June 13, 2013

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

via RESS and courier

Dear Ms. Walli:

Re: Defining and Measuring Performance of Electricity Distributors
Expert Report of Power System Engineering ("PSE") Inc. (Consultant to the Coalition of Large Distributors)
Board File No. EB-2010-0379

On May 3, 2013, the Ontario Energy Board ("OEB" or the "Board") released the report of its consultant, Pacific Economics Group ("PEG") on benchmarking and rate adjustment parameters and invited stakeholder comment on such. The Coalition of Large Distributors ("CLD"), comprised Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro Hydro-Electric System Limited and Veridian Connections Inc., is pleased to participate in this process.

On May 30, 2013, the Board advised that it would make provision for stakeholders to review the expert reports filed by other stakeholders before filing submissions. Please find attached herewith the expert report of PSE, consultant to the CLD.

Should you have any questions, please do not hesitate to contact me.

Yours truly,

[Original signed on behalf of the CLD]

Indy J. Butany-DeSouza, MBA
Vice President, Regulatory Affairs
Horizon Utilities Corporation

Gia M. DeJulio
Enersource Hydro Mississauga Inc.
(905) 283-4098
gdejulio@enersource.com

Indy J. Butany-DeSouza
Horizon Utilities Corporation
(905) 317-4765
indy.butany@horizonutilities.com

Patrick Hoey
Hydro Ottawa Limited
(613) 738-5499 x 7472
patrickhoey@hydroottawa.com

Colleen Richmond
PowerStream Inc.
(905) 417-6900 x 25186
colleen.richmond@powerstream.ca

Amanda Klein
Toronto Hydro-Electric System Limited
(416) 542-2729
regulatoryaffairs@torontohydro.com

George Armstrong
Veridian Connections Inc.
(905) 427-9870 x2202
garmstrong@veridian.on.ca

the power to help you succeed.

Expert Report for

Defining and Measuring Performance of Electricity Distributors (EB-2010-0379)

PSE Expert Report: Recommendations on the Design of 4th Generation Incentive Regulation

Authors

Steven A. Fenrick, M.S.

Lullit Getachew, Ph.D.

David Williams, J.D.

June 13, 2013

Contact: Steven A. Fenrick

1532 W. Broadway

Madison, WI 53713

Direct: 608-268-3549

Fax: 608-222-9378

Email: fenricks@powersystem.org

Web Site: www.powersystem.org

Table of Contents

List of Tables and Figures

1 Summary of Recommendations

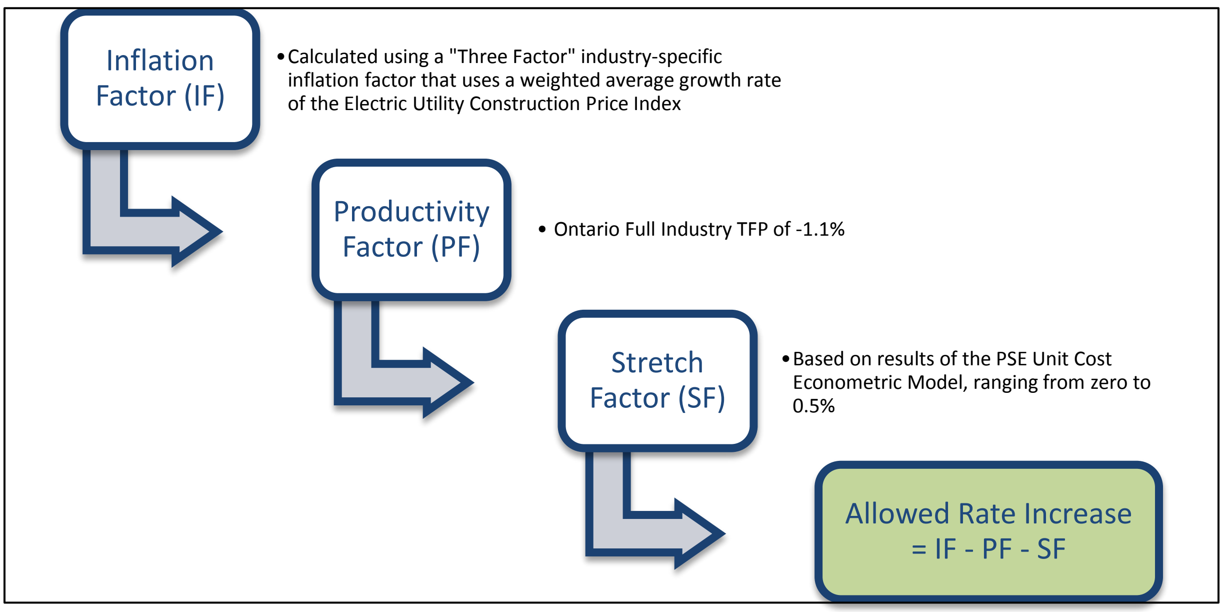
This report provides the Ontario Energy Board (the "Board") and other stakeholders with the perspective and recommendations of Power System Engineering, Inc. ("PSE") regarding the parameters and design of the upcoming 4th Generation Incentive Regulation ("4GIR") rate plan. PSE is offering our perspective and recommendations on behalf of The Coalition of Large Distributors ("CLD").[1]

This expert report will be focused on four 4GIR issues in particular. These four issues within the 4GIR rate plan are:

1. The proposed method for calculating the inflation factor,
2. The proposed method for calculating the productivity factor,
3. The recommended cost benchmarking framework and the proposed econometric model, and
4. The proposed method for calculating the stretch factor parameters.

The 4GIR plan will allow electric distribution rates to annually escalate by the increase in the inflation factor ("IF") minus both the productivity factor ("PF") and the stretch factor ("SF"). Figure 1 provides a summary of PSE's recommendations regarding the 4GIR parameters of the inflation factor, productivity factor, and the stretch factor. We also recommend using the PSE Unit Cost Econometric Model as the sole basis for determining distributor stretch factors, thereby eliminating the use of the "peer group" approach.

Figure 1 Summary of PSE's Recommendations



[1] The CLD includes Enersource Hydro Mississauga Inc. ("Enersource"), Horizon Utilities Corp. ("Horizon"), Hydro Ottawa Ltd. ("Hydro Ottawa"), PowerStream Inc. ("PowerStream"), Toronto Hydro-Electric System Ltd. ("Toronto Hydro" or "THESL"), and Veridian Connections Inc. ("Veridian").

PSE's recommendations differ from those proposed by Pacific Economics Group ("PEG") in its May 2013 report titled "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board".[2] A summary of PSE's recommendations in comparison to PEG's recommendations are provided in Table 1 below.

Table 1 PEG Recommendations vs. PSE Recommendations

4GIR Component	PEG Recommendations	PSE Recommendations
Inflation Factor	"Three Factor" using PEG's capital service price calculation as the capital price component	"Three Factor" using a weighted average of the EUCPI as the capital component
Productivity Factor	0.1%	-1.1%
Benchmarking Framework	PEG Table 12 Econometric Model Results, along with Unit Cost Indexing Results (i.e. peer groups)	PSE's Unit Cost Econometric Model, and eliminate the peer group approach
Stretch Factor	5 Cohorts ranging from 0.0% to 0.6%	6 Cohorts ranging from 0.0% to 0.5%

Comparison of PSE and PEG Recommendations on 4GIR Rate Formula

The proper calibration of the 4GIR parameters is imperative to a well-functioning incentive regulation plan. If the 4GIR parameters are not reflective of the cost pressures faced by distributors, the plan can cause financial stress during the 4GIR interim years, followed by a substantial rate increase during re-basing. Additionally, parameter values that are too restrictive will likely push distributors to forgo the 4GIR rate plan in favor of the other options laid out in the Renewed Regulatory Framework for Electricity ("RRFE") document.

Our recommendations are in response to PEG's research and recommendations found in the PEG May 2013 report. We believe many of the methodologies employed in the PEG report are best practice. However, PSE feels that certain refinements to their recommendations are absolutely necessary to developing a 4GIR plan that adequately reflects the cost pressures faced by Ontario distributors.

First Recommendation: Inflation Factor

PEG recommends a "three factor" industry-specific inflation factor. The capital component is based on a 3-year moving average of PEG's capital service price calculation. It is our understanding that the reason PEG instituted the 3-year moving average is to reduce the annual volatility in the index. However, the volatility in PEG's recommended inflation factor will still be greater than the historic volatility of the 3rd Generation Incentive Regulation inflation factor,

[2] The PEG recommendations discussed in this PSE Report are the ones found in the last version of their May 2013 report. To avoid confusion, it is worth noting that an earlier version of the PEG report contained different recommendations, e.g. their recommended productivity factor was zero rather than 0.1%.

the GDP-IPI.

PSE agrees with PEG's "three factor" approach in general, and with making the inflation factor industry-specific. We also believe the two OM&A input price components of labour and non-labour put forth by PEG are appropriate. However, the capital component can easily be adjusted to allow the use of the most current annual number, rather than a 3-year moving average, thus substantially reducing volatility. This can be done by eliminating the cost of capital component in the inflation factor. We recommend using a simple weighted average of the annual Electric Utility Construction Price Index ("EUCPI") to form the basis of the capital component of the inflation factor.[3]

To put the PEG recommendations into context, and to show their inapplicability to most distributors, in 2012 PEG's recommended 4GIR parameters would have resulted in an average allowed rate increase of about 0.1 percent. Some distributors would have actually faced rate decreases. The PEG recommendations would essentially result in a rate freeze in 2012.

A rate freeze simply does not square with the fact that recent distributor unit costs are increasing by about 3.5 percent per year from 2007 to 2011 and by about 2.6 percent from 2002 to 2011. Given PEG's 0.1% productivity factor recommendation, combined with the fact that PEG's recommended inflation factor is based on a 3-year moving average, it is likely that PEG's recommendations would result in a de facto rate freeze for the next one to three years.

What is even more worrisome than the unsustainable rate freeze result is the volatility in PEG's recommended inflation factor. The annual 2012 PEG inflation result equaled -1.62%. When averaged with the 2011 and 2010 annual numbers, the resultant inflation factor equals 0.51%. This result shows how one year of inflation data can bring down PEG's inflation factor substantially, thus increasing volatility.

If 2013 or 2014 show a near zero annual inflation factor, PEG's 3-year moving average recommended inflation factor could be even lower than the 0.51% shown in 2012. It is even conceivable the 3-year moving average PEG inflation factor becomes negative. This would result in rate declines across all the distributors who choose the IRM mechanism. An inflation index showing a -1.62% annual number in 2012, which implies deflation in distribution input prices, is highly questionable. It was this result that caused us to investigate more sensible and stable inflation factor alternatives.

In the next few years it is possible that interest rates and inflation begin a pronounced upward trend. Given the volatility in the PEG inflation factor, this could result in a rate freeze (or decline) for the first couple of years, followed by substantial rate increases in the later years of the plan. In our opinion, this potential extreme volatility is harmful to customers and distribution planners, and is not in the interests of Ontario ratepayers. It is also completely avoidable.

---

[3] The spreadsheet calculations for the inflation factor put forth by PSE can be found here: http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Renewed%20Regulatory%20Framework/Measuring%20Performance%20of%20Electricity%20Distributors

We believe our recommendations for the 4GIR plan mitigate the potential of this roller coaster ride and adequately account for the cost pressures faced by distributors. Our recommendations lay out a plan that provides for gradual rate increases that are in-line with the historic unit cost increases of distributors and are founded on sound empirical productivity research. PSE's inflation factor is an industry-specific measure which tracks the three input factors of labour, non-labour, and capital. The calculation of the PSE inflation factor is transparent and fairly simple. It only requires inputting the new EUCPI for each year and taking a weighted average of those numbers.

PSE's recommendation is far more stable than PEG's recommendation, and also represents a more current inflation measure. The following table shows the standard deviation in the inflation numbers for the GDP-IPI, PEG's inflation factor, and PSE's inflation factor. Notice that PSE's inflation factor has nearly the same volatility as the GDP-IPI, and has far less volatility than PEG's inflation factor. This advantage is combined with the index being a current measure rather than a 3-year moving average.

Table 2 PEG Inflaction Factor vs. PSE Inflation Factor

Year	GDP-IPI (3GIR)	PEG "Three Factor" (Annual)	PEG "Three Factor" (3-Year Moving Average)	PSE "Three Factor" (Annual)
2006	1.90%	0.12%	0.97%	2.57%
2007	2.10%	2.68%	1.52%	3.22%
2008	2.30%	2.36%	1.72%	2.73%
2009	1.30%	1.24%	2.09%	2.21%
2010	1.30%	2.44%	2.01%	2.86%
2011	2.00%	0.70%	1.46%	2.31%
2012	1.60%	-1.62%	0.51%	2.16%
Standard Deviation	**0.39%**	**1.55%**	**0.56%**	**0.39%**

Second Recommendation: Productivity Factor

PSE recommends using an industry-wide total factor productivity ("TFP") indexing measure as the basis for the productivity factor. PEG's full industry TFP estimate is -1.10% for 2002-2011. We recommend using that -1.10% estimate as the basis for the productivity factor. We recommend simply using the full industry TFP trend rather than suggesting individual external productivity factors for each distributor.[4]

However, even if the Board desires an external TFP measure, this would imply a productivity factor between -0.56% and -1.18%. If Hydro One is excluded the TFP number becomes -0.56% (this is the exclusion that results in the highest TFP). If Hydro Ottawa alone is excluded, the TFP estimate becomes -1.18% (the exclusion resulting in the lowest TFP). Excluding Toronto Hydro alone results in a TFP between these two extremes. Thus the range for the sample external TFP estimates is between these two estimates of -0.56% to -1.18%.

