EXHIBIT 7 – COST ALLOCATION

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EXHIBIT 7 – COST ALLOCATION

COST ALLOCATION OVERVIEW

Introduction

On September 29, 2006, the Ontario Energy Board ("Board") issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors (the "Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. Grimsby Power prepared a cost allocation information filing consistent with Grimsby Power's understanding of the Directions, the Guidelines, the Model and the Instructions. Grimsby Power submitted this filing to the OEB on February 27, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

As part of Grimsby Power's 2012 COS Application (EB-2011-0273), the original cost allocation information filing was updated to reflect 2012 Test Year costs, customer numbers and demand values. The 2012 demand values were based on the weather normalized load forecast used to design rates. The results of the 2012 cost allocation model was used to move the revenue to cost ratios to be within the Board's acceptable range as outlined in the "Report on Application of Cost Allocation for Electricity Distributors" (the "Cost Allocation Report") issued by the OEB on November 28, 2007.

On September 2, 2010, the Board began a proceeding, EB-2010-0219, with the mandate to review and revise the Cost Allocation policy as needed. On March 31, 2011, the Report of the Board was released in relation to EB-2010-0219 ("March Board Report"). In the letter accompanying the report, the Board indicated that a Working Group would be formed to revise the original Cost Allocation Model to address the revision highlighted in the March Board Report. On August 5, 2011, the Board released the new Cost Allocation model and instructed 2012 Cost of Service filers to use the revised model in their applications. This model has been subsequently updated by the Board with some minor revision on an annual basis. On July 7, 2015, the Board released an updated Cost Allocation model to be used by 2016 Cost of Service applicants in their applications. This updated version of the cost allocation model has been used by Grimsby Power in this application.

In Section 2.6.4 of the March Board Report, the Board stated that "default weighting factors should now be utilized only in exceptional circumstances". Distributors are therefore now expected to develop their own weighting factors.

Grimsby Power has used the 2016 version of the cost allocation study model and submitted the revised cost allocation study to reflect 2016 Test Year costs, customer numbers and demand values. The 2016 demand values are based on the weather normalized load forecast used to design rates. Grimsby Power has developed weighting factors as outlined below based on discussions with staff experienced in the subject area.

WEIGHTING FACTORS

Weighting Factor for Services (Account 1855)

The analysis for the Services weighting factor included a review of Grimsby Power's internal policy in regards to the installation and cost recovery for Services. Grimsby Power charges customers for all new or upgraded services unless the change to the servicing falls under an internal capital project and involves correcting non-standard or outdated servicing. As per the suggested methodology on the Cost Allocation instruction sheet the Residential class was given a weighting factor of 1.0. General Service < 50 kW servicing is typically more complex than Residential servicing as it may include the creation of a unique work order, a dedicated construction crew to install and may require after hour attendance to mitigate against interruptions during normal business hours. Additional time may also be required to ensure demand data is programmed and monitored appropriately. Due to these varying considerations, the weighting factor for General Service < 50 kW was set higher at 3.14. General Service 50 to 4999 kW involves significantly more work than Residential and GS < 50 kW servicing both from a design and construction perspective, but due to the ownership rules for these services, Grimsby Power does not own the assets that would be charged against account 1855 and therefore these customer categories have been assigned a weighting factor of 0.0. For Street Lighting, Unmetered Scattered Load and Embedded

Distributor classes Grimsby Power does not have assets in account 1855 associated with these classes which causes the assigned weighting factor to be set at 0.0.

Table 7-1

Weighting Factors for Services

Rate Class	Weighting Factors for Services
Residential	1.00
General Service < 50 kW	3.14
General Service 50 to 4,999 kW	0.00
Street Lighting	0.00
Unmetered Scattered Load	0.00
Embedded Distributor	0.00

Weighting Factor for Billing and Collection (Accounts 5315 – 5330)

In determining the weighting factors for Billing and Collecting, an analysis of Accounts 5315 – 5330, was conducted. Each individual expense within these accounts was allocated to each rate class with a factor of one or less. A one represented that the expense was attributable to this class. A number of less than one, for example 0.5, meant that only half of expense was related to this class. For example the expenses related to operating the customer information system software is attributed to each class (a factor of 1) because the CIS is used to bill all of the classes. In another example the wages of the Customer Account Representatives are allocated fully (factor of 1) to Residential and GS<50 classes, partially (a factor of 0.25) to GS>50, and a factor of zero to Street Light (SL) and Unmetered Scattered Load (USL). This is because most of their time is spent with Residential and GS<50 customers and no time with SL or USL customers. These factors were used to calculate the total number of customers affected by the expense and then the total cost per customer was calculated. This cost was then multiplied by the number of customers affected in each class to calculate the expense attributed to each class for each expense line item. The sum total expense per line per class was then calculated and divided by the total number of customers in the class to determine the portion of expense related to each class. With the Residential factor set to one, each of the other class factors were calculated.

Through this analysis, Grimsby Power was able to align the Billing and Collection expenses to each rate class and thus calculate the factors shown below in Table 7-2.

Table 7-2

Weighting Factors for Billing and Collection

Rate Class	Weighting Factors for Billing and Collection
Residential	1.00
General Service < 50 kW	1.02
General Service 50 to 4,999 kW	9.62
Street Lighting	15.05
Unmetered Scattered Load	11.19
Embedded Distributor	0.00

Installation Cost per Meter (Sheet I7.1)

The installation cost for smart meters is consistent with the installation cost outlined in the smart meter recovery application approved by the Board and was part of EB-2014-0157. Installation costs included in the table below are reflective of 2015 costs including the cost of the meter, the labour cost and truck costs for each meter type.

Table 7-3

Installation Cost per Meter

Meter Type	Installation Cost per Meter
Smart Meters	135
Interval Meter	475
Network Meter	196
Demand without IT (usually three-phase)	539
Demand with IT and Interval Capability - Secondary	2,947
Demand with IT and Interval Capability - Primary	24,279
Demand with IT and Interval Capability -Special (WMP)	29,279

Weighting Factor for Meter Reading (Sheet I7.2)

Grimsby Power completed an analysis of the costs included in meter reading and assigned the costs to the appropriate class based on the nature of the cost. Based on this activity analysis, Grimsby Power calculated the overall cost per class by customer and assigned a weighting of 1 for the meter reading costs related to smart meters for the Residential class. The weighting factors for the remaining classes were then determined as a factor of the Residential class.

Table 7-4
Weighting Factors for Meter Reading

Meter Type	Weighting Factors for Meter Reading
Smart Meter	1.00
LDC Specific 3	885.80

The LDC Specific 3 meter type is the type of meter utilized for the GS>50kW customer class.

