EB-2015-0072

Grimsby Power Inc.

Application for electricity distribution rates beginning May 1, 2016.

SUBMISSIONS OF
ENERGY PROBE RESEARCH FOUNDATION
("ENERGY PROBE")

July 29, 2016

GRIMSBYH POWER INC.
2016 RATES CASE
EB-2015-0072

SUBMISSIONS OF ENERGY PROBE RESEARCH FOUNDATION

I - INTRODUCTION

Grimsby Power Inc. ("GPI") filed a complete application with the Ontario Energy Board ("Board") on December 23, 2015 seeking approval for changes to the rates that GPI charges for electricity distribution, to be effective May 1, 2016. The OEB issued an Issues List Decision for this proceeding on May 20, 2016. A settlement conference was held on May 24, 25 and 26, 2016 and GPI filed a Settlement Proposal between all parties to the proceeding on June 24, 2016. An oral hearing was held on July 13 and 14, 2016 to hear a presentation on the settlement proposal and to examine the unsettled issues.

The Settlement Proposal reflected a partial settlement of the issues in this proceeding. The issues that were not settled were:

a) Operations, Maintenance and Administration ("OM&A") expense for the test year,
b) Payment in Lieu of Taxes (PILS), and
c) Effective Date of Rates.

The following are the submissions of the Energy Probe Research Foundation ("Energy Probe") with respect to unsettled issues related to OM&A, PILS and the effective date for new rates.

II - SUBMISSIONS

A) Operations, Maintenance & Operations

i) General Comments

In their original application, GPI proposed an increase in OM&A costs (excluding LEAP and property taxes) from $2,779,744 in 2014 to forecast figures of $3,233,500 in the bridge year and $3,925,363 in the test year (Exhibit 4, Table 4-1). This test year forecast represented an increase in the test year OM&A of more than 21% over the bridge year forecast and more than 41% over the 2014 actual expenditures. Energy Probe notes that this original evidence was filed approximately one week before the end of the 2015 bridge year.

As part of an interrogatory response (4-Energy Probe-21), GPI updated Table 4-1 to reflect actual data for the bridge year. The actual expenditures in 2015 were $2,918,395, a decrease of approximately $315,000 and more than 10% of the actual figure as compared to the forecast. However, no change was made to the test year forecast. This resulted in a forecasted increase of more than $1,000,000 or nearly 35% from the actual level of expenditures in the bridge year.

Finally, as shown in the response to Undertaking J1.1 (Revised), GPI has now provided the Board and parties a forecast for 2016 OM&A expenditures of $3,733,648, a decrease of approximately 5% or $192,000. This forecast is based on 6 months of actual expenditures and a forecast for the remainder of the year.

In addition, GPI's own evidence indicates that using actuals for part of a year is not a sound basis for doing an annual forecast. In the response to Technical Conference Undertaking JT1.9, which asked for the latest year to date actuals for the test year, GPI stated:

> *GPI budgets annually on a calendar basis (January 1 to December 31) and within any given period within the calendar year different aspects of spending can be executed. This means that due to timing differences costs from one year to the next for periods of less than 12 months (as in this case from January to May) will be different.*

Energy Probe submits that the Board should have no confidence whatsoever in this forecast. GPI submitted a bridge year forecast 8 days from the end of that year that was more than $300,000 and 10% higher than the actual expenditures.

Energy Probe submits that GPI has not provided evidence to support the requested increase in OM&A.

Mr. Curtiss stated (Tr. Vol. 1, page 125):

> *MR. CURTISS: We've presented our case. We've presented the reasons why we -- where the cost drivers are and those costs that are included in those incremental increases will support the four RRFE objectives. And that will be measured partly by the scorecard, and partly by the customer satisfaction surveys, and everything else that we do to maintain that contact with the customer and the stakeholders.*

In fact, the evidence clearly shows that GPI made no attempt to show the cost drivers between actual expenditures in the bridge year and those forecast for the test year. In fact, all GPI did was change the cost driver figures between the actual 2015 and forecast 2016 figures. As shown in the original Table 4-5 in Exhibit 4, the variance between the test year forecast and the 2014 actual level of expenditures was $1,146, 618. As shown in the response in the updated Table 4-5 in 4-Energy Probe-21, this difference was maintained even though the actual 2015 expenditures were 10% and more than $300,000 below the bridge year forecast. Ms. Domokos confirmed that the variance between 2014 and 2016 remained the same and that the test year forecast had not been changed as a result of the 2015 expenditures being significantly below forecast (Tr. Vol., 1, pages 149-150). Clearly the cost drivers do not reflect why increases are needed from the 2015 actual amounts.

In the above quote, Mr. Curtiss talked maintaining contact with the customers. Yet, as indicated in the response to 1-Staff-4, GPI did not undertake any customer engagement with respect to the proposed rate application. Part of the response, reproduced below, shows that GPI decided to forgo customer engagement, a requirement of the Renewed Regulatory Framework for Electricity Distributors ("RRFE") for three reasons. First, GPI was late filing; second, GPI states that it thought customer engagement was not that informative; and third, any information received would not be statistically significant.

> *With its late filing Grimsby Power was faced with the decision to organize and perform its customer engagement activities to meet the filing requirements or to proceed and file the application without this step. Based on informal inquiries with industry peers and the information provided above, this customer engagement activity was, in many cases, not that informative (in some certainly not all cases).*
>
> *Based on this information Grimsby Power made the decision to file its rate application without having executed this step. This decision is further supported by the above references where some utilities received considerable feedback and others received very little feedback. In three of the cases above this feedback was a result of extensive activities performed by a third party firm to ascertain how customers perceived the proposed rate application. Furthermore, customer engagement activities with the smaller utilities is not well supported by customers which in Grimsby Power's opinion makes the information received not statistically relevant.*

Energy Probe submits that none of the reasons given for not following the RRFE requirements for customer engagement are reasonable. The late filing was the fault of GPI. Stating that informal inquiries with industry peers indicate that the customer engagement activity was not that informative in some cases does not mean it would not have been informative for GPI. Being a smaller distributor does not relieve GPI of its responsibility to follow the RRFE and it does not excuse GPI from undertaking customer engagement.

Further, Energy Probe submits that the real reason GPI did not undertake any customer engagement before or during its preparation of its cost of service application is that it did not want the negative publicity associated with a request to increase distribution revenues by more than 42%, as illustrated in Exhibit 6, Table 6-1.

It is, therefore, submitted that GPI has failed with respect to the Custom Focus outcome of the RRFE. Services are supposed to be provided in a manner that responds to identified customer preferences. GPI did not identify customer preferences.

It is further submitted that GPI has filed with respect to the Operational Effectiveness outcome under RRFE. As is illustrated later in this submission, GPI has failed to show continuous improvement in productivity and cost performance has been achieved. In fact, Energy Probe will show that GPI illustrated negative productivity and/or diseconomies of scale in the OM&A costs.

GPI has also admitted that it has not built in any new incremental productivity improvements into its forecast. In fact, it has not even identified any such improvements at this time, but that it would be something they do over the IRM term (Tr. Vol. 1, pages 127-128):

> *MR. RUBENSTEIN: So these improvements, it seems you're just continuing something that you've already put in place. And the question asked, and I want to know: What incremental things are you doing in the test year to drive further productivity improvements?*
>
> *MR. CURTISS: I don't believe we have identified any. I think my answer to that would be that meeting all the requirements of the application process takes time to execute and -- is our application and our response to all these questions perfect? No, it isn't.*
>
> *We still have much work to do and we will continue to do so, and I know we haven't identified any particular productivity improvements, other than continuing on with -- we haven't identified any new ones.*
>
> *But that will be something in the next five years that we'll have to bring front and centre and create a process to do that.*

Energy Probe notes that throughout its evidence, GPI makes reference to "normalized" OM&A costs for the test year. This normalization includes the addition of future year costs for positions that may be required in the future. In other words, GPI is trying to average out the costs for 2016 and future years.

As illustrated in the above response from Mr. Curtiss, however, GPI has not tried to average in any reductions in costs over this period because they have not been identified.

This "normalization" of OM&A costs highlights two issues for Energy Probe. First, it clearly shows the addition of costs in the test year for people/positions that may or may not be in place over the IRM horizon. This is discussed in further detail below. At the same time, efficiency or productivity improvements over the IRM horizon have not been factored into the costs. This results in a one-sided view of the IRM term with additional costs but no savings.

The second issue related to this normalization is that GPI filed a cost of service application for the 2016 test year. It did not file a Custom IR application. The Board should not consider out of period costs when reviewing a test year cost of service application. This is especially true when GPI has not included in any out of period productivity or efficiency gains even though the evidence is "*that will be something in the next five years that we'll have to bring front and centre and create a process to do that.*" In other words, GPI will be looking for ways to increase productivity and reduce costs, but has not reflected any such cost savings in its normalized forecasts.

GPI could have filed a Custom IR application. It chose not to do so, but wants the same impact through its normalization process. Energy Probe submits that the Board should reject this approach and set rates only on the test year information.

Energy Probe has provided submissions on the OM&A based on two approaches. The first is on an envelope basis, based on inflation, customer growth, expected productivity gains, and a stretch factor. The second is based on specific cost items.

Based on these two approaches, which follow, Energy Probe submits that the Board should reduce the test year OM&A expense request of GPI by an amount in the range of $500,000 to $600,000 from the updated forecast of $3,733,648 provided in the response to Undertaking J1.1.

ii) The Envelope Approach

Energy Probe submits that the Board should use an envelope approach in determining what a reasonable increase in OM&A expenditures is appropriate for the test year. Further, Energy Probe submits that this approach should take into consideration past actual expenditures, rates of inflation, base productivity and customer expectation with respect to stretch factor gains. In addition, Energy Probe submits that the approach needs to adjust actual expenditures for one-time costs and for major changes in the operation of the distributor.

