Pacific Economics Group Research, LLC

SUPPLEMENTARY EMPIRICAL ANALYSES

At the May 27-28, 2013 EB-2010-0379 Stakeholder Conference, Pacific Economics Group Research (PEG) was asked to undertake two supplementary empirical analyses: (1) estimate TFP growth for the Ontario electricity distribution industry using an average of each distributor's estimated TFP growth over the 2002-2011 period; and (2) re-estimate the econometric model used to benchmark distributors' cost performance using a measure of total cost that excluded the LV charges that embedded distributors pay to host distributors. This document summarizes PEG's results on these supplementary empirical analyses.

Average TFP Growth

In our May 2013 reports, PEG estimated industry TFP using aggregate measures of output quantity and input quantity growth. In an "aggregate" measure of output quantity or input quantity, larger distributors effectively receive more weight than smaller distributors, for the reason that larger distributors' account for relatively larger shares of industry-wide output or input quantity. PEG's industry aggregate was comprised of 71 electricity distributors in Ontario. The two largest distributors – Hydro One (HONI) and Toronto Hydro (THESL) – were excluded from the aggregate in order to produce an estimate of TFP growth that would be "external" to all the distributors in the Province who are potentially subject to rate adjustments under the fourth generation incentive rate setting (4th Gen IR) plan. Our results (as well as formal statistical tests) showed that Hydro One and Toronto Hydro were having a significant, downward impact on the industry's TFP trend.

An alternate measure of the industry's TFP growth would be to estimate each distributor's average TFP growth over the 2002-2011 period and then average these distributor-specific TFP trends across distributors in the industry. The "average" TFP growth rate computed with this approach treats the TFP experience of every distributor equally. More particularly, the TFP growth of larger distributors is given the same weight as the TFP growth of smaller distributors when computing the industry's average TFP growth.

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PEG was asked to compute "average" in addition to "industry aggregate" measures of TFP growth. Below we present the results of both the Average and Aggregate measures of TFP growth (per annum) for the Ontario electricity distribution industry over the 2002-1011 period.

	Average	Aggregate
All distributors	-0.26%	-1.10%
All distributors excluding HONI and THESL	-0.20%	0.10%
All distributors excluding HONI only	-0.24%	-0.56%
All distributors excluding THESL only	-0.23%	-0.81%
All distributors excluding THESL, HONI and other 2002 benchmark	-0.09%	0.21%

In PEG's May 27th presentation at the Stakeholder Conference, PEG recommended a 0.1% value for the productivity factor. This value is equal to the TFP trend of 0.1% estimated for the industry aggregate that excludes HONI and THESL. If HONI and THESL are included, the industry aggregate TFP trend for the 2002-2011 period would be -1.10%. If THESL only is excluded from the aggregate, the industry TFP growth would be -0.81%. If HONI only is excluded from the aggregate, the industry TFP growth would be -0.56%. If THESL, HONI and the other distributors that used a 2002 capital benchmark year ("other 2002 benchmark") are excluded from the aggregate, the industry TFP trend would be 0.21%.

The "average" TFP trends for different partitions of the industry fall within a smaller range. When the TFP trends of all 73 distributors are averaged, the industry average TFP trend over the 2002-2011 period is -0.26%. When HONI and THESL are excluded, the industry average TFP trend for the other 71 distributors is -0.20%. If HONI only is excluded, the industry average TFP trend is -0.24%. If THESL only is excluded, the industry average TFP trend is -0.23%. If THESL, HONI and the five other distributors with a 2002 benchmark are excluded, the industry average TFP trend for the remaining 66 distributors is -0.09%. It is not surprising that the average TFP measures are closer together than the aggregate TFP measures, because in the latter measures the larger, negative TFP trends of HONI and THESL are given more weight than in the "average" TFP approach, where every distributor is given equal weight.

After considering these results on the “average” TFP trends, PEG’s recommendation of a value of 0.1% for the productivity factor is unchanged. At the first stakeholder meeting on January 10th 2013, PEG was asked about “average” versus “aggregate” TFP measures. PEG responded by saying that aggregate TFP measures are preferred in conceptual terms. The reason is that placing equal weight on every distributor, even when some distributors provide relatively greater shares of industry output or account for greater shares of industry cost, will lead to a type of “aggregation bias.” PEG continues to believe that this is the case. While the average TFP growth measures presented above may be informative to stakeholders, Staff and the Board, PEG continues to recommend that the productivity factor for 4th Gen IR be set using the aggregate TFP trend (excluding HONI and THESL) and have a value of 0.1%.

