Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5680
Cell: (416) 568-5534
frank.dandrea@HydroOne.com

Frank D'Andrea
Vice President, Regulatory Affairs & Chief Risk Officer

BY COURIER

December 20, 2018

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

Dear Ms. Walli,

EB-2018-0218 - Hydro One Sault St. Marie LP – Revised Interrogatory Response

On December 7, 2018, Hydro One Sault St. Marie LP ("HOSSM") filed the interrogatory responses with the Ontario Energy Board ("OEB"). HOSSM had redacted the names and billing determinants of its customers in the Load Forecast Report attached to its response to OEB Staff Interrogatory #4. In the OEB's Decision on Confidentiality and Procedural Order No. 3 ("P.O. #3") in this proceeding, the OEB determined that the data related to HOSSM's electricity distributor customers should be unredacted as that information is publicly available.

In accordance with P.O. #3, HOSSM has provided a revised copy of Attachment 1 to OEB staff Interrogatory #4 showing all data in the Load Forecast Report relating to HOSSM's licensed electricity distributor customers as unredacted. The names and billing determinants of HOSSM's other directly connected customers remain redacted, consistent with the OEB's findings.

An electronic copy of the evidence has been submitted using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Weather Normalized Transmission System Load Forecast: 2017-2018

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Great Lakes Power Transmission

01/06/2016

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1 INTRODUCTION

This report outlines the results and methodology used to derive the weather normal load forecast prepared for use in the Cost of Service application for 2017-2018 rates for Great Lakes Power Transmission ("GLP Transmission").

GLP Transmission has two connected LDC customers, as well as four large and a few smaller directly connected end use customers. The LDC customers are weather sensitive while the other customers load is the result of situations specific to those customers. As a result, a weather normalized regression approach is used to forecast the two LDC customers, while other customers are forecasted based on historical average consumption. The 4 large are forecasted individually, and the remaining customers are forecasted as a group.

The regression equations used to normalize and forecast GLP Transmission's weather sensitive load use monthly heating degree days and cooling degree days as measured at Environment Canada's Sault Ste Marie A station to take into account temperature sensitivity. This location is relatively central to the PUC distribution customer, is at one end of the Algoma Power Inc. (API) service territory, and is the only nearby weather station for API. Environment Canada defines heating degree days and cooling degree days as the difference between the average daily temperature and 18°C for each day (below for heating, above for cooling).

Overall economic activity also impacts energy consumption. In order to measure the impact of change in economic activity on energy consumption, a data series must be chosen which represents, as much as possible, that of the service territory. There is no known agency that publishes monthly economic accounts on a regional basis for Ontario. Regional employment levels are available, but the nearest region for which data is available is Sudbury. Given that income from employment and labour sources accounts for the largest portion of GDP on an income basis, and a study by Statistics Canada that has indicated that "turning points in the growth of output and employment appear to have been virtually the same over the past three decades"[1], employment has been chosen as the economic variable to consider for the analysis. Specifically, the monthly full-time employment level for Ontario, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series Table 282-0135) is used.

In addition to the weather and economic variables, a time trend variable, number of days and number of working days in each month, and month of year variables, have been examined for all rate classes. More details on the individual LDC specifications are provided in the next section.

In order to select explanatory variables which more accurately forecast each LDC customer, the two LDC customers were forecasted separately. GLP Transmission does not have access to energy consumption data. In order to capture the relationship between degree days, other explanatory variables, and electric use, a proxy for Energy was used. GLP Transmission has data on hourly peak MW per delivery

[1] Philip Cross, "Cyclical changes in output and employment," *Canadian Economic Observer*, May 2009.

point, which responds to explanatory variables on the same way that MWh would, and is used as MWh would be.

Finally, transmission connected customers are billed on charge determinants for Network (NW), Connection (CN), and Transformation (TRN). An annual ratio of MWh as described above to charge determinants, is calculated using actual observations for each historical year and applied to the normalized MWh to derive weather normalized charge determinants. For forecast values, the average of the ratios from 2011-2015 applied.