Energy Probe has developed a comprehensive model for reviewing OM&A expenses. This model has been provided in Appendix 1 to this submission. The following submissions are reflected in the figures provided in Appendix 1 and the references in what follows to line numbers are to the line numbers in Appendix 1. The submissions have also been separated into the four Sections shown in Appendix 1.

Section 1 - Adjustments to OM&A

Before an envelope approach to OM&A can be used to evaluate the forecast, it must be determined what costs are included in the envelope, and what costs are outside of the envelope. As show in Appendix 1, the costs associated with LEAP and property taxes have been excluded from this analysis.

Energy Probe submits that what should be included in the envelope are the expenses that reflect the normal operation of the distributor. These are generally all of the OM&A expenses incurred by a distributor, after adjusting for specific items that have been identified. These specific items include the removal of any one-time costs that have been incurred historically, but are not expected to be incurred in the test year, such as costs related to ice storm costs. Out of period expenses should be adjusted so that the actual OM&A expenses reflect expenses that actually incurred in any given year, or should have incurred in that year. An adjustment should also be made to both the historical, bridge and test years to reflect any significant changes in the operation of a distributor. These changes include accounting changes such as the change from CGAAP to MIFRS and any other changes in capitalization policy or any significant changes to the way that a distributor operates.

With respect to GPI, there is no adjustment necessary for accounting changes related to the move from CXGAAP to MIFRS or changes in capitalization policy, since GPI filed all of its evidence based on MIFRS accounting. GPI did, however, have one major change in its operation, being the merger with Niagara West Transformation Corporation ("NWTS") in the bridge year.

Section 1 of Appendix 1 reflects the adjustments made by Energy Probe to the OM&A expenses of GPI.

The total OM&A expenditures and forecasts are taken from the updated evidence and undertaking responses. In particular, line 8 reflects the updated information provided in Table 4-1 in 4-Energy Probe-21, including the updated OM&A actual expenditures for the 2015 bridge year, and the $3,477,360 test year forecast based on the response to Undertaking J1.1.

Energy Probe submits that there are five adjustments that should be made to the actual and forecasted OM&A costs. Each of these is explained in detail in what follows.

The first of the adjustments is the removal of the smart meter costs of $155,528 in 2012 (line 10). These costs were identified in Exhibit 4, Table 4-4 that were transferred to OM&A from the regulatory deferral account set up for smart meter related costs. It was confirmed that these costs were incurred prior to 2012 and were not included in the 2012 Board approved OM&A costs (Tr. Vol. 1, pages 150-151).

The second adjustment is the removal of $21,750 in one-time costs incurred in 2014 for recruiting and talent search (line 11). This was also identified in Table 4-4 and confirmed to be a one-time cost (Tr. Vol. 1, pages 151-152).

The third adjustment relates to the addition of OM&A costs related to the merger with NWTC and the operation of the station. GPI did not have any OM&A costs associated with this asset prior to the merger, which took place on October 1, 2015. As shown in the response to 1-Energy Probe-5 and confirmed during the oral proceeding (Tr. Vol. 1, page 153) the all inclusive OM&A numbers associated with the operation of this station are significant and need to be removed from both the 2015 actual and 2016 forecast in order to get an accurate view of the OM&A costs. Energy Probe notes that it has no issues with the addition of these costs associated with the operation of the station and believes they appear to be appropriate.

The fourth adjustment that needs to be made is for the deferral of tree trimming from 2015 to 2016 (line 13).As indicated in the response to Technical Conference Undertaking JT1.9, some tree trimming scheduled for 2015 was deferred to and carried out in 2016. Specifically, 2016 costs were incurred to complete tree trimming for both 2015 and 2016. The response to Undertaking J1.2 shows that a cost of $38,550 has been included in the 2016 test year forecast that was related to the 2015 tree trimming that was deferred to 2016. Energy Probe submits that this amount should be removed from the 2016 forecast request of OM&A, but included in the 2015 adjusted actual figure.

The final adjustment, shown on line 14, is related to the GPI accounting treatment of the 2012 COS application costs. Instead of amortizing the costs over four years (rebasing year plus 3 IRM years), as approved by the Board and included in the 2012 Board Approved figure, GPI management made the decision to expense the entire amount in the 2012 year (4-Energy Probe-23). This artificially increases the 2012 costs, while at the same time lowering the costs in 2013 through 2015. As noted above, it also distorts the comparison between 2012 actuals and 2012 Board Approved expenditures.

As shown in the response to 4-Energy Probe-23, the actual costs associated with the 2012 COS application were $198,368. Amortized over four years, this amounts to $49,592 per year. These are the figures that are shown on line 14 for each of 2013, 2014 and 2015. The adjustment for 2012 reflects the sum of these amounts, $148,776, that has been moved to the other years.

Line 15 in Appendix 1 shows the resulting total adjusted OM&A expense based on the adjustments discussed above.

Line 16 shows the percentage change in the OM&A expenses on a year to year basis of this adjusted amount. Line 17 shows the average annual compound rate of increase in the OM&A envelope from 2012 to 2016, being 7.22%.

Section 2 - Customers

One of the drivers in the change in the envelope of the OM&A costs is customer growth. Section 2 shows the number of customers for each year (line 21), taken from Table 4-6 in 4-Energy Probe-21, along with the annual growth in customers (line 22) and the average annual compound rate of increase in the number of customers from 2012 to 2016, being 1.72% (line 23). The response to 4-Energy Probe-21 provides the actual number of customers for 2015, consistent with that in previous years and the forecast for 2016.

Energy Probe submits that these average annual compound increases should sound some alarms for the Board. The growth in the adjusted OM&A of 7.22% per year is significantly higher than the growth in customers of 1.72% over the 2012 to 2016 period.

The difference of 5.50% is higher than the rate of inflation over this period (line 27), which, on a compound annual basis, is 1.80%. In other words, the OM&A increase at GPI is significantly greater than the sum of customer growth and inflation combined. There are no net productivity gains over the 2012 through 2016 period. There are no net stretch factor benefits for customers over this period either. In addition, there are absolutely no economies of scale being achieved. This is discussed further in Section 4 below.

Section 3 - Escalators

Section 3 of Appendix 1 reflects the components of the overall escalators that Energy Probe believes that the OEB should take into consideration when evaluating changes in the adjusted OM&A envelope. These factors include inflation, base productivity, stretch factors and customer growth.

Energy Probe has used the inflation factors (line27), base productivity (line 28) and stretch factors (line 29) based on the OEB policy related to setting price caps, which in turn is based on external benchmarking.

The inflation rate reflects the inflation rates as determined by the Board each year for 2013 through 2016 (and reflected on the Board's website), based on a mix of labour related and non labour related costs. Energy Probe submits that this is an appropriate inflation rate to use in the envelope calculations, since it represents a good external benchmark for all distributors in Ontario.

The base productivity also reflects an external benchmark, as utilized by the Board in the setting of rates. The 0.72% figure in for 2013 reflects the Board determined base productivity in the third generation IRM model and the 0.00% shown for 2014 through 2016 reflect the Board determined figures for the fourth generation IRM model.

The stretch factors for 2013 through 2016 reflect the actual cohort rankings for GPI as calculated by Pacific Economics Group ("PEG") each year and published by the Board. As reflected in these figures, GPI has slid from the best performing cohort in 2013 to the second best cohort in each of 2014 through 2016. This PEG analysis is used to calculate the cohorts and the resulting stretch factor. This means that GPI has a larger cost escalator that most distributors since its required stretch factor is lower that most distributors.

The final component of the escalator is the growth in customers and how that impacts the growth in OM&A. When asked, GPI indicated that it had not done any studies or calculations to determine the relationship between the growth in OM&A costs and the growth in the number of customers. Further, GPI indicated that it did not have any estimate of what the percentage change in OM&A expenditures would be for a 1 percent change in the number of customers (Tr. Vol. 1, page 154).

As the Board is aware, electricity distributors in general have always argued that their costs are primarily fixed and are based on the number of customers and not on the amount of electricity they consume. This was a primary reason for the Board moving the residential rate class to a fully fixed monthly charge.

Fortunately, the relationship between customer growth and growth in OM&A costs has been estimated by PEG in the model that is used for benchmarking distributors and determining which cohort in which they reside. In particular, in the *"Empirical Research in Support of Incentive Rate-Setting: 2014 Benchmarking Update"* Report to the Ontario Energy Board dated July 2015, PEG states (page 6) that for the average company, the number of customers is a more important cost driver than the kWh delivered and capacity combined. The report then states that for the average company, for each 1% change in the number of customers, costs were estimated to change by 0.44%.

Energy Probe submits that it is important to understand the context of the PEG report. At page 2 of the report the benchmarking methodology is described as follows:

> *The model used to determine the cost efficiency of distributors is based on econometrics. Distributor cost in this model is estimated as a function of business conditions faced by each distributor. These business conditions include the number of customers served and the price of inputs such as labor and capital. The parameters of this model establish the relationship between each business condition and distributor cost. These parameters were estimated using Ontario LDC data from 2002-2012.*
>
> *The model can make a prediction of each distributor's cost given its business conditions by multiplying the company's business condition variables by the model parameters and summing the results.* (emphasis added)

A review of the PEG model, which is available on the Board's website (http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Renewed+Regulatory+Framework/Measuring+Performance+of+Electricity+Distributors), shows that in place of the 0.44% factor noted in the PEG report for the average distributor, the specific GPI figure is 0.4390 (Validation Tab, cell J164). In other words, an increase of 1% in the number of customers at GPI would increase OM&A costs by 0.4390%. This figure is shown on line 31 in Appendix 1 and is multiplied by the customer growth shown on line 22 to come up with the impact of customer growth on OM&A expenses for each of the years shown.

Energy Probe submits that use of this figure of 0.4390 is appropriate, as it is specific to GPI, has a solid foundation in its estimation and is the only factor on the record in this proceeding.