SUMMARY OF RESULTS AND PROPOSED CHANGES

The data used in the updated cost allocation study is consistent with Grimsby Power's cost data that supports the proposed 2016 revenue requirement outlined in this application. Consistent with the Guidelines, Grimsby Power's assets were broken out into primary and secondary distribution functions using breakout percentages consistent with the original cost allocation informational filing. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to Grimsby Power, its engineering records, and its customer and financial information systems. An Excel version of the updated cost allocation study has been included with the filed application material. In addition, Appendix 7-A outlines Input Sheets I-6 & I-8 and Output Sheets O-1 & O-2.

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2016 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2016 customer forecast outlined in Exhibit 3. The load profiles for each rate class are the same as those used in the original information filing but have been scaled to match the 2016 load forecast. The following Table 7-5 outlines the scaling factors used by rate class.

Table 7-5

Load Profiling Scaling Factors

Rate Class	2004 Weather Normal Values used in Orig. Information Filing (kWh)	2016 Weather Normal Values (kWh)	Scaling Factor
Residential	86,181,393	92,563,942	107.4%
General Service < 50 kW	18,082,932	18,812,265	104.0%
General Service 50 to 4,999 kW	57,699,153	69,648,507	120.7%
Street Lighting	1,618,360	1,145,992	70.8%
Unmetered Scattered Load	390,158	373,349	95.7%
Embedded Distributor	n/a	n/a	n/a
Total	**163,971,997**	**182,544,054**	**111.3%**

The allocated cost by rate class for the 2012 Cost of Service filing and the 2016 updated study are provided in the following Table 7-6.

Table 7-6

Allocated Cost

(Consistent with Appendix 2-P: Allocated Costs)

Rate Class	2012 Board Approved Cost Allocation Study	%	Cost Allocated in the 2016 Study	%
Residential	$3,088,935	69.6%	$3,964,452	60.3%
General Service < 50 kW	$486,612	11.0%	$683,857	10.4%
General Service 50 to 4,999 kW	$695,962	15.7%	$1,189,015	18.1%
Street Lighting	$142,035	3.2%	$119,503	1.8%
Unmetered Scattered Load	$23,086	0.5%	$74,208	1.1%
Embedded Distributor	n/a	n/a	$543,909	8.3%
Total	**$4,436,631**	**100.0%**	**$6,574,945**	**100.0%**

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The Board has established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7-7 below. In addition, Table 7-7 provides Grimsby Power's revenue to cost ratios from the 2012 Cost of Service application, the updated 2016 cost allocation study and the proposed 2017 to 2020 ratios.

Table 7-7
Revenue to Cost Ratios
(Consistent with Appendix 2-P: Revenue to Cost Ratios)

Rate Class	2012 Board Approved	2016 Updated Cost Allocation Study	2016 Proposed Ratios	2017 to 2020 Proposed Ratios	Board Targets Min to Max	
Residential	105.7%	115.2%	105.3%	105.3%	85.0%	115.0%
General Service < 50 kW	101.9%	105.4%	105.3%	105.3%	80.0%	120.0%
General Service 50 to 4,999 kW	80.0%	66.1%	80.0%	80.0%	80.0%	120.0%
Street Lighting	70.0%	111.3%	105.3%	105.3%	80.0%	120.0%
Unmetered Scattered Load	103.6%	47.4%	80.0%	80.0%	80.0%	120.0%
Embedded Distributor	n/a	61.3%	100.0%	100.0%	80.0%	120.0%

The 2016 cost allocation study indicates the revenue to cost ratios for General Service 50 to 4,999 kW, Unmetered Scattered Load and Embedded Distributor are outside the Board's acceptable range. For 2016, it is proposed the ratios for General Service 50 to 4,999 kW and Unmetered Scattered Load classes be increased to the minimum value of the Board's acceptable range. For the Embedded Distributor it is proposed the ratio be set at 100% to ensure that Grimsby Power customers are not subsidizing the customers of the Embedded Distributor. For the Residential, General Service < 50 kW and Street Lighting classes it is proposed the ratios be lowered to a common value to maintain revenue neutrality.

The following Table 7-8 provides information on calculated class revenue. The resulting 2016 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

Table 7-8
Calculated Class Revenue
(Consistent with Appendix 2-P: Calculated Class Revenue)

Rate Class	2016 Base Revenue at Existing Rates	2016 Proposed Base Revenue Allocated at Existing Rates Proportion	2016 Proposed Base Revenue	Miscellaneous Revenue
Residential	$3,061,190	$4,363,237	$3,969,342	$205,185
General Service < 50 kW	$486,791	$693,842	$693,752	$26,343
General Service 50 to 4,999 kW	$521,870	$743,842	$910,255	$40,958
Street Lighting	$86,669	$123,532	$116,640	$9,196
Unmetered Scattered Load	$20,661	$29,449	$53,452	$5,915
Embedded Distributor	$224,125	$319,454	$529,917	$13,992
Total	**$4,401,305**	**$6,273,356**	**$6,273,356**	**$301,588**

Embedded Distributor Class

As outlined in Exhibit 3, on October 1, 2015 the amalgamation of Grimsby Power and Niagara West Transformation Corporation was completed. Previously, Niagara Peninsula Energy Inc. was a customer of Niagara West Transformation Corporation. With the amalgamation, the transformer station assets previously owned by Niagara West Transformation Corporation became part of Grimsby Power which in turn meant Niagara Peninsula Energy Inc. became a customer of Grimsby Power. The station is now referred to as Niagara West MTS. As part of this application, Grimsby Power proposes to establish an Embedded Distributor class which would include Niagara Peninsula Energy Inc. as the only customer in the this class.

With regards to cost allocation and the resulting rate design for the Embedded Distributor class, this application is the first time the distribution rate has been established for this class. Grimsby Power submits it would be reasonable and appropriate to propose a cost allocation and rate design method that would be consistent with the Board's recent decision and direction on rate design for distribution services. On April 2, 2015, the Board issued its policy on A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410) ('The Policy"). The Policy established that the appropriate distribution rate design for Residential customers is 100% fixed charge.

On page 10 of the Policy the following discussion on Distribution costs is provided.

"A distributor plans and builds its system to be large enough to serve all of its customers when overall demand is at its highest (for example, a very hot day), even if customers only reach that peak occasionally. These are the costs for transformer stations, poles, meters, trucks, wires, computer systems, etc. We call these distribution costs "fixed costs" because they do not increase or decrease with short-term changes in a customer's usage. The OEB has commissioned analysis related to this point as part of the work done on our new electricity rate regulation framework. That work shows that a distributor's long-term costs are driven largely by two factors: the number of customers and the peak demand on the entire distribution system. Further analysis confirms that the main cost driver is the number of customers, followed by the peak demand, and that the total amount of electricity (as opposed to the peak) has less of an impact on long-term costs for distributors.