1.1 Summarized Results

The following table summarizes the charge determinant forecasts for 2017-2018. The calculations can be found as follows:

Normal Forecast

NW Charge Determinant	2014 Actual	2015 Actual	2015 Normalized	2016 Forecast	2017 Forecast	2018 Forecast
API	383,401	367,735	369,806	370,768	369,806	369,806
PUC	1,201,907	1,152,823	1,117,530	1,082,991	1,041,941	1,004,147
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	3,371,301	3,181,059	3,196,432	3,162,855	3,120,843	3,083,048

Table 1 NW Forecast

CN Charge Determinant	2014 Actual	2015 Actual	2015 Normalized	2016 Forecast	2017 Forecast	2018 Forecast
API	207,943	206,990	209,140	209,684	209,140	209,140
PUC	0	0	0	0	0	0
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	2,574,147	2,553,111	2,618,518	2,619,062	2,618,518	2,618,518

Table 2 CN Forecast

TRN Charge Determinant	2014 Actual	2015 Actual	2015 Normalized	2016 Forecast	2017 Forecast	2018 Forecast
API	434,724	417,212	421,882	422,979	421,882	421,882
PUC	0	0	0	0	0	0
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	448,556	469,939	484,506	485,603	484,506	484,506

Table 1 TRN Forecast

The following table summarizes 2017-2018 CDM Load Forecast kW adjustment. Details for this calculation can be found at the end of Schedule 6 of this report.

CDM Adjusted 2017

NW Charge Determinant	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
API	369,806	5,167	364,639
PUC	1,041,941	19,322	1,022,619
[redacted]	[redacted]	[redacted]	[redacted]
Total	3,120,843	24,490	3,096,353

Table 4 2017 CDM Adjusted NW Forecast

CN Charge Determinant	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
API	209,140	2,922	206,217
PUC	0	0	0
[redacted]	[redacted]	[redacted]	[redacted]
Total	2,618,518	2,922	2,615,596

Table 5 2017 CDM Adjusted CN Forecast

TRN Charge Determinant	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
API	421,882	5,895	415,987
PUC	0	0	0
[redacted]	[redacted]	[redacted]	[redacted]
Total	484,506	5,895	478,611

Table 6 2017 CDM Adjusted TRN Forecast

CDM Adjusted 2018

NW Charge Determinant	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
API	369,806	7,751	362,055
PUC	1,0 [redacted]	27,93 [redacted]	9 [redacted]
[redacted]	[redacted]	[redacted]	[redacted]
Total	3, [redacted]	35,68 [redacted]	3,0 [redacted]

Table 7 2018 CDM Adjusted NW Forecast

CN Charge Determinant	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
API	209,140	4,383	204,756
PUC	0	0	0
[redacted]	[redacted]	[redacted]	[redacted]
Total	2,618,518	4,383	2,614,135

Table 8 2018 CDM Adjusted CN Forecast

TRN Charge Determinant	2018 Weather Normal Forecast	CDM Adjustment	2018 CDM Adjusted Forecast
API	421,882	8,842	413,039
PUC	0	0	0
[redacted]	[redacted]	[redacted]	[redacted]
Total	484,506	8,842	475,663

Table 9 2018 CDM Adjusted TRN Forecast

Summarized CDM Adjusted Load Forecast

Charge Determinant	2017 CDM Adjusted Forecast	2018 CDM Adjusted Forecast
NW	3,096,353	3,047,365
CN	2,615,596	2,614,135
TRN	478,611	475,663

Table 10 2017-2018 CDM Adjusted Charge Determinant Forecast

2 LDC Specific MWh Regression

2.1 Algoma Power Inc.

For API consumption the equation was estimated using 60 observations from 2011:01-2015:12.

Heating and Cooling Degree days were used, as measured at the Sault Ste. Marie A weather station as described in the introduction. An indicator of the number of calendar days in the month, MonthDays was used.

Binary variables representing spring months' and fall months' consumption have also been included. In recent LDC cost-of-service filings in which Elenchus has participated, both Board Staff and intervenors have requested that separate variables for spring and fall be included for testing. The spring variable designates the months of March, April, May, and June as spring months while the fall variable designates the months of September, October and November as fall months. Therefore, the variables take a value of 1 in the indicated months and a value of 0 in all other months.

Several other variables were examined, and found to not show a statistically significant relationship to energy usage. Those included an economic indicator of full time employment, the number of working days in the month, and a trend variable.