Updated Econometric Model

One of the surprising results of the econometric model PEG developed to benchmark distributors’ cost performance was a positive estimated coefficient for the time trend variable. This result is counter to an expected negative value for the trend coefficient, which is typically taken to be a proxy for technological change in the industry. A positive coefficient on the trend variable shows that, even after controlling for changes in input prices, output and other business condition variables, there have been systematic cost increases for the Ontario electricity distribution industry over the 2002-2011 period.

At the May 28th Stakeholder Conference, PEG hypothesized that these upward cost pressures could be a consequence of the data sources that were available to and used by PEG to construct the distribution cost measures used for benchmarking. In particular, PEG’s benchmarking cost measure included the LV charges paid by embedded distributors to host distributors. These costs are not included in the RRR data and are not subject to price cap index adjustments under 4th Gen IR, but they should be included in the costs that are used to make “apples to apples” benchmarking comparisons across distributors. Over the 2002-2011 period, the industry-wide LV charges were either zero or very small in the early years of the sample period, but they grew to much larger amounts by the end of the period. It is possible, then, that the positive trend coefficient could simply reflect the increasing, regulatory practice of charging embedded distributors for the use of host distributors’ LV assets rather than a sign of systematic, industry-wide cost pressures.

PEG was asked to investigate this hypothesis by re-estimating its benchmarking cost model with a cost measure that excluded the LV charges paid by embedded distributors to host distributors. The results of this re-estimated model are presented below.

The coefficients in this model are similar to those presented on Table 12 of PEG's redlined, May 31 report. The trend coefficient estimated without the LV costs included is .011 whereas the estimated coefficient in the May 31st, redlined report is .012. Both estimates are highly significant statistically. Because these coefficient estimates are so similar, there is little to no empirical support for the hypothesis that the positive trend coefficient is due to the particular features of the LV cost data.

Notwithstanding this finding, PEG believes it is not appropriate to use the positive trend coefficient in the econometric model as the basis for a negative recommended value for the productivity factor. Such an interpretation and application of the econometric model is unwarranted for two reasons: (1) consistency in cost and input quantity measures; and (2) it does not appropriately account for changes in output quantities.

On the input quantity side, it must be recognized that the costs used in the econometric model are *not* consistent with the costs used in the TFP analysis. PEG made three adjustments to the costs used in the TFP analysis in order to make apples-to-apples, benchmarking comparisons of total costs. One of those adjustments involved the LV data, and this adjustment was reversed in the exercise above. But there are still two differences between the cost data used to estimate the cost model coefficients presented above and the cost data used in the TFP analysis. These concern the treatment of HV transformation costs and customer contributions in aid of construction. The positive trend coefficient could still result from either, or both, of these adjustments to the cost data.

More generally, PEG cautions the Board against placing any weight on an estimated trend coefficient as a basis of the productivity factor if the cost measure used as a dependent variable in the econometric model is not identical to the cost measure used in the TFP analysis. Only the latter costs are relevant for the productivity factor, and analysis based on any alternate cost measure is potentially misleading. For simplicity, and to prevent the confusion that may have resulted if multiple econometric results using different cost specifications were presented in our May 2013 reports, PEG has not undertaken an econometric analysis of the cost measure used in our TFP analysis.

Updated Econometric Coefficients with LV Costs Eliminated from Cost Measure

VARIABLE KEY

Input Price: WK = Capital Price Index
Outputs: N = Number of Customers
C = System Capacity
D = Retail Deliveries
Other Business Conditions: U = % of Lines Underground
A = 2011 Service Territory
L = Average Line Length (km)
NG = % of 2011 Customers added in the last 10 years
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.601	88.710	WKxN*	0.032	1.658
N*	0.464	8.318	WKxC	0.029	1.546
C*	0.201	3.699	WKxD	0.000	0.038
D*	0.054	1.883	NxC	0.127	0.487
WKxWK	0.063	1.414	NxD	0.125	1.140
NxN	-0.471	-1.636	CxD*	-0.219	-2.326
C*C	0.267	0.994	A	0.012	0.855
DxD	0.112	1.536	U	0.011	0.670
			L*	0.239	7.712
			NG*	0.024	3.085
Trend*	0.011	8.125			
Constant*	12.135	504.371			
System Rbar-Squared	0.979				
Sample Period	2002-2011				
Number of Observations	709				

*Variable is significant at 90% confidence level

On the output side, Professor Yatchew advanced an intriguing hypothesis at the May 27-28 Stakeholder Conference that deserves greater attention. Professor Yatchew argued that the positive trend coefficient, and hence the upward trend in industry cost, is likely related to the change in 'unmeasured' outputs provided by distributors over the 2002-2011 period. These unmeasured outputs include smart metering (a new, enhanced metering service), connections for renewable generators, and greater facilitation of CDM.

