output does not decline as a result of the reduction in capital expenditures. If the reduction is permanent, long-run TFP is improved. If the reduction is temporary, short-run TFP is improved. While long-run TFP improvement is preferable, short-run TFP improvement is also of value. A strategy of deferring investment falls in the category of short-term TFP improvement, as long as the utility does not reduce the quality of its service offerings.

The strategy of deferring capital expenditures is clearly beneficial to the utility. The question is: Is it harmful to customers? During the IR period, rates are set independently of the utility's capital expenditures, so customers' welfare during the IR period is not reduced by any strategy of deferred investment that is in play, absent quality of service decline. Customers' welfare may be increased if the utility's increased profitability is sufficient to place it in the zone where earnings are shared.

What is the effect on customers in the subsequent IR period? If the utility includes the deferred capital expenditures in the test year rate base, what is the effect on rates? The effect on rates will depend on how the rate base in this scenario would differ from the rate base if capital expenditures were not deferred. I would argue that the difference in rate bases in the two cases would be relatively minor. The gross plant would be the same except for the impact of asset price changes with respect to the deferred investment between the year in which the investment was deferred and .the test year. Accumulated depreciation would be slightly higher if investment were not deferred since the capital would be slightly older. Thus it is likely the net capital, and thus the rate base would be slightly greater in the case of deferred replacement investment. In this case, rates would be slightly higher, but customers would benefit from the slightly newer capital, both in terms of expected reduced maintenance expenditures and any technological change that might be embodied in the newer capital goods.

The impact of deferred investment on next period's customer welfare can be expected to be small. The effect applies only to the replacement portion of capital expenditures. The time period is short – a maximum of five years, and inflation has been and is expected to be relatively low over the five years. There are offsetting benefits to having newer capital goods in the system.

The above argument that if Union practiced a strategy of deferred capital expenditures, that strategy was benign with respect to other stakeholders depends on Union maintaining the quality of its services during the IR period. PEG investigated this question of service quality performance in Section 7 of its report. PEG concluded with respect to Union:

> 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.[30]

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[30] PEG Report, page 117.

> 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 the 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.[31]
>
> Overall, PEG-R concludes that Union is satisfying all of the Board's service quality requirements … [32]

The theoretical literature on IR regulation emphasizes that the problem with a utility having an incentive to defer capital expenditures is that it will do so by reducing the quality of its services to the detriment of its customers. The above quotes from PEG's report indicate that Union is not subject to this particular problem. It has maintained the quality of its services and may even have improved quality during the IR period.

(d) Conclusion

While the theory of deferred capital expenditures supports the idea that Union had an incentive to defer replacement investment during the IR period, the evidence indicates that Union has not acted on this incentive. Replacement investment has not declined over the IR period compared with 2007 replacement investment. Forecast replacement investment in 2013 does not show evidence of an attempt to recoup foregone replacement investment.

Even if deferred investment has occurred despite evidence to the contrary, the deferment is benign with respect to customers as long as quality is maintained. The service quality indicators evidence indicates that Union has maintained its quality during the IR period.

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[31] PEG Report, page 118.
[32] PER Report, page 120.

9. Conclusions

PEG's September 2011 report (revised April 2012) contains much information of interest. Nevertheless, it is not a particularly good source of information (with respect to Union Gas) on which to base estimates of the IR parameters for the next IR regime. The time period from which data for Ontario utilities is drawn is too short. In addition, in the case of Union, I have a number of reservations about the specific data and capital accumulation model employed. I also believe PEG's calculation of an historical stretch factor is flawed conceptually because the current specification of the econometric cost model does not allow for the possible differential impact of IR regulation on costs.

Because I do not have access to PEG's detailed data, some of my reservations regarding the data may turn out to have been correctly dealt with by PEG, or quantitatively unimportant. That does not mean that I believe TFP growth estimates in the range 1.58% – 1.70% should be applied in the next IR regime.

Suppose PEG's data withstand detailed analysis, the choice of capital accumulation model is unimportant quantitatively, and the econometric model is applicable to Union's data. Under these conditions, an estimate of the long-run TFP growth parameter arising from the information available in PEG's report is 0.88%, an estimate which I calculated in section 3 of this evidence.

Finally, PEG's statement that Union may be deferring capital expenditures during the IR period with the expectation that a return on these expenditures will be recouped in the test year 2013 is not supported by the available evidence. The theory of deferred capital expenditures also does not support the idea that deferral should be of concern to the Board since Union has maintained its level of service quality during the IR period.