The following table outlines the resulting regression model:

Model 4: OLS, using observations 2011:01-2015:12 (T = 60)
Dependent variable: ALGOMAPI_TN_MWh

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	−2822.28	3269.28	−0.8633	0.3918	
HDD	10.71	0.439532	24.3668	<0.0001	***
CDD	15.3822	8.66549	1.7751	0.0815	*
Spring	−1203.56	233.987	−5.1437	<0.0001	***
Fall	−866.618	261.186	−3.3180	0.0016	***
MonthDays	559.115	106.189	5.2653	<0.0001	***

Mean dependent var	17935.81	S.D. dependent var	3205.987
Sum squared resid	22969747	S.E. of regression	652.2006
R-squared	0.962123	Adjusted R-squared	0.958615
F(5, 54)	274.3302	P-value(F)	4.41e-37
Log-likelihood	−470.7966	Akaike criterion	953.5933
Schwarz criterion	966.1593	Hannan-Quinn	958.5085
rho	0.414128	Durbin-Watson	1.168430
Theil's U	0.31701		

Table 11 API Regression Model

Using the above model coefficients we derive the following:

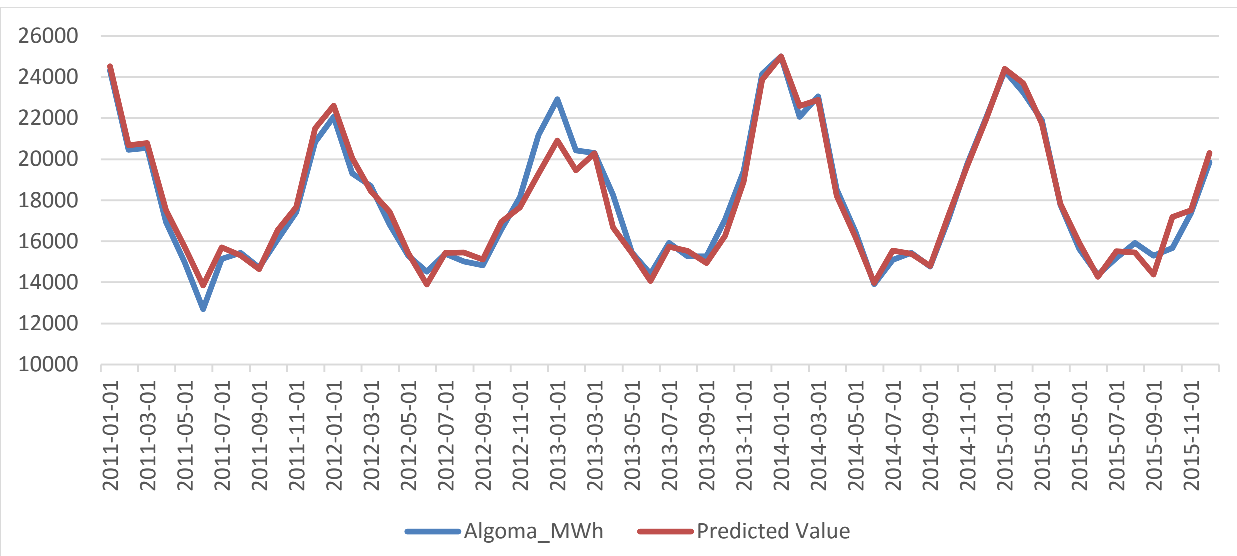

Figure 1 API Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.3%. Annual errors are calculated as the model is used to derive annual forecasts. However, in proceedings Elenchus has been involved in, intervenors and Board Staff have requested MAPE calculated on a monthly basis and this has been provided as well. The MAPE calculated monthly over the period is 2.5%.

	API_MWh		Absolute Error
Year	Actual	Predicted	(%)
2011	209,628	214,495	2.3%
2012	207,862	207,776	0.0%
2013	218,899	212,125	3.1%
2014	223,178	223,525	0.2%
2015	216,582	218,226	0.8%
Mean Absolute Percentage of Error (Annual)			1.3%
Mean Absolute Percentage of Error (Monthly)			2.5%

Table 12 API model error

2.2 PUC

For PUC, the regression equation was also estimated using 60 observations from 2011:01-2015:12.

Heating degree days was used, as measured at the Sault Ste. Marie A weather station as described in the introduction. An indicator of the number of calendar days in the month, MonthDays was used. A Trend variable was also used, indicating 1 in January 2011, and incrementing once each month, reaching 60 in the last month of the regression, December 2015.