PEG agrees with Professor Yatchew that these “unmeasured” outputs are an important feature of the new environment in which distributors are operating. In fact, this is discussed in the Concept Paper that PEG wrote at the outset of this consultation process. The Appendix to this document includes the relevant pages (pp. 15-20) from the April 2011 Concept Paper which discuss the relationship between ‘traditional’ and ‘new’ distribution services. This discussion concludes by noting that the complexities and inter-relationships between traditional and new distribution services

> “…suggest that there is not a bright line between networks’ “traditional’ and “new" functions. Some of the investments necessary to comply with GEA (the Green Energy and Green Economy Act) mandates may have implications for how traditional outputs are provided, while some assets that help perform traditional functions more efficiently (*e.g.* smart meters) may prove valuable in helping networks cope with the challenges of delivering power from more diverse and less centralized supply sources to end-users. Regulators may therefore need to take a broader view of how traditional outputs are being provided, and be sensitive to the potential linkages between investments needed for the “new“ marketplace and the network outputs that have traditionally been subject to economic regulation.”

PEG considered these issues when it began its empirical work for 4th Gen IR. PEG has been able to develop a data series on some of the costs associated with the new unmeasured services, particularly for smart meters. However, nearly all of the “new” generation connection and smart metering services provided by distributors remain unmeasured in PEG’s study because the data do not exist to measure them appropriately.

It is important to keep this fact in mind when considering the relationship between changes in industry cost, PEG’s econometric results, and the implications for an appropriate productivity factor for 4th Gen IR. Recall that TFP growth is by definition equal to the growth in output quantities minus the growth in input quantities. Professor Yatchew has argued that the positive trend coefficient in our econometric model reflects (to a considerable extent) the cost consequences associated with distributors providing a greater volume and array of unmeasured outputs. But the recommended productivity factor cannot focus solely on the cost consequences of the new distribution marketplace, because doing so captures only the *changes in input quantity*, which is only one component of the TFP growth calculation. A full accounting of distributors’ increasing obligations must consider both the changes in output distributors provide *and* the changes in inputs/costs they incur to provide them.

A positive trend coefficient in an econometric cost model is an indicator of input changes only and therefore not a sufficient or appropriate measure of the impact of changes in unmeasured outputs on the industry's TFP growth.

Moreover, if (as Professor Yatchew has argued) these cost changes are associated with the growth in distributors' unmeasured outputs, the magnitude of the trend coefficient must under-state TFP growth because it does not account for the (unmeasured) output growth that is giving rise to the increase in cost. Indeed, a positive trend coefficient - in isolation - will necessarily be manifested as negative TFP growth, because it captures the (measured) growth in cost but not the (unmeasured) output growth that is motivating distributors' spending. A zero value for output quantity growth minus positive cost/input quantity growth must be equal to negative TFP growth, but this result simply indicates that the critical outputs provided by distributors are unmeasurable and therefore omitted from the analysis. It does not indicate that the impact of changes in unmeasured outputs on industry TFP growth is actually negative.

In sum, if a positive trend coefficient in an econometric model stems from unmeasured output growth, the (negative) magnitude of this coefficient must necessarily understate TFP growth. PEG believes this phenomenon could be reflected in its empirical results (with the proviso that the current econometric results do not have any direct implications for the productivity factor, because they are based on a different cost measure). PEG's TFP and econometric datasets include the cost of smart meters, but the output side of our TFP and econometric studies do not take account of the enhanced outputs provided by smart meters. The RRR data also include at least some of the costs of connections provided to generators, but these connection outputs are not fully captured in our study. It should also be noted that a significant share of the costs of these new, non-traditional outputs are recovered through rate riders and funding adders rather than through distribution rates that will be adjusted under 4th Gen IR. Any costs reflected in the RRR data, and therefore PEG's TFP and econometric studies, that are not recovered by the rates subject to 4th Gen IR creates a mismatch between costs/inputs and the outputs that PEG was able to identify and utilize in our work given available data sources. This concern is another reason why the Board should exercise caution before interpreting a positive trend coefficient in an econometric model as a basis for a negative productivity factor in an incentive rate-setting formula.

