EB-2007-0615: Enbridge Gas Distribution's Interrogatories for Pacific Economics Group

Preamble

In this document:

I. "Usable electronic format" means in the same electronic format that PEG used in the computer model or data management. In other words, computer code should be provided in a form such that it can be used by the appropriate software package (such as GAUSS, STATA or some other software package used by PEG), and not as a ".pdf" file. Similarly, data should be provided in spreadsheet format (such as MS Excel) or database format (such as MS Access) or in an electronic format such as a ".csv" file that can easily be accessed by a program such as MS Excel, and not as a ".pdf" file.

II. Unless otherwise noted all interrogatories relate to PEG's June 20, 2007 report entitled "Rate Adjustment Indexes for Ontario's Natural Gas Utilities."

General

1. Please produce all communications between Board Staff, intervenors, and PEG with respect to the X-factor that occurred after the initial release of the March 2007 report.

Econometric Cost Model and Productivity Differential

2. Please provide all computer code, spreadsheets, data and other work papers PEG relied for the June 20, 2007 report "Rate Adjustment Indexes for Ontario's Natural Gas Utilities." These materials should be sufficient to replicate all results reported or discussed in PEG's June 20, 2007 report. Please provide all materials relied upon in usable electronic format. The response should include but not be limited to:
    a. All data on U.S. utilities either used or considered for the June 20, 2007 report.

b. All data on Union or EGDI either used or considered for the June 20, 2007 report.
c. The model code, data and regressions used to estimate weather normalized U.S. residential and commercial volumes, and Union and EGDI's residential and commercial volumes, as described on pages 71-74 of the June 20, 2007 report.
d. All weather normalized volumes calculated using PEG's model or otherwise relied on for EGDI, Union or U.S. utilities.
e. The econometric cost model.
f. The model, computer code or spreadsheets used to calculate input price differentials.
g. The model, computer code or spreadsheets used to calculate capital cost under both the GD and COS methodologies.
h. The incentive power model, as described on pages 61-63 of the June 20, 2007 report.

3. Please provide the results from all statistical tests showing that all or any sub-group of the 36 U.S. utilities over the period 1994-2004 can be used to benchmark the costs, productivity and other characteristics of Enbridge and Union.

4. Please provide the total number of regression models that were actually estimated in order to arrive at PEG's econometric cost model estimates.

5. Please provide the results from all statistical hypothesis tests used to accept the specification of the truncated or restricted translog model rather than the full translog model presented in PEG's study.

6. Please provide the following:
   a. Indicate whether or not the estimated cost function in the June 20th study is concave in factor prices at each time period and for each of the 36 U.S. utilities.

b. Provide the statistical tests conducted to determine concavity.
c. If the function is not concave throughout the sample then provide the years and companies for which concavity is satisfied.
d. Using Enbridge and Union data, along with the estimates of the econometric cost model indicate whether or not the cost function is concave for all time periods, and if not then identify which years concavity is satisfied.

7. Please provide all factor price elasticities, output elasticities, and rates of technological change for each U.S. utility and for each year in the sample period based on PEG's estimation results.

8. Please provide the residuals for each equation for PEG's econometric cost model.

9. Please provide the following:
   a. Were adjustments made to the stochastic errors in PEG's econometric model for autocorrelation and/or heteroskedasticity?
   b. If yes, please provide the complete details of how these adjustments were performed, including programming code, and spreadsheets.
   c. Also please provide estimates of the model without these adjustments, including programming code, and spreadsheets.

10. Please re-estimate the cost model such that the output variables from the June 20, 2007 study are replaced by the weather normalizing equations provided at the top of page 72 that characterize output quantities. Provide the data, computer code and spreadsheets and complete estimation results.

11. On page 46 of the June 20, 2007 report, PEG reports,

    "As an extra check, we regressed the growth in the TFP of our sampled U.S. utilities (using both approaches to capital costing) on the change in their cast iron reliance using data for the sample period. Using each approach, the estimated effect of reduced reliance on cost was negative (suggesting that it raises cost), but the hypothesis that a change in cast iron reliance has no effect on TFP growth could not be rejected at a high level of confidence. Our research does not then prompt us to adjust the econometric TFP target for Enbridge to reflect its plan for cast iron reduction."