PSE believes the recommendation of using the full industry TFP trend (with no exclusions) is more in-line with the requirements put forth by the Board in the "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" ("RRFE"), dated October 18, 2012. On page 17 the RRFE states:

> The Board has concluded that X-factors for individual distributors under 4th Generation IR will continue to consist of an empirically derived industry productivity trend (productivity factor) and stretch factor, but will be based on Ontario Total Factor Productivity (TFP) trends.

In our opinion, using the full industry TFP trend most directly matches the RRFE conclusion that the TFP trend be an "empirically derived industry productivity trend" and "based on Ontario Total Factor Productivity trends."

PEG's recommendation of a productivity factor of 0.1% is based on the TFP trend after excluding nearly 40% of the industry (Toronto Hydro and Hydro One). It is our understanding that this exclusion was done on the basis that this large segment of the industry substantially impacts the TFP trend. This exclusion criterion is not mentioned in the RRFE document, nor is it logical. There are a number of industry segments that would change the TFP estimate if excluded. It is wholly unsurprising that an industry segment comprising 40% of customers has an impact on the TFP estimate.

For example, if northern distributors were excluded, that would likely have a substantial impact on the measured TFP trend. Similarly, if the Greater Toronto Area ("GTA") distributors were excluded, this again would likely substantially impact the measured trend. Any segment that comprises around 40% of the industry will probably have a substantial impact; however, it is an arbitrary distinction to choose the large utility segment to exclude, and yet leave in all other possible "outlier" industry segments.

---

[4] PSE's recommendation is also driven by the requirements of the RRFE, which states on page 17: "All distributors will be subject to the same productivity factor that will be set in advance for the purposes of the 4th Generation method."

Excluding observations based on the fact they impact the result is not a typical practice. In fact, Dr. Kaufmann from PEG was asked in the stakeholder conference if PEG has ever before excluded large utilities out of the TFP indexing approach because of their impact on the TFP index. Dr. Kaufmann stated, "I don't think we have ever specifically done that…"[5,6] Dr. Kaufmann did go on to discuss the importance of an external TFP measure; however, as discussed previously, an external measure can be accomplished without excluding 40% of the industry, and an external measure results in a TFP estimate between -0.56% and -1.18%.

The RRFE states on page 17 that all distributors will be subject to the same productivity factor. It is the most consistent, transparent, and empirical approach to calculate the full industry TFP trend and use that number as the basis for the productivity factor. Excluding industry segments on the basis of their impact on the TFP trend is not consistent with the fact that all distributors will be subject to the same productivity factor, nor is there any empirical basis for excluding certain distributors because of their impact on the TFP trend.

Table 3 below summarizes the TFP trends for the full industry, minus Toronto Hydro and Hydro One, and the TFP range when utilities are excluded one at a time.

Table 3 Industry TFP Trends

	% of Industry Retail Customers Included in Sample	2002-2011 TFP Trend
Full Industry (PSE Recommendation)	100.0%	-1.10%
Exclude Hydro One & Toronto Hydro (PEG Recommendation)	60.3%	0.10%
Systematically exclude one distributor at a time	75.0% to 99.98%	-0.56% to -1.18%

The full industry TFP index trend result of -1.10% is also supported by PEG's econometric model. PEG's model includes a time trend coefficient that estimates the annual percentage increase in cost pressures after adjusting for inflation, output levels, and other business conditions. In the PEG full industry econometric model (which includes Toronto Hydro and Hydro One) the trend coefficient is 0.012 (PEG Table 10). This implies that costs are increasing by 1.2% above and beyond inflation, outputs, and other variables. The trend coefficient estimate in the restricted sample (excludes Toronto Hydro and Hydro One) is again 0.012 (PEG Table 12). Both of the trend coefficients are statistically significant at very high levels, well in excess of 99% confidence.

[5] EB-2010-0379, Encouraging Electricity Distributor Efficiency Stakeholder Conference: "Empirical Work in Support of Incentive Rate Setting in Ontario", Volume 1, May 27, 2013, pages 131-132.

[6] Dr. Kaufmann also reiterates that they have never excluded utilities on this basis during the second day, May 28th, of the stakeholder conference. This is found in Volume 2, May 28, 2013, page 37.

In Section Three, we discuss how this trend coefficient and the other econometric estimates should be properly applied to calculating a TFP trend backcast or projection. While this explanation can get technical, the bottom line is that if costs are estimated to be increasing by 1.2% above and beyond inflation, outputs, and other variables, then it is logical to conclude a rate adjustment formula based on the historical performance of the Ontario industry would include an X-factor that increases the allowed rates, above inflation, by around that 1.2% estimate.[7] This is true especially given the fact that this estimate is highly statistically significant, both for the full and restricted sample.

The RRFE points to using the Ontario industry TFP indexing result as the basis for the productivity factor. For this reason, PSE is recommending the productivity factor be based on the full industry TFP trend of -1.10%, which was calculated by PEG. The econometric TFP estimate also supports this recommendation. Both of the TFP approaches (when properly applied) lend themselves to suggesting a negative productivity factor.

PSE would also like to put on the record a related recommendation regarding the productivity factor, which is that PSE believes the productivity factor should not exclude cost categories that are included in the 4GIR rate formula. During the stakeholder conference, Dr. Kaufmann revealed that bad debt expenses were excluded in the TFP indexing research based on his opinion these expenses are unlikely to continue at the same levels into the 4GIR period.[8] Similar to arbitrarily excluding distributors from the sample, this exclusion of an expense category based on the consultant's opinion of future conditions lacks an empirical, objective basis.

Third Recommendation: General Benchmarking Framework

PEG recommended a benchmarking framework to determine the 4GIR stretch factors. There are two evaluations that comprise the PEG benchmarking framework. These two evaluations are referred to as the econometric benchmarking approach, and the unit cost indexing (or peer group) approach.

PSE is proposing to condense the two approaches into one benchmarking evaluation, using what we call the Unit Cost Econometric Model. This approach estimates the impact of a number of cost drivers onto the cost-per-customer (after adjusting for input price differences) of each distributor, in each year. There are eleven cost drivers included in the model:

1. Kilometers of line per customer
2. Peak demand (kW) per customer
3. Service area per customer
4. Percent of large and general service volume in total volume
5. Percent of customer additions in the last ten years

[7] Technically-speaking, the productivity factor should be this trend coefficient minus an adjustment for the change in other business conditions, mainly realized scale economies. After this adjustment is made the econometric TFP estimate is around -0.85%.

[8] EB-2010-0379, Encouraging Electricity Distributor Efficiency Stakeholder Conference: "Empirical Work in Support of Incentive Rate Setting in Ontario", Volume 2, May 28, 2013, page 103.

6. Hourly wind variable based on the difference in actual wind above 10 knots
7. Percent of lines that are single phase
8. Load factor
9. Percent of lines that are underground
10. Percent of lines that are underground multiplied by customers per service area (separates the cost of undergrounding in urban/suburban areas versus rural areas)
11. Time trend

It is important to note that PEG's peer group approach is heavily dependent on the econometric approach to calculate its results, and so the peer group is not a true independent check on the econometric approach. The unit cost indexes for the peer group are calculated by dividing total costs by a bilateral output index, which uses the econometric model's coefficient estimates. Furthermore, the peer groups have been developed using the econometric-dependent bilateral output index, service area, percent undergrounding, and customer growth.

Despite the unit cost indexing approach being dependent on the econometric model, PEG's latest econometric model is showing that certain variables used in designing the peer groups are not statistically significant at a 90 percent confidence level. In PEG's Table 12, service area and percent undergrounding are not statistically significant at the 90 percent level (even though they are still included in PEG's econometric model). Yet these variables are still being used to design peer groups and calculate the bilateral output index.

It is PSE's opinion that the unit cost indexing (peer group) approach has two major flaws: (1) it is not an independent benchmarking evaluation, and (2) it is actually more misleading than it is informative. Regarding the first flaw, a true "double check" would be independent of the econometric method. However, PEG's approach to the peer group uses certain results from the econometric equation as an input in the peer group process. Thus, the peer group approach is not truly independent. In fact, it is not obvious whether PEG's peer group approach provides any new information at all.

The second major flaw of the peer group approach is that it ignores the magnitude of business condition variable values, except for their use in constructing the peer groups. For example, PEG's econometric results show that Wasaga Distribution is the second most efficient distributor in the Province (PEG Table 13, Wasaga Distribution is "Distributor Number 5"). However, the peer group results rank Wasaga Distribution 16th (PEG Table 25).

Why the discrepancy? It is not because the peer group approach is inputting new or different data. It is because the peer group approach does not make any adjustments for how Wasaga Distribution's business conditions compare to that of its peer group. For example, Wasaga Distribution's percent undergrounding is 47.7% in 2011. Its peer group undergrounding average is 39.2%.[9] There is no adjustment in the peer group approach for that difference. However, in the econometric approach, the difference in the business condition variable is incorporated into the benchmark result.

---

[9] The percent undergrounding varies dramatically for Group D. The minimum value is 17.4% (Lakefront Utilities) and the maximum value within that same peer group is 60.3% (Guelph Hydro Electric Systems).

PSE recommends eliminating the unit cost indexing (peer group) approach from the process that determines the 4GIR stretch factors.[10] It is an inferior approach to a robust econometric model and is dependent on the econometric model to begin with. It is essentially an approach that provides different results from the econometric results only because it is ignoring key information on variable values. PSE's view is that not only is the peer group approach unhelpful, but it is actually detrimental to the endeavor of accurately determining distributor cost performance and creating cost containment incentives to distributors.

PSE recommends using the Unit Cost Econometric Model ("UCEM") that we have developed as the basis for the 4GIR stretch factors. The UCEM combines the unit cost indexing approach with the econometric approach. The UCEM has a number of advantages over PEG's econometric model, these are:

1. More business condition variables
2. Transparent and easier to understand and explain
3. Does not penalize distributors for realizing efficiency gains through economies of scale
4. Provides distributors with information on how the benchmark is determined and what the variable impacts are
5. Eliminates the need for a second approach

The use of the UCEM is thus PSE's third recommendation.

Fourth Recommendation: Stretch Factors

We propose six cohorts based on the rankings of the UCEM benchmark results. Currently there are 73 distributors in the sample, the top sixth would be placed in Cohort One, the second sixth into Cohort Two, and on to the bottom sixth distributors being placed in Cohort Six. Cohort One would have a stretch factor of zero, with the stretch factors increasing progressively by 0.1% for each Cohort.

Table 4 below provides our recommended Cohorts and stretch factors.

[10] We recommend eliminating the peer group approach even if the Board decides PEG's econometric benchmarking model is to be used for the calculation of stretch factors.

Table 4 Recommended Cohorts and Stretch Factors

Rank	Stretch Factor
#1 to #12	0.00%
#13 to #24	0.10%
#25 to #36	0.20%
#37 to #48	0.30%
#49 to #60	0.40%
#61 to #73	0.50%

These stretch factors, along with the use of PSE's UCEM and the elimination of the peer group approach, should enhance the ability of distributors to move from one cohort group to another. This will encourage competition between distributors, since internal cost saving efforts will now be rewarded through a stretch factor that is no longer dependent on the peer group in which a distributor is placed—cost saving will now be more influenced by the cost levels of each distributor. Increased competition will best serve Ontario electric customers.

The proposed stretch factors include a slight reduction in the range relative to 3GIR and PEG's recommendations. Given that this is will be the 4th Generation of incentive regulation, it is appropriate to reduce the stretch factor to reflect the fact that most distributors have already been given incentives to reduce costs, and the historical Ontario productivity estimate is already based on an industry which has undertaken incentive regulation.

Summary of Reasons for and Benefits from PSE's Four Recommendations

In summary format, here are the reasons and benefits resulting from PSE's recommendations relative to PEG's recommendations. Each 4GIR component will be discussed in more detail in the following sections of this report.

Table 5 Summary of PSE's Four Recommendations: Reasons and Benefits

4GIR Component	Reasons for and Benefits from PSE Recommendation
Inflation Factor	1. Reduced volatility 2. Contemporary inflation measure (annual rather than 3-year moving average) 3. Consistent with RRFE requirement of an industry-specific measure 4. Calculation is simpler than PEG's capital service price index 5. Better tracks the historical unit costs of Ontario distributors
Productivity Factor	1. Full industry TFP measure consistent with RRFE requirement 2. No need to exclude utilities based on their TFP impact 3. Applicable to all distributors 4. Empirically derived rather than including a subjective decision on which industry segments to exclude and why 5. Better tracks the historical unit costs of Ontario distributors
Benchmarking Framework	1. More business conditions than PEG's model 2. Easier to understand and explain 3. Does not penalize or include disincentives for finding efficiency gains through the realization of scale economies 4. Provides distributors with more information on how the benchmarks are calculated and the impacts of each variable 5. Combines the unit cost and econometric approach thus eliminating the need for a second approach (increasing the ability of distributors to move between cohort groups)
Stretch Factor	1. Range should be reduced from 3rd Generation IR since large efficiency gains have likely already been found 2. IR plans in other jurisdictions tend to have stretch factors between zero and 0.5% 3. Six cohorts will lead to an increased ability to move

The remainder of the report provides more background and details on each of these four recommendations.