The resulting total escalator for each of 2013 through 2016 is shown on line 32 and is the sum of the inflation rate less the base productivity, less the stretch factor offset plus the increase due to customer growth. These figures range from a low of 1.08% to a high of 2.62%.

Section 4 - OM&A Growth at Escalator

Section 4 in Appendix 1 applies the escalators calculated in Section 3 to the historical actual costs (and to the 2012 Board Approved figure) to bring them up to 2016 costs. In particular, Section 4 provides 5 separate calculations, using different starting points - 2012 Board Approved, 2012 actual, 2013 actual, 2014 actual and 2015 actual - and applying the appropriate escalators to the starting point. As an example, line 40 starts with the actual adjusted 2012 OM&A expense of $2,631,268 (from line 15) and increases it by the 2013 escalator of 1.98% (line 32), followed by an increase of 2.62% for 2014, 2.34% for 2015 and 2.61% for 2016. This results in a 2016 figure of $2,866,144. Line 41 shows the adjusted 2016 test year request of $3,477,360, taken from line 15. Line 42 shows the reduction necessary ($611,216) for the 2016 figure to match the calculated figure based on the 2012 starting point. Similar calculations are done for each of the other starting points.

Energy Probe submits that it would not be reasonable to pick only one starting point to compare and contrast to the 2016 requested OM&A. This is because any individual year can be influenced by decisions made in that year or in a previous year. For example, the cost associated with employees could vary from year to year due to vacancies, timing of hiring, timing of retirements, maternity leaves, sick leaves and so on.

Energy Probe submits that using the average of all of the available starting points, which is shown on line 56, is more appropriate. This averages out any ups and downs from one year to another and gives a better long term view of the OM&A costs.

As shown on line 56, this average would result in a reduction of just under $600,000 in the adjusted OM&A forecast for the 2016 test year.

However, GPI has indicated that it believes the 2012 Board Approved level of OM&A expenditures was too low because it did not include a number of costs in the forecast that it knew it would incur in 2012. A review of the adjusted OM&A shown in Appendix 1 shows that the actual adjusted OM&A expenditures were approximately $224,000 higher than the Board Approved figure (line 15).

If the 2012 Board Approved comparator is removed from the calculation of the average reduction, the average reduction based on 2012 through 2015 actuals is approximately $533,000 (line 57).

iii) Specific OM&A Expenses

The following is a list of expenses that Energy Probe submits supports the magnitude of the reduction using the envelope approach discussed above. This list is not intended to be comprehensive, but to reflect the opportunities for the cost reductions that Energy Probe submits would be reasonable. The list is focused on the costs of employees, including wages and benefits and the number of employees. This is because, as can be seen in the Table 4-18 provided in the response to 4-VECC-32, the cost of human resources is forecast to increase by nearly $750,000, or 38%, from an actual cost of $1,957,224 in 2015 to the forecast for the test year of $2,705,703. This $750,000 increase represents approximately 92% of the increase between the actual bridge year expenses and the revised OM&A request as provided in the response to Undertaking J1.1.

a) Number of Employees

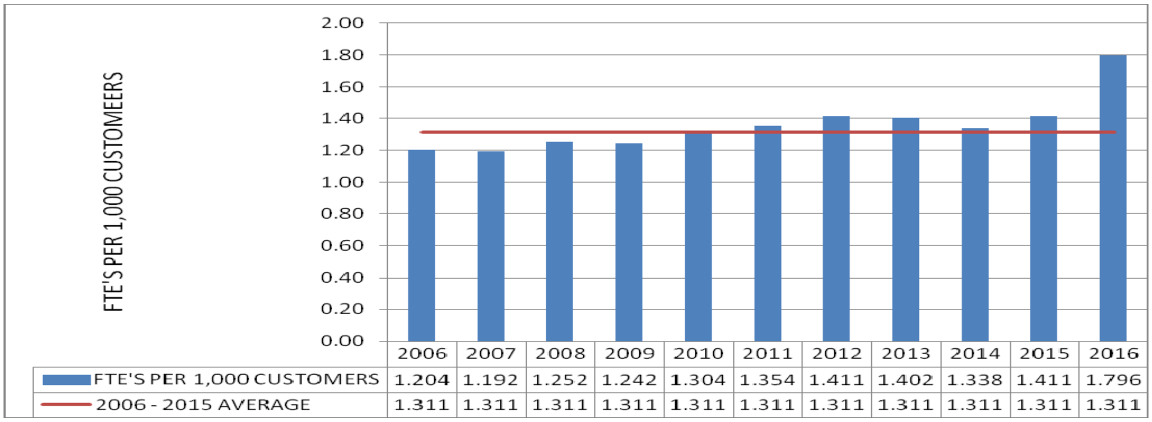
As shown in the response to 4-Energy Probe-21 and OM&A Question 2 in the Materials for Oral Hearing (Exhibit KT1.3) and the updated load forecast model filed as part of the interrogatory responses, there has been a significant change in the trajectory of the number of employees relative to customers in 2016 as compared to previous years. In particular, between 2006 and 2015 the number of FTE's per 1,000 customers has been relatively steady.

The following graph shows the number of FTE's per 1,000 customers for GPI over the 2006 through 2016 period. The number of FTE's is taken from page 10 of Exhibit KT1.3 for 2010 through 2016 and from Table 4.2 in EB-2011-0273 for 2006 through 2009, while the number of customers used in the calculation comes directly from the load forecast Excel spreadsheet filed as part of the interrogatory responses on May 6, 2016.

The bars in the following graph show that the number of FTE's per 1,000 customers has been relatively stable over the 2006 through 2015 period, ranging from 1.192 in 2007 to 1.411 in both 2012 and 2015. Moreover, the variability in the ratio has been relatively small, with the highest ratio and the lowest ratio being about equidistant from the 2006 to 2015 average. This is the line shown on the graph. The average number of FTE's is 1.311 per 1,000 customers over this period of stability.

FTE's per 1,000 Customers

Source: Exhibit KT1.3, page 10 & EB-2011-0273, Table 4.2 & Updated Load Forecast



In 2016, GPI is forecasting a significant increase in the ratio, to a level (1.796 FTE's per 1,000 customers) not seen at GPI in the last decade, or perhaps ever. In other words, GPI would have the OEB believe that the despite being able to maintain a fairly stable ratio of FTE's per 1,000 customers over the 2006 through 2015 period it is no longer possible to do so in the rebasing year. This also implies diseconomies of scale as the number of FTE's would be growing significantly more than the number of customers. Energy Probe submits that this increase is not warranted and should not be approved by the Board.

Energy Probe has also done a simple regression analysis of the number of FTE's related to the number of customers over the same 2006 through 2015 period reflected in the above graph. The data comes from the same sources as that used in the graph and were used to calculate the ratios shown in the graph and is shown below.

YEAR	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
FTE	14.5	14.5	15.5	15.5	16.5	17.39	18.47	18.52	18.11	19.48	25.16
CUSTOMERS	12046	12161	12382	12477	12653	12839	13088	13208	13531	13804	14011
FTE'S PER 1,000 CUSTOMERS	1.204	1.192	1.252	1.242	1.304	1.354	1.411	1.402	1.338	1.411	1.796

The results of the regression analysis are provided in Appendix 2. This regression shows that for the 2006 through 2015 period the number of customers explains more than 91% of the variance in the number of FTE's (adjusted R-squared). The equation is statistically significant at a confidence level of more than 99.9% and the intercept and customer coefficients are both statistically significant at levels in excess of 99.9% as well. The customer coefficient of 0.002952654 means that for an increase of 1,000 customers, there should be a corresponding increase of just under 3.0 FTE's.

Based on the above analysis, Energy Probe submits that the number of FTE's should be reduced in the 2016 test year by about 5.0, from 25.16 to 20.07.

The reduction of 5 FTE's is based on an average of the above two methodologies. As noted above in relation to the graph, the highest ratio of FTE's to 1,000 customers at GPI has been 1.411, which occurred in both 2012 and 2015. Using this ratio multiplied by the forecast number of customers in the 2016 of 14,011 yields a forecast of 19.77 FTE's, a reduction of 5.39 FTE's from the GPI request. Using the ratio of 1.411 would imply no economies of scale, but also no diseconomies of scale.

The regression equation results in a forecast of 20.37 FTE's when the coefficients are applied to the forecasted number of customers in the test year. This is a reduction of 4.79 FTE's from the request.

As a result, the average number of FTE's is about 20, a reduction of 5 from the GPI proposal. Energy Probe further notes that this is more than a 10% increase over the number of FTE's at GPI as of the June 27, 2016. This figure, which is shown on page 10 of Exhibit KT1.3, is 17.94. As noted in response to Undertaking J1.3, this figure is really 16.94, since there is a current, temporary, overlap in the CEO position.

In order to calculate the OM&A impact of this reduction, the average OM&A cost associated with the proposed reduction of 5 FTE's must be calculated. Based on Table 5 in Undertaking J1.3, the average cost included in the rate application for positions that are new to company and/or positions as a result of retirements & succession planning is $109,712 ($415,412 + $266,996) / (4.02 + 2.2)). Assuming an average cost included in the rate application of $100,000, the proposed reduction of 5 FTE's would result in a reduction of about $500,000.

b) Compensation Increases

Energy Probe is very concerned about the increases in compensation for both management and non-management personnel between 2015 and 2016. As shown in Table 4-18 provided in the response to 4-VECC-32, management wages, incentives and benefits are forecast to increase by $154,268 or 17.4% between 2015 and 2016. Non-management wages, overtime and benefits are forecast to increase $85,560, or 8.9%.