Binary variables representing spring months' consumption was also included. The spring variable designates the months of March, April, May, and June as spring months. Specific dummy variables for September, October, and December were used in lieu of a Fall variable as these exhibited a more statistically significant relationship to energy use. The variables take a value of 1 in the indicated months and a value of 0 in all other months.

Several other variables were examined, and found to not show a statistically significant relationship to energy usage. Those included an economic indicator of full time employment, the number of working days in the month, and the number of cooling degree days.

The following table outlines the resulting regression model:

Model 21: OLS, using observations 2011:01-2015:12 (T = 60)
Dependent variable: PUC_TN_MWh

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	−8802.59	17456.3	−0.5043	0.6162	
HDD	40.8551	1.59573	25.6027	<0.0001	***
Trend	−143.494	24.0395	−5.9691	<0.0001	***
Sept	−4545.5	1655.33	−2.7460	0.0083	***
Oct	−4129.94	1621.48	−2.5470	0.0139	**
Dec	3845.56	1689.19	2.2766	0.0270	**
MonthDays	1779.79	568.626	3.1300	0.0029	***
Spring	−6826.29	970.724	−7.0322	<0.0001	***

Mean dependent var	54464.47	S.D. dependent var	13785.80
Sum squared resid	5.30e+08	S.E. of regression	3193.964
R-squared	0.952691	Adjusted R-squared	0.946322
F(7, 52)	149.5924	P-value(F)	3.84e-32
Log-likelihood	−564.9844	Akaike criterion	1145.969
Schwarz criterion	1162.723	Hannan-Quinn	1152.522
rho	0.340290	Durbin-Watson	1.315827
Theil's U	0.37995		

Table 13 PUC Regression Model

Using the above model coefficients we derive the following:

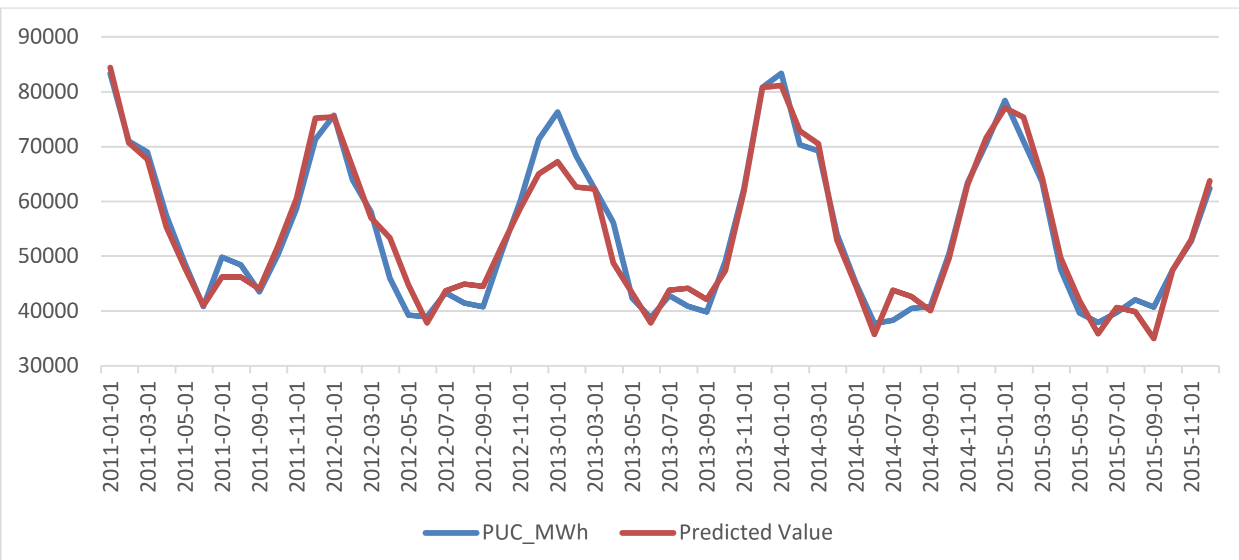

Figure 2 PUC Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.2%. Annual errors are calculated as the model is used to derive annual forecasts. However, in recent proceedings Elenchus has been involved in, intervenors and Board Staff have requested MAPE calculated on a monthly basis and this has been provided as well. The MAPE calculated monthly over the period is 4.2%.