2 Inflation Factor

Among the requirements put forth by the RRFE Report are:

(1) The 4GIR inflation factor should be an industry-specific measure, and

(2) Concerns regarding the volatility will be mitigated by the methodology selected by the Board (RRFE, page 16).

PSE's recommended inflation factor meets the RRFE requirement of an industry-specific inflation measure, and it also provides the Board with an inflation factor that has far less volatility than PEG's recommended approach. In fact, the volatility under the PSE approach is about the same as that of the GDP-IPI, but the PSE inflation factor also includes three input price factors, with the capital component specific to the electric distribution industry.

The table below summarizes the growth rates of the inflation factors. The bottom row displays the standard deviation (i.e., the volatility) of the GDP-IPI, PEG's "Three Factor" annual and 3-year moving average index, and PSE's "Three Factor" recommendation.

Table 6 Growth Rates of Inflation Factors

Year	GDP-IPI (3GIR)	PEG "Three Factor" (Annual)	PEG "Three Factor" (3-Year Moving Average)	PSE "Three Factor" (Annual)
2006	1.90%	0.12%	0.97%	2.57%
2007	2.10%	2.68%	1.52%	3.22%
2008	2.30%	2.36%	1.72%	2.73%
2009	1.30%	1.24%	2.09%	2.21%
2010	1.30%	2.44%	2.01%	2.86%
2011	2.00%	0.70%	1.46%	2.31%
2012	1.60%	-1.62%	0.51%	2.16%
Standard Deviation	**0.39%**	**1.55%**	**0.56%**	**0.39%**

PSE's recommendation has far less volatility than PEG's, in accordance with the RRFE concerns. This is primarily due to the fact that PEG's inflation factor includes cost of capital changes, whereas PSE's approach assumes that cost of capital is fixed between re-basing years. This is typically how cost of service regulation is done. It was also the approach used during 3rd Generation Incentive Regulation which included no explicit term for the cost of capital within the inflation factor.

In most cost of service cases, revenue requirements and rates are set based on the cost of capital during the test year, and then these rates remain until the next cost of service application. Likewise, most other incentive regulation plans do not explicitly include cost of capital changes within the inflation factor. For example, Alberta's Performance Based Regulation initiative resulted in an inflation factor that does not explicitly account for changes in cost of capital during the automatic rate adjustment period. Another example is, again, Ontario's 3rd Generation IR plan.

However, in the Alberta Utilities Commission decision, the Commission acknowledges that the broad-based inflation indexes implicitly incorporate the cost of capital. They state "[a]ccordingly, the Commission considers that a composite I factor consisting of two broad-based indexes for labour and non-labour costs captures changes in the cost of capital (both debt and equity)." (AUC Decision 2012-237, page 38).

The downside for including the capital cost changes in the inflation factor stems from the volatility in inflation. Currently, interest rates and inflation are at historical lows. However, if inflation begins to increase, it is also likely that interest rates will also surge. This may result in large inflation factor increases. The capital component in PEG's inflation factor includes both the inflation from the EUCPI and the change in the weighted average cost of capital ("WACC"). Price inflation is likely to move in the same direction as interest rates, leading to an implicit capturing of interest rate changes, and thus a separate input for this factor may be redundant and only serve to amplify volatility.

Additionally, PEG's recommendation includes using a 3-year moving average in an attempt to reduce the volatility of the index. This method can actually increase volatility down the road. To see why, consider the 2012 PEG inflation factor. The 2012 annual PEG number equals -1.60%. This indicates that in the next couple of years, PEG's recommended 3-year moving average inflation factor will include the -1.60% 2012 observation. Unless inflation and interest rates substantially increase in 2013 or 2014, the PEG recommendation will produce what is tantamount to a rate freeze for distributors who choose to pursue the 4GIR option or the annual IR option.

Furthermore, by 2015 if inflation and interest rates have increased, the PEG inflation factor could then be showing substantial increases. Ontario customers would be going from a rate freeze to substantial rate increases, rather than having gradual rate increases, which enable better planning for both customers and distributors. The good news is this volatility can easily be avoided by using PSE's recommended inflation factor approach.

PEG's recommendations do not track the historical unit costs of distributors. If distributors continue with unit cost growth around three percent but are subject to a de facto rate freeze for the next one to three years, this will put tremendous financial strain onto the distributors and set up customers for a rate shock either when re-basing occurs or possibly in the later years if PEG's inflation factor creates large rate increases.

In the table below, notice the 2012 inflation factor for PEG versus the PSE recommendation. PEG's recommendations lead to an inflation factor of 0.51% in 2012. Combined with PEG's productivity factor and stretch factor recommendations, this would lead to an average rate increase of only 0.11%. This is for those distributors in the middle Cohort group. If a distributor is in the bottom two Cohorts, it would be facing a rate **decrease**. This is in a time of increasing cost pressures (as PEG's econometric trend coefficient shows) that are raising costs above and beyond the ordinary inflationary pressures. Also notice the comparison to the GDP-IPI. That inflation measure has grown faster than PEG's recommendation and is 1.09% higher than PEG's 2012 inflation recommendation.

PSE's inflation factor in 2012 is more stable and does a far better job of tracking the industry's unit cost growth, although it is still over one percent below the industry's unit cost growth. In 2012, PSE's inflation factor is 0.56% higher than the GDP-IPI. The PSE inflation factor is far more representative, and is a better measure of, the inflationary pressures facing distributors. It is also a more current measure, enabling the inflation factor to better track contemporary cost pressures.

Table 7 Actual Unit Cost Growth vs. Inflation Factor Recommendations

Year	Industry Unit Cost Growth	GDP-IPI	PEG Recommendation on Inflation Factor	PSE Recommendation on Inflation Factor
2006	2.05%	1.90%	0.97%	2.57%
2007	6.21%	2.10%	1.52%	3.22%
2008	3.04%	2.30%	1.72%	2.73%
2009	2.04%	1.30%	2.09%	2.21%
2010	5.63%	1.30%	2.01%	2.86%
2011	3.22%	2.00%	1.46%	2.31%
2012	N/A	1.60%	0.51%	2.16%
Average	**3.70%**	**1.79%**	**1.47%**	**2.58%**

2.1 PSE's Inflation Factor Calculation

PSE proposes a "Three Factor" inflation factor that uses an industry-specific capital component. The three input price factors are: labour, non-labor, and capital. The growth rate in the Ontario Average Weekly Earnings ("AWE") forms the basis for the labour factor. The non-labour factor is derived from the Canadian GDP-IPI (or Ontario GDP-IPI, if the schedule allows). The triangularized weighted average ("TWA") of the EUCPI forms the basis for the capital factor. PSE produced a simple spreadsheet on the calculations which can be found on the Board's website.

The growth rates in these three indexes would be weighted based on the average cost share weights found in PEG's dataset. These weights are approximately 60 percent for capital, 28 percent for labour, and 12 percent for non-labour. The inflation factor is calculated by the following equation.

$$IF = 0.28 * \Delta\, AWE + 0.12 * \Delta\, GDPIPI + 0.60 * \Delta\, TWA\ of\ EUCPI$$

Given the limited volatility in the PSE inflation index, we recommend not smoothing it over three years, but rather using the most current annual inflation data in the 4GIR allowed rate escalation formula.

Capital Component Calculation

The capital component is a weighted average of the historical EUCPI values. The weighting is based on an approximation of the prices paid by a distributor for the capital included in its rate base. The weights are based on a straight-line depreciation assumption of 40 years. The calculation assumes that 1/40th of the assets purchased 40 years ago are still in the rate base today. Likewise, it assumes that 2/40^{ths} of the assets purchased 39 years ago are still in the rate base.

The assumption keeps moving forward until the current year, where it is assumed that all of the assets purchased in the current year are still in the rate base. These weights are then added to sum up the assets assumed to still be in the rate base. Each year's weight is then determined by the amount of asset left in the rate base for that year divided by the sum of all the assets. These weights then form the basis for the historical weighted average of the EUCPI.

Table 8 illustrates the calculation. Assume year T is 2010. Then T-40 is 1970. Only 1/40th of the assets purchased in 1970 are assumed to be in the 2010 rate base. This weight is divided by the total assets for the 1970-2010 period and multiplied by the EUCPI in 1970. This process is done in every year from 1970 to 2010. The sum of the weights multiplied by the EUCPI forms the TWA value in 2010.

Table 8 Capital Component Calculation

Year	EUCPI Value [A]	Straight-line Asset Left in Year T [B]	Weight [C=B/Sum(B)]	Weight*EUCPI [D=C*A]	Sum to Get Capital Index [Sum(D)]
T-40	24.1	1/40	0.12%	0.03	
T-20	98.5	20/40	2.44%	2.40	
T-4	142.4	36/40	4.39%	6.25	
T-3	148.8	37/40	4.51%	6.71	
T-2	150.3	38/40	4.63%	6.96	
T-1	151.1	39/40	4.76%	7.19	
T (current year)	155.1	40/40	4.88%	7.57	
Sum		**20.5**			**115.9 in 2010**

In the capital component calculation, there is no term for changes in the cost of capital. Price inflation is likely to move in the same direction as interest rates, leading to an implicit capturing of interest rate changes. The absence of a term for cost of capital changes substantially reduces volatility. It also produces a more stable inflation factor, which in turn provides for more predictable rate changes for customers and distribution planners. It also allows the annual number to be used, making it a more current inflation trend.

At first glance the capital calculation may seem complicated. It is simply a weighted average of the historical EUCPI values. The most complicated part is calculating the weights, which are based on an assumption of straight-line depreciation and a constant investment in capital over time. Each year's weight is calculated by the assumed amount of asset remaining in that year divided by the total assets remaining.

The table below summarizes the reasons that PSE recommends this particular inflation factor and why it believes it best serves the interests of Ontario.

	Reasons for and Benefits from PSE Recommendation
Inflation Factor	1. Reduced volatility 2. Contemporary inflation measure (annual rather than 3-year moving average) 3. Consistent with RRFE requirement of an industry-specific measure 4. Calculation is simpler than PEG's capital service price index 5. Better tracks the historical unit costs of Ontario distributors

3 Productivity Factor

The RRFE Report indicates on page 17 that the productivity factor is intended to be based on Ontario TFP trends, which are derived through an index-based approach that calculates the industry productivity trend. All distributors are to be subject to this same productivity factor.

PEG used indexing as the primary method for calculating the productivity factor, and used econometric backcasting as a "double check" on the indexing approach. PSE has determined that PEG's indexing approach is generally correct, although we recommend that the full industry sample should form the basis for the Ontario TFP trend (rather than excluding Toronto Hydro and Hydro One). And while the general strategy of using an econometric model as a double check is a good idea, PSE believes that PEG incorrectly applied its econometric model when calculating the econometric TFP estimate. A corrected econometric TFP estimate is supportive of PSE's productivity factor recommendation.

We feel our recommendations most directly fulfill the productivity factor intention of the RRFE. Our recommendation is to use PEG's 2002-2011 TFP indexing result for the entire industry (i.e., no exclusions). PSE's recommendation has the following benefits: (1) it provides for a productivity factor that can be applied to all distributors, (2) it is fully based on the historical Ontario industry TFP trend, and (3) it is supported empirically by both the TFP indexing and the econometric TFP results.

3.1 PEG's Primary TFP Calculation Approach: Indexing

We reviewed PEG's TFP indexing methodology and calculations. On the whole, we believe they are based on sound principles, and we are comfortable with their general approach. There are some areas where PSE disagrees with the details of the approach. For example, during the stakeholder conference Dr. Kaufmann reveals the TFP cost definition excludes bad debt expenses on the basis they are not likely to continue at the same recent levels in the future.[11] We would disagree with excluding any cost categories which are part of the 4GIR rate formula. However, for the most part, PEG's TFP indexing calculations should be accepted as they are. Our only real source of disagreement with PEG's recommended productivity factor is that the full industry sample should form the basis for the Ontario TFP trend, whereas PEG excludes a large portion of the industry to form their recommended productivity factor.

Table 9 below summarizes the results of using the full industry sample, with no exclusions. We recommend using the industry 2002-2011 TFP trend of -1.10% as the basis for the productivity factor. Notice that PEG's recommendation of excluding Toronto Hydro and Hydro One essentially eliminates 40% of the Ontario industry from the analysis. Ignoring this segment of the industry because they impact the measured TFP trend does not fulfill, in our opinion, the RRFE requirements of calculating a productivity factor that: (1) applies to all distributors, and

[11] EB-2010-0379, Encouraging Electricity Distributor Efficiency Stakeholder Conference: "Empirical Work in Support of Incentive Rate Setting in Ontario", Volume 2, May 28, 2013, page 103.

(2) is based on the Ontario industry TFP trend.

If PEG's recommendation is used as precedent, numerous other industry segments (e.g., northern distributors, GTA distributors, rural distributors, etc.) could also be arbitrarily excluded, and this could move the TFP trend significantly up or down. Rather than an empirically driven result, the result would, instead, be driven by subjective choices lacking empirical support.