Both of these categories, which total an increase of about $240,000, are for existing employees only and do not include any of the additional staff positions. Those additions are shown in separate lines in Table 4-18 and Ms. Domokos confirmed that these line items in Table 4-5 from 4-Energy Probe-21 did not include new positions and were for only existing positions for both the management and non-management categories (Tr. Vol. 1, page 155). The figures in both Table 4-5 and in Table 4-18 in the Energy Probe and VECC responses have identical figures for these categories in 2015 and 2016.

Energy Probe submits that GPI has not provided any compelling evidence to support the increase in costs of $240,000. The increase of 17.4% for management and 8.9% for non-management are well in excess of the benchmark increase in labour costs. Even with increases for progressions, Energy Probe submits that at least half of the $240,000, or $120,000, is excessive and should be reduced by the Board.

c) To Normalize or Not To Normalize?

Yes, that is the question. The impact on GPI of normalizing for the untested costs forecast for 2017 through 2020 is a staggering addition to the revenue requirement in 2016 of more than $500,000. This is illustrated in Table 5 in the response to Undertaking J1.3.

The updated normalized forecast for 2016 as shown in Table 5 is $817,325, while the actual amount forecast to be spent in 2016 is $298,223. The difference of $519,102 is based on a lot of assumptions and conjectures about when and if new positions are required in the future beyond the test year. For example, the two journeyman lineman positions are forecast to retire in 2018 and 2023, so GPI has built costs for these positions into the 2016 revenue requirement. As indicated in the response to 4-Energy Probe 36, GPI has not yet determined if a fully qualified journeyman lineman or an apprentice would be hired for either of these positions. Energy Probe submits that if these positions are filled by a fully qualified journeyman lineman, the need for an overlap of several years is not needed, like it would be for an apprentice. This would significantly affect the calculation of normalized costs. At this time, however, GPI has not made a decision as to what it will do.

Energy Probe submits that the Board should not allow GPI to hijack a cost of service application for the 2016 test year with a proposal to "normalize" select costs. The GPI proposal is nothing but cherry picking that favours the shareholder and costs the ratepayers.

GPI did not normalize revenues to reflect the strong growth in customers that has taken place and is likely to continue in the foreseeable future. GPI did not normalize for the growth in the capital cost allowance deduction for PILS purposes that will be the result of the asset additions and replacements provided in the distribution system plan. GPI did not normalize for productivity and efficiency improvements that were initiated by GPI in the recent past. For example, getting more customers to move from paper invoices to electronic invoices will save on postage, stationary and envelope costs. However, no normalization of these costs has been provided. As noted elsewhere in this submission, there has been no normalization for cost savings related to new productivity and efficiency initiatives that are required to satisfy the outcomes of the RRFE have been identified or quantified.

GPI did not provide any forecasts for overall OM&A costs over the 2016 through 2020 period. As a result, the Board cannot determine if the OM&A over this period is adequately and appropriately paced.

When asked about whether or not he was aware of the "normalization" approach being used for anything other than regulatory costs associated with an application, Mr. Curtiss indicated he was not (Tr. Vol. 1, pages 147-148).

Energy Probe submits that the Board should deny the selective and biased normalization proposal of GPI. The Board should not and cannot accept the normalization of one cost, while ignoring other aspects of costs and revenues that would impact on rates. There is no evidence of the pacing of total OM&A costs over the period that GPI has used for normalizing compensation related costs. Further, the Board has no tested evidence to support the need for any of the positions that are new or based on succession planning as far out as the year 2023.

If GPI wanted to recover rates for the 2016 to 2020 period, it should have filed a Custom IR application, in which all of costs and revenues over the five year period could be tested. It did not; it chose to cherry pick a particular cost and ignore all of the other factors that could affect future revenue requirements in the 2017 to 2020 period.

The reduction of $519,102 to reflect the removal of the normalized 2016 forecast of $817,325 and replace it with the forecast of actual costs to be incurred in the 2016 test year of $298,223 produces a similar result to the elimination of the costs for 5 employees at a cost of about $500,000 as calculated above.

d) Deferred 2015 Tree Trimming Costs

As noted in Appendix 1 at line 13, GPI deferred $38,550 worth of tree trimming expenses from 2015 to 2016 and included this additional amount in the 2016 budget to be recovered from ratepayers.

Energy Probe submits that the Board should not allow a distributor to increase rates in the test year because it deferred the costs for something as important as tree trimming from one year to another. This deferral could have resulted in increased interruptions and/or increased duration of interruptions, thereby negatively impacting outcomes for customers of the decision to defer the cost and seek to recover it in rates going forward.

e) Tendency to Over Forecast

GPI has exhibited a trend to increasing its over forecast of OM&A expenses when compared to actual expenditures in 2012 through 2015. As shown in the response to 4-Staff-33, GPI under forecast its 2012 expenditures by 11.3%. In 2013 actual expenditures were 1.3% below budget. This grew to 4.8% in 2014 and ballooned to 9.8% in the 2015 bridge year.

In the response GPI states that their actual expenditures have been below budget in all years except 2012. The response goes on to indicate that GPI is fully capable of executing a plan against budget and has been successful in accomplishing this for three years in a row - 2013 through 2016.

Energy Probe notes that there is a disconnect between what GPI believes is an accomplishment and what matters to ratepayers. Coming in under budget for OM&A expenses is likely a good thing for the shareholder and any employee that may get a bonus as a result of the better than expected financial results. However, from a ratepayers point of view, it is a different story. If GPI comes in under forecast, ratepayers are paying for costs that do not materialize. A variance of 9.8% such as that recorded in the last year of actuals (2015) would be a significant burden on ratepayers for costs that were not incurred. The objective, from a rate setting perspective and from a ratepayer perspective is not to come in under budget, but to realistically forecast the OM&A costs that you want to recover through rates. This would be a successful accomplishment from the ratepayer point of view.

f) Summary

Based on the above quantified adjustments for employees ($500,000), or the elimination of the $ "normalized" costs ($519,000), compensation for existing employees ($120,000) and the 2015 deferred tree trimming costs ($38,550), Energy Probe submits that a reasonable reduction in test year OM&A costs is in the range of $650,000. This estimate is slightly higher than the reductions shown in Appendix 1.

iv) Reasonableness of the Request

As noted above, the average annual increase in adjusted OM&A costs of 7.22% is significantly higher than the average annual increase in customers of 1.72%. Put another way, the increase in adjusted OM&A costs, as shown in Appendix 1, between 2012 and 2016 is more than 32%, while the total increase in the number of customers is only 7%. Energy Probe submits that this is a red flag.

Energy Probe has used its analysis and model to look at the reasonableness of the OM&A request for the 2016 test year. As noted above, this reality check is based on the adjusted OM&A envelope excluding the costs associated with the NWTC station. This analysis is provided in Appendix 3.

Energy Probe has done the same analysis and calculations as noted in the envelope section (Appendix 1), but has eliminated all productivity gains, included no stretch factor gains and assumed no economies of scale.

These assumptions are reflected in Appendix 3 in lines 28 and 29, which now show 0.00 for all years for base productivity and stretch factors. The 0.4390 factor calculated by PEG has been replaced by a factor of 1.000, as shown in line 31. This means that a 1% increase in the number of customers results in a 1% increase in OM&A costs. That is, there are no economies of scale realized by GPI from customer growth. The resulting escalator is simply the sum of the growth in customers and the inflation rate.

Energy Probe submits that while none of these assumptions is realistic, the results are enlightening. As shown on line 56, the average implied test year reduction, assuming no productivity gains, no stretch factors, and no economies of scale, is still a significant reduction of almost $500,000. In other words, GPI is asking for nearly $500,000 more than what is required to account for customer growth and inflation over this period and assuming absolutely no net productivity gains or any benefits from economies of scale from a growing distributor. If the 2012 Board Approved comparison point is removed from the analysis, the implied reduction is still in excess of $440,000.

Another way to look at the 2016 OM&A request is to assume no stretch factors and no economies of scale, and calculate what the average annual base productivity would be over the 2012 through 2016 period to justify the requested amount in 2016. Appendix 4 shows this analysis. This is accomplished by setting the result in line 57 to $0 and solving for the annual base productivity factor in line 28. As shown in Appendix 4, this reflects a negative productivity factor of 5.75% per year over the entire period, or an aggregate productivity loss of more than 23% between 2012 and 2016.

Based on the analysis provided in Appendix 3 and Appendix 4, and given the Board's requirement that distributors show value for money and continuous improvement, Energy Probe submits that the adjusted OM&A request of GPI is not reasonable and represents a failure by GPI to meet the requirements of the RRFE.

An even simpler analysis can be undertaken by reviewing the figures in lines 15 and 16 for the 2013 through 2015 years. These figures are based on the adjusted actual expenditures. That is, they provide an apples to apples comparison of the ongoing OM&A costs for GPI. The average percentage increase in 2013 through 2015 in the adjusted OM&A expenses is 3.8%. Applying this figure to the 2015 actual of $1,941,961 yields an adjusted OM&A forecast of $3,053,756. With the addition of the $217,738 in costs associated with the NWTC station, with which Energy Probe has no issue, the resulting OM&A forecast for the 2016 test year is $$3,271,494, a reduction from the current estimate of $3,733,648 (Undertaking J1.1) of more than $462,000.

Energy Probe has not re-included the $38,550 in deferred tree trimming expenses in its simple analysis for the 2016 OM&A because it believes that it would be inappropriate for GPI to recover these costs in the test year simply because they deferred the 2015 tree trimming program.

Energy Probe submits that the $462,000 reduction based on the simple analysis is the minimum reduction to the OM&A costs that the Board should consider approving.

<u>v) Summary</u>

In summary, Energy Probe submits that the Board should reduce the 2016 OM&A included in the revenue requirement by an amount in the range of $500,000 to $600,000. This corresponds to the reductions calculated in Appendix 1, and also is within the range of the $462,000 calculated using the simple analysis and the $650,000 calculation based on specific cost items.