Even though almost all distribution costs are fixed, these costs are recovered through a combination of a fixed charge and a charge that varies with usage. As indicated above, we looked at a sample of Ontario distributors and found that fixed charges were collecting between 38% and 72% of the costs of residential distribution service, and the usage charges were collecting between 28% and 62% of the costs.

The result of the current rate design is that customers who use a lot of electricity pay more than their fair share of distribution costs, in other words these customers subsidize the low volume customers. It might seem that customers that use more (or who live in larger houses) should pay more, but that would only be fair if by using more those customers caused more costs on the system. In the case of electricity generation, using more does cause more costs, and customers who use more will continue to pay more for generation costs. However, if a residential customer uses more electricity it does not cause more distribution costs in the short term. It is a bit like basic landline telephone *service, or basic cable service, where the price is the same no matter how large your house, or how many phones or televisions you have.*

Although high volume residential customers are paying more than their fair share of distribution costs, after the rate change they will still have higher total bills than customers with smaller houses or customers who conserve more. The high volume customers will have higher bills because they will be paying more for generation.

Under the current system, a distributor's revenues also vary with the weather. If the weather is colder or warmer than had been forecast, then the distributor may earn additional unexpected revenue. However, these volume changes will not change the distributor's actual costs by much. The result is that the customers may pay more or less than necessary to cover the costs of distribution service, just because of the weather."

Similarly, the costs associated with the Niagara West MTS are 100% fixed. They do not increase or decrease with changes in a customer's usage. From a historic perspective the Niagara West MTS was built by two LDC partners in 2003/2004 to serve their load – Grimsby Power and the former Peninsula West Utilities. The former Peninsula West Utilities is now part of Niagara Peninsula Energy Inc. Thus, there are two wholesale customers that use the Niagara West MTS that being Niagara Peninsula Energy Inc. and Grimsby Power. Consistent with the Board's approach on the distribution rate design for Residential customers, Grimsby Power proposes the allocation of the Niagara West MTS be split 50/50 between Niagara Peninsula Energy Inc. and Grimsby Power since these two wholesale customers remain embedded to the station. In addition, the rate design for the Embedded Distributor class should be 100% fixed charge. Within the cost allocation model, 50% of the Niagara West MTS costs have been allocated to the Embedded Distributor by using the direct allocation method by directly assigning costs in sheet I9 of the model.

The initial allocation of deemed interest expense, income taxes and return on deemed equity in the cost allocation model was based on the NFA allocator. For the embedded distributor, this allocator included the amount of net fixed assets directly allocated to the embedded distributor and divided that by the total net fixed Assets. The resulting percentage of 12.65% was then applied to the deemed interest expense, income taxes and return on deemed equity net of amounts that were directly allocated in tab I9 of the cost allocation model. As a result, deemed interest expense, income taxes and return on deemed equity, net of the amounts directly allocated, was allocated to the embedded distributor. When Grimsby Power reviewed this allocation it was determined that the amount being allocated was too high and included amounts reflecting the distribution assets that were directly allocated in tab I9. The direct allocation process in tab I9 allocates deemed interest expense, income taxes and return on deemed equity based on the level of net fixed assets that are directly allocated. To then allocate the amounts that are not directly allocated based on the NFA allocator double counts the amount of deemed interest expense, income taxes and return on deemed equity allocated to the directly allocated net fixed assets. Grimsby Power determined that the allocation of deemed interest expense, income taxes and return on deemed equity that was not directly allocated should be based on the net plant assets allocated to the embedded distributor that excluded the direct allocation assets. In order to resolve this issue, Grimsby Power developed the NFAEXDA (Net Fixed Assets Excluding Direct Allocation) allocator in tab E2, row 121 and used it in tab E4, cells L84, K208 and K210 of the cost allocation model. This allocator takes the total net plant allocated to the embedded distributor in cell M51 of O1 Revenue to cost|RR, which does not include any directly allocated net fixed assets and divides that by the total net plant in cell C51 of O1 Revenue to cost|RR. The result is 1.34% for the Embedded Distributor. Grimsby Power believes this percentage is more reflective of the amount that should be allocated to the embedded distributor for deemed interest expense, income taxes and return on deemed equity that are not directly allocated in tab I9.

In regards to Grimsby Power consulting with its Embedded Distributor there has been correspondence between Niagara Peninsula Energy Inc. and Grimsby Power in regards to this matter. The response from Niagara Peninsula Energy Inc., dated November 4, 2015, to a letter from Grimsby Power, dated September 22, 2015, indicates Niagara Peninsula Energy Inc. does not support the approach to the allocation of costs to the Embedded Distributor class. This is also consistent with the submission from Niagara Peninsula Energy Inc. at the time the application for the amalgamation of Niagara West Transformation Corporation and Grimsby Power was before the Board (EB-2014-0344). Copies of the referenced letters and submission are provided in Appendix 7-B.

Even though Niagara Peninsula Energy Inc. does not support the approach, Grimsby Power submits it is the most reasonable approach considering the Board's recent decision on the distribution rate design for Residential customers.

Unmetered Loads

Grimsby Power communicates with unmetered load customers, including street lighting customers, as the needs arise.

From a street lighting perspective, Grimsby Power has had regular communication with Town of Grimsby staff on changes to rates. As an example, the Town of Grimsby recently conducted a street light retrofit project converting high pressure sodium to LED's. Throughout this project Grimsby Power worked closely with Town of Grimsby staff on all aspects of the project including the connection count and rate implications.

From a USL perspective Grimsby Power has not had communication with these customers other than to connect new loads. Grimsby Power has undertaken a review of its Unmetered Scattered Load class and a nominal number of connections remain in the class.

From this applications point of view Grimsby Power has invited all USL and street lighting customers to make inquiries regarding this rate proposal. This has been accomplished by sending written correspondence to all account holders. This correspondence was issued in December 2015.

microFIT Class

Grimsby Power is not proposing to include microFIT as a separate class in the cost allocation model in 2016. It is Grimsby Power's understanding that the cost allocation model will produce a calculation of unit costs which the Board will use to update the uniform microFIT rate at a future date.

New Customer Class

Grimsby Power is not proposing to include a new customer class.

Eliminated Customer Class

Grimsby Power is not proposing to eliminate any customer class.