Table 9 Recommended TFP Trend

	% of Industry Retail Customers Included in Sample	2002-2011 TFP Trend
Full Industry (PSE Recommendation)	**100.0%**	**-1.10%**
Exclude Hydro One & Toronto Hydro (PEG Recommendation)	60.3%	0.10%
Systematically exclude one distributor at a time	75.0% to 99.98%	-0.56% to -1.18%

Given the RRFE requirement of having one productivity factor that applies to all distributors, PSE is recommending the full industry TFP trend of -1.10%. However, if an externalized measure is desired, we have also calculated what the TFP trend range is if each distributor is systematically taken out of the sample one at a time. This "out of sample" exercise produces an external TFP trend between -0.56% to -1.18%. This can be seen in the last row of the table above.

We also note that excluding a utility like Toronto Hydro does not result in a massive change in the TFP trend. Excluding Toronto Hydro from the full industry changes the TFP trend by 0.29%. On the opposite side, if Hydro Ottawa is excluded the measured TFP trend moves by 0.08%. We are left wondering what the empirical criterion is for excluding Toronto Hydro or Hydro One, but not Hydro Ottawa? It appears PEG believes the line should be drawn somewhere between 0.08% and 0.29%, but on what basis was this threshold chosen? How will that precedent play out in the future if the industry continues to consolidate? The practice of excluding distributors or industry segments based on their TFP impact is arbitrary and makes the analysis more subjective rather than objective.

	Reasons for and Benefits from PSE Recommendation
Productivity Factor	1. Full industry TFP measure consistent with RRFE requirement 2. No need to exclude utilities based on their TFP impact 3. Applicable to all distributors 4. Empirically derived rather than including a subjective decision on which industry segments to exclude and why 5. Better tracks the historical unit costs of Ontario distributors

3.2 PEG's Secondary TFP Calculation Approach: Econometric TFP Projections

In its May 2013 report, PEG also conducted econometric TFP projections, or backcasts. These projections use the econometric model coefficient estimates and the observed 2002-2011 growth rates in the variables to provide an econometric TFP projection. PEG used their econometric TFP finding to provide further evidence in support of their indexing productivity factor recommendation, as a "sanity check." On page 69 of the PEG May 2013 report, PEG states that, "[t]his provides another piece of evidence on TFP growth for the Ontario industry that may inform the Board's choice for a productivity factor."

We note that the RRFE calls for the use of an Ontario industry TFP indexing approach as the basis for the productivity factor. This is why PSE's recommended productivity factor is based on the full industry TFP index trend. However, we also think it is important to evaluate PEG's econometric TFP estimate, since it is used to provide "another piece of evidence on TFP growth for the Ontario industry".

PSE believes that PEG's econometric TFP projection of 0.07% is inaccurate for two reasons:

1. PEG, again, excludes Toronto Hydro and Hydro One from the analysis. Our belief that an Ontario industry TFP estimate should not exclude 40% of the industry is just as relevant here as it is in the TFP indexing discussion.

2. PEG is making a crucial, although easily fixed, error in its calculations of the econometric TFP projection. It omits an important variable, namely the OM&A input price.

The corrected econometric TFP projection is around -0.80% (using the full or restricted dataset). This result substantiates the TFP indexing finding of a TFP decrease of around -1.10%.

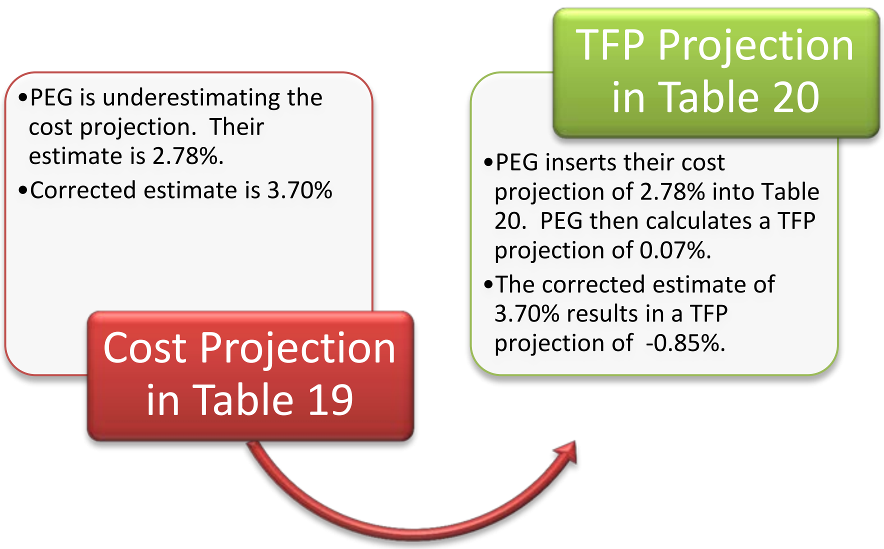
In the previous section, we have already laid out why PSE believes the full industry should be used rather than a sub-set of the industry. So we will turn our attention to point #2.

While the mathematics in explaining PEG's error can be a challenge, the key issue is simply this: PEG is not using the actual variables that are in the econometric model to project costs (PEG

Table 19), which in turn, is used to project TFP (PEG Table 20). On Table 19, PEG has neglected to include the OM&A input price into the projection, even though the OM&A input price is part of the PEG model equation. The result of PEG's error is that their cost projection, and subsequently the TFP projection, is ignoring the cost pressures resulting from OM&A input price inflation from 2002-2011.

By ignoring the OM&A variable and its role in PEG's econometric model, PEG is under-estimating its cost projection found on Table 19. This cost projection in Table 19 is then inserted into Table 20. The under-estimate in the cost projection results in an over-estimate in the TFP projection. Figure 2 below shows the flow of PEG's econometric TFP projection.

Figure 2 Relationship between Table 19 and Table 20



The key issue is found on PEG's Table 19 (reproduced as Table 10 of this Report). The table only needs a few modifications to align it with the actual variables used in PEG's econometric model. The following Table 11 is PSE's revised version of Table 19. We have bolded in red where changes are needed to align the cost projection with the actual variables used in the model.

Table 10 Original PEG Table 19

PEG Table 19 (Original)	
Econometric Coefficient Estimates	**Average 2002-2011**
Customers [A]	0.44
System Capacity [B]	0.22
Total Deliveries [C]	0.05
Service Territory Size [D]	0.02
Percentage of Lines Underground [E]	0.01
Average Line Length [F]	0.24
Customer Additions in Previous 10 Years [G]	0.02
Capital Input Price [H]	0.60
Sum of Output Elasticities [I=A+B+C+F]	0.950
Output Index Weights	
Customers [J=A/I]	1.61%
System Capacity [K=B/I]	0.95%
Total Deliveries [L=C/I]	0.93%
Average Line Length [M=F/I]	0.00%
Subindex Growth	
Customers [N]	1.61%
System Capacity [O]	0.95%
Total Deliveries [P]	0.93%
Service Territory Size [Q]	0.00%
Percentage of Lines Underground [R]	1.93%
Average Line Length [S]	0.00%
Customer Additions in Previous 10 Years [T]	0.00%
Capital Input Price [U]	1.01%
Subindex Growth*Econometric Coefficients	
Customers [V=A*N]	0.71%
System Capacity [W=B*O]	0.20%
Total Deliveries [X=C*P]	0.05%
Service Territory Size [Y=D*Q]	0.00%
Percentage of Lines Underground [Z=E*R]	0.03%
Average Line Length [AA=F*S]	0.00%
Customer Additions in Previous 10 Years [BB=G*T]	0.00%
Capital Input Price [CC=H*U]	0.61%
Trend [DD]	1.18%
Change in Projected Cost [EE=V+W+X+Y+Z+AA+BB+CC+DD]	2.78%

Table 11 PSE Revised Table 19

PSE Revised Table 19	
Econometric Coefficient Estimates	**Average 2002-2011**
Customers [A]	0.44
System Capacity [B]	0.22
Total Deliveries [C]	0.05
Service Territory Size [D]	0.02
Percentage of Lines Underground [E]	0.01
Average Line Length [F]	0.24
Customer Additions in Previous 10 Years [G]	0.02
Capital Input Price/**OM&A Input Price** [H]	0.60
Sum of Output Elasticities [I=A+B+C+F]	0.950
Output Index Weights	
Customers [J=A/I]	46.74%
System Capacity [K=B/I]	22.64%
Total Deliveries [L=C/I]	5.29%
Average Line Length [M=F/I]	25.33%
Subindex Growth	
Customers [N]	1.61%
System Capacity [O]	0.95%
Total Deliveries [P]	0.93%
Service Territory Size [Q]	0.00%
Percentage of Lines Underground [R]	1.93%
Average Line Length [S]	0.00%
Customer Additions in Previous 10 Years [T]	0.00%
Capital Input Price/**OM&A Input Price** [U]	**-1.29%**
Subindex Growth*Econometric Coefficients	
Customers [V=A*N]	0.72%
System Capacity [W=B*O]	0.20%
Total Deliveries [X=C*P]	0.05%
Service Territory Size [Y=D*Q]	0.00%
Percentage of Lines Underground [Z=E*R]	0.03%
Average Line Length [AA=F*S]	0.00%
Customer Additions in Previous 10 Years [BB=G*T]	0.00%
Capital Input Price/**OM&A Input Price** [CC=H*U]	**-0.78%**
Trend [DD]	1.18%
Change in Projected Cost/OM&A Input Price [EE=V+W+X+Y+Z+AA+BB+CC+DD]	**1.40%**
Change in Projected Cost [DD+OM&A Input Price Inflation of 2.30%]	**3.70%**

Actual variable definition in the econometric model is the capital input price divided by the OM&A input price. No change in the coefficient is necessary.

The variable in the model is the capital input price divided by the OM&A input price. The growth rate needs to be changed to the growth rate in the capital input price divided by the OM&A input price. PEG has mistakenly inserted the capital input price growth rate of 1.01% rather than the growth rate in the variable in the model (which is capital price divided by OM&A input price). The growth rate of the actual variable used in the model is -1.29%.

This number just incorporates the corrected growth rate of -1.29% found above in [U].

To calculate a total cost projection (which is what Table 20 requires) the OM&A input price growth rate now needs to be added.

Near the end of this section we show the full math and all of the variables that go into PEG's econometric model. We then show how the equation should be used to project, or "backcast," total costs. However, before presenting the math, we want to show the "eyeball checks" that PSE conducted; these five tests illustrate that the PSE revised Table 19 is the correct way to project cost using PEG's econometric model.

Four of these tests were discussed during Mr. Fenrick's stakeholder presentation.[12] We also conducted another test subsequent to that presentation to better illustrate the issue. This fifth test involved taking PEG's exact benchmarking dataset and then increasing both of the input prices (capital and OM&A) and the total cost by ten percent per year for all observations. Once we did this, we re-ran the econometric model and found, as expected, all of the coefficient estimates stayed exactly the same. PEG's Table 19, however, only showed a cost projection increase of 6% rather than the expected 10%. PSE's revised Table 19, which properly incorporates the cost impact of OM&A input price inflation, showed the expected 10% cost projection increase.

Before getting to the five tests, we should also mention the logic behind the trend coefficient found in PEG's econometric model, which was discussed quite a bit during the stakeholder conference, particularly by Professor Adonis Yatchew.[13] The trend variable estimates the cost pressures on distributors after adjusting for inflation, output growth, and other business conditions. PEG's estimated trend variable is 0.012, implying costs are increasing by 1.2% above and beyond inflation and output growth. It is impossible for us to reconcile this trend variable with PEG's econometric TFP projection of a positive productivity backcast of 0.07%. The trend variable coefficient implies a negative TFP trend near -1.2%, it does not imply a positive TFP trend.[14]

This statistically significant trend coefficient of 0.012 percent implies that TFP growth during the period was negative. The trend variable is implying a -1.2% technology trend. While the true econometric TFP trend will need to add in realized scale economies (see Test 2 below for a breakdown of the components of the negative TFP trend), the sum of these to TFP components implies a negative TFP trend in the ballpark of -0.8%.

Here are the five tests that PSE ran to better illustrate the proper econometric TFP projection.

1. We looked at the **actual cost growth in the benchmarking dataset**. A cost backcast that uses the coefficient estimates of the benchmarking model and the historical growth rates of the benchmarking data should project cost growth in line with the actual cost data found in the dataset.
2. In **2007 PEG produced an econometric TFP method** in work for the Board regarding

[12] EB-2010-0379, Encouraging Electricity Distributor Efficiency Stakeholder Conference: "Empirical Work in Support of Incentive Rate Setting in Ontario", Volume 1, May 27, 2013, pages 50-57.

[13] EB-2010-0379, Encouraging Electricity Distributor Efficiency Stakeholder Conference: "Empirical Work in Support of Incentive Rate Setting in Ontario", Volume 1, May 27, 2013, pages 11-12, 22, 28-30. Volume 2, May 28, 2013, pages 4-5.

[14] As we will show, this trend variable when combined with the realization of scale economies actually implies a TFP trend of -0.8%. Certainly not the 0.07% that PEG claims to be the econometric TFP projection.

the incentive regulation plan for the natural gas utilities.[15] We reconstructed the econometric TFP method used by PEG in 2007 and compared the results to PEG's current 2013 econometric TFP projection. We did this by inserting the PEG 2013 electric coefficients and growth rates found in their model and dataset and then using PEG's exact calculations found in their 2007 Report (Table 10 of the 2007 PEG Report).