This reduction of $500,000 to $600,000 would reduce the OM&A to a range of $3,134,000 to $3,234,000. At the higher end of this range, GPI would get an increase of about $315,000 over its actual 2015expenditures, of which approximately $155,000 are related to the increased costs associated with the NWTC station, leaving $160,000 in other OM&A increases. At the lower end of the range, the increase would be $60,000 in other OM&A increases. This compares to increase of about $100,000 in 2013 over actual 2012 costs, and increases of about $77,000 in 2014 and $134,000 in 2015. Energy Probe submits that the resulting range of increases of $60,000 to $160,000, in addition to the increase of about $155,000 in NWTC costs, is appropriate and is consistent with historical increases in actual expenditures in the 2012 through 2015 period.

B) Payment in Lieu of Taxes (PILS)

i) Introduction

There was no settlement with regards to PILS. However, as indicated in the Settlement Proposal the only component of PILS that is not settled was the methodology regarding the determination and application of loss carry forwards ("LCF").

GPI has filed a number of PILS workforms as part of this proceeding. In addition to the original model filed on December 23, 2015, GPI filed a live Excel spreadsheet as an integral part of the Settlement Proposal on June 24, 2016. GPI subsequently changed its evidence through the filing of new evidence on June 29, 2016.

GPI subsequently filed a correction to the PILS calculation on July 8, 2016 as part of the response to Undertaking JT1.5. On behalf of GPI, Ms. Domokos confirmed that the requested PILS provision included in the revenue requirement had fallen from the $92,030 calculated in the June 29 updated evidence to a figure of $65,351 calculated in the Undertaking JT1.5 response (Tr. Vol. 1, pages 27-28). This was a correction based on the CCA rate used and was not related to the proposed changes in the determination and application of loss carry forwards. Energy Probe submits that the Board should accept this correction.

The following table provides a summary of the figures used as LCF amounts in the various PILS spreadsheets noted above. The table shows the 2015 bridge year opening LCF, the change in the LCF for the bridge year and the closing 2015 LCF, which is then the amount available for use in the 2016 test year and future years.

	Original Evidence 2015-12-23	Settlement Agreement 2016-06-24	New Evidence 2016-06-29
Opening Loss Carry Forward	712,155	765,394	234,927
2015 Additions/(Reductions)	122,313	-(373,573)	-(234,927)
Closing Loss Carry Forward	834,468	391,821	0

In the original evidence filing, GPI forecast a LCF at the end of 2014 of $712,155, and the loss of an additional $122,313 in 2015. This amount was the net income for tax purposes calculated in the PILS model for the bridge year, resulting in a LCF of $834,468 for use in 2016 and future years.

As filed with the settlement agreement, the LCF at the end of 2014 had increased to $765,394. As explained below, this was the total for both pre-merge GPI and NWTC. GPI reflected the use of $373,573 of this amount in the 2015 bridge year, even though the PILS model calculated a net income for tax purposes of a loss of $318,021. In other words, GPI was proposing to use some of the LCF in 2015 even though there was a loss for the bridge year net income. This represented a change in the GPI proposal and calculation. The resulting LCF was $391,821 that was available for use in 2016 and future years.

In the new evidence, GPI reduced the opening LCF in 2015 to $234,927 and indicated that all of this amount would be used to reduce 2015 net income for PILS purposes, resulting in no LCF available for use in 2016 and future years.

The opening balance in the new evidence reflected the proposed removal of the LCF associated with NWTC. In particular, the evidence indicates that at the end of 2014, GPI had a LCF of $1,190,808. This amount did not include any amount associated with NWTC since the merger did not take place until 2015. GPI then carried back $955,881 of this amount to reduce PILS for 2012 and 2013. This left an amount of $234,921 associated with the pre-merger GPI brought forward into 2015, as shown in the above table for the new evidence. This amount is shown in Exhibit 4, Appendix 4-C.

In addition to the pre-merger GPI LCF, there was a LCF brought forward into 2015 associated with NWTC. This amount, as used by GPI, was $530,467 and can be found in the 2015 tax return contained in the response to Undertaking JT1.3.

Addition of the NWTC LCF of $530,467 with the GPI LCF $234,921 results in the LCF of $765,388, which is the figure shown in the above table based for the settlement agreement.

The unsettled issue with respect to the determination and application of LCF has two main components. The first component is the calculation of the net income for tax purposes in the 2015 bridge year and the second component is whether the LCF associated with NWTC should be included in the calculation of the LCF in 2015. Each is discussed in detail below.

ii) Calculation of Net Income for Tax Purposes in 2015 Bridge Year

The issue with respect to the calculation of net income for tax purposes in the 2015 test year comes down to whether the PILS should be calculated on an actual accounting basis or on an actual regulatory basis. Energy Probe submits that it should be the latter, consistent with the calculation of PILS for the test year. GPI has used the former approach.

A comparison of the Net Income for Tax Purposes (line 107) on the B1 Adj. Taxable Income Bridge tab in the Settlement Agreement PILS workform to the same line in the B1 Update Adj. Taxable Income Bridge tab in the New Evidence PILS workform shows the magnitude of the difference. The first calculation results in a loss of \$318,021, while the second shows a positive amount of \$589,098, a difference in the net income of more than \$900,000. This difference highlighted in Table 5 of response to Undertaking JT1.6 and was included on page 10 of the Energy Probe cross-examination compendium, Exhibit K1.3. For ease of reference, this table has been attached to this submission, as Appendix 5.

As shown in the table, the net income for tax purposes per the Settlement PILS model was (\$318,022). This is found at the bottom of the top half of the table. GPI has added \$907,120 to the net income for tax purposes not included in the Settlement PILS model, as shown near the bottom of the table. The resulting net income as calculated by GPI is \$589,098, as shown at the bottom of the table and in the 2015 bridge year calculation in the PILS workform filed as part of the new evidence.

Energy Probe has highlighted the five areas where GPI has made additions or changes to the PILS model. These five areas are colour coded in Table 5 in Appendix 5.

Three of the five identified areas result in a change in net income for tax purposes that Energy Probe does not oppose. In particular, the changes associated with reserves (lines 126 and 414) result in an increase in net income of \$73,449 and are highlighted in orange are the result of updated information and a correction to the PILS model (Tr. Vol. 1, pages 31-34). Similarly, the reduction in net income of \$66,550 shown on line 43 (highlighted in green) is the result of a correction to the CCA calculations (Tr. Vol. 1, pages 34-36). Finally, the additions (line 604) and deductions (line 700) exactly offset one another and have no impact on the net income for tax purposes. Energy Probe submits that the Board should accept all of these changes since they are only updates and corrections to what was previously filed.

However, Energy Probe submits that the Board should not approve the other two changes, being the addition to net income before taxes, which are highlighted in yellow in Table 5 in Appendix 5 and add $216,365 to net income, and the change in the regulatory assets balance highlighted in blue that add $683,856 to net income. Energy Probe discusses each of these two issues below.

a) Additions to Net Income

GPI has added $216,365 to the 2015 bridge year net income for the addition of provision for income tax - current, provision for income tax - deferred and accounting net income before taxes. These changes are shown in greater detail in Table 4 as found in the response to Undertaking JT1.6.

Table 4 shows the increase in accounting net income between the actual accounting and actual regulatory basis of $216,365. This can be seen in more detail in the note following the table. In particular, the $216,365 increase is made up of an increase of $186,620 being the difference between deemed interest ($666,376) and actual interest ($479,756). Because the actual interest is lower, income for account tax purposes is higher than income for PILS or regulatory tax purposes.

The remainder of the difference is due to a gain on the change in the fair market value for interest rate swaps and the inclusion of $1,721 in donations that are not included in the regulated revenue requirement.

As is shown in the note at the bottom of Table 4, the current and future taxes are then subtracted off to arrive at the figure of $39,988 that is shown in Table 5 in Appendix 5 as "Accounting Net Income before Taxes". GPI has then also added lines 101 and 102 the PILS model, as they do not exist in the PILS model (Tr. Vol. 1, page 31).

GPI has changed the PILS model for the 2015 bridge year so it no longer reflects the Board's policy with respect to PILS being calculated based on deemed interest costs and not including accounting adjustments for current and future taxes. These adjustments being made for 2015 are not made in the test year.

As the Board is aware, the PILS model reflects the Board policy of calculating PILS. In particular, PILS are calculated based on deemed interest expense and does not allow for an accounting adjustment for current or deferred taxes.

On behalf of GPI, Mr. Picard indicated that he believed the actual accounting tax return should be used rather than actuals calculated using the regulatory PILS model because the 2006 EDR Handbook stated that any tax losses that were available at the end of 2005 had to be used in the 2006 rate applications (Tr. Vol. 1, page 38).

What Mr. Picard failed to point out was the direct comments in the 2006 EDR Handbook. Specifically, with respect to the interest deduction, as stated in Section 7.2.6 of the Handbook, for the purposes of the 2006 regulatory tax calculation, the greater of the amount of the actual 2004 interest expense (taking into account the interest effect of any Tier 1 and Tier 2 adjustments proposed in the application), and the deemed interest expense calculated by the main model must be treated as a deduction for the purpose of calculating PILS/taxes.

In addition, in Section 7.1 of the Handbook, the Board stated that *"The tax amount included in rates reflects taxes payable as a result of operating the distribution-only business, rather than taxes calculated for accounting purposes, and hence future/deferred taxes will not be recovered through rates as a result of this filing."*

Energy Probe submits that the Board policy with respect to taxes calculated for accounting purposes and the use of the deemed interest costs is clear. The GPI proposal with respect to the additional $216,365 in net income for tax purposes is not in compliance with Board policy.