APPENDIX 7-A – COST ALLOCATIONS I-6, I-8, O-1 & O-2

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0072

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	182,544,054

Total kWs from Load Forecast	316,626

Deficiency/sufficiency (RRWF 8. cell F51)	- 1,872,051

Miscellaneous Revenue (RRWF 5. cell F48)	301,588

			1	2	3	7	9	10
	ID	**Total**	**Residential**	**GS <50**	**General Service 50 to 4,999 KW**	**Street Light**	**Unmetered Scattered Load**	**Embedded Distributor**
Billing Data								
Forecast kWh	**CEN**	182,544,054	92,563,942	18,812,265	69,648,507	1,145,992	373,349	
Forecast kW	**CDEM**	316,626			186,573	3,429		126,624
Forecast kW, included in CDEM, of customers receiving line transformer allowance		48,332			48,332			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	178,071,521	92,606,467	18,814,527	65,131,299	1,145,878	373,349	-
Existing Monthly Charge			$15.69	$26.67	$172.24	$2.13	$18.39	
Existing Distribution kWh Rate			$0.0121	$0.0131			$0.0116	
Existing Distribution kW Rate					$1.7672	$5.2987		$1.7700
Existing TOA Rate					$0.60			
Additional Charges								
Distribution Revenue from Rates		$4,430,305	$3,061,190	$486,791	$550,869	$86,669	$20,661	$224,125
Transformer Ownership Allowance		$28,999	$0	$0	$28,999	$0	$0	$0
Net Class Revenue	**CREV**	$4,401,305	$3,061,190	$486,791	$521,870	$86,669	$20,661	$224,125

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0072

Sheet I6.2 Customer Data Worksheet -

	ID	Total	1 Residential	2 GS <50	3 General Service 50 to 4,999 KW	7 Street Light	9 Unmetered Scattered Load	10 Embedded Distributor
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$10,669	$9,350	$1,320	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$60,000	$43,100	$6,666	$10,220	$13	$1	
Number of Bills	CNB	134,940	123,720	9,012.00	1,284.00	24.00	888.00	12
Number of Devices	CDEV					2,680		
Number of Connections (Unmetered)	CCON	2,754				2,680	74	
Total Number of Customers	CCA	11,171	10,310	751	107	2		1
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	11,311	10,310	751	108	142		
Line Transformer Customer Base	CCLT	11,300	10,310	751	97	142		
Secondary Customer Base	CCS	11,167	10,310	751	106			
Weighted - Services	CWCS	12,668	10,310	2,357	-	-	-	-
Weighted Meter -Capital	CWMC	2,113,809	1,435,235	265,730	412,844	-	-	-
Weighted Meter Reading	CWMR	105,841	10,310	751	94,780	-	-	-
Weighted Bills	CWNB	155,548	123,720	9,183	12,346	361	9,938	0

Bad Debt Data

Historic Year:	2012	6,648	6,826	-179				
Historic Year:	2013	16,969	15,853	1,117				
Historic Year:	2014	8,391	5,370	3,021				
Three-year average		**10,669**	**9,350**	**1,320**	**-**	**-**	**-**	**-**

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0072

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	9	10
Customer Classes		Total	Residential	GS <50	General Service 50 to 4,999 KW	Street Light	Unmetered Scattered Load	Embedded Distributor
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	38,489	20,860	5,444	12,144		40	
Bulk Delivery CP	BCP1	38,489	20,860	5,444	12,144		40	
Total Sytem CP	DCP1	38,489	20,860	5,444	12,144		40	
4 CP								
Transformation CP	TCP4	142,133	78,599	20,771	42,605		159	
Bulk Delivery CP	BCP4	142,133	78,599	20,771	42,605		159	
Total Sytem CP	DCP4	142,133	78,599	20,771	42,605		159	
12 CP								
Transformation CP	TCP12	361,818	193,403	46,500	119,450	1,953	512	
Bulk Delivery CP	BCP12	361,818	193,403	46,500	119,450	1,953	512	
Total Sytem CP	DCP12	361,818	193,403	46,500	119,450	1,953	512	
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	41,788	22,438	5,913	13,096	281	59	
Primary NCP	PNCP1	41,788	22,438	5,913	13,096	281	59	
Line Transformer NCP	LTNCP1	40,451	22,438	5,913	11,759	281	59	
Secondary NCP	SNCP1	41,545	22,438	5,913	12,853	281	59	
4 NCP								
Classification NCP from Load Data Provider	DNCP4	151,663	80,458	21,841	48,054	1,107	202	
Primary NCP	PNCP4	151,663	80,458	21,841	48,054	1,107	202	
Line Transformer NCP	LTNCP4	146,755	80,458	21,841	43,147	1,107	202	
Secondary NCP	SNCP4	150,771	80,458	21,841	47,162	1,107	202	
12 NCP								
Classification NCP from Load Data Provider	DNCP12	382,217	199,074	48,787	130,602	3,220	534	
Primary NCP	PNCP12	382,217	199,074	48,787	130,602	3,220	534	
Line Transformer NCP	LTNCP12	368,879	199,074	48,787	117,264	3,220	534	
Secondary NCP	SNCP12	379,792	199,074	48,787	128,177	3,220	534	