Appendix: Traditional and New Distribution Services

In general terms, “outputs" are the goods or services that firms provide to their customers… In the current environment, it is important to recognize that energy networks are providing both “traditional“ and “new“ network services to their customers. The line between the traditional and the new, however, is not always clear. Below we discuss the relationship between energy networks' traditional and new functions, as well as the relationship between energy network outputs and networks' output quality.

2.1.1 Traditional Network Services

Traditionally, the main function of electricity transmission networks has been to move bulk power from generation stations to distribution or other high-volume delivery points. The traditional purpose of distribution networks has been to receive power in bulk from points on high-voltage transmission grids and distribute it to consumers in assigned territories. Delivery involves reducing the voltage of bulk power supplies to the levels used in end-use electrical equipment. To satisfy consumer demands, distributors construct and maintain power delivery networks that establish physical contact with almost every business and household in their service territory.

Because interruptions in power delivery are costly to customers, transmission and distribution utilities are expected to design and operate distribution networks to assure reliable deliveries. One important design requirement is that the capacity of the delivery system must be able to accommodate customers‘ peak demands. For transmission utilities, those are the demands at peak times at designated delivery points. For distributors, networks must have sufficient capacity to meet peak demands for all customers throughout the distributor’s assigned territory.[1] Distributors must also endeavor to connect customers rapidly to the network. End use electrical equipment is also designed to operate within a narrow range of voltage levels. Thus, in addition to providing power supplies that

[1] In practice, this means designing distribution networks to accommodate a diverse number of “local“ peak demands throughout their service territory, which may not coincide at the same points in time.

are as continuous and uninterrupted as possible, distributors must attempt to conform to technical standards affecting the quality of power deliveries (*e.g.* regarding voltage, waveform, and harmonics).

In sum, both transmission and distribution utilities are expected to deliver power continuously at all points in time when their customers demand it. Outputs for all energy networks therefore include total delivered electricity (over a defined interval, such as a month) and electricity delivered on peak. In addition, distributors provide the service of connecting end-users to the electricity grid and extending the network to connect new customers in their assigned territories. Although some transmission networks may also deliver to end-users, these are typical few in number and do not vary substantially over time.

2.1.2 "New" Network Services

Under the Green Energy and Green Economy Act, three new objectives have been added to the OEB's traditional economic regulation tasks: promoting energy conservation and demand management; facilitating the development of a smart grid; and encouraging electricity generation from renewable energy sources. Energy networks naturally play a critical role in realizing these objectives. Distributors must directly invest in "smart grid" technology, which is integrated into their existing networks. Both transmission and distribution networks must invest in additional infrastructure to connect renewable generators to the grid. This essentially involves the same "connection" and "peak demand" outputs that distributors have traditionally provided, but in the "new" marketplace energy networks will provide these outputs upstream (to renewable generators and related sources of electricity supplies) as well as downstream (to end-users).

It is also worth noting that many of the investments that networks must make to facilitate GEA mandates are also useful for traditional distribution functions. For example, smart grids or Advanced Metering Infrastructure (AMI) is critical to the energy marketplace of the future. At its most basic level, AMI is designed to automate the process for recording customers' power consumption, but it can also create a much wider array of benefits. AMI systems generally involve three interrelated components. The first is the metering units themselves, which are far more sophisticated than the “accumulation meters” that have essentially been in place since the industry’s inception. The second is the information networks that are used to transmit data on customer consumption to the utility. Some AMI networks also allow data to flow in two directions, from the customer to the company and from the company to the customer. The third component is the meter data management system, where data on customer consumption and market conditions are stored and accessed.

AMI provides a number of benefits to energy distribution networks. Automated meter reading saves costs that would otherwise be incurred from manual meter reads. AMI can also provide “real time” information on the operation of the distribution system, which allows companies to locate faults that lead to power interruptions more quickly and accurately. In addition to enhancing the reliability of service provided to customers, better information on fault location can be used to optimize the size and dispatch of work crews, thereby reducing operating costs. AMI can also monitor the loading and condition of distribution system components, which can help companies optimize their inspection and maintenance cycles as well as extend the periods for replacing capital equipment. Automated meter reads also tend to improve billing accuracy and the timeliness with which bills are produced, thereby improving cash flow and the quality of billing service provided to customers.