In summary, GPI has calculated the 2015 bridge year net income for tax purposes by deviating from Board policy with respect to using actual interest in place of deemed interest and by including accounting provisions for current and deferred taxes. Energy Probe submits that this is not consistent with Board policy, is not consistent with the calculation of PILS in the test year, and should be rejected by the Board. The resulting loss carry forward for 2015 should be recalculated based on the exclusion of these adjustments to the PILS calculations.

b) Regulatory Assets

As noted above, the inclusion of the opening and closing balances in regulatory assets adds $683,856 to net income in 2015 and is the most significant change to the PILS model, and by extension to Board policy, made by GPI.

When asked, Mr. Picard indicated he was unaware of there being any detailed guidance or any guidance in respect of the calculations of PILS in the filing guidelines, other than what was in the 2006 EDR Handbook (Tr. Vol. 1, page 39).

With respect to the inclusion of regulatory assets and liabilities, Energy Probe submits that the Board policy and filing guidelines are crystal clear.

In the July 16, 2015 Filing Guidelines, at section 2.4.5, the following is stated that:

> *Detailed calculations of Income Tax or PILs, as applicable (including a completed pdf and live Microsoft Excel version of the Income Tax /PILs model available on the OEB's web site), including derivation of adjustments (e.g., Tax credits, CCA adjustments) for the* <u>*Historical, Bridge and Test Years. Regulatory assets and liabilities must generally be excluded from PILs calculations both when they were created and when they were disposed, regardless of the actual tax treatment accorded those amounts.*</u> (emphasis added)

In the RP-2004-0188 Report of the Board on the 2006 Electricity Distribution Rate Handbook dated May 11, 2005, the Board concluded that with respect to regulatory assets and liabilities (page 61):

> *A PILs or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will deduct, these costs in calculating taxable income in their tax returns. The Handbook will reflect this treatment.*

There may be higher taxable income in a year when a distributor recovers regulatory assets. However, because the distributor also took a tax deduction when allowed by tax law in a prior period, that deduction provides the funds to pay the taxes in the year of recovery. In other words, regulatory assets and liabilities are not included in the calculation of PILS because they represent a timing difference, not a difference in the absolute level of PILS being paid.

The Board has denied the addition of regulatory asset recoveries in the PILS calculations in a number of cases, including RP-2005-0020/EB-2005-0412 (PUC Distribution Inc.'s 2006 EDR application), EB-2007-0723 (PUC Distribution application for adjustment to 2007 PILS proxy), and EB-2007-0522 (EnWin Utilities application for adjustment to 2007 PILS proxy).

Specifically, in RP-2005-0020/EB-2005-0412, the Board indicated that it did not accept the amount of regulatory asset recovery being included in the PILS calculation because it was a delayed recovery of costs from previous years that would have already been expensed for tax purposes.

The same principle holds for the calculation of the loss carry forward component of PILS as it does for PILS in general. In the current case, GPI is eliminating the LCF by including the recovery of regulatory assets in the bridge year PILS calculation. This has been accomplished by adding line items to the PILS model that were not included and by changing some of the formulas in the PILS model (Tr. Vol. 1, pages 56-58) so that GPI could get the result they wanted, which was to match their actual accounting tax filing.

The recovery of the regulatory assets in 2015 results in higher income and thus results in higher PILS. However, this also means that income in previous years was lower than it would otherwise have been if the regulatory assets had been recovered in the previous years when it was actually earned. This resulted in lower PILS being paid in the previous year. This is entirely consistent with the Board conclusion in RP-2004-0188 noted above.

Energy Probe submits that the GPI proposal double counts the PILS impact in the 2015 bridge year. The increase in PILS is simply a timing difference with lower PILS paid in previous years. That should be the end of the story.

However, by including the regulatory assets in the PILS calculation for 2015, which is clearly different from Board Policy, the effect is to eliminate the LCF into the test year. If GPI were not in a loss position with respect to net income for tax purposes, this would have no effect on ratepayers as no costs or losses would be carried forward. However, because GPI has a LCF coming into 2015 and a further loss in 2015 if the regulatory assets are removed from the calculation, as per Board policy, there will be a larger LCF carried into the 2016 and future years.

Energy Probe also notes in the March 2016 RRR 2.1.5.6 ROE Complete Filing Guide, Section A.6 states the methodology used to calculate current tax for regulatory purposes in the calculating the actual return on equity is consistent with the methodology set out in the RP-2004-0188 Report of the Board. In particular, the Filing Guide states (page 23) that *"The activity of regulatory asset and liability accounts is not allowed in PILS embedded into the rates as stated in the 2006 EDR Handbook, Report of the Board and Chapter2 of the Filing Requirements. As a result, if a distributor has included the activity of regulatory accounts in its taxable income, it must be removed from the current tax provision for the purposes of determining regulatory ROE."*

Energy Probe submits that the calculation of the PILS, whether it be for a test year, for calculating actual regulatory ROE or regulatory loss carry forwards should be consistent.

In summary, Energy Probe submits that the Board should disallow the inclusion of regulatory assets in the 2015 PILS calculation and that the loss carry forward calculation should reflect this elimination.

<u>iii) NWTC Loss Carry Forward</u>

GPI has proposed to remove the WTC loss carry forward, which they estimate to be $530,467 over the 2006 to 2015 period, as shown in non-capital loss continuity workchart for the 2015 PILS filing in Appendix B to Exhibit KT1.3. Also as shown in the exhibit, GPI has used $138,646 of the LCF to reduce 2015 net income for tax purposes.

If the Board concludes that the 2015 PILS calculation for regulatory purposes should not include the regulatory assets and the other adjustments made by GPI, then GPI will not have a positive net income for tax purposes and no LCF will be required for 2015, leaving the higher amount available for future use.

GPI has indicated that there are two main reasons for proposing that the LCF associated with the merger of NWTC accrue to the shareholder rather than to ratepayers. The first is that historical rates did not include an allowance for PILS and the second is that the losses were actually created by the fact that actual interest costs were higher than the deemed interest costs (Tr. Vol. 1, page 22).

With respect to the first reason given, that there was not an allowance for PILS in the historical rates, the rates referred to are those set for 2011 in EB-2010-0345. On page 6 of 66 of that evidence, it states that no PILS were assumed in the application for 2011 since NWTC had previous losses carried forward that were available to offset the 2011 PILS requirement.

Energy Probe submits that this is a clear indication that there was a PILS requirement built into the 2011 revenue requirement, but it was offset by the LCF available. To say no PILS were included in rates is not correct. If this were the case, then no LCF would be needed and the LCF could be carried forward indefinitely.

The evidence, however, indicates that NWTC applied to reduce its ROE to 7.00% in order to maintain the $1.77 transformation rate as set out in the Uniform Transmission Rate (Undertaking J1.12). This means that PILS would have been forecast since a positive return on equity will result in positive net income for tax purposes. The GPI witnesses agreed that on a generic basis this would be true (Tr. Vol. 1, pages 42 to 43). This PILS forecast was then reduced by the use of the LCF amounts. This is different than saying no PILS were built into rates. They were, in fact, built into rates, but offset by the LCF.

Mr. Picard stated that despite forecasting a profit, NWTC incurred a loss of $12,000 in 2011. He also stated that this loss reflected the confluence of negative factors including a reduction in load (reduction revenue), an increase in OM&A, and more specifically, an increase in interest expense of $110,000 above the deemed interest that was included in rates (Tr. Vol. 1, page 22).

Energy Probe submits that this testimony illustrates that the Board cannot accept the proposition that the losses incurred were because there were no PILS included in the revenue requirement approved by the Board. The losses were, in fact, incurred because of lower than forecast revenues and higher than forecast OM&A costs and interest expense.

Mr. Picard then went on to stress that the actual interest expenses were higher than the deemed interest in each of 2011 through 2015. he then concluded that the tax losses incurred in 2011 through 2015 can be almost all attributed to the difference between the actual and deemed interest (Tr. Vol. 1 page 23). He also indicated that in the years prior to 2011 the same situation existed. Mr. Picard concluded that almost all the losses could be attributed to the difference between the actual interest and the deemed interest.

Energy Probe submits that the KPMG evidence is misleading and is of little value. This is because the net tax losses reported for NWTC are directly the result of the Board policy that a regulated entity must use the maximum capital cost allowance ("CCA") available to it each year. The following table illustrates the results for NWTC for each year where a loss was reported.

Year	Losses Incurred	CCA Deduction	CCA Needed
2006	157,321	237,793	80,472
2008	128,090	228,201	100,111
2010	118,425	210,384	91,959
2011	46,358	212,322	165,964
2012	344	205,755	205,411
2014	26,690	189,700	163,010
2015	53,239	136,100	82,861
Total	530,467	1,420,255	889,788

The first column shows the year and the second column shown shows the losses incurred for tax purposes. These figures are taken from the non-capital loss continuity workchart filed as part of the 2015 tax filing in Appendix B to Exhibit KT1.3.

The third column shows the CCA deduction used for each year and is taken from Schedule 1 for each of the relevant tax years where a loss was recorded. These tax filings were provided in the response to Undertaking JT1.3.

A comparison of columns 2 and 3 show that the CCA deduction in each and every year was greater than that needed to reduce net income for tax purposes to $0. The fourth column shows the CCA that would have been enough to reduce the net income to $0. For example, in 2006 the use of $80,472 in CCA would have reduced net income to zero. The use of the further $157,321 in CCA (the increase from $80,472 to $237,793) created the loss of the same amount.

In summary, the losses created in NWTC from 2006 through 2015 are clearly the result of the Board policy that requires the use of the maximum CCA deduction available.

Energy Probe submits that in a normal situation, it really does not matter to ratepayers whether the CCA deduction creates a loss and a resulting LCF. In either case, the ratepayers benefit from the reduction in PILS payable, either through the CCA deduction or the application of the LCF. Over the life of the asset, the deductions in the PILS amounts total the same amount. Ms. Domokos explained this and agreed that over the life of an asset, whether the PILS deduction was in the form of a loss carry forward or in the form of CCA, that the net impact is the same and the dollars are the same (Tr. Vol. 1, pages 47-48).