	PUC_MWh		Absolute
Year	Actual	Predicted	Error (%)
2011	692,261	690,948	0.2%
2012	629,433	643,031	2.2%
2013	659,677	641,819	2.7%
2014	663,550	668,339	0.7%
2015	622,946	623,731	0.1%
Mean Absolute Percentage of Error (Annual)			1.2%
Mean Absolute Percentage of Error (Monthly)			4.2%

Table 14 PUC model error

3 WEATHER NORMALIZATION

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells “average” out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. While there are several different approaches to determining an appropriate weather normal, GLP Transmission has adopted the most recent 10 year monthly degree day average as the definition of weather normal, which to our knowledge, is consistent with many LDCs load forecast filings for cost-of-service rebasing applications.

The table below displays the most recent 10 year average of heating degree days and cooling degree days as reported by Environment Canada for Sault Ste. Marie A, which is used as the weather station for GLP Transmission.

10 Year Average		HDD	CDD
Sault Ste Marie A	January	820.37	0
Sault Ste Marie A	February	774.93	0
Sault Ste Marie A	March	678.89	0
Sault Ste Marie A	April	419.9	0.02
Sault Ste Marie A	May	228.805	5.64
Sault Ste Marie A	June	96.81	13.745
Sault Ste Marie A	July	38.17	41.67
Sault Ste Marie A	August	41.65	33.97
Sault Ste Marie A	September	139.21	9.19
Sault Ste Marie A	October	313.64	0.36
Sault Ste Marie A	November	482.63	0
Sault Ste Marie A	December	688.15	0

Table 15 10 Year Average HDD and CDD

As part of the minimum distribution filing requirements the OEB has requested monthly degree days calculated using a trend based on 20 years. This is shown in the table below.

20 Year Trend		2017		2018	
		HDD	CDD	HDD	CDD
Sault Ste Marie A	January	817.44	0.00	814.38	0.00
Sault Ste Marie A	February	802.84	0.00	807.05	0.00
Sault Ste Marie A	March	686.19	0.00	685.82	0.00
Sault Ste Marie A	April	417.33	0.03	416.24	0.03
Sault Ste Marie A	May	217.98	5.96	215.85	6.19
Sault Ste Marie A	June	103.53	10.91	104.21	10.43
Sault Ste Marie A	July	35.88	43.23	35.42	43.35
Sault Ste Marie A	August	39.86	36.15	39.50	36.42
Sault Ste Marie A	September	137.63	9.75	138.29	9.48
Sault Ste Marie A	October	299.47	0.63	297.41	0.62
Sault Ste Marie A	November	472.43	0.00	470.92	0.00
Sault Ste Marie A	December	671.37	0.00	668.88	0.00

Table 16 20 Year Trend HDD and CDD

4 LDC SPECIFIC NORMALIZED FORECASTS

4.1 ALGOMA POWER INC.

Incorporating the forecast economic variables, 10-yr weather normal heating and cooling degree days, and calendar variables, the following weather corrected consumption and forecast values are calculated:

Year	API_MWh Actual	Annual Change	Normalized	Annual Change
2011	209,628		214,989	
2012	207,862	-0.8%	215,548	0.3%
2013	218,899	5.3%	214,989	-0.3%
2014	223,178	2.0%	214,989	0.0%
2015	216,582	-3.0%	214,989	0.0%
2016			215,548	0.3%
2017			214,989	-0.3%
2018			214,989	0.0%