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0072

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	9	10
Rate Base Assets		**Total**	**Residential**	**GS <50**	**General Service 50 to 4,999 KW**	**Street Light**	**Unmetered Scattered Load**	**Embedded Distributor**
crev	Distribution Revenue at Existing Rates	$4,401,305	$3,061,190	$486,791	$521,870	$86,669	$20,661	$224,125
mi	Miscellaneous Revenue (mi)	$301,588	$205,185	$26,343	$40,958	$9,196	$5,915	$13,992
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$4,702,894	$3,266,376	$513,134	$562,827	$95,864	$26,576	$238,117
	Factor required to recover deficiency (1 + D)	1.4253						
	Distribution Revenue at Status Quo Rates	$6,273,356	$4,363,237	$693,842	$743,842	$123,532	$29,449	$319,454
	Miscellaneous Revenue (mi)	$301,588	$205,185	$26,343	$40,958	$9,196	$5,915	$13,992
	Total Revenue at Status Quo Rates	$6,574,945	$4,568,422	$720,185	$784,799	$132,728	$35,364	$333,446
	Expenses							
di	Distribution Costs (di)	$1,350,982	$862,220	$173,072	$276,634	$35,878	$3,180	$0
cu	Customer Related Costs (cu)	$869,525	$625,891	$59,806	$139,880	$5,732	$38,214	$2
ad	General and Administration (ad)	$1,631,109	$1,036,778	$163,647	$291,765	$29,223	$28,064	$81,631
dep	Depreciation and Amortization (dep)	$909,131	$557,735	$110,586	$182,775	$17,362	$1,715	$38,958
INPUT	PILs (INPUT)	$60,458	$37,817	$7,580	$12,778	$1,343	$130	$810
INT	Interest	$547,832	$342,679	$68,684	$115,788	$12,166	$1,179	$7,335
	Total Expenses	$5,369,036	$3,463,120	$583,374	$1,019,620	$101,704	$72,483	$128,735
	Direct Allocation	$404,442	$0	$0	$0	$0	$0	$404,442
NI	Allocated Net Income (NI)	$801,467	$501,332	$100,483	$169,395	$17,799	$1,726	$10,731
	Revenue Requirement (includes NI)	$6,574,945	$3,964,452	$683,857	$1,189,015	$119,503	$74,208	$543,909
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$25,428,270	$16,245,734	$3,280,396	$5,305,168	$543,892	$53,079	$0
gp	General Plant - Gross	$2,912,288	$1,582,953	$317,772	$507,414	$55,536	$5,293	$443,319
accum dep	Accumulated Depreciation	($4,825,046)	($2,914,032)	($603,553)	($1,051,037)	($77,093)	($8,649)	($170,682)
co	Capital Contribution	($3,308,172)	($2,274,582)	($461,129)	($490,598)	($73,576)	($6,218)	($2,070)
	Total Net Plant	$20,207,339	$12,640,072	$2,533,486	$4,270,948	$448,759	$43,506	$270,568
	Directly Allocated Net Fixed Assets	$2,668,489	$0	$0	$0	$0	$0	$2,668,489
COP	Cost of Power (COP)	$23,822,037	$12,377,899	$2,504,742	$8,716,851	$172,395	$50,149	$0
	OM&A Expenses	$3,851,616	$2,524,889	$396,524	$708,279	$70,833	$69,458	$81,633
	Directly Allocated Expenses	$108,869	$0	$0	$0	$0	$0	$108,869
	Subtotal	*$27,782,522*	*$14,902,788*	*$2,901,266*	*$9,425,131*	*$243,228*	*$119,607*	*$190,502*
	Working Capital	$2,083,689	$1,117,709	$217,595	$706,885	$18,242	$8,971	$14,288
	Total Rate Base	$24,959,517	$13,757,781	$2,751,081	$4,977,833	$467,001	$52,477	$2,953,345
		Rate Base Input equals Output						
	Equity Component of Rate Base	$9,983,807	$5,503,113	$1,100,432	$1,991,133	$186,800	$20,991	$1,181,338
	Net Income on Allocated Assets	$801,467	$1,105,303	$136,811	($234,821)	$31,023	($37,119)	($199,732)
	Net Income on Direct Allocation Assets	$116,045	$0	$0	$0	$0	$0	$116,045
	Net Income	$917,512	$1,105,303	$136,811	($234,821)	$31,023	($37,119)	($83,686)

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0072

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

		1	2	3	7	9	10
Rate Base Assets	Total	Residential	GS <50	General Service 50 to 4,999 KW	Street Light	Unmetered Scattered Load	Embedded Distributor
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**115.23%**	**105.31%**	**66.00%**	**111.07%**	**47.66%**	61.31%
EXISTING REVENUE MINUS ALLOCATED COSTS	**($1,872,051)**	($698,076)	($170,723)	($626,188)	($23,639)	($47,632)	($305,792)
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**$0**	$603,970	$36,328	($404,216)	$13,225	($38,844)	($210,463)
RETURN ON EQUITY COMPONENT OF RATE BASE	9.19%	20.09%	12.43%	-11.79%	16.61%	-176.83%	-7.08%

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0072

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	9	10
	Residential	GS <50	General Service 50 to 4,999 KW	Street Light	Unmetered Scattered Load	Embedded Distributor
Customer Unit Cost per month - Avoided Cost	$5.59	$8.72	$135.50	$0.17	$39.39	$0.43
Customer Unit Cost per month - Directly Related	$8.93	$13.32	$213.63	$0.30	$66.09	$0.53
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$19.23	$28.53	$226.18	$3.38	$79.19	$0.53
Existing Approved Fixed Charge	$15.69	$26.67	$172.24	$2.13	$18.39	$0.00

APPENDIX 7-B – REFERENCE LETTERS

- Grimsby Power letter dated September 22, 2015
- Niagara Peninsula Energy Inc. Letter dated November 4, 2015
- Niagara Peninsula Energy Inc. submission from EB-2014-034

Grimsby Power Incorporated
231 Roberts Road
Grimsby, ON
L3M 5N2
PH: 905.945.5437 x 221
FX: 905.945.9933

Via Courier

September 22, 2015

Niagara Peninsula Energy Inc.
7447 Pin Oak Drive
Niagara Falls, ON
L2E 6S9

Attention: Mr. Brian Wilkie, President & CEO

Dear Brian,

Re: Customer Engagement Process Regarding GPI's Cost of Service Application for 2016

As you are aware Grimsby Power (GPI) agreed to consult with Niagara Peninsula Energy Inc. (NPEI) regarding the creation of an Embedded Distributor rate class in its response to Board Staff interrogatories in Board File No. EB-2014-0377 – GPI and Niagara West Transformer Corporation (NWTC) amalgamation proceeding. A meeting took place on June 11, 2015 at GPI with both GPI and NPEI representatives. A large part of the discussion in this meeting related to the rate implications for NPEI as GPI moves forward with its cost of service application for 2016 rates.

GPI is in the process of closing the amalgamation process and we are hopeful that this will be official October 1, 2015. After the amalgamation process is completed NPEI will become a customer of GPI.

In preparation for GPI's rate application submission and in the context of the Regional Planning requirements outlined by the Board, GPI would formally request NPEI to make known any load or generation requirements from the Niagara West MTS. This would include (but not limited to) the following aspects over the planning horizon of five years (2016 to 2020):

- A load forecast broken down into individual feeders if available (M2, M4 (partial), M5);
- A forecast of additional generation broken down into size (small, medium, large);
- Any infrastructure investments NPEI would like GPI to consider with respect to the operation of the station.

GPI is requesting that NPEI respond in writing. If you would like to meet to discuss your requirements we would be pleased to arrange a meeting. We look forward to your response.

Regards,

Doug Curtiss, P.Eng.
Chief Executive Officer
Grimsby Power Inc.

niagara
peninsula
energy

Our energy
works
for you.