3. We again reconstructed **PEG's 2007 method but included the impacts of business condition variables**.
4. We devised a **new approach to backcasting total costs**. We averaged all of the variables in 2002 and used PEG's econometric model equation to estimate 2002 costs at the sample mean. We then did the same thing for 2011 to estimate 2011 costs at the sample mean. We then calculated the annual growth rate from 2002 to 2011 for these econometric cost projections.
5. We conducted the **experiment of increasing both of the input prices and total costs by ten percent** and then inserted the changes into PEG's Table 19 and PSE's revised Table 19 to see if they would return the expected cost projection increase of ten percent.

<u>Test 1:</u> Actual Cost Growth in the Benchmarking Dataset

The total cost average annual growth rate found in the benchmarking data is 3.41%. This is much closer to the PSE cost projection of 3.70% than PEG's cost projection of 2.78%. It should be expected that an econometric backcast cost projection that uses the coefficients estimated from a given dataset and the actual growth rates of the variables in that same dataset would show a similar cost growth projection as the actual cost growth for that dataset.

<u>Test 2:</u> PEG's 2007 Econometric TFP Method

PSE went back to PEG's TFP projection method in a 2007 Report for the Board involving the gas distribution industry.[16] The report is titled, "Rate Adjustment Indexes for Ontario's Natural Gas Utilities" and dated June 20, 2007. Table 10 of that report provides the calculations for PEG's 2007 method of using an econometric model to project TFP growth. We have used those exact calculations but have inserted PEG's 2013 cost model coefficients and variable growth rates for the electric industry. We found that PEG's prior methodology produces econometric TFP estimates in-line with PSE's econometric TFP estimates of around -0.8%. Notice that in 2007, PEG believed that TFP growth comes from essentially two sources, 1) Technology Trend, and 2) Returns to Scale.

Using PEG's 2013 model and variable growth rates, but their 2007 method, they would have estimated the contribution of the technology trend to TFP growth at -1.18%. The returns to scale

[15] The PEG 2007 Report can be found on the Board's website here: http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0209/PEG_TFP_study_revised_20070620.pdf. Table 10 shows PEG's 2007 TFP projection method.

[16] This same method was also peer reviewed and published in the *Review of Network Economics*.

Lowry, Mark N. and Lullit Getachew (2009). Review of Network Economics, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry." Vol. 8, Issue 4 December 2009.

component would have contributed about 0.40% to TFP growth. The sum of these two results in a TFP projection of -0.78%.

Figure 3 Calculation of TFP Projection

We have replicated PEG's 2007 Table 10 in PSE Table 12 below. Again, we have inserted the 2013 electric cost coefficients and variable growth rates, but have left the calculations exactly the same as what was put forth in PEG's 2007 report. We have inserted both the PEG 2013 restricted sample model coefficients (excludes Toronto Hydro and Hydro One) and the PEG 2013 full sample coefficients. The restricted sample results in a TFP projection of the -0.78% discussed above, and the full sample results in a TFP projection of -0.83%.

Table 12 TFP Growth Projections

TFP Growth Projections from Econometric Research (PEG 2007 Gas Report)

	2002-2011 (Table 12 Model of 2013 Report, restricted sample)	2002-2011 (Table 10 Model of 2013 Report, full sample)
Elasticity Estimates from PEG-R cost model		
Customers [A]	0.444	0.398
System Capacity [B]	0.215	0.22
Total Deliveries [C]	0.050	0.102
Output Index Weights from PEG-R cost model		
Customers [D]	62.6%	55.3%
System Capacity [E]	30.3%	30.6%
Total Deliveries [F]	7.1%	14.2%
Subindex Growth based on PEG-R Report		
Customers [G]	1.61%	1.61%
System Capacity [H]	0.95%	0.95%
Total Deliveries [I]	0.93%	0.93%
Sum of Output Elasticities [J = A+B+C]	0.709	0.720
Output Growth (elasticity weighted from PEG-R Report) [K=D*G+E*H+F*I]	1.36%	1.31%
Technology Change [L]	-1.18%	-1.20%
Returns to Scale [M=(1-J)*K]	0.40%	0.37%
TFP Projection "2007 PEG Method" [L+M]	**-0.78%**	**-0.83%**

These results again substantiate PSE's corrected econometric TFP projection of -0.85% rather than PEG's 2013 econometric TFP projection of 0.07%.[17]

<u>Test 3:</u> PEG's 2007 Econometric TFP Method with Business Condition Impacts

To be thorough, we also used PEG's 2007 econometric TFP method to estimate the business condition impacts on the 2013 econometric TFP estimate. As expected, including business conditions had a very minimal impact on the econometric TFP estimate. Using the restricted sample, the TFP estimate becomes -0.81%. The full sample estimate stays the same as before, at -0.83%.

<u>Test 4:</u> New Approach to Econometric Cost Projections

PSE was able to replicate PEG's econometric model for the restricted sample. We then averaged

[17] We would actually prefer to use the method PEG used in 2007 when conducting econometric TFP backcasts or projections. It provides a breakdown of the components to TFP growth (technology and economies of scale) and can be done in one simple table, rather than the two needed for PEG's 2013 method.

all of the variables in 2002 and used PEG's econometric model equation to estimate 2002 costs at the sample mean. We then did the same thing for 2011 to estimate 2011 costs at the sample mean. We then calculated the annual growth rate from 2002 to 2011 for these econometric cost projections. This provides a new, and far simpler, method of using the econometric model to project a cost growth rate.

We found that the model expects a hypothetical distributor at the 2002 mean for all of the explanatory variables to have total costs of $17.0 million in that same year. At the 2011 mean for all of the explanatory variables the model predicts total costs of $23.7 million. The average annual growth rate between these two numbers is 3.69%. This cost projection implies an econometric TFP projection of -0.84%.

This more transparent approach of conducting an econometric cost projection corroborates PSE's corrected Table 19 methodology, which again shows a cost projection growth rate of 3.70%. It also supports the proper econometric TFP projection of approximately -0.8%. This TFP projection of -0.8% appears to be quite consistent across the four tests, PSE's corrected method, and the plain interpretation of the trend variable in relation to TFP growth.

Summary of the Four Tests

The table below summarizes the PEG econometric cost and TFP projections, PSE's finding, and the four tests described above. Recall the relationship between the cost projection and the TFP projection. The cost projection found on Table 19 in PEG's report is inserted into Table 20 to determine the TFP projection.

Table 13 Summary of PSE's First Four "Eyeball Tests" for TFP

Method	2002-2011 Cost Projection	Econometric TFP Estimate
PEG's Table 19 Or PSE's Revised Table 19	2.78% Or 3.70%	0.07% Or -0.85%
Test 1: Actual Cost Growth	3.41%	-0.56%
Test 2: PEG's 2007 Method	N/A	-0.78% or -0.83%
Test 3: PEG's 2007 Method with business conditions	N/A	-0.81% or -0.83%
Test 4: Mean Model Cost Prediction of 2002 and 2011	3.69%	-0.84%

<u>Test 5:</u> Hypothetical Experiment of Increasing the Input Prices and Total Costs by Ten Percent

PSE conducted a hypothetical experiment where we increased the capital and OM&A input prices by ten percent per year for every distributor, and also increased the total costs by ten percent per year. We then re-ran PEG's econometric model and found, as expected, the coefficient estimates stayed exactly the same. We then inserted the new input price growth rates, which are ten percent higher in the experiment, and re-calculated PEG's Table 19 and PSE's revised Table 19. We found that PEG's Table 19 only showed a cost projection increase of 6.0%, whereas PSE's Table 19 showed a cost projection increase of 10.0%. This conforms to PSE's assertion that PEG is omitting OM&A input price inflation with their cost projections.

3.2.1 Math Details for the Econometric TFP Backcasts

We forewarn readers that this sub-section provides technical details showing the underlying equations that provide a mathematical proof for the proper way to translate PEG's cost model to a cost projection. Similar to the five tests we conducted in the previous section, this mathematical proof supports the PSE revised Table 19 and the econometric TFP estimate of -0.85%.

The following is the translog cost function that is estimated by PEG. The dependent variable of the model is the log of total cost per OM&A input price. The right-hand-side variables include the price of capital per OM&A input price; the number of customers; capacity; deliveries; their square and interaction terms; area; percent lines underground; average line length; percent customers added in the last ten years; and time trend. All terms are logged except for percent lines underground, percent customers added in the last ten years, and time trend.

We note that all right-hand-side variables (except the trend) have been mean-scaled. Mean-scaling involves the division of each variable by its sample mean and is undertaken routinely to estimate translog cost functions; mean values have bars above them. Here is the full equation of PEG's econometric model.

Equation 1

$$
\begin{aligned}
\boldsymbol{ln\left(\frac{C}{wom}\right)} &= \boldsymbol{\alpha + \alpha_k ln\left(\frac{wk/\overline{wk}}{wom/\overline{wom}}\right) + \alpha_N ln(N/\overline{N}) + \alpha_C ln(C/\overline{C}) + \alpha_D ln(D/\overline{D})} \\
&\quad \boldsymbol{+ \alpha_{kk}\frac{1}{2} ln\left(\frac{wk/\overline{wk}}{wom/\overline{wom}}\right) ln\left(\frac{wk/\overline{wk}}{wom/\overline{wom}}\right) + \alpha_{NN}\frac{1}{2} ln(N/\overline{N}) ln(N/\overline{N})} \\
&\quad \boldsymbol{+ \alpha_{CC}\frac{1}{2} ln(C/\overline{C}) ln(C/\overline{C}) + \alpha_{DD}\frac{1}{2} ln(D/\overline{D}) ln(D/\overline{D})} \\
&\quad \boldsymbol{+ \alpha_{KN} ln\left(\frac{wk/\overline{wk}}{wom/\overline{wom}}\right) ln(N/\overline{N}) + \alpha_{KC} ln\left(\frac{wk/\overline{wk}}{wom/\overline{wom}}\right) ln(C/\overline{C})} \\
&\quad \boldsymbol{+ \alpha_{KD} ln\left(\frac{wk/\overline{wk}}{wom/\overline{wom}}\right) ln(D/\overline{D}) + \alpha_{NC} ln(N/\overline{N}) ln(C/\overline{C})} \\
&\quad \boldsymbol{+ \alpha_{ND} ln(N/\overline{N}) ln(D/\overline{D}) + \alpha_{CD} ln(C/\overline{C}) ln(D/\overline{D}) + \alpha_A ln(A/\overline{A}) + \alpha_U (U/\overline{U})} \\
&\quad \boldsymbol{+ \alpha_L ln(L/\overline{L}) + \alpha_{NG}(NG/\overline{NG}) + \alpha_t trend + \varepsilon}
\end{aligned}
$$

The TFP backcast calculations that show the predicted change in total cost over 2002-2011 (in Tables 19 and 20) are based on the estimates and values of the above model. The backcast calculations use the parameter estimates of the model and values for average changes in the cost driver variables over this period. As Table 19 shows, only parameter estimates of first-order terms of the model are used for this purpose. This is because cost per OM&A input price growth is evaluated at sample average growth rates.

At the sample mean, the change in $ln\left(\frac{C}{wom}\right)$ with respect to $ln\left(\frac{wk/\overline{wk}}{wom/\overline{wom}}\right)$ is equal to α_k. To see this, consider the derivative of $ln\left(\frac{C}{wom}\right)$ with respect to $ln\left(\frac{wk/\overline{wk}}{wom/\overline{wom}}\right)$, which captures the instantaneous rate of change (of the log of total cost per OM&A price with respect to the log of the ratio of the input price):

Equation 2

$$\frac{\partial \boldsymbol{ln}\left(\frac{\boldsymbol{C}}{\boldsymbol{wom}}\right)}{\partial \boldsymbol{ln}\left(\frac{\boldsymbol{wk}/\overline{\boldsymbol{wk}}}{\boldsymbol{wom}/\overline{\boldsymbol{wom}}}\right)} = \boldsymbol{\alpha_k} + \boldsymbol{\alpha_{kk}}\boldsymbol{ln}\left(\frac{\boldsymbol{wk}/\overline{\boldsymbol{wk}}}{\boldsymbol{wom}/\overline{\boldsymbol{wom}}}\right) + \boldsymbol{\alpha_{KN}}\boldsymbol{ln}(\boldsymbol{N}/\overline{\boldsymbol{N}}) + \boldsymbol{\alpha_{KC}}\boldsymbol{ln}(\boldsymbol{C}/\overline{\boldsymbol{C}}) + \boldsymbol{\alpha_{KD}}\boldsymbol{ln}(\boldsymbol{D}/\overline{\boldsymbol{D}})$$

Note that $ln\left(\frac{\bar{a}/\bar{a}}{\bar{b}/\bar{b}}\right)$, where terms with bars above them denote averages values, is equal to $\ln(1)$, which is zero. Therefore, the change in $ln\left(\frac{C}{wom}\right)$ with respect to the right-hand-side price ratio is equal to only the first order term's parameter α_k. Similarly, the derivative of $ln\left(\frac{C}{wom}\right)$ with respect to each output variable equals the first order parameter of each $(\alpha_N, \alpha_C, \alpha_D)$.