Table 21 Actual vs Normalized API MWh

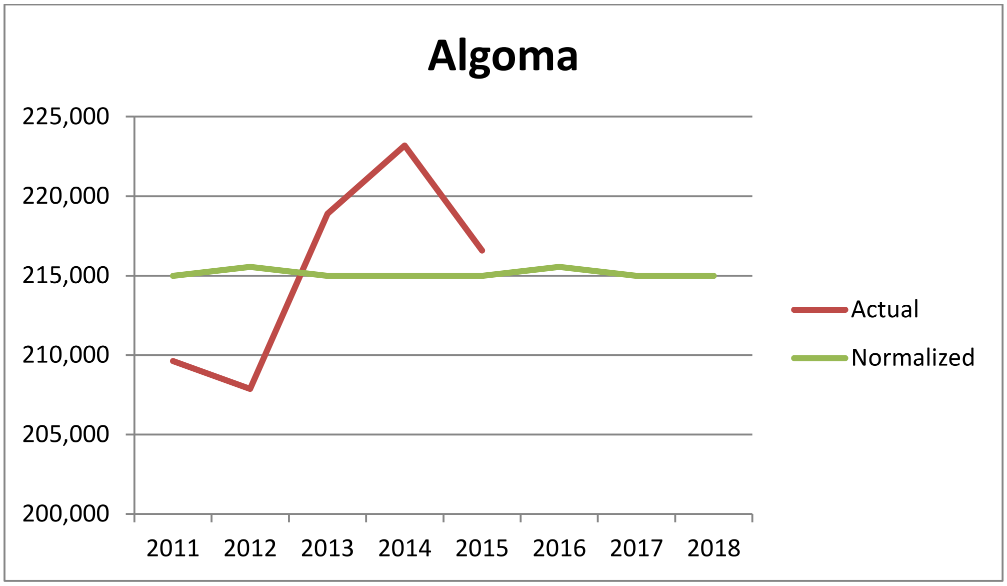

Figure 3 Actual vs Normalized API MWh

API is charged 3 billing determinants, all of which exhibit a relatively stable relationship with the summed hourly MW. A trend or step change in the relationship between the hourly MW and the billing determinants, could indicate a structural change over time. Since none was observed, a 5-year average of the ratio of billing determinant to hourly MW was used in each case.

				API			
Year	MWh Actual	NW Ratio	NW	CN Ratio	CN	TRN Ratio	TRN
	A	**C = B / A**	**B**	**E = D / A**	**D**	**G = F / A**	**F**
2011	209,628	1.7205	360,657	0.9819	205,844	1.9706	413,088
2012	207,862	1.7203	357,584	0.9853	204,802	1.9913	413,926
2013	218,899	1.7440	381,759	1.0093	220,930	1.9755	432,442
2014	223,178	1.7179	383,401	0.9317	207,943	1.9479	434,724
2015	216,582	1.6979	367,735	0.9557	206,990	1.9264	417,212
	MWh Normalized						
	H	**I = Avg (C)**	**J = H * I**	**K = Avg (E)**	**L = H * K**	**M = Avg (G)**	**N = H * M**
2015	214,989	1.7201	369,806	0.9728	209,140	1.9623	421,882
2016	215,548	1.7201	370,768	0.9728	209,684	1.9623	422,979
2017	214,989	1.7201	369,806	0.9728	209,140	1.9623	421,882
2018	214,989	1.7201	369,806	0.9728	209,140	1.9623	421,882

Table 22 API billing determinants

4.2 PUC

Year	PUC_MWh Actual	Annual Change	Normalized	Annual Change
2011	692,261		693,631	
2012	629,433	-9.1%	674,747	-2.7%
2013	659,677	4.8%	652,304	-3.3%
2014	663,550	0.6%	631,641	-3.2%
2015	622,946	-6.1%	610,978	-3.3%
2016			592,095	-3.1%
2017			569,652	-3.8%
2018			548,989	-3.6%