Please provide all computer code, spreadsheets, data and other work papers that PEG relied upon for these statements / conclusions. Please provide all materials in usable electronic format.

12. On page 26 of the June 20, 2007 report, it is stated,

"In the latest research we calculate elasticity-weighted output indexes using elasticity estimates that vary by company and reflect each company's special operating conditions."

a. Please describe in detail the justification for using elasticity estimates that vary by company in the June 20, 2007 report.
b. Has PEG used elasticity estimates that vary by company in any other study that relied on an econometric cost model? If so, please provide a copy of the study.
c. Please provide the formula used to calculate elasticity estimates for EGDI, Union, and each U.S. utility considered for the June 20, 2007 report.
d. Please provide in usable electronic format the data reflecting each company's special operating conditions that was used to calculate elasticity estimates for EGDI, Union, and each U.S. utility considered for the June 20, 2007 report.

13. Please provide the following:

a. The data, programming code and spreadsheets for each year of the U.S. sample output quantity indices in Table 2, for both GD and COS methods, in order to show how the output quantity index was constructed from company-specific output quantity indices.

b. The data, programming code and spreadsheets for each year of the U.S. sample input quantity indices in Table 2, for both GD and COS methods, to show how the input quantity index was constructed from company-specific input quantity indices.

c. Are the cost share weights for each company derived from the econometric results or from observed data?

14. On page 82 of PEG's June 20, 2007 report, it is stated,

"In attempting to operationalize the use of company specific elasticities in our calculations, we discovered that the translog cost function generated some unreasonable values for these. We experimented with several alternative specifications and finally settled on one which differed from the translog form only in excluding the 'output interaction' terms."

a. Please provide all computer code, spreadsheets, data and other work papers associated with the estimation of all translog cost function that generated unreasonable values for company specific elasticities.

b. Please provide tables of results associated with these estimations in the same format as Table 19a and Table 19b.

c. Please provide all company specific elasticities associated with these estimations.

d. Please identify all company specific elasticities provided in c. that were unreasonable, and an explanation of why PEG considered them to be unreasonable.

15. In reference to the passage cited above at page 82 of the June 20, 2007 report, please estimate a full translog cost model, and provide;

a. All econometric estimates, and relevant statistics, such as standard errors in the same format as Tables 19A and 19B.

b. Please provide all programming code, spreadsheets, and data associated with the estimation of the full translog cost function.

c. Please provide all company-specific price elasticities, output elasticities, and rates of technological change for each year associated with this estimation.

16. On Page 84, PEG claims,

> "The results of econometric research are useful in selecting business conditions for cost models. Specifically, tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence. It is sensible to exclude from the model candidate business condition variables that do not have statistically significant parameter estimates, as well as those with implausible parameter estimates. Once such variables have been removed, the model is re-estimated. An econometric model in which business condition variables are selected in this manner is not a 'black box' that confounds earnest attempts at appraisal."

a. Please identify all candidate business condition variables that were considered or tested for potential inclusion in the econometric cost model relied upon for PEG's Ontario work.
b. Please provide all data associated with the candidate business condition variables identified in a. in usable electronic form.
c. Please provide all computer code, spreadsheets and other work papers associated with tests performed to consider excluding or including candidate business condition variables in the econometric cost model relied upon for PEG's Ontario work.

17. Please provide all computer code, spreadsheets, data and other work papers PEG relied on for its April 2007 testimony "Revised Prepared Direct Testimony of Mark Newton Lowry, Ph.D. on Behalf of Southern California Gas Company" in CPUC Docket No. A.06-12-010, and the accompanying report "TFP Research for Southern California Gas." The provided materials should be sufficient to replicate all results reported or discussed in the April 2007 testimony and report in CPUC Docket No.