In addition to providing these benefits for energy networks and their customers, more sophisticated metering systems will be increasingly necessary for distributors to cope with the more diverse and “distributed” (*i.e.* less centralized) nature of new generation technologies. Nearly all distribution systems are “radial” or designed for power to flow in one direction (from the bulk transmission system to the end user). Distributed generation (DG) units that are connected to the distribution network can lead to power flows in more than one direction, potentially decreasing the stability of electrical systems. This can affect the extent to which connected loads and generators interact with each other and, particularly when outages occur, the presence of DG units can lead to broader system instabilities. DG can also complicate the restoration of service whenever faults on distribution lines occur.

AMI is critical for helping distributors cope with these challenges. "Real time" information on the loading of distribution system components can be critical for monitoring the impact of DG units on the stability of the overall distribution system and for efficiently dispatching a portfolio of renewable (including wind) and distributed generators. Distribution AMI investments are therefore an important and increasingly essential complement to the renewable and DG units that are becoming more prominent in the energy marketplace.

Conservation and demand management (CDM) is also an important part of the GEA. Policymakers want consumers to respond naturally to the price signals from the marketplace *e.g.* by reducing consumption during peak hours when energy prices are typically highest. Lower demand pressures at the peak will tend to reduce energy prices and greenhouse gas (GHG) emissions, since energy and line losses are usually greatest during peak hours. Lower peak demands can lead to less energy consumption and reduced GHG emissions and more efficient use of network infrastructure as energy use is shifted from peak to non-peak hours.

As discussed, transmission and distribution (and power generation) infrastructure must all be sized to accommodate peak demands, so reducing peak usage will tend to defer the need for "traditional" energy infrastructure investments. Pushing energy investments into the future saves costs and also increases the probability that R&D devoted to cleaner generation technologies will have come to fruition and can be used when investments are ultimately required. Effective CDM can therefore contribute to a cleaner and lower-cost efficient energy supply and delivery system both now and in the future.

AMI is critical for ensuring optimal CDM. Two-way AMI communication systems can relay price signals in real time from the marketplace back to consumers. Visual displays can let customers know the prices they are paying for power being used in their homes and businesses at that moment, and this information can be used to adjust their consumption accordingly. CDM can be further enhanced if automated direct load control (DLC) devices are installed on customer premises. DLC devices can be programmed to slow consumption (*e.g.* through less frequent cycling of air conditioning units) or eliminate it entirely when power prices hit established thresholds. Automated demand response of this type can be a very effective tool for disciplining the energy marketplace, reducing greenhouse gases and enhancing overall efficiency, but more sophisticated and expensive AMI systems are necessary for achieving these benefits.

The increasing importance of DG and its relationship to AMI has already been discussed, but the relationship between DG and network infrastructure is also complex. DG units can provide voltage control and ancillary services such as spinning reserves that can help networks manage system stability. Energy networks can therefore benefit directly from owning, operating and dispatching DG units, and Ontario's distribution system code has in fact been amended to allow networks to own renewable generation assets.

It should also be recognized that DG can serve as a substitute for energy network investments. Because DG is located closer to customer loads than more centralized generation sources, the need for transportation capacity to move power from supply to demand points is reduced. Networks can therefore use DG to avoid or defer the investments that would otherwise be needed to augment energy transportation capacity. Locating generation closer to end uses also reduces line losses and the energy that must be generated to meet final demands, thereby contributing to lower GHG emissions. Greater reliance on DG also reduces the need for, and defers investment in, larger generation stations, which again increases the probability that cleaner technologies will be utilized when those investments are ultimately made. All of these factors demonstrate that DG can be an important "input" into network operations, with positive benefits in terms of operational flexibility and promoting energy market objectives. Networks should therefore in principle consider DG when evaluating investment choices.

These inter-relationships suggest that there is not a bright line between networks' "traditional" and "new" functions. Some of the investments necessary to comply with GEA mandates may have implications for how traditional outputs are provided, while some assets that help perform traditional functions more efficiently (*e.g.* smart meters) may prove valuable in helping networks cope with the challenges of delivering power from more diverse and less centralized supply sources to end-users. Regulators may therefore need to take a broader view of how traditional outputs are being provided, and be sensitive to the potential linkages between investments needed for the "new" marketplace and the network outputs that have traditionally been subject to economic regulation.