Table 23 Actual vs Normalized PUC MWh

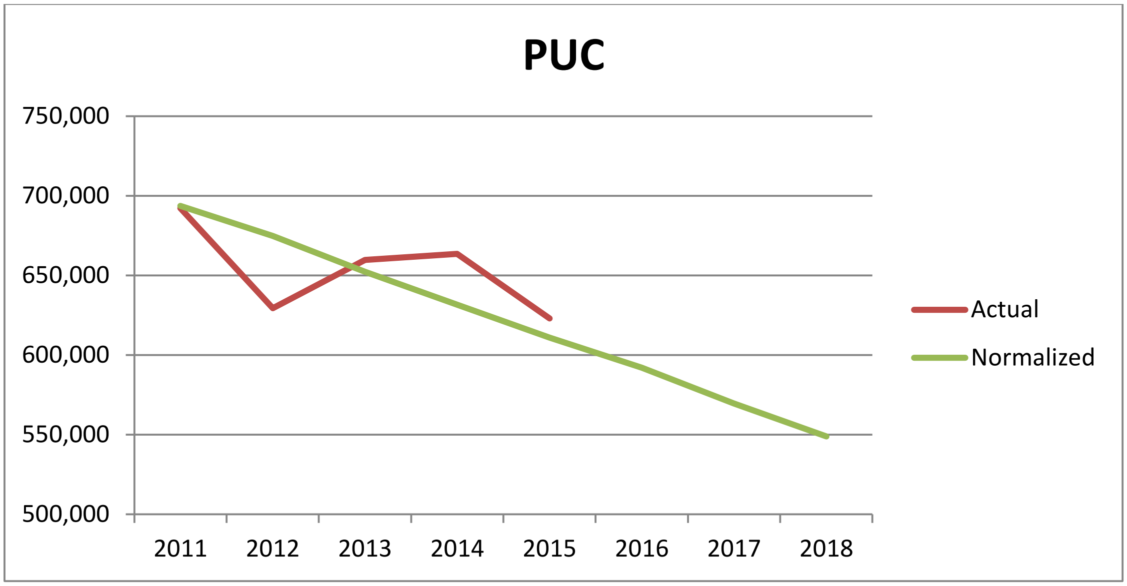

Figure 4 Actual vs Normalized PUC MWh

PUC is only charged the NW billing determinants which exhibits a relatively stable relationship with the summed hourly MW. A trend or step change in the relationship between the hourly MW and the NW billing determinant, could indicate a structural change over time. Since none was observed, a 5-year average of the ratio of NW billing determinant to hourly MW was used.

		PUC	
Year	MWh Actual	NW Ratio	NW
	A	**C = B / A**	**B**
2011	692,261	1.7804	1,232,474
2012	629,433	1.8294	1,151,514
2013	659,677	1.8737	1,236,031
2014	663,550	1.8113	1,201,907
2015	622,946	1.8506	1,152,823
	MWh Normalized		
	H	**I = Avg (C)**	**J = H * I**
2015	610,978	1.8291	1,117,530
2016	592,095	1.8291	1,082,991
2017	569,652	1.8291	1,041,941
2018	548,989	1.8291	1,004,147

Table 24 PUC NW billing determinant

5 CDM Adjustment to Load Forecast

The current Chapter 2 OEB Minimum Distribution Filing requirements, consistent with the Board's CDM Guideline EB-2012-0003, expects the distributors to integrate an adjustment into its load forecast that takes into account the six-year (2015-2020) targets for MWh and kW reductions.

The filing requirements note that the distributors license condition targets and the LRAMVA balances are based on the IESO targets, which are annualized. It is recognized that the CDM programs in a year are not in effect for the full year, although persistence of previous year's programs will be. Therefore, the actual impact on the load forecast for the first year of the program should not be the full annualized amount. GLP Transmission assumes that the distributors in its service territory will choose to achieve their targets with equal reductions in each year over the 6 years.

API's target for 2015-2020 is 7.51 GWh, which Elenchus assumes will occur as a reduction of 1.5 GWh in each of the 5 years. The impact of this reduction is calculated as follows:

API

Year	2015-2020 CDM Target	Application Factor 1.0 Full Year 0.5 Half Year	2017 Net MWh Load Forecast CDM Adjustment	Application Factor 1.0 Full Year 0.5 Half Year	2018 Net MWh Load Forecast CDM Adjustment
	A	B	C = A * B		
2015	1,502	0.5	751	0.5	751
2016	1,502	1	1,502	1	1,502
2017	1,502	0.5	751	1	1,502
2018	1,502			0.5	751
	4,506		3,004		4,506

Table 30 API CDM Impact Forecast

PUC's target is 26.41 GWh, which Elenchus assumes will occur in equal reductions of 5.28 GWh per year. The impact of this reduction is calculated as follows:

PUC

Year	2015-2020 CDM Target	Application Factor 1.0 Full Year 0.5 Half Year	2017 Net MWh Load Forecast CDM Adjustment	Application Factor 1.0 Full Year 0.5 Half Year	2018 Net MWh Load Forecast CDM Adjustment
	A	B	C = A * B		
2015	5,282	0.5	2,641	0.5	2,641
2016	5,282	1	5,282	1	5,282
2017	5,282	0.5	2,641	1	5,282
2018	5,282			0.5	2,641
	15,846		10,564		15,846