A.06-12-010. Please provide materials in usable electronic format. The response should include but not be limited to:

a. All data on U.S. utilities either used or considered for the April 2007 testimony and report.
b. The econometric cost model used for the April 2007 testimony and report.
c. The model, computer code or spreadsheet used to calculate capital cost in the April 2007 testimony and report.
d. The data and model code provided to the California PUC Division of Ratepayer Advocates (DRA) in CPUC Docket No. A.06-12-010.
e. The work papers of the California PUC Division of Ratepayer Advocates (DRA) in CPUC Docket No. A.06-12-010.

18.

a. Please explain why PEG included Boston Gas, Keyspan Energy Delivery, and Atmos Mid-Tex (TXU) in the sample used to estimate the econometric cost model in its April 2007 testimony "Revised Prepared Direct Testimony of Mark Newton Lowry, Ph.D. on Behalf of Southern California Gas Company" in CPUC Docket No. A.06-12-010 and the accompanying report "TFP Research for Southern California Gas," but did not include these utilities in the sample used to estimate the econometric cost model in the June 20, 2007 report "Rate Adjustment Indexes for Ontario's Natural Gas Utilities."
b. Please provide the data on Boston Gas, Keyspan Energy Delivery, and Atmos Mid-Tex (TXU) that would be necessary to include these companies in the econometric cost model relied upon in the June 20, 2007 report "Rate Adjustment Indexes for Ontario's Natural Gas Utilities."

19. On page 7 of PEG's April 2007 revised report in CPUC Docket No. A.06-12-010, PEG states,

"The regional coverage of sampled LDCs can be seen to be somewhat uneven. For example, California distributors accounted for almost 30% of the customers in the sample but for only 15% of U.S. gas end users. In contrast, the South Central states accounted for only 2% of the customers in the sample and for almost 9% of end users nationally. We have made a correction for this imbalance that is discussed further below."

Then, on page 19 of the June 20, 2007 report in EB-2007-0606/0615,

"The regional distribution of sampled companies is uneven. For example, California utilities accounted for about 32% of the customers in the sample but for only 15% of all customers in the continental US. Utilities in the South Central States account for 2.5% of the customers in the sample but almost 15% of those in the continental US."

a. Please explain why there was an adjustment for the regional imbalances in the utility sample in CPUC Docket No. A.06-12-010, but not in the Ontario work.
b. Please comment on, and show the impact of, a similar adjustment for regional imbalances on the results reported in the June 20, 2007 report.

20. Please provide all computer code, spreadsheets, data and other work papers relied upon in the March 30, 2007 report "<u>Price Cap Index Design for Ontario's Natural Gas Utilities.</u>" The provided materials should be sufficient to replicate all results reported or discussed in the March 30, 2007 report. Please provide materials in usable electronic format. The response should include but not be limited to:
    a. All data on U.S. utilities either used or considered for the March 30, 2007 report.
    b. All data on Union or EGDI either used or considered for the March 30, 2007 report.
    c. The model used to weather-normalize U.S. residential and commercial volumes, and Union and EGDI's residential and commercial volumes.
    d. The econometric cost model.
    e. The model, computer code or spreadsheet used to calculate input price differentials.

f. The model, computer code and/or spreadsheets used to calculate capital cost under both the GD and COS methodologies.

21. Please provide all computer code, spreadsheets, data and other work papers PEG relied upon for DTE Docket No. 03-40, and the accompanying reports "X-Factor Calibration for Boston Gas" and "The Cost Performance of Boston Gas." The provided materials should be sufficient to replicate all results reported or discussed by PEG in DTE Docket No. 03-40. Please provide materials in usable electronic format. The response should include but not be limited to:
    a. All data on U.S. utilities either used or considered for PEG's testimony and reports in DTE Docket No. 03-40.
    b. The econometric cost model used for PEG's testimony and reports in DTE Docket No. 03-40.
    c. The model, computer code or spreadsheet used to calculate capital cost in PEG's testimony and reports in DTE Docket No. 03-40.