The NWTC situation, however, is not normal. The reality of this situation is that the only reason that NWTC has any LCF is because of Board policy. The filing guidelines state that the CCA is maximized even if there are loss carry forwards.

Board policy has created the loss carry forward of $530,467. This has resulted in a transfer of tax deductibility from the CCA to the LCF. If the amount had been retained in CCA, the future benefits of the full CCA would accrue to ratepayers, as it does for all assets. However, the result of the Board policy has been to reduce the remaining CCA that will accrue to ratepayers and transfer it to a LCF. That, in and of itself, is not harmful to ratepayers.

However, the GPI proposal for the LCF to accrue to the shareholder and not to ratepayers is harmful to ratepayers, as they will receive no credit for the tax deductions that have been transferred from the CCA to the LCF. The Board policy would benefit the shareholder at the expense of the ratepayer. Energy Probe submits that this could not have been the intention when setting its policy with respect to the use of the maximum CCA available.

Energy Probe submits that if the NWTC tax losses accrue to the ratepayer, then the Board policy of maximizing the CCA deduction has no impact on ratepayers over the life of the asset. They will receive the tax benefits through both the CCA and the LCF. However, in this case, the Board policy has an adverse impact on ratepayers if the Board were to determine that the LCF for NWTC should accrue to the shareholder. This is because the LCF is the direct result of the Board policy.

As a result, Energy Probe submits that the Board should not allow GPI to remove the losses at NWTC from the calculation of the LCF for GPI. These losses are nothing but an artificial transfer of CCA deductions based on a Board policy that was meant to help ratepayers through the maximization of deductions for PILS purposes. The GPI proposal, combined with the Board policy, results in a perverse outcome that is not acceptable to ratepayers.

iv) Amortization of Loss Carry Forward

In their original filing, GPI proposed to amortize the LCF available at the end of 2015 over five years, consistent with the IRM period and rebasing year. Energy Probe supports this approach as it replicates the amortization of regulatory costs associated with the application and smoothes out the revenue requirement and, therefore, rates over the five year IRM horizon.

C) Effective Date of Rates

Grimsby continues to request an effective date for rates of May 1, 2016 (Tr. Vol. 2, page 72).

Energy Probe notes that GPI's rates were final for the period May 1, 2016 through July 13, 2016 because the rates were not declared interim until July 14, 2016 in the Interim Rate Order and Procedural Order No. 3 date July 15, 2016.

As a result, Energy Probe submits that making the rates effective as of May 1, 2016 would constitute retroactive ratemaking. Customers should be expected to pay more for consumption that has already taken place and when rates were finalized.

Energy Prober further submits that rates should not be made effective July 14, 2016, which is when rates became interim. Rather, rates should be effective on the first day of the month following the Board decision in this application.

GPI notes that it is on a calendar year basis for rates. This means that based on the Board's filing schedule, the filing deadline for January 1, 2016 rates was April 24, 2015. GPI wrote to the Board on March 12, 2015 advising the Board that it *"fully intends to file a cost of service application under the Price Cap IR rate setting method for 2016 rates and has been working towards fulfilling the filing requirements since January 1, 2014."*

The letter goes on to state that GPI would not meet the April 24, 2015 deadline but that it was diligently working towards the completion of its application submission and anticipated that the application would be delayed by up to three months.

GPI filed their application and evidence on December 23, 2015, a full 9 months after their letter indicating they would be delayed by up to 3 months. Acknowledging the lateness of the filing, GPI proposes that rates would be effective May 1, 2016 rather than January 1, 2016.

However, the deadline for filing applications for May 1, 2016 rates was August 28, 2015. In other words, not only was GPI late in filing for January 1, 2016 rates by 8 months, it was also 4 months late in filing for May 1, 2016 rates.

In the EB-2012-0113 Decision and Order dated May 28, 2013, the Board issued a decision with respect to the effective date for rates for Centre Wellington Hydro Ltd. In that decision the Board stated that even though Board Staff and VECC (the only parties to the proceeding) took no issue with the request for an effective date of May 1, 2013, that (page 2):

> *The Board will not accept the proposal to make rates effective on May 1, 2013 or allow for recovery of any foregone revenue. CWH filed its complete application in November 2012, more than two months after the Board's target date of August 31, 2012. The target date is established to allow sufficient time to complete the proceeding and issue a final rate order before May 1, 2013. In addition, the company revised its evidence regarding the accounting method used to determine rates which added a second round of interrogatories and delayed the filing of submissions. These timing issues were within the company's control. The Board therefore concludes that it would not be appropriate to make the rates effective back to May 1. CWH's new rates will be effective July 1, 2013.* (emphasis added)

In this proceeding GPI was 4 months late in filing for May 1 rates, double that of Centre Wellington Hydro. Just like Centre Wellington Hydro, the timing issues were within the control of GPI. Indeed, they stated that they had started working on the application at the beginning of 2014, but it was not complete for nearly two years. It is clear to Energy Probe that GPI management failed to appropriately prioritize the regulatory filing.

In the EB-2012-0113 proceeding, rates were effective the first day of the second month following the Board's decision, and no recovery of foregone revenue was allowed. Energy Probe suggests that the effective date should be the first day of the month following the Board decision, and that no foregone revenue should be recovered for the period prior to this date. Given that the rate order may not be issued before the effective date, Energy Probe submits that it would be appropriate to allow GPI to collect the revenue from the effective date to the implementation date through a rate rider.

III - COSTS

Energy Probe requests that it be awarded 100% of its reasonably incurred costs. Energy Probe worked with other intervenors throughout the process to limit duplication while ensuring that the record was complete.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

July 29, 2016

Randy Aiken
Consultant to Energy Probe

1 # APPENDIX 1

2 ## OM&A CALCULATIONS

3 **(Excludes Property Taxes and LEAP)**

Line								
6	**SECTION 1 ADJUSTMENTS TO OM&A**		**2012 BA**	**2012**	**2013**	**2014**	**2015**	**2016**
8	Total OM&A - 4-EP-21 - Table 4-1 & J1.1		2,407,163	2,935,572	2,681,285	2,779,745	2,918,395	3,733,648
10	Smart Meters - Exhibit 4 - Table 4-4			(155,528)				
11	Recruiting & Talent Search - Exhibit 4 - Table 4-4					(21,750)		
12	New Costs for NWTC - 1-EP-5						(64,576)	(217,738)
13	Deferral of 2015 Tree Trimming to 2016 - J1.2						38,550	(38,550)
14	2012 COS Application Adjustment - 4-EP-23			(148,776)	49,592	49,592	49,592	0
15	Total OM&A - Adjusted for Above Items		**2,407,163**	**2,631,268**	**2,730,877**	**2,807,587**	**2,941,961**	**3,477,360**
16	% Increase per Year			**9.31%**	**3.79%**	**2.81%**	**4.79%**	**18.20%**
17	**% Average Annual Compound Increase 2012 to 2016**							**7.22%**
19	**SECTION 2 CUSTOMERS**		**2012 BA**	**2012**	**2013**	**2014**	**2015**	**2016**
21	Customers - 4-EP-21 - Table 4-6		13,114	13,088	13,208	13,531	13,804	14,011
22	Customer Growth				0.92%	2.45%	2.02%	1.50%
23	**% Average Annual Compound Increase 2012 to 2016**							**1.72%**
25	**SECTION 3 ESCALATORS**				**2013**	**2014**	**2015**	**2016**
27	Inflation - OEB Determined Inflation Rate				1.60%	1.70%	1.60%	2.10%
28	Base Productivity				0.72%	0.00%	0.00%	0.00%
29	Stretch Factor - PEG Reports & Interrogatory 1-Staff-7				0.20%	0.15%	0.15%	0.15%
30	Sub-Total (lines 27 - 28 - 30)				0.68%	1.55%	1.45%	1.95%
31	Customer Growth - PEG Model	0.439			0.40%	1.07%	0.89%	0.66%
32	Total Escalator (lines 30 + 31)				**1.08%**	**2.62%**	**2.34%**	**2.61%**
34	**SECTION 4 OM&A GROWTH AT ESCALATOR**			**2012**	**2013**	**2014**	**2015**	**2016**
36	Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2012 BA**			2,407,163	2,433,221	2,497,058	2,555,382	2,622,035
37	Test Year Forecast (line 15)							3,477,360
38	Implied Test Year Reduction							**(855,325)**
40	Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2012**			2,631,268	2,659,752	2,729,532	2,793,286	2,866,144
41	Test Year Forecast (line 15)							3,477,360
42	Implied Test Year Reduction							**(611,216)**
44	Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2013**				2,730,877	2,802,523	2,867,983	2,942,788
45	Test Year Forecast (line 15)							3,477,360
46	Implied Test Year Reduction							**(534,572)**
48	Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2014**					2,807,587	2,873,164	2,948,105
49	Test Year Forecast (line 15)							3,477,360
50	Implied Test Year Reduction							**(529,255)**
52	Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2015**						2,941,961	3,018,696
53	Test Year Forecast (line 15)							3,477,360
54	Implied Test Year Reduction							**(458,664)**
56	**Average Implied Test Year Reduction** (average of lines 38, 42, 46, 50 and 54)							**(597,806)**
57	**Average Implied Test Year Reduction excl. BA** (average of lines 42, 46, 50 and 54)							**(533,426)**

APPENDIX 2

REGRESSION ANALYSIS RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.959894856
R Square	0.921398134
Adjusted R Square	0.911572901
Standard Error	0.533990685
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	26.74064159	26.74064	93.77875468	1.07826E-05
Residual	8	2.28116841	0.285146		
Total	9	29.02181			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-21.00277431	3.912154585	-5.3686	0.00067073	-30.02421895	-11.98132967
No. Of Customers	0.002952654	0.000304902	9.683943	1.07826E-05	0.002249549	0.003655759