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Appendix

Benchmark Capital and the Growth Rate of the Capital Input Quantity and Price

In order to calculate the rates of growth of the capital input over the 2005-2010 period, it is necessary to start with an estimate of the net capital in 2005. This involves combining the net (surviving) vintages of capital stretching back N-1 years, where N is the average lifetime of a particular vintage of capital. Capital additions data exist only back to 1986, so as long as N>20, some net capital surviving to 2005 cannot be calculated directly. The conventional method to deal with this problem is to establish a benchmark in 1985 which is an estimate of the net capital surviving to 1985. PEG establishes such a benchmark.

I begin by explaining how PEG obtains its benchmark capital for 1985.

Let NBV_{85} = the net book value of capital for 1985
X_{85} = the total net quantity of capital in 1985
x_{85-s} = the net quantity of capital from 1985-s surviving in 1985
p_{85} = the capital asset price index in 1985
p_{85-s} = the capital asset price index in1985-s.

The net book value in 1985 can be calculated as

$$NBV_{85} = \sum p_{85-s}\, x_{85-s} \qquad \text{(A.1)}$$

The sum in equation (A.1) is summed over s and runs from 0 to N-1. That will be true for all sums in the equations that follow.

I now divide both sides of equation (A.1) by $p_{85}\, X_{85}$, which is the expression for the constant dollar total net capital quantity in 1985 dollars.

$$NBV_{85} / (p_{85}\, X_{85}) = \sum (p_{85-s}/p_{85})\, (p_{85}\, x_{85-s} / p_{85}\, X_{85})$$

(A.2)

I can now solve equation (A.2) for the constant dollar total capital input $p_{85}\, X_{85}$ in terms of the net book value.

$$p_{85}\, X_{85} = NBV_{85} / [\sum(p_{85\text{-}s}/p_{85})\, (p_{85}\, x_{85\text{-}s} / p_{85}\, X_{85})]$$

(A.3)

Equation (A.3) can also be written as

$$p_{85}\, X_{85} = NBV_{85} / [\sum(p_{85\text{-}s}/p_{85})\, (x_{85\text{-}s} / X_{85})] \qquad \text{(A.4)}$$

I now turn to the quotation from PEG's 2007 report which appears in the main text of this evidence. To obtain the inflation adjusted value of net plant ($p_{85}\, X_{85}$), PEG divides the net plant book value (NBV_{85}) by the average of the construction cost index for a period ending in the benchmark year [$\sum(1/N)(p_{85\text{-}s}/p_{85})$]. The method in the quotation coincides with equation (A.4) when

$$x_{85\text{-}s} / X_{85} = 1/N \qquad \text{(A.5)}$$

What is the implication of equation (A.5), which is actually the assumption used by PEG to estimate the $x_{85\text{-}s}$ for which data are not available[33]? Equation (A.5) represents the distribution of the net surviving capital in 1985 of the various vintages of additions in prior years. The assumption implied by equation (A.5) is that equal amounts (1/N of the total) survive to 1985 regardless of their age in 1985. For example, if the average age of survival is greater than 40 years, equal amounts of capital added in 1984 and in 1946 will survive (in efficiency units) to 1985. This does not seem to me to be a reasonable assumption, and will likely lead to an overestimate of the constant dollar capital in 1985 as long as years prior to 1985 were years of positive inflation. The more conventional assumption used by those who estimate a benchmark capital stock in this

[33] Note that $X_{85} = \sum x_{85\text{-}s}$.

manner[34] is to assume declining ratios for $x_{85\text{-}s}/X_{85}$ as s increases. This assumption implies that survival of older capital is not on a par with that of newer capital.

An often used declining weight procedure is the sum of years digits method introduced into the literature by Stevenson (1980). Under this procedure equation (A.5) is replaced by the equation

$$x_{85\text{-}s}/X_{85} = (N\text{-}s)/(\textstyle\sum(N\text{-}s) \qquad \text{(A.6)}$$

Suppose the average survival lifetime N is 46 years[35]. When the ratios $x_{85\text{-}s}/X_{85}$ follow the pattern described by equation (A.6), the weight for additions in 1984 would be 45/1081. The weight for 1946 would be 7/1081. Hence the weights decline as the capital is drawn from an older vintage.

If efficiency decay is straight line, equation (A.6) provides an exact distribution of the vintages of net capital, relative to the total net capital, when annual real additions have been constant for the prior N years ending in 1985.

A continuation of the example will give an idea of the approximate magnitude of the overestimate of the 1985 benchmark net capital. Suppose asset price inflation was 2% per year for each year of the 46 years prior to 1985. Then using equations (A.4) – (A.6), it is possible to demonstrate that the 1985 benchmark capital stock utilizing equation (A.5) is 15% greater than the 1985 benchmark capital stock utilizing equation (A.6).

[34] This method is known as the triangularization method.
[35] PEG does not provide the estimate of N used in their April 2012 report. However, I have a copy of PEG's computer program used to calculate net capital on a COS basis in the 2007 hearings (dated March 2007). In that program PEG chooses N=46.