22. Please provide all computer code, spreadsheets, data and other work papers PEG relied upon for the June 2004 report "New Zealand Natural Gas Distribution Cost Performance: Results from International Benchmarking" and the June 2004 report "Comments on Meyrick and Associates Reports Prepared for the Commerce Commission's Inquiry into New Zealand Gas Transmission and Distribution Sectors." The provided materials should be sufficient to replicate all results reported or discussed by PEG in these reports. Please provide materials in usable electronic format. The response should include but not be limited to:
    a. All data on U.S. utilities either used or considered for PEG's June 2004 reports.
    b. The econometric cost model used for PEG's June 2004 reports.
    c. The model, computer code or spreadsheets used to calculate capital cost in PEG's June 2004 reports.

23. On page ii of the June 20, 2007 report presented for Ontario, PEG states,

> "The issuance of a preliminary report resulted in helpful comments that have prompted us to revise our research methods in several important respects. On the basis of the new work, we recommend the use of the COS approach for the design of the rate adjustment mechanism."

   a. Please explain in detail the justification for recommending, on the basis of new work, the use of the COS approach.
   b. Please provide all computer code, spreadsheets, data, work papers and other documentation associated with the new work performed in response to comments, including new work that led PEG to recommend the use of the COS approach.

24. On page 3 of the June 20, 2007 report,

> "These and other comments of stakeholders and Board staff prompted upgrades in our methods that materially altered some of the research results."

   Please describe in detail all such upgrades in PEG's methods, and how they materially altered some of the research results.

25. With regard to your "urban core" dummy variable, please explain in detail the criteria used to determine whether an LDC serves an "urban core.

26. On page 36 of PEG's June 20, 2007 report, PEG states,

> "It should also be noted that PEG has long had difficulty identifying statistically any special impact on gas utility cost management that results from transmission and storage operations. There was for this reason no compelling need to take transmission and storage into account in choosing Union's peer group."

   Please provide all support, including all computer code, spreadsheets, data, work papers and other documentation associated with any of the work performed, underpinning these statements.

27. On page 25, of the June 20, 2007 report,

> "The incremental scale economies from output growth are even greater for large companies like Enbridge and Union than they are for smaller companies. This is due, apparently, to special economies in the delivery of volumes, which are characteristic of piping systems."

a. Please explain in detail what is meant by the phrase "special economies in the delivery of volumes, which are characteristic of piping systems."
b. Please provide any and all analyses PEG has undertaken related to "special economies in the delivery of volumes, which are characteristic of piping systems."

28. On page 39 of the June 20, 2007 report, PEG states,

> "Enbridge and Union face rather different operating challenges."

Please specify and describe in detail the different operating challenges faced by Enbridge and Union.

29. Please provide PEG's TFP growth projections for Enbridge and Union based on the GD and COS approaches to capital input price measurement, as in Table 10, for each of the years 2000, 2001, 2002, 2003, 2004, and 2005. Provide the data, programming code, and spreadsheets.

30. Please provide the following:

a. The exact source for Canadian multifactor productivity (MFP) or total factor productivity (TFP) growth as described in PEG's study at page 46:

> "As discussed further in Section 3.5 below, we found 1998-2005 to be a sensible input price comparison period when COS capital costing is used. The MFP trend of the Canadian economy was 1.21% during this period."

b. Please provide Canadian MFP levels and growth rates for each available year.
c. Are the Canadian MFP indices based on a GD or COS concept for capital input price measurement?

31. Please confirm from Table 2 that over the period 1994-2004 the average annual TFP differential between the U.S. industry and the U.S. economy was 0.04% (= 1.43 - 1.39) under the industry's COS method, and -0.21% (= 1.18 - 1.39) under the industry's GD method.

32. Please provide the following:
    a. The exact source for the U.S. economy's MFP level and growth rates.
    b. The levels and rates for each year available.
    c. Are the U.S. MFP indices based on a GD or COS concept for the capital input price calculation?

33. Please provide in-sample and out-of-sample statistical measures as evidence of the U.S. econometric model's ability to predict the costs for each of the sampled U.S. utilities. Specifically, please produce the root mean squared percentage error (RMSPE), the mean percent error (MPE), and the mean absolute percent error (MAPE), measured both in-sample and out-of-sample lagged 1 year for each year for the period 1994-2004 for each of the 36 firms listed in the sample group. Please provide the same measures for the 3 firms not included in the Ontario sample (OEB case EB-2007-0606/0615) but included in the California sample (CPUC Docket No. A.06-12-010). Please provide these measures using each of the following:
    a. The March 30, 2007 model presented in Ontario.
    b. The April 2007 model presented in California.
    c. The June 20, 2007 model presented in Ontario.