Head Office:
7447 Pin Oak Drive
Box 120
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Toll Free: 1-877-270-3938
F: 905-356-0118
E: info@npei.ca
www.npei.ca

November 4, 2015

NOV - 5 2015

Grimsby Power Incorporated
231 Roberts Road
Grimsby, ON L3M 5N2

Attention: Mr. Doug Curtiss, P. Eng., Chief Executive Officer

Dear Doug:

Re: Grimsby Power Inc. Cost of Service Application for 2016

I am responding to your September 22, 2015 letter to Mr. Wilkie seeking input into your cost of service rate application for 2016.

Niagara Peninsula Energy Inc. has included responses to each of the issues for which you sought input in the attached. At this time we would ask if you could provide your anticipated time of filing the application?

If there are any questions, please contact the undersigned.

Yours truly,

Paul Blythin
Director of Regulatory Affairs
Paul.Blythin@npei.ca
905-356-2681 ext 6064

cc: S. Stoll

B. Wilkie

24178687.1

November 4, 2015

RE: Customer Engagement Process Regarding GPI's Cost of Service Application for 2016

Niagara Peninsula Energy Inc. ("NPEI") is in receipt of a letter from Grimsby Power Incorporated ("GPI"), regarding GPI's Customer Engagement process for its 2016 Cost of Service ("COS") Rate Application.

The letter states *"In preparation for GPI's rate application submission and in the context of the Regional Planning requirements outlined by the Board, GPI would formally request NPEI to make known any load or generation requirements from the Niagara West MTS. This would include (but not limited to) the following aspects over the planning horizon of five years (2016 to 2020):*

- *A load forecast broken down into individual feeders if available (M2, M4 (partial), M5);*
- *A forecast of additional generation broken down into size (small, medium, large);*
- *Any infrastructure investments NPEI would like GPI to consider with respect to the operation of the station."*

Response

Load Forecast

The table below shows NPEI's forecast peak demand on the Niagara West station for 2016 to 2020. This is based on the last 12 months of actual data, and incorporates a 1% per year increase for load growth.

NWTS - NPEI Portion
Peak Demand Forecast (MW)
(Excludes the impact of HAF Wind)

	2016	2017	2018	2019	2020
Jan	11.2	11.3	11.4	11.6	11.7
Feb	15.4	15.5	15.7	15.8	16.0
Mar	12.1	12.2	12.4	12.5	12.6
Apr	9.4	9.5	9.6	9.7	9.8
May	10.7	10.8	10.9	11.0	11.1
Jun	10.8	10.9	11.0	11.1	11.2
Jul	12.6	12.7	12.8	12.9	13.1
Aug	13.2	13.3	13.5	13.6	13.7
Sep	13.1	13.3	13.4	13.5	13.7
Oct	11.3	11.5	11.6	11.7	11.8
Nov	10.6	10.7	10.8	10.9	11.0
Dec	12.8	12.9	13.0	13.2	13.3
Average	**11.9**	**12.0**	**12.2**	**12.3**	**12.4**

Note: the above forecast does not include the impact, if any, of the HAF Wind facility on the peak demand.

As GPI is aware, the HAF Wind generation facility is connected to NPEI's M2 circuit, and has a peak capacity of 9.8 MW. Since HAF Wind began operating in June 2014, NPEI's actual peak demand on the Niagara West Station during certain months has been lower than it otherwise would have been. However, due to the intermittent nature of the generation, NPEI is not able to forecast whether the HAF Wind facility will impact the monthly peak demand in any particular month. NPEI has calculated the average generation output for the wind facility to be approximately 3.5 MW.

NPEI is not aware at this time of any significant proposed additional generation facilities that would impact NPEI's peak demand on the Niagara West Station. Currently, NPEI has 38 MicroFIT (less than 10kW) generators and one 250 kW FIT generator connected to its Niagara West circuits, for a total of 615 kW of capacity. NPEI forecasts 1 additional 250 kW FIT and 18 additional MicroFITs (less than 10 kW each) to be connected in 2016. NPEI is not able to provide any forecast of other generators at this time.

NPEI is not able to provide the load forecast by feeder.

Other

NPEI was an intervenor of record in the Niagara West Transformation Corporation ("NWTC") and GPI amalgamation proceeding (EB-2014-0344).

NPEI reiterates the positions taken in its Submission in the EB-2014-0344 proceeding[1], including but not limited the following:

"NPEI is the meter market participant for the transformer station. Currently settlement is achieved viable the wholesale market. It is unclear what changes to the current settlement process will result from the proposal. Certainly no financial impacts have been specifically identified regarding the settlement process and so the Applicant should not be able to increase costs to customers that would result from such."[2]

"The evidence shows NPEI utilizes 2 of the potential 6 feeders and has historically used approximately 44% of the demand through the TS. The capacity assigned to NPEI is 18.4 MW of 45.8 MW or 40%. Further, the NPEI circuit exiting from the TS is connected to a new generation facility that has been in operation less than 12 months. As such, it is reasonable to conclude that NPEI will not increase its use of the TS and one could conclude it would be expected that the operation of the HAF Wind Farm will further reduce the energy taken by NPEI through this station"[3]

"NPEI has significantly more customers than GPI and, according to the Applicants, all of NPEI's customers will see an increase in their rates following the transaction in the order of 25%. NPEI would note that no specific cost drivers for the rate increase were identified but rather it is presumed from the evidence that the proposed increase that GPI will seek is based upon achieving specific financial performance metrics in accordance with Board approval and industry norms. However, if the rate increase is attributable to any cost - such as capital deployment resulting from the proposed amalgamation - then such costs should have been identified as part of the "no-harm test". The absence of such costs in the tests would lead to the conclusion that no such costs will result or no such costs will be passed along to ratepayers"[4]

"A 25% increase will change the current rate of NPEI from $1.77/kW to approximately $2.20/kW which is more than the Hydro One rate incurred by NPEI. Such a change would require the issue of mitigation to be considered in the 2016 COS hearing. If such a situation as is being proposed by the Applicants is to come into existence, NPEI, would be obligated to shift load away from the TS to Hydro One delivery points to reduce the costs to its customers. This would

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[1] EB-2014-0344, Submissions of Niagara Peninsula Energy Inc., filed February 20, 2015.
[2] EB-2014-0344, Submissions of Niagara Peninsula Energy Inc., paragraph 6.
[3] EB-2014-0344, Submissions of Niagara Peninsula Energy Inc., paragraph 7.
[4] EB-2014-0344, Submissions of Niagara Peninsula Energy Inc., paragraph 15.

render the Applicants' proposed 50:50 allocation even further astray from a proper allocation of costs and benefits"[5]

Given NPEI's load forecast and assigned capacity, NPEI is not requesting GPI to consider any infrastructure investments with respect to capacity at this time.