APPENDIX 3

OM&A CALCULATIONS - NO PRODUCTIVITY, STRETCH FACTORS OR ECONOMIES OF SCALE

(Excludes Property Taxes and LEAP)

SECTION 1 ADJUSTMENTS TO OM&A	**2012 BA**	**2012**	**2013**	**2014**	**2015**	**2016**
Total OM&A - 4-EP-21 - Table 4-1 & J1.1	2,407,163	2,935,572	2,681,285	2,779,745	2,918,395	3,733,648
Smart Meters - Exhibit 4 - Table 4-4		(155,528)				
Recruiting & Talent Search - Exhibit 4 - Table 4-4				(21,750)		
New Costs for NWTC - 1-EP-5					(64,576)	(217,738)
Deferral of 2015 Tree Trimming to 2016 - J1.2					38,550	(38,550)
2012 COS Application Adjustment - 4-EP-23		(148,776)	49,592	49,592	49,592	0
Total OM&A - Adjusted for Above Items	**2,407,163**	**2,631,268**	**2,730,877**	**2,807,587**	**2,941,961**	**3,477,360**
% Increase per Year		**9.31%**	**3.79%**	**2.81%**	**4.79%**	**18.20%**
% Average Annual Compound Increase 2012 to 2016						**7.22%**
SECTION 2 CUSTOMERS	**2012 BA**	**2012**	**2013**	**2014**	**2015**	**2016**
Customers - 4-EP-21 - Table 4-6	13,114	13,088	13,208	13,531	13,804	14,011
Customer Growth			0.92%	2.45%	2.02%	1.50%
% Average Annual Compound Increase 2012 to 2016						**1.72%**
SECTION 3 ESCALATORS			**2013**	**2014**	**2015**	**2016**
Inflation - OEB Determined Inflation Rate			1.60%	1.70%	1.60%	2.10%
Base Productivity			0.00%	0.00%	0.00%	0.00%
Stretch Factor - PEG Reports & Interrogatory 1-Staff-7			0.00%	0.00%	0.00%	0.00%
Sub-Total (lines 27 - 28 - 30)			1.60%	1.70%	1.60%	2.10%
Customer Growth - PEG Model 1			0.92%	2.45%	2.02%	1.50%
Total Escalator (lines 30 + 31)			**2.52%**	**4.15%**	**3.62%**	**3.60%**
SECTION 4 OM&A GROWTH AT ESCALATOR		**2012**	**2013**	**2014**	**2015**	**2016**
Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2012 BA**		2,407,163	2,467,748	2,570,048	2,663,022	2,758,879
Test Year Forecast (line 15)						3,477,360
Implied Test Year Reduction						**(718,481)**
Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2012**		2,631,268	2,697,494	2,809,318	2,910,947	3,015,729
Test Year Forecast (line 15)						3,477,360
Implied Test Year Reduction						**(461,631)**
Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2013**			2,730,877	2,844,085	2,946,972	3,053,051
Test Year Forecast (line 15)						3,477,360
Implied Test Year Reduction						**(424,309)**
Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2014**				2,807,587	2,909,154	3,013,871
Test Year Forecast (line 15)						3,477,360
Implied Test Year Reduction						**(463,489)**
Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2015**					2,941,961	3,047,859
Test Year Forecast (line 15)						3,477,360
Implied Test Year Reduction						**(429,501)**
Average Implied Test Year Reduction (average of lines 38, 42, 46, 50 and 54)						**(499,482)**
Average Implied Test Year Reduction excl. BA (average of lines 42, 46, 50 and 54)						**(444,733)**

APPENDIX 4

OM&A CALCULATIONS - NO STRETCH FACTOR OR ECONOMIES OF SCALE - RESULTING NEGATIVE PRODUCTIVITY

(Excludes Property Taxes and LEAP)

Line		2012 BA	2012	2013	2014	2015	2016
4							
5							
6	**SECTION 1** **ADJUSTMENTS TO OM&A**	**2012 BA**	**2012**	**2013**	**2014**	**2015**	**2016**
7							
8	Total OM&A - 4-EP-21 - Table 4-1 & J1.1	2,407,163	2,935,572	2,681,285	2,779,745	2,918,395	3,733,648
9							
10	Smart Meters - Exhibit 4 - Table 4-4		(155,528)				
11	Recruiting & Talent Search - Exhibit 4 - Table 4-4				(21,750)		
12	New Costs for NWTC - 1-EP-5					(64,576)	(217,738)
13	Deferral of 2015 Tree Trimming to 2016 - J1.2					38,550	(38,550)
14	2012 COS Application Adjustment - 4-EP-23		(148,776)	49,592	49,592	49,592	0
15	Total OM&A - Adjusted for Above Items	**2,407,163**	**2,631,268**	**2,730,877**	**2,807,587**	**2,941,961**	**3,477,360**
16	% Increase per Year		**9.31%**	**3.79%**	**2.81%**	**4.79%**	**18.20%**
17	**% Average Annual Compound Increase 2012 to 2016**						**7.22%**
18							
19	**SECTION 2** **CUSTOMERS**	**2012 BA**	**2012**	**2013**	**2014**	**2015**	**2016**
20							
21	Customers - 4-EP-21 - Table 4-6	13,114	13,088	13,208	13,531	13,804	14,011
22	Customer Growth			0.92%	2.45%	2.02%	1.50%
23	**% Average Annual Compound Increase 2012 to 2016**						**1.72%**
24							
25	**SECTION 3** **ESCALATORS**			**2013**	**2014**	**2015**	**2016**
26							
27	Inflation - OEB Determined Inflation Rate			1.60%	1.70%	1.60%	2.10%
28	Base Productivity			(5.75%)	(5.75%)	(5.75%)	(5.75%)
29	Stretch Factor - PEG Reports & Interrogatory 1-Staff-7			0.00%	0.00%	0.00%	0.00%
30	Sub-Total (lines 27 - 28 - 30)			7.35%	7.45%	7.35%	7.85%
31	Customer Growth - PEG Model 1			0.92%	2.45%	2.02%	1.50%
32	Total Escalator (lines 30 + 31)			**8.27%**	**9.90%**	**9.37%**	**9.35%**
33							
34	**SECTION 4** **OM&A GROWTH AT ESCALATOR**		**2012**	**2013**	**2014**	**2015**	**2016**
35							
36	Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2012 BA**		2,407,163	2,606,273	2,864,299	3,132,750	3,425,795
37	Test Year Forecast (line 15)						3,477,360
38	Implied Test Year Reduction						**(51,565)**
39							
40	Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2012**		2,631,268	2,848,915	3,130,963	3,424,406	3,744,734
41	Test Year Forecast (line 15)						3,477,360
42	Implied Test Year Reduction						**267,374**
43							
44	Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2013**			2,730,877	3,001,239	3,282,524	3,589,580
45	Test Year Forecast (line 15)						3,477,360
46	Implied Test Year Reduction						**112,220**
47							
48	Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2014**				2,807,587	3,070,722	3,357,966
49	Test Year Forecast (line 15)						3,477,360
50	Implied Test Year Reduction						**(119,394)**
51							
52	Adjusted OM&A Growth - Based on Escalator (line 32) starting with **2015**					2,941,961	3,217,160
53	Test Year Forecast (line 15)						3,477,360
54	Implied Test Year Reduction						**(260,200)**
55							
56	**Average Implied Test Year Reduction** (average of lines 38, 42, 46, 50 and 54)						**(10,313)**
57	**Average Implied Test Year Reduction excl. BA** (average of lines 42, 46, 50 and 54)						**(0)**
58							

Table 5 - Updated Table 2 from Materials for Oral Hearing

T2S1 line #	ITEM	2015 PILS Model Settlement Proposal	
	Accounting Net Income	**195,848**	
	Additions:		
104	Amortization of Tangible Assets	910,805	
121	Non-Deductible Meals and Entertainment Expenses	2,534	
125	Other Reserves from Schedules 13	672,897	
126	Reserves @ End of the Year	6,500	
	Subtotal of additions	1,592,736	
	Other Additions		
603	Inducement - ITA 12(1)(x)	17,479	
199	Subtotal of other additions	17,479	
500	**Total Additions:**	**1,610,215**	
	Deductions		
401	Gain on Disposal of Assets	15,824	
403	Capital Cost Allowance from Schedule 8	1,323,949	
413	Other Reserves from Schedules 13	746,346	
414	Reserves @Beginning of the Year	6,500	
	Subtotal of deductions	2,092,619	
	Other Deductions		
700	Unrealized interest rate adjustment	31,466	
499	Subtotal of other deductions	31,466	
510	**Total Deductions:**	**2,124,085**	
	Net Income for Tax Purposes Per Settlement PILs Model	**(318,022)**	
		Additions Deductions	
	*Accounting Net Income before Taxes	39,988	
	Additions:		
101	**Provisions for Income Taxes - Current	48,209	216,365
102	**Provisions for Income Taxes - Deferred	128,168	
126	*Reserves @ End of the Year	746,346	
	Subtotal of additions	922,723	73,449
	Other Additions		
600	**Opening Regulatory Assets Balance	738,802	
604	**Capital Assets Additions Included in Regulatory Balance	399,728	
199	Subtotal of other additions	1,138,530	683,856
500	**Total Additions:**	**2,061,253**	
	Deductions		
403	*Capital Cost Allowance from Schedule 8	66,550	
414	*Reserves @Beginning of the Year	672,897	0
	Subtotal of deductions	739,447	
	Other Deductions		
700	**Capital Assets Deductions Included in Regulatory Balance	399,728	-66,550
702	**Closing Regulatory Assets	54,946	
499	Subtotal of other deductions	**454,674**	
510	**Total Deductions:**	**1,194,121**	
	Net Income for Tax Purposes Not Included in Settlement PILs Model	**907,120**	
		589,098	

* Difference between Actual Corporate Tax and Settlement PILs Model
** Not included in Settlement PILs Model