34. The June 2007 version of the U.S. model's peer group TFP estimations changed significantly, as the following table demonstrates. The new report details TFP rates that are 0.27% higher, on average. The range of differences in historical growth rates is from -1.21% (Connecticut Energy) to +1.90% (Orange & Rockland), for a total range of difference of 3.11%. Similarly, the new report details scale economies that are -1.05% lower on average. The range of differences in historical scale

economies is from -4.26% (Southwest Gas) to +2.07% (Connecticut Natural Gas), for a total range of difference of 6.33%.

Peer Group Candidates	PEG (March 2007)		PEG (June 2007)		TFP Increase / Decrease	Scale Economies Increase / Decrease
	TFP (GD)	Scale Economies (GD)	TFP (GD)	Scale Economies (GD)		
Alabama Gas	-1.9%	0.3%	-2.11%	-0.08%	-0.21%	-0.38%
Atlanta Gas Light	1.1%	1.3%	1.32%	0.19%	0.22%	-1.11%
Baltimore Gas and Electric	0.3%	0.6%	1.29%	0.13%	0.99%	-0.47%
Cascade Natural Gas	3.2%	3.9%	2.70%	-0.08%	-0.50%	-3.98%
Central Hudson Gas & Electric	1.0%	0.6%	2.00%	-0.06%	1.00%	-0.66%
Connecticut Energy	2.4%	2.5%	1.19%	0.05%	-1.21%	-2.45%
Connecticut Natural Gas	-1.6%	-2.1%	0.27%	-0.03%	1.87%	2.07%
Consolidated Edison	0.5%	0.1%	0.87%	0.17%	0.37%	0.07%
Consumers Power	0.2%	1.0%	0.46%	0.10%	0.26%	-0.90%
East Ohio Gas	1.9%	0.7%	2.00%	0.41%	0.10%	-0.29%
Illinois Power	2.2%	0.2%	1.98%	0.15%	-0.22%	-0.05%
Louisville Gas & Electric	0.3%	1.4%	-0.08%	-0.01%	-0.38%	-1.41%
Madison Gas & Electric	0.8%	2.2%	0.74%	0.02%	-0.06%	-2.18%
Mountain Fuel Supply	1.2%	2.0%	1.89%	0.25%	0.69%	-1.75%
New Jersey Natural	1.5%	2.4%	1.77%	0.19%	0.27%	-2.21%
Niagara Mohawk	0.9%	0.2%	0.98%	0.15%	0.08%	-0.05%
North Shore Gas	1.7%	1.1%	1.97%	0.17%	0.27%	-0.93%
Northern Illinois Gas	0.9%	1.2%	1.18%	0.29%	0.28%	-0.91%
Northwest Natural Gas	1.8%	3.5%	1.94%	0.13%	0.14%	-3.37%
Nstar Gas	1.9%	0.6%	2.54%	0.23%	0.64%	-0.37%
Orange and Rockland	-3.0%	-1.0%	-1.10%	-0.05%	1.90%	0.95%
Pacific Gas & Electric	1.8%	0.8%	2.11%	0.40%	0.31%	-0.40%
PECO	0.5%	1.2%	0.81%	0.09%	0.31%	-1.11%
Peoples Gas Light & Coke	-0.4%	-1.4%	0.14%	0.03%	0.54%	1.43%
People's Natural Gas	0.3%	0.0%	0.30%	0.03%	0.00%	0.03%
PG Energy	1.3%	1.3%	0.91%	0.05%	-0.39%	-1.25%
Public Service Electric & Gas	-0.9%	0.3%	-0.61%	-0.13%	0.29%	-0.43%
Public Service of NC	0.4%	3.3%	0.41%	0.01%	0.01%	-3.29%