As noted above, NPEI is currently the metered market participant for the Niagara West Station. NPEI is not aware of what proposals GPI may have in relation to the market participant and metering arrangements, and therefore can provide no comments on this issue at this time.

[5] EB-2014-0344, Submissions of Niagara Peninsula Energy Inc., paragraph 16.

AIRD & BERLIS LLP

Barristers and Solicitors

Scott Stoll
Direct: 416.865.4703
E-mail: sstoll@airdberlis.com

February 20, 2015

RESS, EMAIL AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Application for approval of the amalgamation of Niagara West Transformation Corporation ("NWTC") and Grimsby Power Inc. ("GPI") under subsection 86(1)(c) of the *Ontario Energy Board Act*, 1998.
Board File No.: EB-2014-0344
Our File No. 123132

We are counsel to the Intervenor, Niagara Peninsula Energy Inc. (**"NPEI"**), in the above noted proceeding.

Pursuant to Procedural Order No. 2 dated February 10, 2015, please find attached the Submissions of NPEI.

If there are any questions, please contact the undersigned.

Yours very truly,

AIRD & BERLIS LLP

Scott Stoll

Scott Stoll

SAS/bm

Attach

cc: Applicant, GPI *(via email)*
Applicant, NWTC *(via email)*
Mark Rodger, Counsel to the Applicants GPI and NWTC *(via email)*
Brian Wilkie, Niagara Peninsula Energy Inc. *(via email)*

21767287.1

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O. 1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Grimsby Power Inc. and Niagara West Transformation Corporation under section 86(1)(c) of the *Ontario Energy Board Act*, 1998 for leave to amalgamate and continue as Grimsby Power Inc.;

AND IN THE MATTER OF an application by Grimsby Power Inc. and Niagara West Transformation Corporation under section 84 of the *Ontario Energy Board Act*, 1998 for a determination that the Niagara West Transformation Corporation transmission system which will become part of the amalgamated distributor, is deemed to be a distribution system;

AND IN THE MATTER OF an application by Grimsby Power Inc. and Niagara West Transformation Corporation under section 78 of the *Ontario Energy Board Act*, 1998 seeking approval for Grimsby Power Inc. to charge Niagara Peninsula Energy Inc., an electricity distributor that will be embedded within the amalgamated distributor, the Board-approved Niagara West Transformation Corporation's transmission rate as a distribution rate from the completion of the proposed transaction until the amalgamated distributor's next rebasing;

AND IN THE MATTER OF an application by Grimsby Power Inc. and Niagara West Transformation Corporation under section 78 of the *Ontario Energy Board Act*, 1998 seeking approval for the amalgamated distributor to charge its customers other than Niagara Peninsula Energy Inc. a retail transmission rate that includes the incremental contribution of the Niagara West Transformation transformer station assets as if they were part of the revenue requirement until the amalgamated distributor's next rebasing;

AND IN THE MATTER OF an application by Grimsby Power Inc. and Niagara West Transformation Corporation under section 77(5) of the *Ontario Energy Board Act*, 1998 for cancellation of Niagara West Transformation Corporation's transmission licence, upon completion of the proposed transaction.

SUBMISSIONS OF NIAGARA PENINSULA ENERGY INC. ("NPEI")

PART I. Introduction

1. These are the submissions of NPEI in respect of the proposed amalgamation of Niagara West Transformation Corporation ("**NWTC**") and Grimsby Power Inc. ("**GPI**", together the "**Applicants**"). NPEI submits there are deficiencies in the methodology used by the Applicants for the "no harm test". As such, based upon the current evidence NPEI cannot support the proposed amalgamation at this time. However, if the Board approves the amalgamation and relief sought, NPEI requests the Board order:

(a) GPI to expressly deal with a proper cost allocation study and rate mitigation in the 2016 Cost of Service Application in the design of any rate for NPEI;

(b) GPI to obtain the written consent of NPEI prior to GPI seeking any amendment to its distribution license that would permit GPI to distribute electricity to any additional customers within the NPEI service territory; and

(c) GPI be prevented from passing along to customers any costs directly related or attributable to the proposed amalgamation regardless of whether the costs are transactional or necessary changes to the physical elements of the Transformer Station.

2. NWTC has one physical asset – the Niagara West Transformer Station ("**TS**"). There are other assets, such as non-capital tax losses, in addition to the TS. NPEI understands the

amalgamation, if approved, would result in GPI obtaining the rights and obligations that were previously held by NWTC. The current financial situation for NWTC was not sustainable.[1]

3. The Applicants have indicated that while there may be some savings, approximately $35,000,[2] that the Applicants have forecasted a 25.3% increase in rates following the 2016 Cost of Service ("**COS**") rate hearing.[3] Further, the 2016 COS is intended to create a situation where NPEI is the only customer in a new Embedded Distributor rate class.

4. The physical location of the TS in the distribution territory of NPEI, a transmitter that relies exclusively upon third party service providers, an acquiring utility that has does not have transmission assets or in-house technical capabilities, that a regulated transmission utility had significant prolonged financial concerns, and the proposed massive increase in costs to customers makes this a unique situation.

Technical or Operational Issues

5. The TS is located within NPEI's service territory.[4] NPEI is concerned the existence of a distribution asset will be used to justify future incursions into NPEI's service territory. NPEI is opposed to any such incursions and requests the Board make it abundantly clear that the change of the TS to a distribution asset should not be seen as a beachhead for expansion by GPI.

6. NPEI is the meter market participant for the transformer station. Currently settlement is achieved viable the wholesale market. It is unclear what changes to the current settlement

[1] EB-2014-0344, Application, page 6, paragraph 17, lines 13 to 17. NWTC has not recovered return on equity or long term debt.
[2] EB-2014-0344, Application, page 5, paragraph 13, line 17.
[3] EB-2014-0344, Application, page 6, paragraph 18, line 18.
[4] EB-2014-0344, Response to Interrogatory, Board Staff 1.1 and NPEI 1(b).

process will result from the proposal. Certainly no financial impacts have been specifically identified regarding the settlement process and so the Applicant should not be able to increase costs to customers that would result from such.

7. The evidence shows NPEI utilizes 2 of the potential 6 feeders and has historically used approximately 44% of the demand through the TS.[5] The capacity assigned to NPEI is 18.4 MW of 45.8 MW or 40%.[6] Further, the NPEI circuit exiting from the TS is connected to a new generation facility that has been in operation less than 12 months.[7] As such, it is reasonable to conclude that NPEI will not increase its use of the TS and one could conclude it would be expected that the operation of the HAF Wind Farm will further reduce the energy taken by NPEI through this station.