Table 31 PUC CDM Impact Forecast

The following is the proposed adjustment to the MWh forecast for GLP Transmission's LDC customers

MWh	Weather Normalized 2017 (Elenchus)	2017 CDM Load Forecast Adjustment	2017 CDM Adjusted Load Forecast	2018 CDM Load Forecast Adjustment	2018 CDM Adjusted Load Forecast
	A	B	C=A-B	D	E=A-B
API	214,989	3,004	211,985	4,506	210,483
PUC	569,652	10,564	559,088	15,846	553,806
Total Customer (MWh)	784,641	13,568	771,073	20,352	764,289

Table 32 LDC CDM Adjusted Forecasts

In order to calculate the charge determinant impacts Elenchus proposes using a proportional ratio utilizing the base load forecast charge determinants and MWh

NW	Weather Normalized 2017 (Elenchus)	CDM Load Forecast Adjustment	2017 CDM Adjusted Load Forecast
	F	G = F / A * B	H = F - G
API	369,806	5,167	364,639
PUC	1,041,941	19,322	1,022,619
	1,411,747	24,490	1,387,258

Table 33 LDC CDM Adjusted 2017 NW Forecast

NW	Weather Normalized 2018 (Elenchus)	CDM Load Forecast Adjustment	2018 CDM Adjusted Load Forecast
	I	J = I / A * D	K = I - J
API	369,806	7,751	362,055
PUC	1,004,147	27,932	976,214
	1,373,953	35,683	1,338,270

Table 34 LDC CDM Adjusted 2018 NW Forecast

CN	Weather Normalized 2017 (Elenchus)	CDM Load Forecast Adjustment	2017 CDM Adjusted Load Forecast
	L	M = L / A * B	N = L - M
API	209,140	2,922	206,217
PUC	-	-	-
	209,140	2,922	206,217

Table 35 LDC CDM Adjusted 2017 CN Forecast

CN	Weather Normalized 2018 (Elenchus)	CDM Load Forecast Adjustment	2018 CDM Adjusted Load Forecast
	N	O = N / A * D	P = N - O
API	209,140	4,383	204,756
PUC	-	-	-
	209,140	4,383	204,756

Table 36 LDC CDM Adjusted 2018 CN Forecast

TRN	Weather Normalized 2017 (Elenchus)	CDM Load Forecast Adjustment	2017 CDM Adjusted Load Forecast
	Q	R = Q / A * B	S = Q - R
API	421,882	5,895	415,987
PUC	-	-	-
	421,882	5,895	415,987

Table 37 LDC CDM Adjusted 2017 TRN Forecast

TRN	Weather Normalized 2018 (Elenchus)	CDM Load Forecast Adjustment	2018 CDM Adjusted Load Forecast
	T	U = T / A * D	V = T - U
API	421,882	8,842	413,039
PUC	-	-	-
	421,882	8,842	413,039

Table 38 LDC CDM Adjusted 2018 TRN Forecast

6 Direct Connected Customers

The Direct Connected Customers are industrial or natural resource in nature, and therefore, are not weather sensitive loads. GLP Transmission has been in contact with the major directly connected customers about plans for future use, and believes that recent historical load is the best predictor of load for the test year.

[redacted] has expanded their operations, and load stabilized early in 2015. This new level is projected to persist into 2017 and 2018.

[redacted]

Year	NW	CN	TRN
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]

Table 25 [redacted] billing determinants [redacted], [redacted], and [redacted] have all exhibited stable load since 2011. 2017 and 2018 are forecasted based on the average consumption from 2011-2015.

[redacted]

Year	NW	CN	TRN
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]

Table 26 [redacted] billing determinants

[redacted]

Year	NW	CN	TRN
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]

Table 27 [redacted] billing determinants

[redacted]

Year	NW	CN	TRN
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]

Table 28 [redacted] billing determinants

GLP Transmission added a few customers in 2014-2015. 2014 was a comparatively heavy utilization year for the existing customer base – both compared to 2011-2013, and compared to 2015. The year 2015, reflecting all customers has been selected as most representative of the load anticipated in 2017 and 2018.

		[redacted]	
Year	NW	CN	TRN
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]

Table 29 [redacted] customers billing determinants