Peer Group Candidates	PEG (March 2007)		PEG (June 2007)		TFP Increase / Decrease	Scale Economies Increase / Decrease
	TFP (GD)	Scale Economies (GD)	TFP (GD)	Scale Economies (GD)		
Rochester Gas and Electric	0.8%	0.5%	0.79%	0.07%	-0.01%	-0.43%
San Diego Gas & Electric	-0.5%	1.6%	-0.59%	-0.01%	-0.09%	-1.61%
Southern California Gas	1.1%	0.6%	1.52%	0.28%	0.42%	-0.32%
Southwest Gas	2.6%	4.5%	2.63%	0.24%	0.03%	-4.26%
Washingon Natural Gas	0.6%	2.8%	2.08%	0.46%	1.48%	-2.34%
Washington Gas Light	-0.1%	0.6%	0.95%	0.12%	1.05%	-0.48%
Wisconsin Gas	1.6%	1.2%	1.57%	0.16%	-0.03%	-1.04%
Wisconsin Power & Light	1.9%	2.1%	1.22%	0.01%	-0.68%	-2.09%
				Average	**0.27%**	**-1.05%**

a. For each of the firms listed in the table above, please provide all details that caused the change in TFP estimation.

b. For each of the firms listed in the table above, please provide all details that caused the change in estimated scale economies.

c. The TFP projection for Enbridge is calculated as returns to scale plus the rate of technological change. Please calculate for each of the firms in the table above, for both the March and June estimations, the implicit rate of technological change implied by this formula.

35. On p. 46 PEG states,

> "It is noteworthy that the target for Enbridge is well above its recent historical trend. One theory that fits these facts is that the frequent rate cases of Enbridge produced unusually weak performance incentives."

Please produce the historical trends for each of the sample U.S. firms (including the 3 missing from the sample used in Ontario relative to those used in CPUC Docket No. A.06-12-010). Please comment on any "unusually weak performance incentives" for each U.S. utility whose TFP estimate is above its historical trend for the 1994-2004 period.

36. Please provide the following:
    a. All the data, programming code and spreadsheets used to construct all the indices and growth rates, including the fixed revenue share-weighted output quantity indices and growth rates, in Table 7.
    b. All the data, programming code and spreadsheets that enable the construction of flexible revenue share-weighted output quantity indices and growth rates.
    c. All the data, programming code and spreadsheets used to construct all the indices and growth rates in Table 6.

37. Please confirm that Enbridge's annual average TFP growth rate calculated from Tables 7 and 6 using revenue share weights is -0.1% (= 2.02 - 2.12) with the COS method and 0.1% (= 2.02 - 1.92) with the GD method. In addition with the same calculation the average (2000-2005) annual TFP growth rate for Union is 1.15% (= 1.20 - 0.05) with the COS method and 1.13% (= 1.20 - 0.07) with the GD method.

<u>Input Price Differential</u>

38. Please show in tabular format the derivation of the appropriate cost share weights for each year used in each of the March 2007 and June 2007 reports.

39. Please provide the following:
    a. The input price index levels and growth rates, for all U.S. sample utilities, and for each year 1994-2004, constructed in a comparable manner and consistent (in other words using the same data) with the input quantity indices and growth rates found in Table 2. Do this for both the GD and COS methods. Provide all the data, programming code and spreadsheets.

b. The data, programming code and spreadsheets showing how the U.S. sample input price indices from part a), using both GD and COS methods, were constructed from company-specific input price indices.

40. Please calculate U.S. economy input price index and growth rates for each year over the period 1994-2004 in the same manner as PEG calculated the Canadian input price indices and growth rates in Table 14. Provide all data, programming code and spreadsheets.

41. With the same data, namely input prices and quantities used to construct Enbridge's and Union's input quantity indices and growth rates in Table 5, construct annual input price indices and growth rates for both companies, using the GD and COS methods. Provide all data, programming code and spreadsheets.

42. Construct an implicit Tornqvist input price index and associated growth rates for both Enbridge and Union using the GD and COS methods. Provide all the data, programming code and spreadsheets. This index is calculated by the following steps; 1) form the ratio of cost in period t to cost in period t-1, using the appropriate input prices and quantities for Enbridge and Union that was used to construct their input quantity indices; 2) divide the ratio by the appropriate (explicit) Tornqvist input quantity index; and 3) calculate the growth rate from the resulting implicit index.