8. The Applicants have indicated there will be no change in the service quality or service providers as a result of the amalgamation.[8]

9. Based upon this commitment to maintain current service providers and reliability, NPEI does not have further comments regarding the reliability or operational issues associated with the TS under the proposed transaction.

Financial Issues

10. NWTC filed its financial statements with the Application.[9] It is clear the income from operations, $28,771,[10] the reduction in equity to approximately 12%[11], is not sufficient for a sustainable business. Further, NWTC has non-capital losses in the amount of $657,944 which

[5] EB-2014-0344, Response to Interrogatory, NPEI 1(d).
[6] EB-2014-0344, Response to Interrogatory, NPEI 1(e).
[7] EB-2014-0344, Response to Interrogatory, NPEI 1(j).
[8] EB-2014-0344, Application, page 7, paragraph 20, lines 4 to 9.
[9] EB-2014-0344, Attachment 1.4.3(a) and (b).
[10] EB-2014-0344, Attachment 1.4.3(a), page 4, Income from Operations.
[11] EB-2014-0344, Attachment 1.4.3(a), page 2. Shareholder Equity $925,848 divided by Total Assets $7,134,564.

could be used to offset future PILs payments.[12] As such, the current cost structure is not appropriate to use for the base of comparisons. NWTC should have considered alternatives to maximize the benefit to its customers in conducting the “no-harm test”.

11. The Applicants have based their analysis for the “no-harm test” on the fact there will be certain activities that will no longer be carried out by NWTC following the amalgamation – thereby creating a “savings” of $35,000. [13] The analysis is flawed because it does not properly allocate future costs and benefits, results in significantly higher costs and risk for a greater number of customers; and did not consider the fact the current situation was unsustainable. Further, it does not indicate how the non-capital losses will be used – whether to the benefit of the ratepayer or to the shareholder. The shareholder of GPI should not benefit in such a situation.

12. First, the analysis is based upon the supposition of a 50:50 sharing of costs and benefits which NPEI believes is inappropriate. Currently, the TS has two circuits serving each of NPEI and GPI and two spare circuits. As noted above, demand usage, allocation and other factors confirm allocating 50% to NPEI is not supportable using any criteria.

13. The Applicants seek to transition the current rate applied to NPEI from a transmission rate to a distribution rate until GPI completes the 2016 COS rebasing. In the circumstances this is a reasonable approach if the Board approves the Application.

14. The Applicants have identified modest savings, $35,000[14] annually, as a result of the proposed amalgamation. However, the Applicants have indicated that it is their intent to create a new Embedded Distributor rate class as part of GPI’s 2016 COS hearing. As a single class, in

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[12] EB-2014-0344, Attachment 1.4.3(a), page 11, Note 8.
[13] EB-2014-0344, Application, page 5, paragraph 13, line 17.
[14] EB-2014-0344, Application, page 5, paragraph 13, line 17.

contrast to GPI allocating across a number of classes, NPEI is concerned that it could be over-allocated future capital costs related to the TS and subject to further significant cost increases.

15. NPEI has significantly more customers than GPI[15] and, according to the Applicants, all of NPEI's customers will see an increase in their rates following the transaction in the order of 25%. NPEI would note that no specific cost drivers for the rate increase were identified but rather it is presumed from the evidence that the proposed increase that GPI will seek is based upon achieving specific financial performance metrics in accordance with Board approval and industry norms. However, if the rate increase is attributable to any cost – such as capital deployment resulting from the proposed amalgamation – then such costs should have been identified as part of the "no-harm test". The absence of such costs in the tests would lead to the conclusion that no such costs will result or no such costs will be passed along to ratepayers.

16. A 25% increase will change the current rate of NPEI from $1.77/kW to approximately $2.20/kW which is more than the Hydro One rate incurred by NPEI. Such a change would require the issue of mitigation to be considered in the 2016 COS hearing. If such a situation as is being proposed by the Applicants is to come into existence, NPEI, would be obligated to shift load away from the TS to Hydro One delivery points to reduce the costs to its customers. This would render the Applicants' proposed 50:50 allocation even further astray from a proper allocation of costs and benefits.

17. Given there is no basis for the purported 50:50 allocation – NPEI is of the view the analysis is fatally flawed and cannot be relied upon by the Board to grant the amalgamation. However, if the amalgamation is approved by the Board, NPEI would request that the Board

[15] EB-2014-0344, Response to NPEI Interrogatory 1(p).

order GPI to specifically prepare a detailed cost allocation study and consider rate mitigation in the 2016 COS.

18. Next, NPEI would make the submission that 1 year horizon for consideration of the "no harm test" is not appropriate. If the current rate situation is not sustainable, then the Applicants should have provided a clear base of the future of NWTC for comparison purposes. Clearly, this is distinguishable from situations where acquisitions were resulting in promises of lower rates for 5 year or extended periods time.

19. It is clear beyond year 1 that costs will increase, presumably for all customers – GPI's existing customers and NPEI. As such, the result is not "no-harm" for NPEI.

20. It appears the proposed amalgamation was the result of an uneconomically sustainable situation. Therefore, something had to be done. However, there was no consideration of any other options which may have provided significantly more benefits. The Board, in its Report of the Board - *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*[16] directed distributors to consider how value for ratepayers is being provided in the decisions that are being made. Specifically, the Board stated the "*renewed regulatory framework for electricity is designed to support cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable and provides value for customers.*"[17] It does not appear that the proposed amalgamation has provided value to the customer – especially NPEI.

21. For the above reasons, NPEI is of the view the current evidence is insufficient to grant the Application.

[16] Ontario Energy Board, October 18, 2012, page 1.
[17] Ontario Energy Board, October 18, 2012, page 1.

Conclusions

22. Given the unique situation, the physical location of the transformer station and the minimal savings, it is disappointing that other options were not considered and NPEI was not provided an opportunity to consider and have input into the future of the transformer station. It would appear that while savings may result in respect of the proposed transaction versus a status quo, it is not apparent that there was any attempt to obtain the best result for ratepayers. The disappointment is reinforced with the general concerns ratepayers have regarding concerns with costs and the Board should be encouraging regulated entities in considering these types of situations to consider ratepayer impact.

23. Given the above comments, NPEI would request that if the Board approves this Application that the Board include certain conditions in its order as provided above.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Dated: February 20, 2015	**AIRD & BERLIS LLP** Barristers and Solicitors Brookfield Place 181 Bay Street, Suite 1800 Toronto, Ontario M5J 2T9 Scott Stoll ______________________ **Scott Stoll** (LSUC #45822G) Tel: 416.865.4703 Fax: 416.863.1515 Counsel for Niagara Peninsula Energy Inc. ("NPEI").