When evaluating the change in total cost for the TFP backcast, therefore, we only consider the first-order coefficients as is done in Table 19. Because the cost function is specified as the ratio of total cost to OM&A input price, the rate of change of this variable is captured by the following:

Equation 3

$$\boldsymbol{\%\Delta C} - \%\Delta\boldsymbol{wom} = \boldsymbol{\alpha_k}(\%\Delta\boldsymbol{wk} - \%\Delta\boldsymbol{wom}) + \boldsymbol{\alpha_N}\%\Delta\boldsymbol{N} + \boldsymbol{\alpha_C}\%\Delta\boldsymbol{C} + \boldsymbol{\alpha_D}\%\Delta\boldsymbol{D} + \boldsymbol{\alpha_A}\%\Delta\boldsymbol{A} + \boldsymbol{\alpha_U}\%\Delta\boldsymbol{U} + \boldsymbol{\alpha_L}\%\Delta\boldsymbol{L} + \boldsymbol{\alpha_{NG}}\%\Delta\boldsymbol{NG} + \boldsymbol{\alpha_t}$$

where Δ denotes the rate of change. We collect terms in the above by moving the change in OM&A input price term to the right-hand-side and obtain the following:

Equation 4

$$\%\Delta\boldsymbol{C} = \boldsymbol{\alpha_k}\%\Delta\boldsymbol{wk} + (\boldsymbol{1} - \boldsymbol{\alpha_k})\%\Delta\boldsymbol{wom} + \boldsymbol{\alpha_N}\%\Delta\boldsymbol{N} + \boldsymbol{\alpha_C}\%\Delta\boldsymbol{C} + \boldsymbol{\alpha_D}\%\Delta\boldsymbol{D} + \boldsymbol{\alpha_A}\%\Delta\boldsymbol{A} + \boldsymbol{\alpha_U}\%\Delta\boldsymbol{U} + \boldsymbol{\alpha_L}\%\Delta\boldsymbol{L} + \boldsymbol{\alpha_{NG}}\%\Delta\boldsymbol{NG} + \boldsymbol{\alpha_t}$$

Since α_k =0.60, the term $(1-\alpha_k)$ = 0.40 and $(1-\alpha_k)\Delta wom$ = 0.40*2.3% or 0.92%. This is the term,$(\boldsymbol{1}-\boldsymbol{\alpha_k})\%\Delta\boldsymbol{wom}$, that is missing from the change in predicted cost used in the TFP backcast in PEG's Table 19. When inserted, the cost projection in Table 19 increases by 0.92%, and then on Table 20 this leads to a reduction in the TFP by 0.92% to -0.85%.

This math explains how the OM&A input price term should enter into Table 19. We started with PEG's econometric equation and have shown that a proper cost projection should include a term that is equal to: (one minus the capital price coefficient), multiplied by the average annual growth rate in the OM&A input price. A cost projection that does not include this term is not accounting for the cost pressures of OM&A inflation.

In layman's terms, PEG is omitting the impact of OM&A inflation. There is absolutely no term for OM&A inflation in their Table 19 and it is not being accounted for (explicitly or implicitly) in PEG's cost and subsequent TFP projections. This omission is causing PEG to mistakenly claim an econometric TFP estimate of 0.07%, when the correct answer is around -0.8%. The math discussed above, in concert with the five tests PSE ran, clearly shows that there is an OM&A term in PEG's econometric equation, and a proper cost projection must include that term.

4 Unit Cost Econometric Benchmarking Model

The RRFE Report states that benchmarking will continue to be used to inform the rate-making process in Ontario. Total cost benchmarking, which includes both OM&A and capital carrying costs, will be used to improve and build on the benchmarking framework.

The move to total cost benchmarking and the gathering of the necessary data is a major step forward. Total costs, which can be thought of as a sort of revenue requirement evaluation, are more comprehensive and complete than an OM&A examination. Customer's rates are ultimately driven by the complete, total costs incurred by distributors and upstream utility functions. For this reason, PSE is highly supportive of moving to a total cost benchmarking model. A total cost benchmarking framework that informs the rate making process is the best practice for regulation.[18]

PSE is recommending a benchmarking framework that we believe has some significant advantages relative to the 3GIR benchmarking framework and the 4GIR framework recommended by PEG. PSE has developed a model that estimates the unit costs (cost per customer) using econometrics. We call the model the Unit Cost Econometric Model.

The model equation explains total costs per customer (normalized for input prices) through a number of cost driver variables. The equation is provided below with the variables bolded. All of the variables in the model are statistically significant at a 90% confidence level. All of the variables except load factor (LF) are significant at a 99% confidence level.

Equation 5

$$\ln\left(\frac{\boldsymbol{Costs}/\boldsymbol{W}}{\boldsymbol{N}}\right) = \alpha_1 + \alpha_2 * \ln\left(\frac{\boldsymbol{KM}}{\boldsymbol{N}}\right) + \alpha_3 * \ln\left(\frac{\boldsymbol{P}}{\boldsymbol{N}}\right) + \alpha_4 * \ln\left(\frac{\boldsymbol{A}}{\boldsymbol{N}}\right) + \alpha_5 * \ln(\%\boldsymbol{I}) + \alpha_6 * (\%\boldsymbol{N10}) + \alpha_7 * \ln(\boldsymbol{Wd}) + \alpha_8 * \ln(\%\boldsymbol{S}) + \alpha_9 * \ln(\boldsymbol{LF}) + \alpha_{10} * (\%\boldsymbol{UG}) + \alpha_{11} * \left(\%\boldsymbol{UG} * \frac{\boldsymbol{N}}{\boldsymbol{A}}\right) + \alpha_{12} * \boldsymbol{Trend} + \varepsilon$$

The variables in Equation 5 above are:

- Total costs (costs),
- Bilateral input price (W),
- Number of customers (N),

[18] This statement does not mean that benchmarking evaluations of other key performance areas are not crucial to the entire distributor performance picture. Econometric benchmarking of other performance areas such as reliability, customer satisfaction, and safety should also be considered and inform the rate making process. For example, in other research PSE has estimated the added costs of increasing reliability performance for a distributor. A benchmarking framework that provides the right incentives between balancing the increased costs of reliability with customer demand for better reliability should be a long-term aim.

- Kilometers of distribution lines (KM),
- Annual peak demand (P),
- Service area (A),
- Percentage of large and general service loads (%I),
- Percentage of customers added in last 10 years (%N10),
- Hourly high winds above 10 knots (Wd),
- Percent of lines that are single phase (%S),
- Load factor (LF),
- Percent of lines underground (%UG), and
- A time trend that increases by "one" per year (Trend).

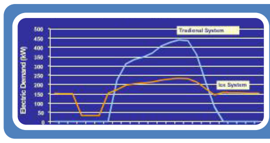
The econometric analysis estimates the alphas (α) in the equation above. The cost per customer benchmark for each distributor observation uses those alpha estimates, along with the actual variable value of each utility observation (in each year) to predict the cost per customer. The alphas for the terms with a natural log can be thought of as unit cost elasticities. For example, α_2 is interpreted as the expected percentage impact on unit costs given a percentage impact on the kilometer length of lines per customer. So if KM of lines increases by 10 percent, we would expect a $10\%*\alpha_2$ impact on the unit costs. The cost per customer benchmark is then built up by inserting each observations values into the estimated equation.

The variables in the Unit Cost Econometric Model are explained further in the following figure.

Figure 4 Variables in the Unit Cost Econometric Model

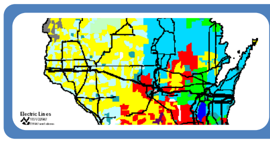
KM per Customer

- Measures system density and how many KM of lines per customer the distributor supports



Peak per Customers

- Measures the peak demand per customer the distributor supports

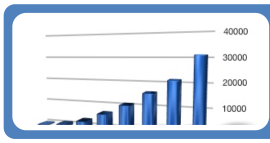


Area per Customers

- Measures the area per customer the distributor supports

% Large & GS

- Measures the percent of volumes that are delivered to large and general service customers



% Customers added in last 10 years

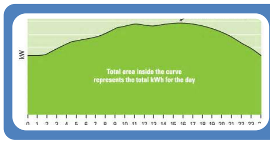
- Measures the new customers the distributor has had to support and connect in last 10 years

Windy Conditions

- Measures the hourly wind observations that are above 10 knots. Distributors with more extreme wind conditions will tend to increase construction costs and service restoration costs

% Single Phase Lines

- Measures the percentage of single phase lines relative to total lines. Single phase lines will tend to require lower capital costs relative to three-phase lines



Load Factor

- Measures the ratio of the average load to the peak load on the system. A higher load factor will cause less stress on system assets and produce a flatter load curve for distributors

% Underground

- Measures the percentage of underground lines to total lines. Underground lines typically cost more to construct but also tend to reduce OM&A expenses and the number of outages.   Direct bury, possible in rural settings, tends to cost less than undergrounding in urban settings.

% Underground times Customers per Area

- This measures the relationship between costs and undergrounding lines in higher density areas. Undergrounding will tend to be far more costly in urban settings versus rural settings.

Time Trend

- This variable measures the annual cost pressures within the industry not measured by the other variables. This is the cost pressure above and beyond inflation and the other changes in measured business conditions

The Unit Cost Econometric Model has a number of advantages over PEG's recommended benchmarking framework. The one possible disadvantage of the PSE framework is that the translog cost form (which is what PEG uses) is more sophisticated and widespread in academic publications when cost function empirical research is presented. This is because, in most applications of cost research, the researcher typically wants to estimate or control for economies of scale.

However, in the context of Ontario regulation, the cost model is meant to be used to rank the overall efficiency of distributors relative to each other. Part of this overall efficiency is the realization of scale economies. Therefore, a model that does NOT control for economies of scale is desirable. PSE's unit cost econometric model better incorporates the efficiency gains from economies of scale into the rankings, whereas PEG's translog cost function uses a number of variables to "pre-judge" efficiency gains from scale economies, and thus does not reflect these efficiency gains into the rankings. In the context of Ontario regulation, PSE believes the UCEM model is in the best interests of customers and provides the correct incentives for distributors to find cost saving opportunities.

The advantages of using PSE's Unit Cost Econometric Model are described below.

1. **PSE's Model has More Business Condition Variables:** PSE's model includes twelve cost drivers in the analysis. Ten variables are statistically significant at a 99% confidence level, and one variable (load factor) is significant at the 90% confidence level. Input prices are inserted in the cost definition to assure conformity with cost theory.

    - In contrast, PEG's econometric model includes only six business condition variables that are statistically significant at a 99% confidence level, one variable at a 90% level (Retail deliveries), and two other variables that are NOT significant at a 90% confidence level (Area and Percent Undergrounding). PEG's model is unable to accommodate these variables, and others, due to the numerous interaction and quadratic terms their model includes.

2. **PSE's Model is Transparent and Easier to Understand and Explain:** PSE's model takes a log-log format rather than using the translog cost function. There are no quadratic variables and only one interaction variable. The parameter coefficients are unit cost elasticities, which means a one percent increase in the cost driver will result in a change in the unit cost benchmark of one percent times the coefficient value.

    - PEG's two benchmarking approaches are a great deal more difficult to understand and explain. Partially, this is because there are two approaches rather than just one. Furthermore, the PEG econometric model using a translog cost function that has a number of quadratic and interaction terms that are difficult to interpret and explain. The translog cost function is a key component of the peer group approach, making it necessary to understand the econometric model to also understand the peer group approach. As stated earlier, this also means that the peer group method is not an independent double check on the econometric method, since it uses results from the econometric method.

3. **PSE's Model Does Not Penalize Distributors for Realizing Efficiency Gains through Economies of Scale:** PSE's model is neutral to distributor size and does not pre-judge efficiency gains through the realization of economies of scale. If two distributors decide to merge and are able to lower overall costs, those cost savings will be reflected in an improved benchmark score and ranking. This provides incentives that are aligned with customer interests. Distributor rankings will improve if they uncover efficiency gains, including realization of scale economies.

    - PEG's econometric model does not produce incentives that are aligned with customer interests. Their model essentially "pre-judges" the efficiency gains resulting from the realization of scale economies. Rather than distributors receiving better scores through finding these efficiency gains, they actually can receive worse scores despite lowering overall costs.

4. **PSE's Model Provides Distributors with Information on How the Benchmark is Determined and What the Variable Impacts are:** Given the less complex approach pursued by PSE, distributors and other stakeholders will have an easier time understanding the model and using it to determine the impacts of the variables included in the model. Key information on what the impacts of variables like percent undergrounding (rural or urban), single phase lines, or windy conditions onto costs per customer can be calculated. This should provide reassurance to managers regarding how the benchmarks are formulated and provide actionable intelligence regarding where cost savings may be found.

    - PEG's two recommended approaches do not lend themselves well to providing stakeholders information on how the benchmark is determined or what the impacts are. The econometric model is also difficult to separate out the variable impacts and does not lead to actionable intelligence.

5. **PSE's Model Eliminates the Need for a Second Approach:** PSE's Unit Cost Econometric Model essentially normalizes for, and adjusts total cost per customer by, eleven different business conditions. This combines PEG's unit cost indexing approach with its econometric approach, in a transparent and less complex way. Given the large number of cost driver variables contained in the UCEM, PSE's model is robust, and a second approach (the peer group approach) would only serve to reduce the quality of the efficiency cohort rankings.