43. Please explain in detail and provide all calculations to show how the capital input cost shares in Tables 13A and 13B are unaffected by the smoothing or non-smoothing of the real rate of return that is used in the calculation of the capital input price.

<u>Stretch Factor</u>

44. On page 61 of PEG's June 20, 2007 report, PEG claims,

> "We have relied on two sources in developing our stretch factor recommendation. One is historical precedent. In research for Board staff last year to develop an IR plan for power distributors we found that the average explicit stretch factor approved for the rate escalation indexes of North American energy utilities is around 0.50%."

a. Please provide all documentation associated with the research PEG performed on historical precedent that was relied on or considered in developing the stretch factor recommendation.
b. Please provide all incentive regulation decisions related to North American energy utilities that incorporated an explicit stretch factor.
c. Please provide all incentive regulation decisions related to North American energy utilities that did not incorporate an explicit stretch factor.

45. PEG states on page 61 that,

> "A second substantive basis for choosing stretch factors is our incentive power research for Board staff. Our incentive power model calculates the typical performance that can be expected of utilities under alternative stylized regulatory systems."

Please provide the data, programming code, and spreadsheets of PEG's incentive power model used to justify the stretch factor.

46. Has PEG's incentive power model ever produced a negative stretch factor? What conditions would have to prevail for this to occur? Please provide examples where this has occurred, or where it could occur.

47. Given the apparent complexity of PEG's incentive power model, please comment on the ability for the OEB (or Intervenors, or the Company) to replicate and/or reproduce results for future PBR periods without reliance on PEG.

48. Please detail PEG's estimate of Enbridge's initial efficiency that went into the incentive power model (or the U.S. proxy that was used instead of Enbridge data).

Average Use Factor

49. PEG states on page 47 that,

> "The average use factor was explained in Section 2 to be the difference between the growth trends in the output quantity indexes with revenue and elasticity weights."

Please provide all data, programming code and spreadsheets used to calculate the output quantity indexes with revenue and elasticity weights for both Enbridge and Union.

50. Is the following correct? Suppose the PD component for both Enbridge and Union were calculated using industry TFP growth rates based on the trend in the output quantity index with revenue weights (from the previous interrogatory) and the AU component is set to zero, all else equal, would the computed X factors equal the ones presented by PEG on page iii? If not, provide a detailed explanation as well as all data, programming codes and spreadsheets.

51. Using the results from Table 4 for the U.S. firms and from page 47 for Enbridge, the following table of AU factors can be inferred:

	US Sample GD	**Enbridge GD**	**US Sample COS**	**Enbridge COS**
Output Growth, revenue-weighted (A)	0.10%	2.02%	0.10%	2.02%
Output Growth, cost elasticity-weighted (B)	1.28%	2.74%	1.37%	2.83%
Average Use Factor (A-B)	**-1.18%**	**-0.72%**	**-1.27%**	**-0.81%**

a. Please provide a similar table for each of the 36 U.S. firms comprising the U.S. sample, and include all data, programming code, and spreadsheets.
b. Please also provide the same for the omitted sample firms that were used in CPUC Docket No. A.06-12-010.

c. The table above shows that revenue-weighted output growth rate for Enbridge is over 20 times greater than for the U.S. firms, while the cost elasticity-weighted output growth rate for Enbridge is 2 times the cost elasticity-weighted output growth rate for the U.S. firms. Please explain this difference in output growth rates. Also provide all data, program code, and spreadsheets used to derive these growth rates.
d. The table shows that the AU factor for the U.S. firms is 64% greater (in absolute value) compared to Enbridge under the GD method and 57% greater in absolute value under the COS method. Please explain this difference, and in particular focus on the findings of the econometric cost model, from which the cost elasticities are obtained.
e. The difference in AU factors between the U.S. firms and Enbridge is 46 basis points, irrespective of whether the GD or COS methods are used. Please explain this coincidence with respect to the findings of the econometric cost model, from which the cost elasticities are obtained.