    - PEG's unit cost indexing approach is heavily dependent on its econometric model. The unit cost indexing approach has the following flaws: (1) it ignores information on the magnitudes of variables, (2) it has peer groups designed on the basis of variables that PEG's econometric model finds to be statistically insignificant, and (3) the peer groups themselves are subjective and lead to disagreements. They also lead to counter-intuitive results, such as small distributors in Group B, D, E, and F having lower unit costs than larger distributors in Group A.

6. **All of the Variables in PSE's model are statistically significant at a 90% confidence**

level. PEG's model includes 20 variables in all, but only 12 of them are significant at a 90% confidence level. Eight variables are NOT significant at the 90% confidence level but are still included in the model and are used to determine distributor benchmarks.

4.1 Model Estimates

The coefficient estimates are provided in the following table. Altogether there are eleven business condition variables (twelve variables with the constant) which are used to predict total costs (divided by an input price) per customer. All variables are statistically significant at a 90% confidence level, with eleven of them being significant at a 99% confidence level. The model takes a log-log form, with all variables being logged except percent customers added in last ten years, percent undergrounding, percent undergrounding times customer per area, and the trend.[19]

Table 14 Coefficient Estimates

VARIABLE KEY

KM/N=	KM of Line per Customer
P/N=	Peak Demand per Customer
A/N=	Service Area per Customer
%GS=	Percent Large and General Service Loads
%N10=	Percent Customers Added in Last 10 Years
Wd=	Hourly Wind Sum Above 10 knots
%S=	Percent Single Phase Lines
LF=	Dummy for Canadian Shield
%UG=	Percent Lines Underground
%UG*N/A=	Percent Lines Underground times Customers per Area
Trend=	Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
KM/N	0.270	24.01	%S	-0.076	-6.85
P/N	0.088	4.28	LF	-0.046	-1.79
A/N	0.051	10.27	%UG	-0.366	-11.25
%GS	0.122	6.34	%UG*N/A	0.001	26.91
%N10	0.134	17.55	Trend	0.015	14.85
Wd	0.020	2.82	Constant	7.153	98.58

[19] These variables are not logged because of the presence of zero or negative values. PEG also does not log the customer addition or percent undergrounding variables. The time trend is traditionally not logged due to the ease of interpreting the non-logged version as being a percent increase in costs per year.

4.2 Ranking Results

The results rankings based on the PSE model are provided in the following Table 15. The first column lists the distributor classification, the second is the actual unit costs, the third column is the unit cost benchmark, and the fourth column is the difference between the benchmark costs per customer and actual costs per customer. This difference is the dollar amount that the distributor would need to reduce costs by in order to be at the benchmark value. Distributors with negative values have actual unit costs below the benchmark. The second to last column is the percentage difference between the actual unit costs and the benchmark unit costs. The rankings, found in the last column, are based on the percentage difference between the actual and benchmarking unit costs.

As in PEG's econometric rankings, we have hidden the identities of distributors. However, there may be some interest in the spread of larger, medium, and smaller distributors within the results. For this reason we have identified the rankings based on three classifications. Small distributors are defined as having less than 15,000 customers in 2011. Medium-sized utilities are defined as having between 15,000 and 75,000 customers in 2011. Large utilities are defined as having greater than 75,000 customers in 2011. We have shown the top 20 results to enable readers to understand what the results look like, and the dispersion between small, medium, and large utilities in the rankings.

Table 15 PSE Benchmark Results

PSE Unit Cost Econometric Model Benchmark Results					
Distributor Classification	**Actual Unit Costs**	**Benchmark Unit Costs**	**Difference ($)**	**Difference (%)**	**Rank**
small	$248.89	$454.94	-$206.05	-60.3%	1
small	$409.56	$552.55	-$143.00	-29.9%	2
medium	$603.86	$802.76	-$198.90	-28.5%	3
small	$507.51	$642.22	-$134.71	-23.5%	4
large	$401.71	$495.20	-$93.49	-20.9%	5
small	$378.64	$463.88	-$85.24	-20.3%	6
large	$398.76	$474.41	-$75.64	-17.4%	7
small	$337.82	$397.09	-$59.26	-16.2%	8
medium	$422.68	$496.58	-$73.90	-16.1%	9
medium	$416.67	$487.61	-$70.94	-15.7%	10
small	$496.71	$578.21	-$81.50	-15.2%	11
large	$620.18	$711.87	-$91.70	-13.8%	12
large	$413.10	$473.96	-$60.86	-13.7%	13
small	$432.05	$493.80	-$61.75	-13.4%	14
small	$746.31	$845.78	-$99.47	-12.5%	15
small	$392.76	$444.81	-$52.05	-12.4%	16
medium	$459.29	$515.47	-$56.18	-11.5%	17
medium	$573.62	$635.84	-$62.22	-10.3%	18
large	$518.06	$572.38	-$54.32	-10.0%	19
small	$546.37	$597.65	-$51.28	-9.0%	20

4.3 Proper Dataset for Outlier Utilities: Benchmarking Caveat

In the course of our benchmarking research, PSE concluded that an Ontario-only dataset with no exclusions is proper for a TFP analysis. However, for a few utilities, when it comes to cost efficiency benchmarking, the proper dataset needs to include supplemental data to accurately estimate the cost performance of the utility.

For this reason, PSE recommends special consideration for utilities such as Algoma Power, Toronto Hydro, and Hydro One when evaluating the cost efficiency of these distributors. PSE's UCEM is an excellent evaluator of cost efficiency for the vast number of distributors in the Province. However, Hydro One and Toronto Hydro are extreme outliers in an Ontario-only benchmarking exercise because of their large size, regardless of what model is chosen. Similarly, Algoma Power is an extreme outlier because of its incredibly low customer density.[20] [21] Benchmark results of these extreme outliers need to be re-evaluated and refined in light of this fact.

4.3.1 Ontario-Only Dataset is Appropriate for Ontario Productivity Trend

Throughout this report we have demonstrated that excluding Hydro One or Toronto Hydro from the TFP analysis is unwarranted and contrary to an empirically-derived Ontario industry productivity trend. It is improper to exclude any distributors in calculating an industry-wide productivity trend which is to be applied to all of the distributors. This is so for two reasons.

First, the TFP is not calculated by reference to a benchmark. In other words, utilities are not being individually judged on their productivity trend based on how an "average" utility would perform. Second, there are many other industry segments (e.g., northern distributors, GTA distributors) that are unlike their peers in other parts of the Province. If Toronto Hydro or Hydro One are to be excluded on the basis that they are unlike other distributors, then an argument can easily be made that numerous other industry segments should be excluded.

4.3.2 Appropriate Dataset for Cost Efficiency Benchmarking

Therefore, when calculating the TFP, a customized benchmark for each utility is not required. However, conducting a proper evaluation of the cost efficiency of each utility <u>does</u> necessitate customization. A customized benchmark specific to the operating conditions of each utility is, in fact, what econometric benchmarking is attempting to achieve.

---

[20] The 2011 customer density of Algoma Power is 6.27 customers per Kilometer of line. The sample average is around 45 customers per KM of line. The second lowest distributor regarding density equals 9.73 customers per KM of line, which is over 50% higher than Algoma. This evidence, along with Algoma's outlier benchmarking results indicates an alternative dataset should be used to properly evaluate their cost performance.

[21] PSE would suggest for Algoma Power a benchmarking dataset that includes U.S. rural electric cooperatives. We have conducted a number of benchmarking studies for these cooperatives and their customer density tends to be similar to that of Algoma's.

For evaluating cost efficiency, the use of an Ontario-only dataset is appropriate for most of the Ontario distributors. The data is representative and encompasses most of the operating conditions facing the vast number of distributors in Ontario. However, for a utility such as Hydro One, Algoma Power, or Toronto Hydro, the data is not representative, and does not encompass the cost drivers facing the distributors. In Toronto Hydro's case, given the lack of any large urban peers, the data set is completely unable to accommodate and adjust for the cost challenges of serving in a large urban core environment. PSE would be unable to build a large urban core variable with Ontario-only utilities. Cities such as Chicago, Minneapolis, New York, etc. will be needed to create the variable.

4.3.3 Toronto Hydro Cost Benchmarking Results

Given the tight time constraints, we have not been able to add the necessary utilities or estimate models that accurately measure the cost performance of Hydro One or Algoma Power.[22] However, we have done this in previous benchmarking research for Toronto Hydro. Last year (in 2012) PSE conducted cost benchmarking research for Toronto Hydro. This research examined Toronto Hydro's cost efficiency levels to a North American dataset comprised of both Ontario distributors and U.S. electric utilities. PSE considers the combined U.S. and Ontario benchmarking dataset to be the most salient benchmarking standard for determining Toronto Hydro's cost performance. Toronto Hydro is an outlier within the Ontario industry, but is well within the variable data ranges for the combined sample. This is because Toronto's urban characteristics are more similar to those of many United States cities. The combined dataset offers a number of advantages over an Ontario-only or US-only dataset. These advantages include:

1. Operating conditions of utilities in the combined dataset encompass those of Toronto Hydro; this is not the case with an Ontario-only dataset. For example, with the combined dataset there are a number of utilities that are both larger and smaller than Toronto Hydro as measured by the number of retail customers, kilowatt hour sales, or kilometers of line. This is imperative so that the influence of the variables onto cost levels can be properly estimated at Toronto Hydro's variable values. An Ontario-only dataset does not include observations that adequately encompass those of Toronto Hydro, and possibly Hydro One.

2. With a combined dataset, key variables can be constructed and included in the analysis that otherwise could not be with an Ontario-only dataset. Most important to a proper evaluation of THESL's cost values is the inclusion of an "urban core" variable. U.S. data needs to be included into the dataset to construct and estimate the influence on costs of serving a large urban core. The Ontario-only dataset only has one utility with a large urban core: Toronto Hydro.

3. The influence of operating in Ontario and Canada is not incorporated into a U.S.-only dataset. Operating a distribution utility in Ontario likely has some differences to U.S. distributors that are difficult to model. For example, financial data, including costs and

[22] Our initial thought on evaluating Hydro One and Algoma Power is the addition of U.S. utility data along with the Ontario data. In particular, these highly rural utilities should be judged based on a dataset that includes other highly rural utilities. This is possible by including data from the U.S., in particular using data from rural electric cooperatives.

input prices, are reported in Canadian versus U.S. dollars. While the currency differences are adjusted for in the analysis, a U.S.-only dataset does not assure that these adjustments fully account for the differences. A combined dataset does.

A combined dataset provides the econometric models with more utilities, more diversity in operating conditions, and more observations. The strength of the econometric benchmarking approach is its ability to incorporate all available data, estimate the influence of external conditions, create a benchmark based on those conditions for each observation, and determine how precise that benchmark is. The more comprehensive and extensive the dataset, the more accurate and precise the econometric models are. The testing of diverse operational conditions with the combined dataset increases the degrees of freedom in the modeling (versus a U.S.-only or Ontario-only dataset).

The details of the Toronto-Hydro benchmarking study are found in the Appendix. We would urge the Board to be cautious with the Ontario-only benchmarking results (both PEG's models and PSE's model) regarding their evaluation of the performance of these outlier distributors. Special consideration is warranted in these individual cases.

4.4 Comparison of Econometric and Peer Group Benchmark Approaches

In a competitive environment, the most important "benchmark" is the price charged to consumers. However, the power distribution industry is ill-suited for such price comparisons. Benchmarking techniques that are legitimate for other industries (e.g., non-econometric unit cost comparisons) do not work well in the power distribution industry, due to the vast differences in operating circumstances that each distributor encounters.[23]

The econometric benchmarking approach used in this report (the Unit Cost Econometric Model) explicitly adjusts for the major factors influencing costs. This allows for normalized comparisons to be made and, therefore, more accurate assessments of performance relative to approaches that do not make explicit adjustments for the variables influencing costs.

The accuracy of the peer group analysis depends on how similar the peer group is to the examined company and the size of the peer group. While PEG's current peer groups each contain at least ten distributors, there are vast business condition differences within each peer group. These variable differences are being ignored in the peer group approach. In contrast, the econometric benchmarking approach adjusts and accounts for the variable differences.

A paper on benchmarking methods was released in March 2010 by the National Regulatory Research Institute (NRRI) entitled, "Utility Performance: How Can State Commissions Evaluate It Using Indexing, Econometrics, and Data Envelopment Analysis?" PSE's econometric benchmarking research was cited in this report.[24] The report concluded that the econometric

[23] Most industries have concentrated production facilities (i.e., factories) and can determine the size of their operations, whereas distribution utilities have assets scattered across the entire service territory. This reality makes the distributor's cost levels highly dependent on the characteristics of the territory it is serving.

[24] Our benchmarking research cited in that report was conducted on behalf of the Citizens Utility Board of Illinois

method provides higher reliability of results compared to the peer group or unit cost indexing method.

A summary of modeling methods as discussed in that report is shown below.

Figure 5 NRRI Summary of Modeling Methods

Method	Ease of Application	Reliability of Results	Data Requirements
Peer Group	Easy to Apply	Not Reliable/Medium Reliability	Low Data Requirements
Econometric	Medium/High Difficulty	**Medium/High Reliability**	High Data Requirements

*** Source: National Regulatory Research Institute

Given the significant data effort put forth by the Board and other stakeholders and the commitment to econometric benchmarking in the past, PSE believes the 4GIR benchmarking framework is substantially enhanced by the elimination of peer grouping. The peer group approach ignores pertinent information and is not independent of the econometric approach to begin with. The peer group approach offers an inferior performance evaluation that waters down and detracts from the more robust and reliable econometric benchmarking results.

It is PSE's recommendation that stretch factors are determined solely on the basis of an econometric model. We believe the PSE UCEM benchmarking results provide the best evaluation of distributor cost efficiency. However, even if another econometric model is used, we recommend eliminating the peer group approach and using the benchmarking results from that econometric model.

and the Illinois Attorney General.

5 Stretch Factor

PSE is recommending a stretch factor that is based off the results of our Unit Cost Econometric Model. We propose six cohorts which are based on the rankings of the benchmark results. Currently there are 73 distributors in the sample, the top sixth would be placed in Cohort One, the second sixth into Cohort Two, and on until the bottom sixth distributors are placed in Cohort Six. Cohort One would have a stretch factor of zero, with the stretch factors increasing by 0.1% for each Cohort above the first one.

The table below provides our recommended Cohorts and stretch factors.

Table 16 Recommended Cohorts and Stretch Factors

Rank	Stretch Factor
#1 to #12	0.00%
#13 to #24	0.10%
#25 to #36	0.20%
#37 to #48	0.30%
#49 to #60	0.40%
#61 to #73	0.50%

Our recommended stretch factor range is zero to 0.50%. This is a slight reduction from 3GIR, where the range was zero to 0.60%. PSE feels this stretch factor range is appropriate for three reasons. These are:

1. One of the primary rationales behind stretch factors is the sharing of benefits with customers resulting from moving from cost of service regulation to incentive regulation. Given the transition, utilities are often expected to achieve higher productivity gains than the historical average. Since the upcoming plan will be the 4th Generation of IR in Ontario, much of the cost saving opportunities have likely been realized. A stretch factor requires most of the utilities to beat the Ontario historical sample average (most of which has been under some form of incentive regulation). Even PSE's recommended stretch factor will require 5/6th of the industry to beat the Ontario historical productivity average.

The 1/6th that have a zero stretch factor will also have a difficult time hitting the historical average given their current position of strong cost efficiency.[25]

2. Most incentive regulation plans have stretch factors between zero and 0.5%. In the footnote of page 74 in the May 2013 PEG Report, PEG lists a number of incentive regulation plans. The plans that explicitly discussed a stretch factor ranged from 0.2% to 0.4%.

3. The last reason that the stretch factor range should be slightly reduced is that Ontario-specific data is now being used to formulate the productivity factor, and the inflation factor will also be industry-specific. Given the increased precision of using an Ontario industry TFP estimate, there is less risk that the productivity factor is not applicable to the entire Ontario industry.

PSE recommends using the distributor rankings to form the cohort groups, rather than statistical significance testing. The reason for this is it assures that there is an even number of firms in each of the cohort groups. Current groupings in the PEG report show 13 distributors in the last cohort group and only 8 in the first group. An even spread based on rankings will increase the ability of distributors to move from one cohort to another, since a disproportionate number are in the middle cohort in the PEG report, making it difficult to move either up or down.

Basing the cohort groups on rankings will also be more transparent, easier to explain than the "statistically superior" classification, and give managers more information on what they need to do to move up cohorts. Under the PEG recommendations, managers won't have a solid cost reduction goal to shoot for, because it is not intuitive or obvious on how to move from "statistically average" to "statistically superior." However, under the PSE recommendations of using the Unit Cost Econometric Model and basing the cohorts on the rankings, a utility can more easily see how much they will need to reduce their costs per customer to move up to the next cohort. This should increase the incentives to decrease costs and provide more information to utility managers.

[25] If the rationale behind a stretch factor is not sharing IR benefits but instead it is to provide increased incentives for distributors to increase cost efficiency, a symmetric stretch factor that ranges from a negative value to a positive value would make a lot of sense. In that case, a larger range may be warranted. This larger range would have the impact of increased cost containment incentives for distributors. For example, one symmetric range could be from negative 0.5% to positive 0.5%. This would enhance the ability of distributors to move from one stretch factor to another and have that move be more meaningful financially.

6 Concluding Remarks

PSE's recommendations will enhance distributor incentives through the improved benchmarking framework, provide utility managers more information on the cost savings their utilities need to achieve to move up cohort groups, and deliver appropriate and gradual rate increases. Gradual and predictable rate increases are in the best interests of both customers and distributors, as are incentives to find and act upon cost saving opportunities.

We appreciate the opportunity to present this expert report to the Board.

Appendix: North American Dataset and Toronto Hydro Results

As discussed in Section 4.3 Toronto Hydro is a unique distributor in Ontario because of its large size and its position as the only distributor serving a large urban core. Throughout this report we have made the argument that excluding Toronto Hydro from the TFP analysis is unwarranted and contrary to an empirically-derived Ontario industry productivity trend. It is improper to exclude any distributors in calculating an industry-wide productivity trend which is to be applied to all of the distributors. Furthermore, there are many other industry segments (e.g., northern distributors, GTA distributors) that are unlike their peers in other parts of the Province. If Toronto Hydro or Hydro One are to be excluded on the basis that they are unlike other distributors then an argument can easily be made that numerous other industry segments should be excluded.

When calculating the TFP, a customized benchmark for each utility is not required. However, conducting a proper evaluation of the cost efficiency of each utility <u>does</u> necessitate customization. A customized benchmark specific to the operating conditions of each utility is, in fact, what econometric benchmarking is attempting to achieve.

For evaluating cost efficiency, the use of an Ontario-only dataset is appropriate for most of the Ontario distributors. The data is representative and encompasses most of the operating conditions facing the vast number of distributors in Ontario. However, for a utility such as Toronto Hydro or Hydro One, the data is not representative, and does not encompass the cost drivers facing the company. Most notably, given the lack of any large urban peers, the data set is completely unable to accommodate and adjust for the cost challenges of serving in a large urban core environment.

Last year PSE conducted cost benchmarking research for Toronto Hydro. This research examined Toronto Hydro's cost efficiency levels to a North American dataset comprised of both Ontario distributors and U.S. electric utilities. PSE considers the combined U.S. and Ontario benchmarking dataset to be the most salient benchmarking standard for determining Toronto Hydro's cost performance. Toronto Hydro is an outlier within the Ontario industry, but is well within the variable data ranges for the combined sample. This is because Toronto's urban characteristics are more similar to those of many United States cities. The combined dataset offers a number of advantages over an Ontario-only or US-only dataset. These advantages include:

1. Operating conditions of utilities in the combined dataset encompass those of Toronto Hydro; this is not the case with an Ontario-only dataset. For example, with the combined dataset there are a number of utilities that are both larger and smaller than THESL as measured by the number of retail customers, kilowatt hour sales, or kilometers of line. This is imperative so that the influence of the variables onto cost levels can be properly estimated at Toronto Hydro's variable values. An Ontario-only dataset does not include observations that adequately encompass those of Toronto Hydro.

2. With a combined dataset, key variables can be constructed and included in the analysis that otherwise could not be with an Ontario-only dataset. Most important to a proper

evaluation of THESL's cost values is the inclusion of an "urban core" variable. U.S. data needs to be included into the dataset to construct and estimate the influence on costs of serving a large urban core. The Ontario-only dataset only has one utility with a large urban core: Toronto Hydro.

3. The influence of operating in Ontario and Canada is not incorporated into a U.S.-only dataset. Operating a distribution utility in Ontario likely has some differences to U.S. distributors that are difficult to model. Financial data, including costs and input prices, are reported in Canadian versus U.S. dollars. While the currency differences are adjusted for in the analysis, a U.S.-only dataset does not assure that these adjustments fully account for the differences. A combined dataset does.

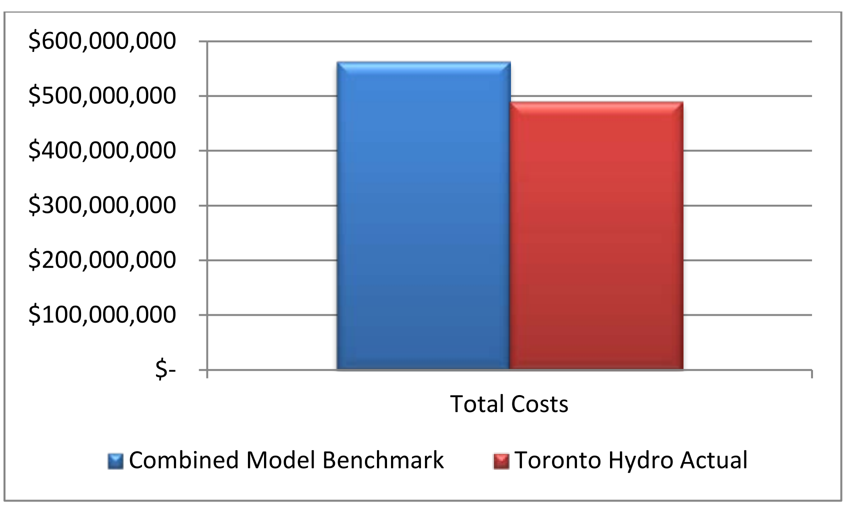
4. A combined dataset provides the econometric models with more utilities, more diversity in operating conditions, and more observations. The strength of the econometric benchmarking approach is its ability to incorporate all available data, estimate the influence of external conditions, create a benchmark based on those conditions for each observation, and determine how precise that benchmark is. The more comprehensive and extensive the dataset, the more accurate and precise the econometric models are. The testing of diverse operational conditions with the combined dataset increases the degrees of freedom in the modeling (versus a U.S.-only or Ontario-only dataset).

6.1.1 Toronto Hydro Total Cost Results with Combined Ontario & U.S. Model

PSE provides the total cost results for Toronto Hydro in this section. We should note that we did not have time to incorporate the pre-2002 historical data provided by PEG into this analysis. Our findings are that Toronto Hydro's 2009-2011 average total costs are 14 percent below the benchmark value. This benchmark value implies better than expected cost performance. The difference in THESL's actual cost level and its benchmark value is significant at a 90 percent confidence level.

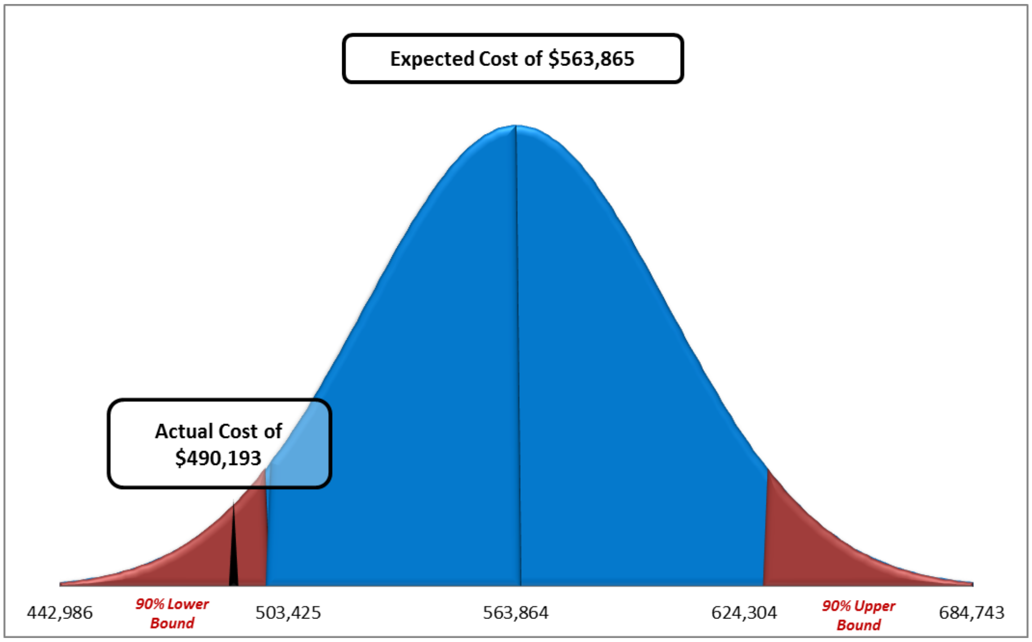
The benchmark to actual comparisons for total costs are summarized in the following figure. The customized model expected average 2009-2011 total costs of $564 million compared with Toronto Hydro's actual total costs of $490 million.

Figure 6 2009-2011 Average Combined Econometric Cost Benchmark Comparisons



The difference between THESL's actual total cost value to its benchmark value is statistically significant at a 90 percent confidence level. This is shown in the figure below.

Figure 7 Probability Distribution for THESL's Combined Total Cost Benchmark: 2009-2011 Average (in $1,000s)



The following figure ranks the average 2009-2011 difference in Toronto Hydro's total costs to its econometric benchmark costs against the combined U.S./Ontario sample. This ranking is based on the difference between the *actual* costs for each utility and the model's *expected* costs for that utility. This allows the ranking to be adjusted for the external factors of each utility's service territory.

The ranking is determined using a two-step process:

1. Calculate benchmark values, which are adjusted for each company's circumstances, for the entire sample, and then compare to their actual values.
2. Rank the sample according to the difference in the benchmark value and the actual value.

Toronto Hydro's total cost performance ranked 39th out of 170 utilities after the econometric model customized the benchmark to its operating conditions.

Figure 8 2009-2011 Average Total Cost Econometric Ranking: Combined Dataset